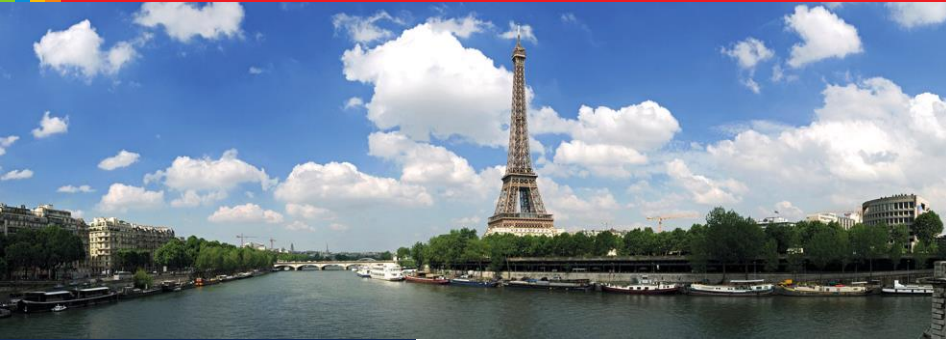


## 2012-2015 Triennium Work Reports



# THE ROLE OF GAS IN ELECTRICITY GENERATION MIX

## Appendix

Program Committee “C”, Study Group 1

June 2015





**2012-2015 Triennium Work Report**  
June 2015

# The Role of Gas in Electricity Generation Mix

---

## Appendix

### **Executive Summary:**

**The Report investigates historical development, current challenges and potential role of natural gas in electricity generation**

**Produced by:  
International Gas Union**

## CONTENTS

Future of gas in the European electricity mix: is it a model for other markets?.....	4
1. Historical prospective.....	4
2. Key factors affecting the development of gas for power: economics & regulation.....	8
3. What is the future of natural gas in base load generation? .....	12
4. Are gas-favoring scenarios relevant in today's world? .....	15
5. What is the future of natural gas in peak load generation? .....	17
6. Conclusion .....	20
Gas for Power in Japan: Uncertainty-driven Demand.....	21
1. Before Fukushima: Review .....	21
2. After Fukushima.....	22
3. Policy Changes on Nuclear Power Plants since Abe Government.....	27
4. The Remaining Uncertainty: Public Acceptance .....	27
5. Conclusion .....	27
Gas for Power in Korea: Policy Uncertainty Forever .....	29
1. Never Ending Chaos .....	29
2. Lessons of History .....	30
Future of gas in the electricity mix and impact on exports' perspectives in the MENA region.....	33
1. Introduction.....	33
2. Gas demand in power generation in the MENA region.....	34
3. Future role of gas in power generation: an uncertain outlook.....	46
4. Gas supply in the MENA region .....	48
5. Gas exports' potential Vs. Gas for power growth in MENA Region .....	52
6. Role of gas in power generation .....	57
7. Gas demand in other than power generation sectors.....	59
8. The evolution of the natural gas supply .....	60

## FUTURE OF GAS IN THE EUROPEAN ELECTRICITY MIX: IS IT A MODEL FOR OTHER MARKETS?

### 1. Historical prospective

Gas for Power (GFP) has been a major key driver of growth since 1995, and for more than a decade, gas consumption for power was regularly increasing. However, starting at the end of last decade, major European countries<sup>1</sup> relying on gas saw a decrease both in power consumption and the use of gas to generate it. Gas for power generation in major European power markets increased from 70 bcm in 1995 to 140 bcm in 2008. Since 2008, this has fallen significantly and was around 90 bcm in 2013. This evolution can be explained by a combination of economic and policy factors.

In considering the early growth of gas, it should be remembered that policy makers allowed gas to be used as a fuel for power generation, after seeing it as “clean and precious” earlier. Coal generation was expected to retire, and so was nuclear in many countries. Gas prices were low and it was easy to build and new CCGTs.

The significant development of gas-fired power plants started in the UK with the so-called “dash for gas”. Its main underlying reasons were economic and can relatively easily be generalised to the rest of Europe. Gas-based power generation became extremely competitive because of three elements: (1) the cost of gas, (2) the cost of building gas power plants, and (3) the cost of capital. On those three criteria, CCGT were more competitive than other alternatives, in particular coal. Therefore, for several years, in Europe and in most liberalised power markets, CCGT technology was considered as the technology of choice in many countries.

In addition to the economic factor, environmental considerations played a role in the development of gas-based generation through some specific regulations. CCGT benefited from an “environmental premium” with gas being the cleanest fossil fuel. This encouraged investors to consider gas-based generation for replacing highly emitting coal and oil plants.

The last two elements (cleaner and cheaper) were reinforced by two sets of policy measures favouring the use of gas for power generation. First, the setup of the European Emissions Trading Scheme (EU ETS) in 2005 played an additional role in favouring gas-based generation. Second, in several countries, policy makers put in place attractive incentive mechanisms to favour cogeneration (e.g. France, Italy...).

If the term “boom” could be used to shortly describe the period before 2008, the following years should be described as a “**bust period**”.

First of all, decrease of electricity consumption and production should be mentioned. The yearly consumption of electricity has been decreasing since 2010. The total decrease between 2010 and 2013 was 86 TWh or 2.6%. Almost half of this decrease occurred between 2012 and 2013. The consumption of electricity reduced from 3317 TWh in 2012 to 3274 TWh in 2013, a reduction of 1.3%. This decrease can be explained by two trends:

- the reduction of electricity demand in industry as a consequence of reduced economic activity in Europe, which started in the end of 2008 with the financial crisis;

---

<sup>1</sup> i.e. DE, FR, BE, NL, UK, ES & IT

- the reduction of electricity demand in households and commercial buildings as a consequence of the EU Ecodesign and labelling directive, which reduced electricity demand for a range of electrical appliances.

The reduction of electricity demand in industry is visible in energy intensive sectors as aluminium smelting. As European electricity prices are high, factories have been closing and thus reducing the demand for electricity.

A typical example of the reduction of electricity demand in households and commercial buildings is the ban of sales of light bulbs since 2012. This has reduced the electricity demand for lighting.

Apart from these two trends the EU has also specific goals to save on the use of energy. There is a target for saving 20% of energy by 2020 as part of the 20/20/20 targets: 20% reduction of CO2 emissions, 20% share of renewable energy and 20% energy demand reduction. The reduction of energy demand is not necessarily the reduction of electricity demand, as electricity could compete with oil products and natural gas for transportation and for heating. But, up till now, these changes are relatively small. New goals for 2030 have been set, with a further reduction of energy demand by 27%.

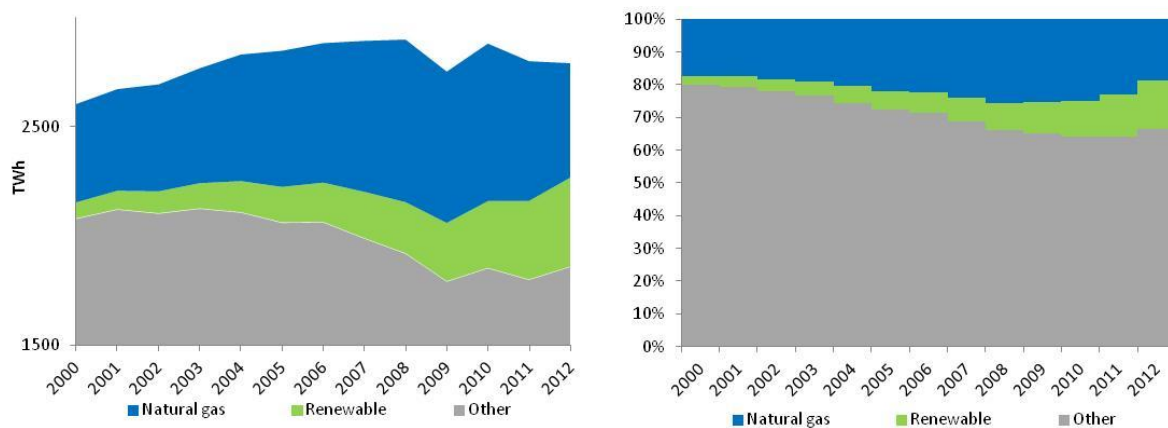
Therefore, the trend for lower electricity consumption is likely to continue in the next years.

As a consequence of the decrease of the electricity consumption, electricity production in Europe has also been decreasing since 2010. The reduction was 1,2% from 3364 TWh in 2012 to 3325 TWh in 2013. This reduction of electricity production by 39 TWh impacted the demand for natural gas-fired power plants by 7 bcm, assuming an efficiency of 50% in the conversion of natural gas to electricity. Between 2010 and 2013, total demand for natural gas for the production of electricity was reduced by 15 bcm as a consequence of the decrease in electricity demand and production.

Gas-based generation started to decrease in 2008. Although some differences can be observed between the countries, the trend was very similar throughout most of Europe. While the boom could be mainly explained by economic reasons reinforced by some policy measures, the bust was clearly a combination of both, with arguably more weight on policy and associated regulations.

On the economic side, the economic crisis has had a negative impact on power demand. The 20% efficiency target reinforced that effect to some extent.

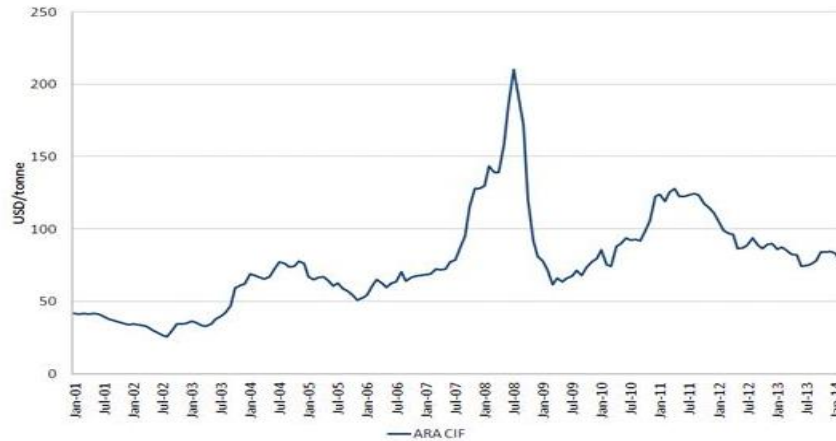
**Figure 1: Power demand EU15 covered by RES, Gas and other**



In addition, coal competitiveness versus gas improved significantly in Europe. Since peak levels reached in 2008, coal prices have indeed been decreasing significantly (Figure 2) due

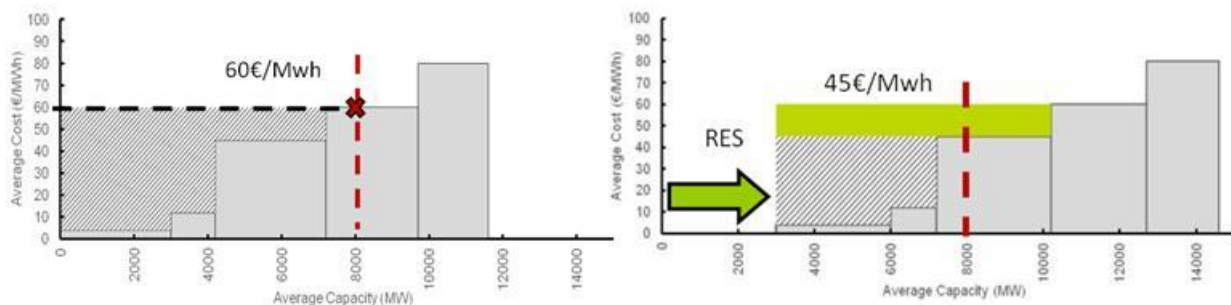
to several economic factors. The development of shale gas in the US led to the export of surplus coal to Europe. Globally, the coal market is considered by several observers as oversupplied with major exporting countries (such as Australia, Colombia, Indonesia and South Africa) having a high level of output combined with weakening international demand, especially from China and emerging markets.

**Figure 2: Historical Coal price - Amsterdam Rotterdam Antwerp CIF**



The environmental premium associated with gas was significantly challenged by massive support to renewable energy. The 20% RES target had a dramatic effect on CCGT operations. The massive development of renewables (mainly wind and solar) through subsidies displaced CCGTs “out of the market” (See Figure 1 & Figure 3) and reduced overall wholesale power prices.

**Figure 3: The impact of RES development on thermal assets**

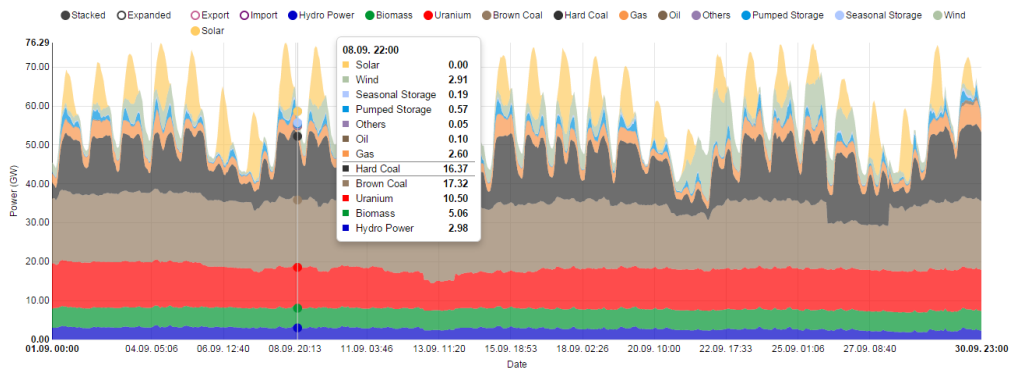


This resulted in a significant decrease of operating hours for CCGTs and mechanically in a decrease of volumes of gas for power. This trend affected very seriously the economics of CCGT which led several key players to mothball gas power plants for a total amount above 50GW on a Europe-wide basis<sup>2</sup>.

In Germany in the year 2014, more electricity was generated from solar (33 TWh) than from gas generation (31 TWh). This gives a load factor of the gas generation of 12%, which is lower than wind at 14%.

<sup>2</sup> Source: Magritte Group. The Magritte Group is an initiative regrouping 12 CEOs of the major utilities in Europe

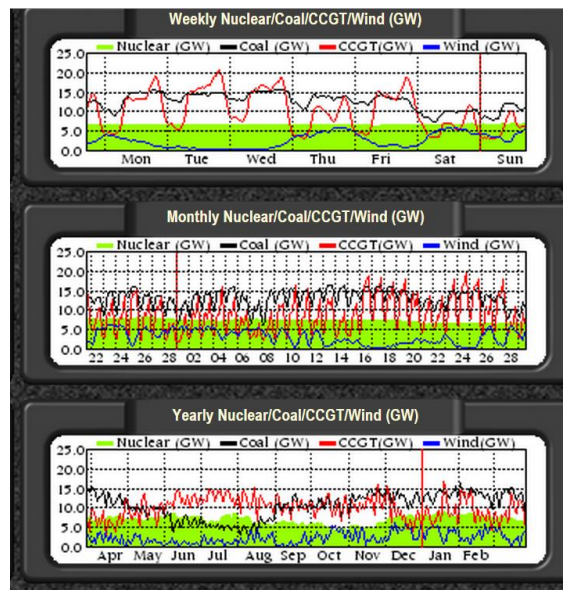
**Figure 4: – Electricity Production in Germany in September 2014, GW**



Source: Fraunhofer

In the UK, where there is less solar than Germany, the gas is mainly depending on variations in wind generation. Also, there are higher CO2 costs than in Germany, and at times lower prices in summer, making more gas run in summer than in winter (resulting in less coal generation in summer). This also reflects the need for more air conditioning in the summer and more gas heating in the winter.

**Figure 5: Electricity Production in UK, GW**



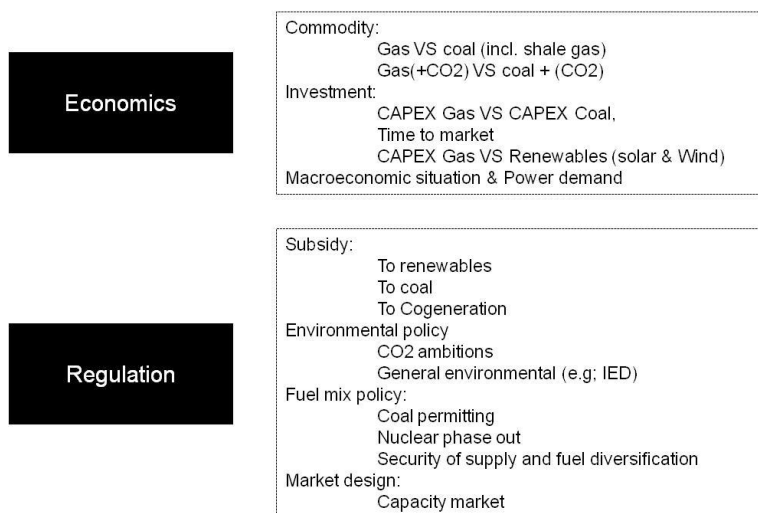
Source: National Grid, UK

The -20% target in CO2 emissions is addressed through the EU-ETS, a cap and trade mechanism. With the combined effect of the economic crisis and the massive development of renewables, this target appears rather “easy” to achieve with, as a result, low carbon prices. This did not succeed in reinforcing the competitiveness of gas against coal. Bluntly speaking, Europe reduced its CO2 emissions through (1) the economic crisis, and (2) the massive development of renewables. Hence, the expected role of CCGT as substitute of coal plants did not materialize.

## 2. Key factors affecting the development of gas for power: economics & regulation

The historical analysis allows identifying two main categories of drivers that could have an impact on the development of gas based power generation: Economics and Regulation. Figure 6 below summarizes the different elements that fall under the two categories.

**Figure 6: Economic and regulatory drivers affecting gas for power**



**The economic drivers** can be split into 3 sub-categories: Commodity, Investment cost and overall macroeconomic conditions.

**Commodity** relates to the traditional competition between gas and coal for power generation. Globally, coal prices are today lower than gas prices in Europe making it more profitable to generate power out of coal rather than out of gas. In the past, however, the price of the gas commodity has been for several years rather competitive against coal thanks to the development of North Sea gas.

Beyond shale gas, one key uncertainty for the gas prices is the behaviour of major gas suppliers such as Norway, Qatar and Russia and the intensity of competition which will necessarily impact hub prices and future long term contractual arrangements.

The CO2 price has to be further added to the commodity price component in order to assess the profitability of gas assets. This leads to what is known as “clean spark spreads” (CSS<sup>3</sup>) for measuring the gross margin generated by these assets. Their value today in Europe is quite bad and substantially lower than the gross margin captured by coal power plants, as represented by clean dark spreads (Figure 7).

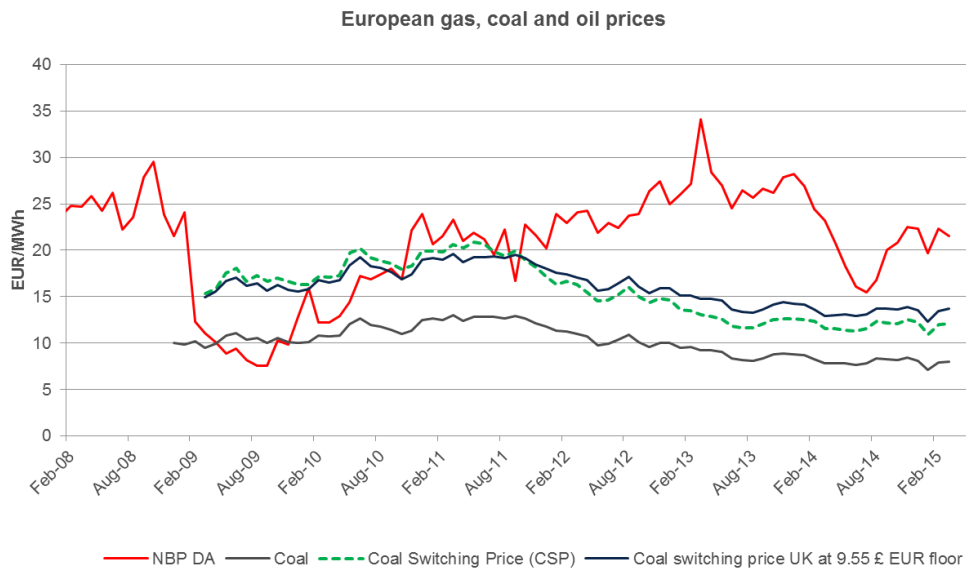
**Investment cost** is the second economic element. Gas-fired power stations are relatively cheap to build compared to other traditional technologies (Coal, Nuclear, and Hydro). CCGTs are characterised by limited capital expenditure per installation, which has facilitated financing historically. In particular compared to coal plants, CCGT are also faster to build. They can be completed in less than two years, rather than the four to five years necessary for coal plants. The lower lead time decreases financing costs. Indeed, each year of construction represents a year of additional interest charges before the plant is put into service, starts generating revenues and therefore is able to repay bank loans. In addition, compared to the other technologies, CCGT are less complex from a technical perspective, which reduces risk. Finally, CCGTs offer a high thermal efficiency, flexibility in operation and better

<sup>3</sup> CSS is a basic estimate of the gross margin of typical Combined Cycle Gas Turbine (CCGT)



environmental performance, which makes permitting issues easier to tackle. Those elements make CCGTs in principle rather appealing to investors.

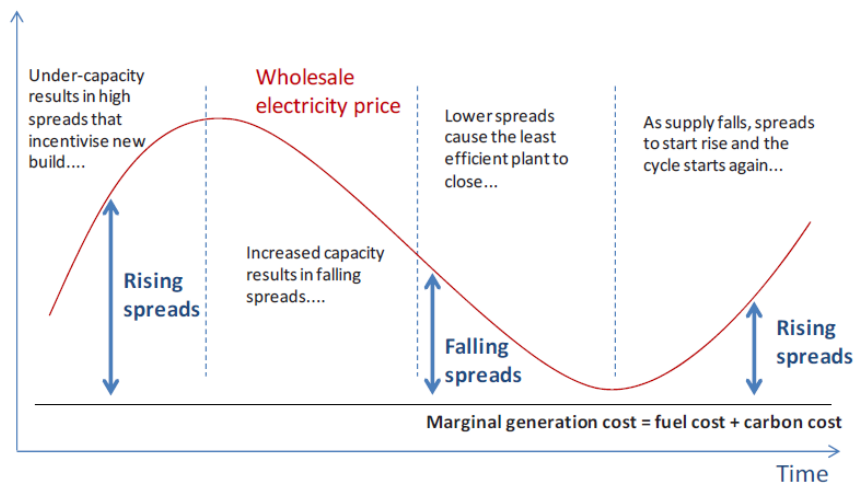
**Figure 7: European Gas, Coal and Oil Prices, EUR/ MWh**



Source: Montel data and Sund Energy analysis

A key barrier today to investment in CCGTs is the uncertainty around future profitability. This depends on the evolution of clean spark spreads which are cyclical and uncertain (Figure 8). Investors are faced with uncertainty on load factors and revenues they will get from their plant. Current levels of clean spark spreads are not only far below new-entrant levels, but are even so low that utilities are mothballing and/or closing existing assets.

**Figure 8: Cycles in spreads**



Source: Gas generation strategy 2012-UK department of energy and climate change

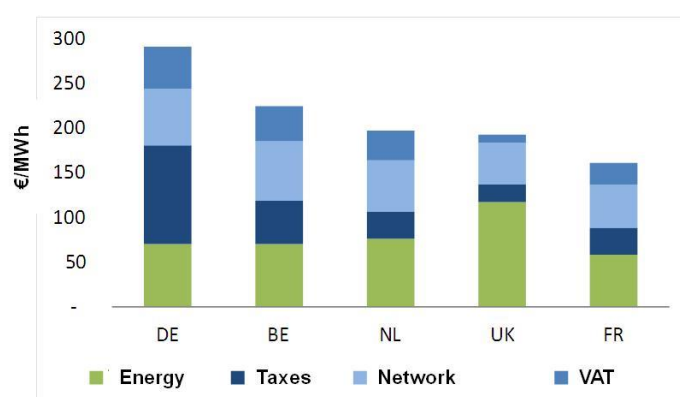
Thirdly, the **overall macroeconomic situation** of Europe is key when considering the fundamental needs for electricity. In a world of economic crisis combined with high efficiency ambitions, the space for gas generation is mechanically reduced.

On the regulation side, four key sub-categories can be identified: subsidies, environmental policy, fuel mix policy and market design. Regulators and policy makers can directly influence the role of gas in power generation by using any of those tools on a stand-alone basis or in combination.

**Subsidies** are arguably the most direct and powerful tool for policy makers. With respect to gas for power, some subsidies favour gas while others negatively impact its development. For instance, generous feed-in tariffs for wind and solar created a competitive advantage for renewable. They distorted the functioning of the market and forced utilities to mothball/close gas-fired power plants unable to compete. By contrast, support schemes for cogenerations allowed developing gas-based generation that would not have been economic on a pure merchant basis. Finally, some countries have been supporting coal-based generation. Subsidies for coal have been made for social/political reasons (e.g. employment level in coal mines in north of Spain) and/or economic reasons to offset the difference between world coal prices and high costs of indigenous coal (e.g. Germany).

The European Commission, through its review of State Aid Guidelines for renewable energy for the period 2014 to 2020, recently pushed for a reduction of subsidies to renewable power. The objective is to reduce policy costs of renewable energy. Similarly, Germany is planning to stop subsidies to coal by 2018. In general, most countries are currently acting seriously in reducing the burden of subsidy on their public finance and/or final customer. It is indeed interesting to note that most subsidies to renewable have been directly paid by final customers (Contribution to Public Service charges in France, additional taxes on final customers in Germany - Figure 9). This led to a paradoxical situation where wholesale power prices have been decreasing while end-user prices have increased with those additional surcharges. In practice, consumers are unhappy paying renewable surcharges on their power bills through retail prices. Similarly gas-fired power owners are also unhappy while facing a low wholesale power price for their assets. Removing and/or reducing subsidies to other production means is one step in the right direction for gas for power. Whether this is enough to allow gas for power generation to come back to previous levels, or even grow, remains to be seen.

**Figure 9: Electricity prices for « reference » household - 3.5 MWh/year**



Source: CREG 2014

Historically, **environmental policy** was perceived as a key driver for gas development. The paradigm was straightforward: gas is cleaner than coal and would effectively be replacing ageing coal capacity. Therefore, for several years, CCGT technology was considered as the technology of choice to get a cleaner fuel mix and decarbonise the economy. This paradigm is now heavily challenged with the massive penetration of renewables which pushes gas fired

generation into a swing role. A large share of power production today in Europe is still based on coal generation and arguably not all of it can be replaced by renewables. In such a context, the question has more to do with European ambitions in terms of environment. The uncertainty around ambitions are both absolute (which target?), time related (by when?) and financial (which cost?). For now, Europe has rather modest short term (2020) greenhouse gas emissions reduction targets and ambitious long term (2050) targets between 80% and 95%. Interim targets (2030) have just been set at 40% and will play a key role.

The EU Emission trading scheme (EU ETS) is one of the key common European policy instrument to address environmental aspirations. By introducing a CO<sub>2</sub> price, the EU ETS was expected to favour gas over coal. However, with the economic crisis on the one hand and the massive development of renewable on the other hand, current CO<sub>2</sub> prices are not high enough to compensate the deficit of competitiveness of gas. For several months, a reform of the EU ETS has been under discussion, but the European Parliament has been rather reluctant to accept any major reform of the current scheme. In a period of economic crisis, the Parliament attention has been more on economic growth than on reforming the CO<sub>2</sub> market. In the medium term, the Large Combustion Plant Directive (LCPD, 2001/80/EC)<sup>4</sup> and the Industrial Emissions Directive (IED, 2010/75/EU)<sup>5</sup> which will force several coal plants to invest in clean technologies or to retire. This is likely to have more impact on gas for power than the EU ETS.

Most countries do not have an explicit **fuel mix policy**. However, in practice, national preferences play a key role in the investment decisions. For instance, the German decision to phase out nuclear by 2022 mechanically leaves space for other technologies. By contrast, France has a long-standing policy in favour of nuclear power. The UK and Italy have historically heavily relied on gas. Those political preferences are not neutral in terms of gas for power.

**Market design** is currently a hot topic in European electricity markets. Amongst the different issues being tackled, the creation of capacity mechanisms is at the heart of the discussion and could have a critical impact on gas plants. In short, capacity mechanisms aim at providing incentives to keep reserve capacity in the system. Today, European power markets operate mainly on an “energy only basis” meaning that only MWh produced are remunerated, but reserve margin (MW) is not remunerated. In such a context, utilities have limited incentives to keep assets that are not remunerated by the market (but needed from a reliability of the system perspective). A capacity mechanism provides incentives for making capacity available. Gas plants are ideal candidates to supply flexibility, balancing and back-up in a world of increasing intermittent renewable power.

There are however two main issues to consider when looking at the impact of capacity mechanisms on gas for power.

First, gas plants are not the only source of flexibility in the system. In practice, gas plants are in competition with many other sources. Demand-side management for instance can offer flexibility at a very low cost<sup>6</sup>. Storage and interconnections are also additional sources of flexibility.

---

<sup>4</sup> The LCPD aims to reduce acidification, ground level ozone and particles by controlling emissions of sulphur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>) and dust from large combustion plants (power stations, petroleum refineries, steelworks...etc).

<sup>5</sup> From January 1st 2015, the LCPD directive will be replaced by the IED directive.

<sup>6</sup> For instance the Federal Energy Regulatory Commission (FERC) estimated that the potential for peak electricity demand reductions across the US was between 38 GW and 188 GW, up to 20 percent of national peak demand. This could reduce the

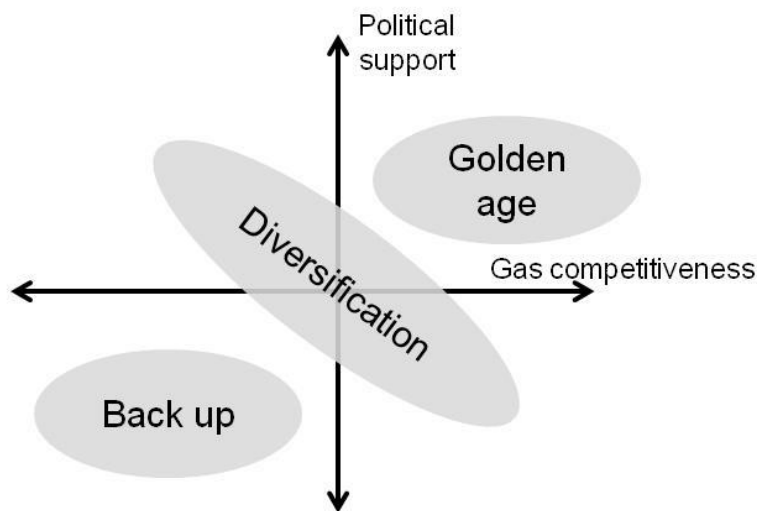
Second, it is worth noting that, if a capacity market could help to keep gas plants into the system, the associated volumes of gas would remain rather limited. In other words, capacity markets are likely to improve the economics of the plant, but the volume of gas used by those plants would remain very limited. One should therefore keep in mind that capacity markets do not aim to directly incentivise gas consumption in power generation.

However, the recent introduction of capacity mechanism in the UK has so far resulted in a final clearing price still insufficient to prevent the closure of existing gas-fired power plants.

### 3. What is the future of natural gas in base load generation?

Given the considerable uncertainty over how the different elements mentioned above could evolve in the years to come, this section offers three contrasted scenarios using different sets of assumptions to structure the discussion about the future of gas for power in Europe. Those scenarios are structured around two axes: political support and economics through gas competitiveness.

**Figure 10: Three scenarios for gas for power in Europe**



The different uncertainties can be summarized in more details for each scenario as follow (Table 1).

---

need to operate hundreds of power plants (A national assessment of Demand response potential, The Brattle Group et al, June 2009)

**Table 1: Risk factor in each scenario**

		Golden age	Diversification	Backup
Economics	Gas price	Low	“Medium”	High
	Coal & RES	Expensive	“Medium”	Cheap
	Power demand	Increasing	Flat	Decreasing
	Competition for flexibility	Limited alternatives	Some alternatives	DSM and storage cheaper
Political	Nuclear	Phase out	As planned today	Renaissance
	Environmental ambitions	Very strict/coal forbidden	Moderate	Weak
	Subside RES/Coal	Totally Disappear	Decrease	Remain
	Market design	Capacity market favoring CCGT	Capacity market	Energy only

The three scenarios could be defined as follows:

**“Golden age”** is a scenario with a dominant role for gas in power production. In such a scenario, all economic and political factors are in favour of gas for power development. Over the medium/long term, coal and nuclear are replaced by a combination of renewables and gas.

The price of gas is extremely competitive against other technologies such as coal and renewable power. The competitiveness of gas is explained by large supply of gas from traditional suppliers. Those historical suppliers favour volumes over price on one hand and benefit on the other hand from technological progress in extraction methods and gas recovery from existing fields. In such a scenario macroeconomic conditions in Europe also improve with a positive impact on overall power demand.

The Golden age scenario assumes that policy focuses mainly on gas generation to get a low carbon energy system and meet the emissions ambitions. The scenario foresees a total removal of any subsidy to renewables. In its competition against renewable power generation, gas keeps significant advantages. The value of flexibility/reliability is fully remunerated in the market, while the intermittency of wind and solar is penalized. This is done in practice with capacity mechanisms. The development of renewable is constrained in different locations due to network constraints and limited natural resources (e.g. number of sites).

Support schemes to coal plants (where they exist) are removed, on the basis of environmental considerations, and related social issues are duly addressed. In the medium term, European countries adopt stricter environmental standards through “new IED directives”. Those new directives forbid *de facto* the construction of new coal plants and force existing ones out of the market.

This scenario assumes that a number of European countries follow the German example in terms of nuclear policy, with a medium term phase-out. In such scenario, gas generation replaces coal and nuclear in the medium term. The European power sector reduces emission significantly based on a combination of renewable and gas.

By contrast, **“back up”** is the other extreme scenario, where gas plays a minor role in power production, like diesel today. Over the medium/long term, renewables and nuclear are the

two technologies of choice for power supply with limited space for traditional thermal technologies. Gas is considered as a last resort option to "keep the lights on".

In such a scenario, the overall power demand in Europe is on the low side, as a result of a combination of poor macroeconomic conditions and significant energy efficiency efforts. Gas prices delivered to Europe remain rather high compared to coal, making coal assets more competitive. The new nuclear policy involves not only extending the lifetime of old nuclear plants, but also significant development of new plants in several countries following the example of the UK.

Simultaneously, renewable developments remain significant as a result of 3 factors: strong subsidies for non-mature technology, significant price decrease for mature technologies (Wind & PV), development of storage strongly mitigating the traditional issue of intermittency. Finally, the development of smart technologies allows an increased usage of demand-side management to deal with flexibility. This scenario assumes therefore that gas power plants face serious competition in terms of flexibility with successful developments of new technologies (smart grid, storage, demand-side response) reducing significantly the "flexibility value" of gas assets. Gas CCS fails to develop as a combination of technical constraints, weak economic competitiveness and strong public opposition. In this scenario, gas consumption for power becomes extremely low. Some gas power plants are kept into the system for back-up/last resort technology, similarly to diesel today.

**"Diversification"** is a scenario where gas is one of the different options amongst others for power production, competing with many alternatives. In such a scenario, a balanced view is considered in the evolution of the different technologies and policy factors.

In the diversification scenario, the precise role of gas generation follows volatile market and regulatory developments. Due to the volatility of different power generation alternatives, including deployment of low-carbon technologies, overall electricity demand and plant capacity retirements, gas maintains its role on average in the European electricity mix. However, on a year-to-year basis, significant differences can be observed.

The evolution of gas for power is affected by a number of institutional, political and economic developments. It cannot be attributed to single factors, such as gas price only or the environmental agenda. Gas for power generation is today at a crossroad, being "squeezed" between coal (cheaper), renewables (greener), and other flexibility providers (demand-side management, storage). While long term technological evolution/rupture and global macroeconomic evolution are hard to predict, regulatory frameworks should provide more visibility and stability. This is where European and national institutions should play a key role in providing stability and visibility. In practice, the key issue for European policy makers is to provide simultaneously (1) a clear strategy to improve European competitiveness at global level, and (2) clear target(s) and appropriate policy tools for a low carbon economy.

A lack of consistent regulatory framework at European level is a real issue for investors, large consumers and gas suppliers. The experience of the last five years is creating a "precedent" for investors with several Gigawatts of gas assets being mothballed and "out of the money". Similarly, gas suppliers cannot get a clear view on future gas demand in Europe. Last but not least, energy consumers are affected by price increase. This uncertainty could in the medium term just push investments outside of Europe and affect the overall European economy.

The economic situation in Europe is making the transition to a low carbon intensive economy, a less popular topic for policy makers but not a less important one for European

citizens. Europe has several options. The challenge is to put in place a regulatory framework that would lead to a balanced and most economically attractive technology mix. In this technology mix, gas for power represents a sizable potential. Concretely, with ~1000 TWh of electricity produced annually using coal and lignite today, Europe could reduce by 500 Mt its CO<sub>2</sub> emissions, at a reduced cost, given the gas-fired capacity already in place. Gas for power represents therefore a very significant potential that should deserve due attention by policy makers.

#### 4. Are gas-favoring scenarios relevant in today's world?

As it was stated before, the future role of gas in European base-load generation depends not only on supply and demand factors in fossil fuel markets, but also on many aspects of market regulation. Taking this into account, in this section, we do not only analyze what factors define the volumes of gas consumed in electricity generation sector, but we also investigate what natural gas can bring to the reliability and sustainability of the European electricity system in the scenario diverging from today's conventional wisdom.

In today's market situation, when coal prices are significantly lower than the prices for gas, the doubts about gas-favouring scenarios may arise. There is some ground for these doubts: conventional wisdom now implies that such price divergence between gas and coal is here to stay. Low coal prices are underpinned by abundant resources with low production costs, as well as by imports from North America where coal is expelled by cheaper gas. Enhanced technologies for using off-spec coal worldwide also contribute to maintaining coal prices at a low level. At the same time, natural gas prices in Europe are not expected to decrease to such low levels: spot prices will be underpinned by global competition for LNG, whilst a large portion of gas supply contracts maintain oil price indexation and are quoted higher than coal even after the oil price slump of 2014-2015.

The divergence between gas and coal prices became an important component of the "perfect storm" for natural gas generation in Europe.

Another component of the "storm" became the drop of carbon prices in the market that used to be a pattern for cap-and-trade schemes in different countries of the world. Historically, carbon prices in the European market were an important factor for electricity generation mix and for investment decisions. Today, with coal prices at \$60/t and gas prices at \$7/MMBtu, carbon price needed to make natural gas-fired electricity generation as profitable as coal-fired generation should be between \$30 and \$40/t.

All this happened on top of a perfect basis for the "perfect storm" – current policies and regulation supporting renewable energy sources - and following increase in RES share in the European generation mix.

It has been said a lot that renewable projects enjoy an unprecedented (and maybe unfair) financial and regulation support from the governmental bodies. In this situation, all fossil fuels are losing their market share to renewables throughout Europe, although this trend is not economically driven and is putting an additional burden on electricity consumers. Nevertheless, since this discussion is not within the scope of this report, we would like to assess the role of natural gas in the European electricity mix in the future from the standpoint of current policies, assuming that support to renewable projects will be continued. Current trends, such as market coupling and increased interconnection are also expected to stay.

With all these assumptions, gas-coal competition becomes the main issue for analyzing the future of European power generation, and fuel price forward curves become almost the sole data needed for analysis of baseload generation.

As it has been mentioned above, current natural gas price level is supported by the competition for LNG with premium Asian markets, while coal supply is abundant and comes from many different sources. Current situation ensures the popularity of low-coal-price forecasts and scenarios: conventional wisdom sees almost no future for natural gas in baseload generation in Europe.

We suggest looking at closer low-coal-price forecasts.

Many of them assume subdued global economic growth, sustained recession in Europe and lower than recent historical average growth in developing markets. All this leads to modest power demand growth anticipation, while global coal production is expected to stay abundant. Under these scenarios, Asian coal demand is going to be met by incremental Australian and South African coal supplies, while plentiful US coal exports will be predominantly destined for Europe keeping a lid on prices.

These assumptions are consistent and there is a solid ground for these scenarios exploration if low economic growth is assumed. Nevertheless, in case of a higher economic growth, abundant supply of cheap coal becomes more questionable. Indeed, quick rebound and strong global economic growth will inevitably challenge coal industry to supply more coal, whilst it is difficult to expect at a same price level.

Moreover, faster than expected economic growth could substantially intensify environmental agenda, and a strong global commitment to tackle climate change does not seem unrealistic under this scenario. If such a global commitment is in place, the OECD countries, including almost all the European countries, will adopt binding carbon reduction commitments. European non-OECD economies are likely to implement carbon pricing with reasonably high carbon credit price level.

We could also expect stricter directives, exceeding other directives such as the Industrial Emissions Directive (IED). The current version of the directive already may lead to changes in market fundamentals. It implies further tightening of the SO<sub>2</sub> and NO<sub>x</sub> levels, and sets emission limits that coal and gas-fired plants will have to comply with. The new emission limits will come into force at the latest by 2016. Non-compliant power stations will be given the option to choose whether they will:

- opt-in, in which case they will be in a position to continue their operation indefinitely after installing suitable emission reduction technologies, such as Flue Gas Desulphurisation for SO<sub>2</sub> and Selective Catalytic Reduction for NO<sub>x</sub>; or
- opt-out, in which case they can continue operating for only up to 17,500 hours between 2016 and 2023 without complying with the new limits and will then have to close down.

The IED will affect the majority of existing coal-fired plants and certain older CCGTs and can thus have a significant impact on the fundamentals of EU power markets. On the one hand, a group of aging plants, which cannot justify the necessary investment in emission abatement equipment, will choose to opt-out and close, leaving behind a gap that must be filled by other generation technologies. On the other hand, non-compliant power stations that choose to opt-in will have to invest significant amounts of money, so as to comply with the new emission limits. So, the Directive will have an impact on market fundamentals, and we can expect even tighter environmental rules under this scenario.



Another approach towards intensifying environmental measures could become aggressive ETS fixing. Among most expected measures in this direction are further EUA backloading or introducing CO<sub>2</sub> price floor, as it has been done in the UK, and more aggressive phasing out of older capacity.

Obviously, some trends in a high economic growth scenario will hamper gas consumption in baseload generation. Among them is a strong support to renewables at the EU level, driven by increased EU commitment for increasing the share of renewables in TPES. This commitment will be implemented into aggressive EU national renewable action plans. Continuation of current EU policies regarding CCS could also be expected. Nevertheless, we do not expect that CCS projects will become economical and that the technology will spread widely in Europe. This may lead to almost no new coal or lignite capacity in the EU and neighboring countries due to perspective EU accession in a high economic growth scenario.

These possible changes demonstrate that the answer of the role of gas in the European baseload generation is not so obvious, and gas still has chances to play a significant role.

With regards to a higher penetration of renewable energy sources, despite the renewables contributing to the decrease of gas consumption in electricity generation, we would like to point out another problem caused by the growing share of renewables – decrease in system predictability and ability to react to stress situations. This issue is investigated in the following section regarding the future of gas in peak load generation.

## 5. What is the future of natural gas in peak load generation?

Historically electricity systems of the European countries have been built on predictable energy sources, mainly fossil fuels. Today the EU electricity markets are experiencing fundamental changes. The Union has set itself three targets to be attained by 2020 for 20% greenhouse gas emissions reductions, 20% share of renewable energy and 20% improvements in energy efficiency. Two of three goals are providing a strong support for renewable energy sources and the share of renewable energy has increased to 13% in 2012, as a proportion of final energy consumed, and is expected to rise further to 21% in 2020 and 24% in 2030. It is an impressive fact that the EU had installed about 44% of the world's renewable electricity (excluding hydro) at the end of 2012.

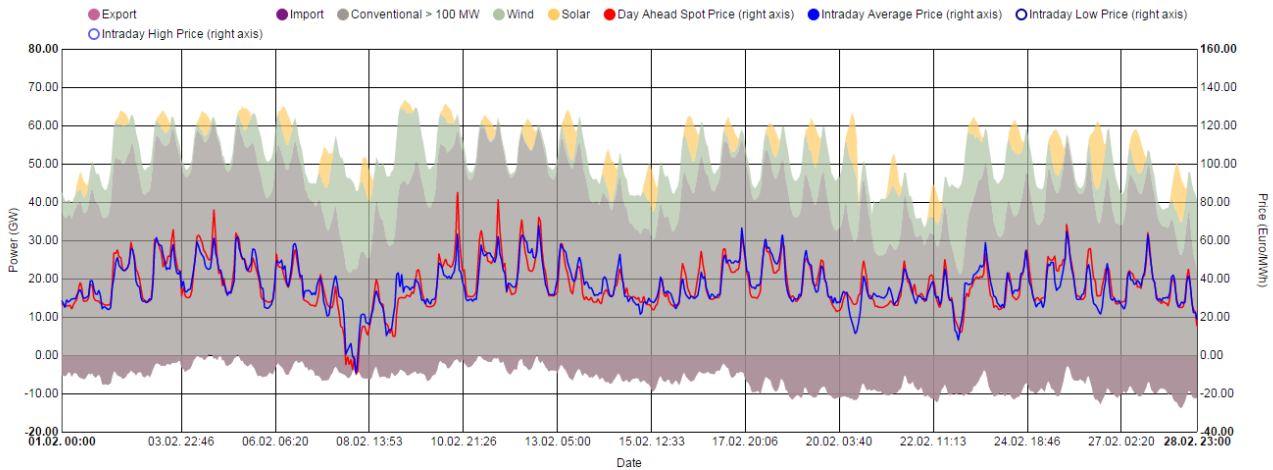
This capacity, when in production, ensures a greater reserve margin and hence a greater system reliability, albeit for a short period. This impact of capacity increase is shown on the chart below.

For many years, this growth has been achieved by wind capacities installment, and the question of wind unpredictability and higher degree of intermittency in the system power output was raised. A typical answer for many years was natural gas as a back-up fuel. Natural gas fitted perfectly for the role due to its flexibility, efficiency and relatively low CO<sub>2</sub> emissions.

Nevertheless, the electricity generation from RES in “must run” regime reduced the operating hours and profitability of other capacities, including those used for flexibility services. Running natural gas station became uneconomical and many of them have been mothballed or permanently closed. This raised the question of the system intermittency again, especially for day-time periods. Technologies aimed at energy storage received new momentum and gained some advances, however they generally did not become economically reasonable, and the spread between peak load and base load electricity price remained high.

The situation changed almost unexpectedly, with lowering solar panel costs and its large installations in a number of European countries. The most important fact is that these panels produce electricity in the daytime, when demand for electricity is the highest in daily pattern.

**Figure 11: Electricity Production and Spot Prices in Germany February 2015**



Source: *Frauenhofer*

To avoid very low, and even negative, prices, Germany has become a major net exporter of electricity, impacting wholesale prices in neighbouring countries, too.

Although it is essential for the creation of a liquid and well-functioning common electricity market, the ongoing work on the harmonisation and further integration of national power markets by means of coupling mechanisms and cross-border balancing markets is unlikely, in our opinion, to play a major role in ensuring security of supply in the long run. As long as the market distortion caused by the subsidization of certain technologies and the regulatory uncertainties persist, the risk of under-investment in generation capacity cannot be ruled out.

Under normal circumstances market coupling, for example, would be expected to generally enhance security of supply by maximizing cross-border capacity utilisation in the most economic direction of flow. Yet, we doubt that it could play a major role in a highly intermittent system, which would require the activation of reserves in specific locations, for specific timeframes and at a very short notice. Furthermore, in the current context of distorted price signals, the extension of coupling mechanisms across all the EU frontiers actually amplify the problem in the sense that coupling increases price convergence, which could well mean that distorted price signals in heavily subsidized markets are being transferred to neighboring markets as well.

Instead of that (or in addition to it), a number of policy measures at a pan-EU level could have a healthy effect for the market. First of all, a pan-European approach towards market-oriented, as opposed to administrative, support schemes for subsidized technologies, could be taken. The system of guaranteed feed-in tariffs, which is widely used across Europe, combined with priority dispatch rules and the fact that subsidized generation is (as a general rule) exempted from imbalance costs, does not incentivise subsidized technologies - particularly intermittent ones - to actively trade their output on the wholesale market, respond to price signals by increasing or decreasing production accordingly and, most importantly, endeavour to accurately forecast their own generation so as to avoid large

deviations between scheduled and actual production. In effect, under the current regime, a large proportion of available supply operates completely outside the market, it is completely indifferent to electricity price signals and hence inelastic to price volatility, and has no incentive to be in balance as it is largely exempted from imbalance costs, which are paid for by end-consumers.

It is widely argued - and we share this view - that the pure market forces are sufficient for delivering sufficient volume of capacity to meet peak demand throughout the year. The situation starts to become problematic when non-market mechanisms, e.g. the support of certain technologies, interfere with the functioning of the market, and it is further aggravated when the means by which regulation tries to address the unintended consequences of those non-market mechanisms leads to even further administrative interference with the market, e.g. centrally dispatched strategic reserves or administratively determined capacity payments.

The “missing money” problem resulting from the fact that peak prices do not rise high enough to reflect the true underlying cost of peak supplies, the fact that an ever increasing part of generation remains completely indifferent to competition by means of guaranteed tariffs and preferential treatment, both of which distort the generation merit order, the existence of more or less outdated rules - particularly in respect of the intraday and balancing markets - that do not provide sufficient flexibility to market participants to optimise their portfolios and self-balance close to real time. To these we would add, as previously mentioned, the lack of confidence in the regulatory framework itself, especially given the raft of reforms currently under way on top of the already frequent changes the market has experienced over the past few years.

So, we believe that capacity mechanisms should be introduced only in “emergency” situations, and it should be understood that they erode markets itself in the longer-term periods.

Distortionary impacts can be effectively mitigated with a model of capacity market which limits the role of the central agency to the following two areas leaving the rest - including price discovery and the delivery of the least cost solution - to the market: first, the determination of the required reliability level and hence the total amount of capacity to be procured by the market, and second, the technological characteristics eligible capacity must meet particularly in terms of flexibility, efficiency and reliability.

The overall objective of any capacity remuneration mechanism should be not only to deliver the right amount of capacity, but (equally importantly) the right type of capacity both in terms of flexibility characteristics, but also in terms of efficiency, carbon emissions and reliability. In our opinion, this can be achieved only if the design of the capacity remuneration mechanism draws upon the following fundamental principles:

- Remuneration should be targeted only at generation technologies that are most flexible, efficient and reliable, therefore best suited to address wind/solar intermittency and general system needs;
- The mechanism should operate as a market that is separate and distinct from the electricity market and should not place any restriction on generators in respect of how they dispatch their plant or sell their output on the forward/spot/intraday and/or balancing markets, except for obligations to be available to generate power when the supply/demand balance is tight.
- Capacity payments should be determined through a competitive process in order to reveal the true value of reliability and thus ensure the lowest cost to consumers.

- The mechanism should look at the entire energy value chain, including fuel supply, so that the fuel is readily available when required. The greater the flexibility needs of the system in terms of dispatchable power generation, the greater the investment that will be required in the upstream fuel supply chain (production facilities, transportation and storage systems) to accommodate this. At the same time, fuel suppliers need to be confident of stable demand that is attractive enough to justify their upstream investments.
- The CO<sub>2</sub> and other emissions produced should be taken into account. This could be done by supporting the EU ETS scheme or by setting an emission performance standard (EPS) for all fossil fuel power stations.
- The mechanism should provide sufficient lead time for the procurement of capacity (minimum 4 years). This will enable new entrants to participate in the capacity mechanism.
- The mechanism should ensure high usage of the infrastructure assets (i.e. power transmission lines and fuel transportation infrastructure) in an optimal way, so that fixed costs are spread over a large number of generating hours.

## 6. Conclusion

Europe is diverse, both in energy mix and preferences. It will be interesting to see if the Energy Union will bring alignment and thereby make planning of future electricity generation easier. Different CO<sub>2</sub> costs, use of nuclear and coal, as well as cross-border trading makes both base load and peak/balancing services more difficult to plan. Another factor impacting the choice of generating fuel and technology, is price. This is now largely a result of balancing supply and demand, so also less predictable than before.

Gas has more stable prices than whole sale electricity, which is getting volatile and at times even negative. Using electricity to generate synthetic gas could avoid negative prices and add to the use of gas. So far, gas is easier to store than electricity, offering another future synergy option for gas.

## GAS FOR POWER IN JAPAN: UNCERTAINTY-DRIVEN DEMAND

### 1. Before Fukushima: Review

Before Fukushima on March 11st 2011, Japan's fuel mix was composed as table 1 below in calendar year 2010. It can be confirmed that natural gas was making the largest portion of 27.13% in generation with highest utilization rate of 73.55% even before Fukushima. Coal and nuclear followed with 26.98% and 26% in generation with lower utilization of 72.28% and 67.2%. Three fuels composed of 80.11% in total generations collectively in 2010.

**Table 2: Electric Power in Japan 2010**

Fuel	TWh	Portion	GW	Portion	Utilization
Coal	299.13	26.98%	47.24	16.46%	72.28%
Oil	91.67	8.27%	41.16	14.34%	25.42%
Natural Gas	300.75	27.13%	46.68	16.26%	73.55%
Not Specified	-	-	48.81	17.01%	-
<i>Thermal</i>	<i>706.46</i>	<i>62.38%</i>	<i>183.88</i>	<i>64.06%</i>	<i>46.86%</i>
Nuclear	288.23	26.00%	48.96	17.06%	67.20%
Hydro	82.22	7.42%	47.74	16.63%	19.66%
Geothermal	2.63	0.24%	0.54	0.19%	55.60%
Solar/Wind/Tide	7.82	0.71%	5.92	2.06%	15.08%
Others	36.21	3.27%	-	-	-
<b>Total</b>	<b>1,108.65</b>	<b>100.00%</b>	<b>287.03</b>	<b>100.00%</b>	<b>44.51%</b>

Note: «Others» means biofuels & waste for generation

Source: IEA, *Electricity Information 2014*, p.IV.439 and pp.IV.449-450

Some basic features of electric power industry in Japan can be summarized as below:

- Japan has a lot of islands with small population. It leads to more use of small-size remote power plant with diesel, fueled by oil. This is the main reason of relatively high dependency on oil-fired power generation.
- Nuclear power plants of Japan were running at relatively low utilization rate. It means that Japan had large capacity in reserve.
- Many thermal power plants in Japan are quite old.<sup>7</sup> It causes Japan to be currently facing the problem of capacity addition and replacement.<sup>8</sup>

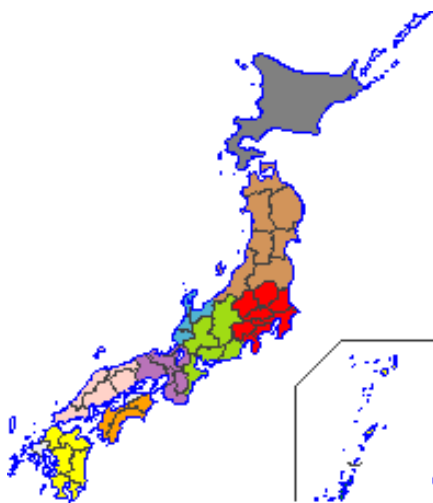
During the period of World War 2, Japanese power industry was originally in monopoly by Japan Electric Generation and Transmission Company which was established on merger of private companies. After the war, the company was divided into 9 private companies in 1951, forming the base of current structure. These 9 companies are called GPU (General Power Utility). In 1972, Okinawa Electric was established as 10th GPU. These 10 GPUs undertake responsibility of power supply to their management regions.

<sup>7</sup> As far as the author studied, the oldest power plant in Japan currently operating is Tanegashima #1 of Kyushu Electric, located in Tanegashima island. It started operation in March 1913, has 5 generators, and total capacity is 16,500kW, fueled by oil. (There is no official data of comprehensive power plant list.)

<sup>8</sup> Most of currently active Japanese power plants were constructed in the period of 1963 – 1990.

Since 1995, power industry liberalization started and new companies participation has been permitted. These new suppliers are basically self-suppliers, but they can also buy and sell electric power with GPUs and other newcomers.

**Figure 12: Management Regions of 10 GPUs**



Source: Wikipedia

Note: Gray (Hokkaido Electric), Brown (Tohoku Electric), Red (Tokyo Electric), Green (Chubu Electric), Blue (Hokuriku Electric), Violet (Kansai Electric), Pink (Chugoku Electric), Orange (Shikoku Electric), Yellow (Kyushu Electric), Dark Green (Okinawa Electric)

## 2. After Fukushima

After Fukushima in 2011, Japan has been struggling to supply its own power demand. As seen in chart 1, most of additional fuel consumption due to the lack of nuclear power was made up by LNG, followed by coal. Oil also expanded much larger compared to before-Fukushima. At the end of fiscal year 2013, LNG fueled almost half of its power demand alone, cementing its position as the largest power fuel in Japan.

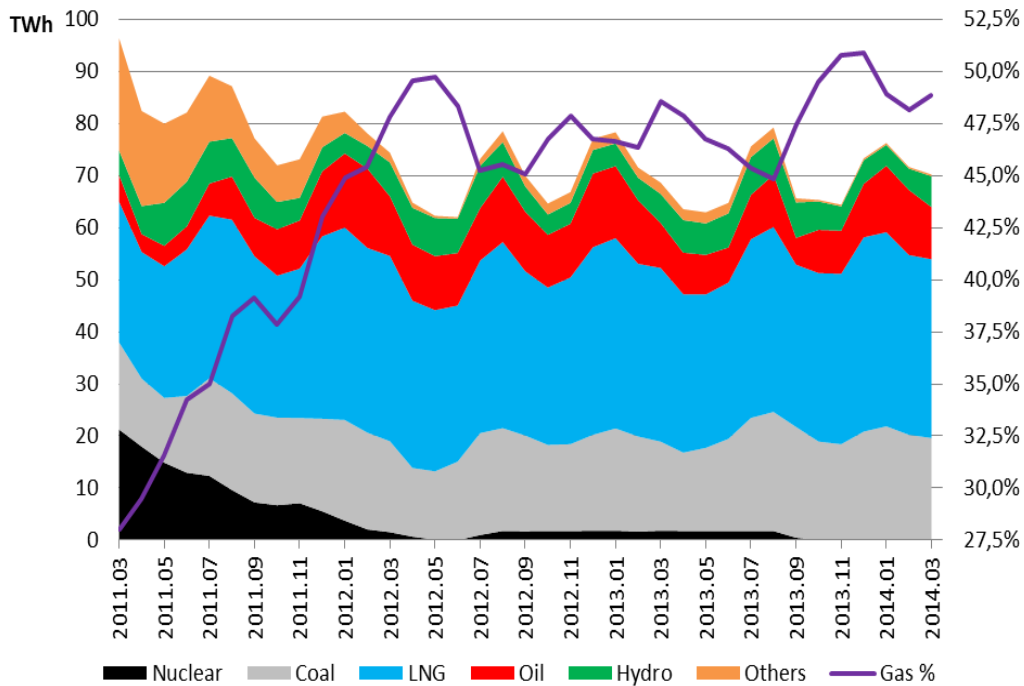
However, heavy dependency on LNG has pushed fuel cost up significantly. Several newspapers reported that Japan is spending nearly “10 billion yen per day” only for power fuel cost, and now it is one of the most widely-spoken phrases. Along with rising public interests in energy issues, LNG contract terms such as oil-indexation and destination clauses are now increasingly acknowledged and under the public critics.

Under the public concerns, Japanese government and LNG importers are now making various efforts to reduce fuel cost. These measures are primarily aimed at reduction of LNG import price.

- Ministry of Export, Trade, and Industry (METI) started to publish Japan Monthly Spot LNG Import Price Statistics from prices for March 2014. According to METI, it is an approach for better transparency in LNG import, aimed at establishment of Asian LNG exchange.
- Interest of LNG importers and the public has grown up in North American LNG export projects, with frequently cited as “shale gas LNG”. It is mostly supported by expectation of possible down in import prices by pricing formula change and contract terms flexibility.
- Tokyo Electric and Chubu Electric have decided to establish JERA, a new child company of 50:50 interests, integrating various businesses from upstream to LNG imports, trading, and foreign electric power. These two companies will also consider whether to merge their

domestic power business in 2017. This is part of efforts to strengthen purchasing power by increasing LNG import size.

**Figure 13: Japan Monthly Power Generation by Fuel since Fukushima**



Note: JANRE started to publish generation by fuel from FY2013; i.e. from April 2013. All figures before are estimated based on 12-month average implied heat efficiency from FY2013 generation and capacity figures.

Source: *Japan Agency for Natural Resources and Energy, Electric Power Statistics*

Yet, despite those efforts, current high dependency on LNG is unlikely to fall soon. Almost all major utilities are planning to deal with upcoming power demand in near future by addition of mainly gas-fired plants, shutdown of primarily coal-fired plants, and replacement of existing plants for higher heat efficiency and fuel change from coal to LNG, as presented below.

**Table 3: Submitted Japanese Power Utilities' Thermal Power Plants Plan: *Shutdown***

Company	Plant	Generator	Type	Fuel	Capacity (kW)	Startup
<b>Tokyo Electric</b>	Kawasaki	1-GT	Close	LNG	128,000	2014/04
<b>Tokyo Electric</b>	Ohi	1-GT	Close	LNG	128,000	2014/04
<b>Kyushu Electric</b>	Karatsu	2	Close	Oil	375,000	2015
<b>Kyushu Electric</b>	Karatsu	3	Close	Oil	500,000	2015
<b>Hokkaido Electric</b>	Onbetsu	1	Close	Oil	74,000	2015/12
<b>Hokkaido Electric</b>	Onbetsu	2	Close	Oil	74,000	2015/12
<b>Tohoku Electric</b>	Akita	5	Close	Oil	333,000	TBD
<b>Tohoku Electric</b>	Niigata	6	Close	LNG	34,000	TBD
<b>Tohoku Electric</b>	Higashi-Niigata	5	Close	LNG	339,000	TBD
<b>Tohoku Electric</b>	Higashi-Niigata	Minato-3	Close	Oil	53,800	TBD

Sources: Japan Ministry of Export, Trade, and Industry, 2014. March 17<sup>th</sup>



**Table 4: Submitted Japanese Power Utilities' Thermal Power Plants Plan: Replacement**

Company	Plant	Generator	Type	Fuel	Capacity (MW)	Startup
<b>Kansai Electric</b>	Himeji 2	5	Shut down	LNG	600,000	2014/10
<b>Kansai Electric</b>	Himeji 2	5	Build up	LNG	486,500	2014/10
<b>Kansai Electric</b>	Himeji 2	6	Shut down	LNG	600,000	2015/03
<b>Kansai Electric</b>	Himeji 2	6	Build up	LNG	486,500	2015/03
<b>Tohoku Electric</b>	Shin-Sendai	1	Shut down	Oil	350,000	2015/12
<b>Tohoku Electric</b>	Shin-Sendai	3-1	Build up	LNG	490,000	2015/12
<b>Tohoku Electric</b>	Shin-Sendai	3-2	Build up	LNG	490,000	2015/12
<b>Shikoku Electric</b>	Sakaide	2	Shut down	Coal	350,000	2016/08
<b>Shikoku Electric</b>	Sakaide	2	Build up	LNG	289,000	2016/08
<b>Chubu Electric</b>	Nishi-Nagoya	7-1	Build up	LNG	1,188,000	2017/09
<b>Hokuriku Electric</b>	Toyama Shinko	1-Coal	Shut down	Coal	250,000	2018
<b>Hokuriku Electric</b>	Toyama Shinko	1-LNG	Build up	LNG	425,000	2018
<b>Chubu Electric</b>	Nishi-Nagoya	7-2	Build up	LNG	1,188,000	2018/03
<b>J-Power</b>	Takehara	1	Shut down	Coal	250,000	2020/09
<b>J-Power</b>	Takehara	2	Shut down	Coal	350,000	2020/09
<b>J-Power</b>	Takehara	1	Build up	Coal	600,000	2020/09
<b>Tokyo Electric</b>	Goi	1	Shut down	LNG	265,000	2024
<b>Tokyo Electric</b>	Goi	2	Shut down	LNG	265,000	2024
<b>Tokyo Electric</b>	Goi	3	Shut down	LNG	265,000	2024
<b>Tokyo Electric</b>	Goi	4	Shut down	LNG	265,000	2024
<b>Tokyo Electric</b>	Goi	5	Shut down	LNG	350,000	2024
<b>Tokyo Electric</b>	Goi	6	Shut down	LNG	476,000	2024
<b>Tokyo Electric</b>	Goi	1-1	Build up	LNG	710,000	2024
<b>Tokyo Electric</b>	Goi	1-2	Build up	LNG	710,000	2024
<b>Tokyo Electric</b>	Goi	1-3	Build up	LNG	710,000	2024
<b>Kansai Electric</b>	Himeji 2	5	Shut down	LNG	600,000	2014/10
<b>Kansai Electric</b>	Himeji 2	5	Build up	LNG	486,500	2014/10
<b>Kansai Electric</b>	Himeji 2	6	Shut down	LNG	600,000	2015/03

<b>Kansai Electric</b>	Himeji 2	6	Build up	LNG	486,500	2015/03
------------------------	----------	---	----------	-----	---------	---------

Sources: Japan Ministry of Export, Trade, and Industry, 2014. March 17<sup>th</sup>

**Table 5: Submitted Japanese Power Utilities' Thermal Power Plan: New Capacity**

Company	Plant	Generator	Type	Fuel	Capacity (kW)	Startup
<b>Tokyo Electric</b>	Chiba	3-1	New	LNG	500,000	2014/04
<b>Tokyo Electric</b>	Kashima	7-1	New	LNG	420,000	2014/05
<b>Chubu Electric</b>	Joetsu	2-2	New	LNG	576,000	2014/05
<b>Tokyo Electric</b>	Chiba	3-2	New	LNG	500,000	2014/06
<b>Tokyo Electric</b>	Kashima	7-3	New	LNG	420,000	2014/06
<b>Tokyo Electric</b>	Chiba	3-3	New	LNG	500,000	2014/07
<b>Tokyo Electric</b>	Kashima	7-2	New	LNG	420,000	2014/07
<b>Tohoku Electric</b>	Hachinohe	5	New	LNG	416,000	2015/07
<b>Tokyo Electric</b>	Yokohama	7-2	New	LNG	377,000	2015/08
<b>Tokyo Electric</b>	Yokohama	8-3	New	LNG	377,000	2016/02
<b>Tokyo Electric</b>	Yokohama	8-4	New	LNG	377,000	2016/06
<b>Tokyo Electric</b>	Kawasaki	2-2	New	LNG	710,000	2016/07
<b>Kyushu Electric</b>	Shin-Ohita	3-4	New	LNG	480,000	2016/07
<b>Tokyo Electric</b>	Yokohama	7-1	New	LNG	377,000	2016/08
<b>Tokyo Electric</b>	Yokohama	7-4	New	LNG	377,000	2017/02
<b>Tokyo Electric</b>	Yokohama	8-1	New	LNG	377,000	2017/06
<b>Tokyo Electric</b>	Kawasaki	2-3	New	LNG	710,000	2017/07
<b>Tokyo Electric</b>	Yokohama	7-3	New	LNG	377,000	2017/08
<b>Tokyo Electric</b>	Yokohama	8-2	New	LNG	377,000	2018/02
<b>Hokkaido Electric</b>	Ishikariwan-Shinko	1	New	LNG	569,000	2019/02
<b>Tohoku Electric</b>	Noshiro	3	New	Coal	600,000	2020
<b>Kyushu Electric</b>	Matsuura	2	New	Coal	1,000,000	2021/06
<b>Hokkaido Electric</b>	Ishikariwan-Shinko	2	New	LNG	569,000	2021/12
<b>Tohoku Electric</b>	Joetsu	1	New	LNG	600,000	2023
<b>Hokkaido Electric</b>	Ishikariwan-Shinko	3	New	LNG	569,000	2028/12

Sources: Japan Ministry of Export, Trade, and Industry, 2014. March 17<sup>th</sup>

It can be pointed that uncertainty around nuclear restart is the key factor of utilities' ongoing dependency on LNG power, because they are now facing both additional/replacement capacity requirement for the future load demand and large capacity waiting for possible restart. Naturally, low CAPEX and operational flexibility of gas-fired plants are best suited for current situation in Japan. Nuclear safety assessment by NRA and public acceptance are

therefore the most important factors for the future gas demand of power ahead in Japan. Next section briefly reviews current status of nuclear safety assessment in Japan.

### **3. Policy Changes on Nuclear Power Plants since Abe Government**

After Fukushima, Japan's nuclear power policy have long hovered under social controversy. As well known, the former Prime Minister Naoto Kan was against nuclear power, and JANRE published nuclear-zero National Energy Plan for 2030. The plan described renewable energy as the next main electric power supply besides all other fuels, and was naturally criticized for its feasibility. The plan was cancelled 5 days after publish.

In 2012, new Prime Minister Abe Shinzo took over the chair. He has mentioned several times that nuclear restart is one of the most important conditions for economic recovery. For his positive attitude and manifesto, it was expected to restart nuclear plants soon when the new nuclear safety standards were enacted with establishment of Nuclear Regulation Authority (NRA) on September 19<sup>th</sup> 2012. NRA safety assessment is taking much longer and more expensive than initially expected. It was initially expected to take 6~8 months to restart the first nuclear plant. However, Sendai #1 and #2 of Kyushu Electric, the first pass, took almost 14 months. (Applied July 12, 2013 and passed September 10, 2014).<sup>9</sup> The second case, Takahama #3 and #4 took 20 months for the pass of the review. (Applied July 8, 2013 and passed February 12, 2015). This regulatory inefficiency is in controversy and the several representatives of LDP (Liberal Democratic Party: currently authority taking party) have suggested to modify current NRA system. Although it has not been realized, this kind of complaints about NRA implies strengthening political momentum towards nuclear restart, as they used to be politically expensive in 2012 or 2013.

### **4. The Remaining Uncertainty: Public Acceptance**

However, despite this political momentum towards nuclear restart, whether they can actually run the reactors is still not sure. And the remaining uncertainty still continues to work as the leverage of dependency on LNG by utilities. Public acceptance is the main remaining uncertainty. April 2015, Fukui and Kagoshima local court have sentenced different conclusion about Takahama and Sendai nuclear plants. Fukui court has accepted 12 residents' appeal to prohibit restart, and Kagoshima court has rejected. The consequence of these decisions will have to wait for more time to see, but this kind of legal appeals implies that it would be possibly time-consuming task to get social acceptance to restart nuclear plants, considering required time and efforts for utilities to deal with these legal matters. It simply means that utilities cannot be assured to restart even after they pass the NRA's safety review, for the possibility of time-consuming lawsuits. As long as public acceptance takes time and efforts, nuclear restart will likely be delayed, leading to more dependency on LNG.

### **5. Conclusion**

As discussed above, demand on natural gas for power in Japan has significantly increased and it is still there. This high demand is mainly supported by the regulatory inefficiency and public acceptance about nuclear restart. Gas-fired power is now expanding for their low CAPEX, short lead time, and operational flexibility, under the uncertainty in nuclear restart. Shortly, LNG is working as a solution to regulatory and social uncertainty about nuclear

---

<sup>9</sup> It is interpreted as a kind of "initial try and error" period to build experience (of both reviewers and applicants) and establish standardized procedure to review. After Sendai passed it, Takahama #3 and #4 of Kansai Electric have got pass on February 12, 2015. It is 5 months after Sendai case, a little bit quick.

restart in Japan. Although it is difficult to generalize, it shows a role of natural gas in electric power mix triggered by special event. The current status and future role and portion of LNG in Japan power industry are now largely dependent of unquantifiable and unpredictable factors such as public reaction and legal matters. As long as these uncertainties persist, LNG's portion in Japan will inevitably continue to stay.

## GAS FOR POWER IN KOREA: POLICY UNCERTAINTY FOREVER

### 1. Never Ending Chaos

For all stakeholders around Korean electric power market, it is becoming more and more uncertain to see what to come. The policy uncertainty is skyrocketing than ever in its history. Under this policy uncertainty, it is very difficult to predict how the market will be shaped.

As the market is still under big uncertainty, in this chapter, this report will focus on the explanation and current status of Korean electric market structure and major factors which will be determined and impact the market in the foreseeable future. The reason of policy uncertainty will follow.

In Korea, natural gas is imported as LNG by Korea Gas Corporation (KOGAS), and then supplied to customers via private distribution companies (for city gas), or directly to electric power utilities (for power demand). KOGAS is the sole market player with supply responsibility. So therefore, natural gas is naturally in the monopoly by KOGAS, the single national company.<sup>10</sup> Meanwhile, Korean electric power industry has been partly liberalized. 6 subsidiaries of Korea Electric Power Corporation (KEPCO) and other private players are operating power plants, and then sale their power to customers via KEPCO's transmission and distribution grids. Daily generation by generators are determined by Korean Power Exchange (KPX) via day-ahead capacity bidding. The methodology is the cumulative capacity to match load demand at least cost. This approach is similar with U.S. power markets.<sup>11</sup> So this is daily operation of Korean electric power market.

For long-term system operation, the government's Basic Plan for Electric Power Demand-Supply (BPEPDS hereafter) is the sole authority. It contains load demand forecast, result of review on every single application of power plant construction submitted by utilities, generation forecast by fuel, plans for renewable and distributed power plants, and also transmission grid construction. Basically, Korean electric power industry is determined by BPEPDS, from generation to distribution.

The importance of BPEPDS is not limited to electric power, but also applied to natural gas directly. From the viewpoint of integrity, the Basic Plan for Natural Gas Demand-Supply (BPNGDS hereafter) is determined corresponding to BPEPDS. And this importance is building up policy uncertainty, because BPEPDS is now facing never-ending delays.<sup>12</sup>

The law determines that the government has to publish this plan bi-annually, and requires it to estimate demand-supply balance for more than 10 years. According to the schedule, the next BPEPDS (7<sup>th</sup> edition this time) should have been announced in 2014. However, as of the date of this report (April 26<sup>th</sup> 2015), it is rumored that the government has not completed demand forecast yet. The official schedule of announcement is the end of 1<sup>st</sup> half of the year.

---

<sup>10</sup> But it should be noted that there are some private industrial companies that are allowed to self-supply their own demand; namely, POSCO, GS, SK, and K-Power. Their demand collectively fluctuates 1 – 2 million tons/year, compared with national LNG demand of 38 million tons (2013). They don't take supply responsibility; i.e. when they are short of LNG, they can request KOGAS for additional LNG supply.

<sup>11</sup> All utilities submit their CAPEX and OPEX data by generators to KPX periodically. Therefore, KPX can determine least-cost operating capacity for day-ahead demand based on demand estimation and those cost data by economic merit order.

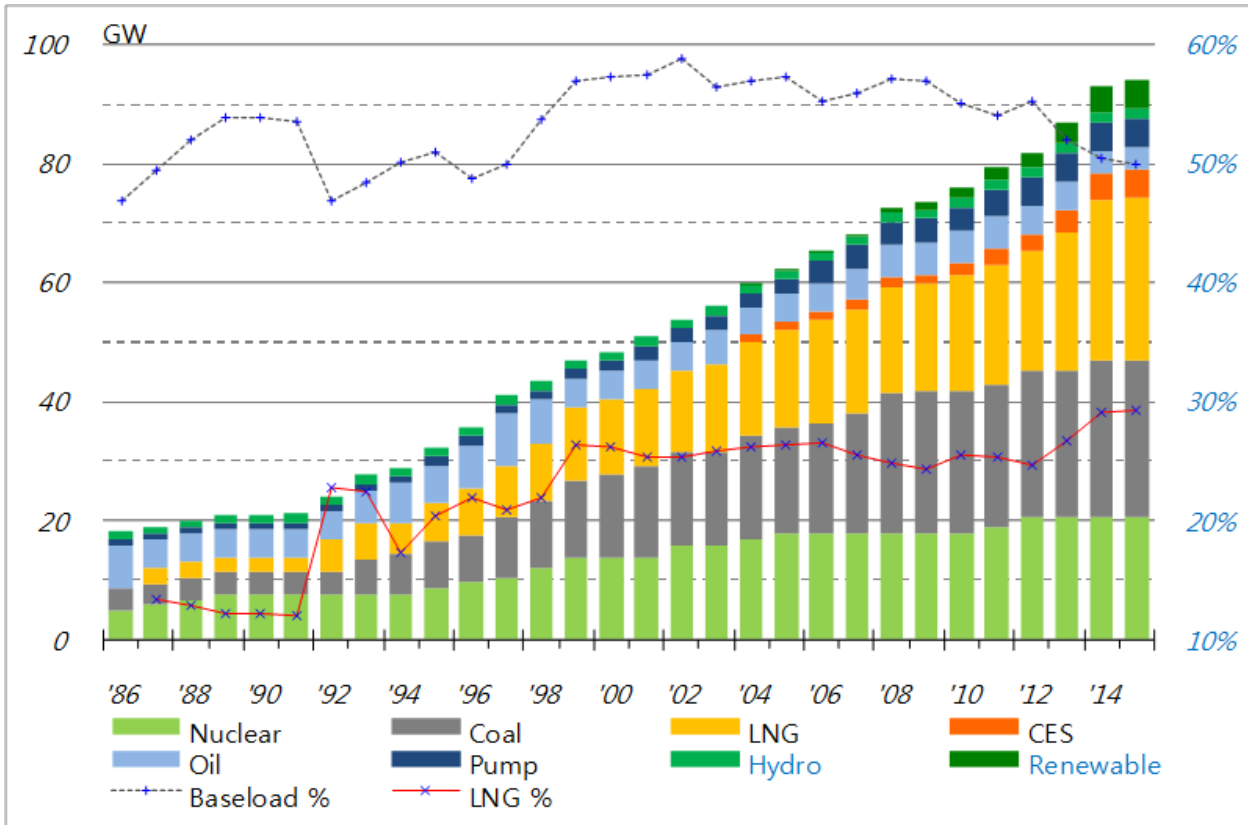
<sup>12</sup> In other words, LNG demand on electric power in BPNGDS must match with BPEPDS. So, BPNGDS cannot be determined until BPEPDS completed. This is why BPEPDS is the most important element of Korean national energy strategy.

However, as demand forecast is the very initial stage of electric power plan, it is naturally expected to be delayed again, likely to the end of the year, or possibly even to 2016.<sup>13</sup>

As mentioned earlier, BPNGDS cannot be determined until BPEPDS completed. Therefore, unfortunately, direct analysis on government policy is very difficult. Instead, this chapter hereafter, looks back historical trends of Korean power market and examines their implications about power fuel mix.

## 2. Lessons of History

Figure 14: Historical Capacity Mix



Note: All data are as of the end of each year, while 2015 is as of end of February

Source: KEPCO Statistics

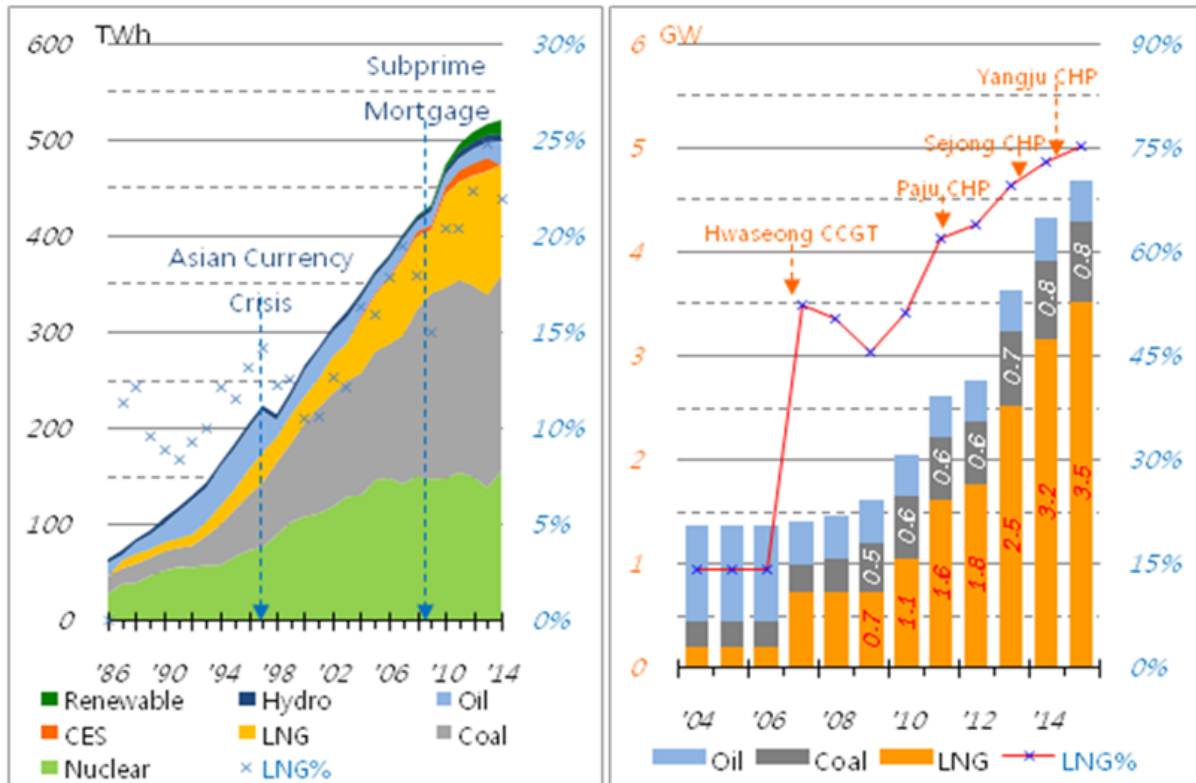
LNG-fired power was 13.4% of total capacity in 1987. It experienced boost in 1992, and then gradually grew up to exceed 25% first time in 1999. After that, for more than decade, its capacity portion stays around 25%. Then in 2012, it saw a bound once again to approach 30% of total capacity at the moment. (Figure 14) Meantime, its generation portion has also been expanding stably, reaching 22% in 2014. (Figure 2)

This LNG-power growth can be attributable to two important reasons. The first one is CES (Community Energy System). For the limited area of the national land, the government has considered CES as a solution to potential transmission constraints, and supported it for

<sup>13</sup> Usually, long-term electric system planning begins from load demand forecast. Under the projected demand, required capacity is determined from the viewpoint of reserve capacity. Then startup/shutdown of existing or candidate power plants are decided, based on simulation during search for optimal plants configuration. Each stage themselves are computed by simulation, but require various discussion and controversy. Therefore, the fact that load demand forecast is not completed means BPEPDS is still at the very first stage.

distributed power expansion since 2004. Naturally, most of CES systems burns LNG as they are located at the site of demand, with exception of few coal-fired CES delivering power and heat to industrial complexes. CES expansion has supported stable increase of LNG demand of power. (Figure 15)

**Figure 15: Historical Generation Mix and CES Power Capacity by Fuel**



Source: KEPCO Statistics

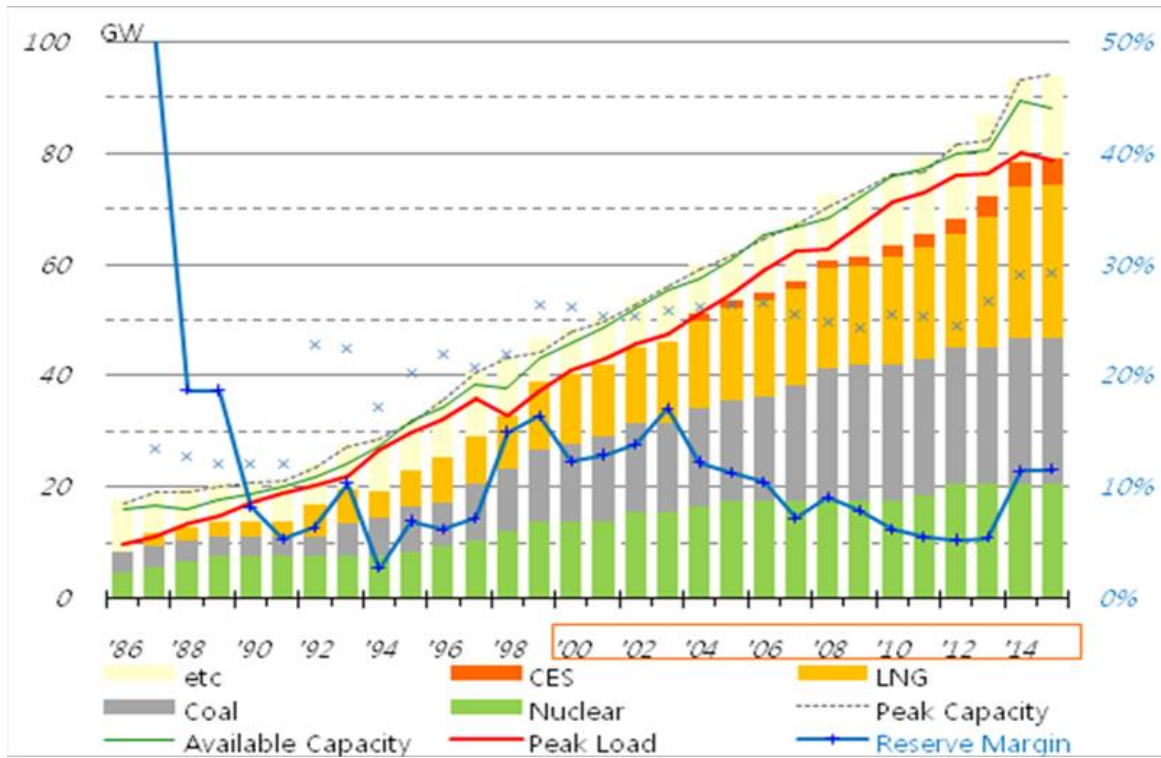
The second and more important reason is the lack of reserve capacity. As seen in Figure 16, Korean government has put the economic operation first for long. Naturally, the power industry has had reserve margin frequently less than 10% for more than two decades. As a result, the power system has stayed with insufficient reserve for long, and it led to nationwide rotating outage in September 15, 2011 for 5 hours. After the rotating outage, the government requested utilities to construct LNG-fired power plants ahead of the planned schedule in order to ensure more capacity. This drove LNG-power rush in Korea, resulting in LNG-power capacity jump during 2012 to 2014.

In short, power system operation too much focusing on economics led to lack of reserve capacity, and then brought nationwide outage. It ended up much more LNG-power and spike of LNG demand of power.

This chapter explained Korean power market structure and major national plans in relation to natural gas and electric power market. The 7th BPEPDS and 12th BPNGDS are upcoming government plan to shape future market. However, as BPEPDS is delayed continuously, it is very difficult to estimate what will be the impact and implications to gas market. However, there are some clear points; from historical experience, natural gas power has, is, and will continue to work as an important supplier. Especially, a system that lacks reserve margin such as Korea contains permanent unreliability in energy supply. It means that the system is continuously exposed to risk of outage, at least to some degree. In other words, a system with insufficient reserve has always possibility of gas power boost for urgent supply

additions. Also, any country with limited land area is inevitably to face location constraints for power plants, resulting to turn into distributed generators. CES, mostly fueled by natural gas, can be an excellent solution for this problem, contributing to both stable electric power supply and environment protection in terms of low emission. As a conclusion, role of natural gas in power mix is undeniable for both system reliability and resource constraints (in terms of land area).

**Figure 16: Capacity and Power Demand-Supply**



Source: KEPCO Statistics



# FUTURE OF GAS IN THE ELECTRICITY MIX AND POTENTIAL IMPACT ON EXPORTS' PERSPECTIVES IN THE MENA REGION

## 1. Introduction

Energy demand in the Middle East and North Africa, MENA, region has grown significantly in recent years. This could impact its oil and gas exports' perspectives, are important issues that draw special attention from players and observers of the international energy scene.

Indeed, the MENA region holds about half of the world's oil gas reserves, and exports respectively 50% and 66% of the global oil and gas exports. The region produces about 715 bcm/year, about 22% global gas sales<sup>14</sup> and providing nearly half of the world LNG exports<sup>15</sup>.

Now demand for energy is growing in the region, particularly for natural gas, driven mainly by the power generation needs. The pace of gas demand growth has brought uncertainties to the regional Demand/Supply perspectives.

MENA gas producing countries are facing an important challenge: satisfying a growing domestic market for gas, and exporting gas to international markets to get the needed revenues. So, what are the possible actions to deal with this challenge? What could be the possible scenarios for the region?

Options include gas demand side management and diversification of the power generation mix, and accelerated gas supply side through imports.

It should be noted that some MENA gas producers have turned to import natural gas to meet the rapid development of their domestic demand. Iran, which was the first country to import gas, Kuwait, UAE and Oman also have seen their imports increasing. The Gas volumes imported by these countries increased from 23 bcm in 2008 to around 30 bcm in 2013 with LNG imports of Kuwait and UAE representing the bulk of additional imported volumes during this period<sup>16</sup>. Egypt will import LNG for 2015, with a first agreement signed with Gazprom for 7 LNG shipments/year (0.525 bcm for five years), and with Algeria for 6 cargoes between April and September 2015.

Imports of natural gas, including LNG, is thus emerging as an option for MENA countries, even for some gas producers and exporters. This option enables, somewhere, countries to meet rapid domestic demand and their international commitments. It's worth noting that MENA gas imports are being mainly sourced from gas producing countries within the MENA region, but the development of LNG provides an opportunity for these importers to source their gas from international markets.

Many scenarios could be envisaged on the prospects of Gas demand and supply as well as on the exports' potential for different MENA countries. Our analysis in this chapter of the study aim to bring some clarifications with regards to these prospects, we focus on the role of gas in power generation which is the main driver of gas demand and also the most exposed sector to 'fuels' competition and diversification. In the first part, we try to understand the determinants of the gas for power growth in MENA region, and highlight the uncertainties characterizing the future role of gas in this sector. In Second part, we analyze the MENA

---

<sup>14</sup> Numbers for the year 2013 according to BP Statistical review 2014

<sup>15</sup> Source: IGU LNG Report Ed 2014

<sup>16</sup> Cedigaz datas 2013

supply of gas and its drivers, before drawing, in the third part, various scenarios for the MENA region

The MENA region is far from being a homogenous region, with significant disparities in terms of demography, economic development and also in terms of natural resources endowments. It should initially be distinguished between, on one side the hydrocarbon exporting countries where the hydrocarbon sector represents, for the majority of these countries, more than 50% of GDP and is the principal source of exports' revenues, and on the other side, the hydrocarbon importing countries whose dependency on oil and gas imports significantly affects their economic growth and exposes them to potential high oil prices.

Despite these disparities, many concerns are shared within the MENA region:

- **A difficult geopolitical context** where a number of countries are affected by crises and political turbulences, especially those experiencing the consequence of the Arab spring. The deepening of the political crises and degradation of security in some countries (Syria, Libya and Iraq) have brought many uncertainties on the evolution of security aspects, as well as on economic and energy perspectives, on the country level and also on the regional level.
- **A significant population growth** with marked trends towards urbanization. This urbanization is driven by unemployment and by the gap in living standards and wealth between urban and rural areas.
- **Needs of Economic development and diversification** in order to meet the aspirations of population and to reduce the structural weaknesses characterizing the economies of many MENA countries (youth unemployment, lack of economic diversification particularly in oil exporting countries, weak private sectors..). Nevertheless, it should be noted that a number of oil exporting countries have benefited from sharp rise of oil prices over the past decade, to increase their spending in order to improve socio economic conditions of their populations.
- **Growing energy needs** driven mainly by population and economic growth experienced in the MENA Region

## 2. Gas demand in power generation in the MENA region

The primary energy demand in the MENA<sup>17</sup> region has observed a sharp increase last years, from about 700 M. Toe in 2007 to nearly 910 M. Toe in 2012<sup>18</sup>. This represents an average annual growth rate of approximately 5.7 % between 2007 and 2012.

Natural gas is the source of energy which has seen the most important progress in the MENA primary energy mix, with an average annual demand growth of about 8% over the period 2007-2012, followed by oil with 3.5% average growth on the same period.

MENA Natural gas consumption increased from about 350 Mtep (400 bcm) in 2007 to over than 450 Mtep (520 bcm) in 2012, driven by the strong progression in the Middle East (CAGR 2007-2012: 8.5%), a region which has seen a strengthening of the leading role of gas in its primary energy mix.

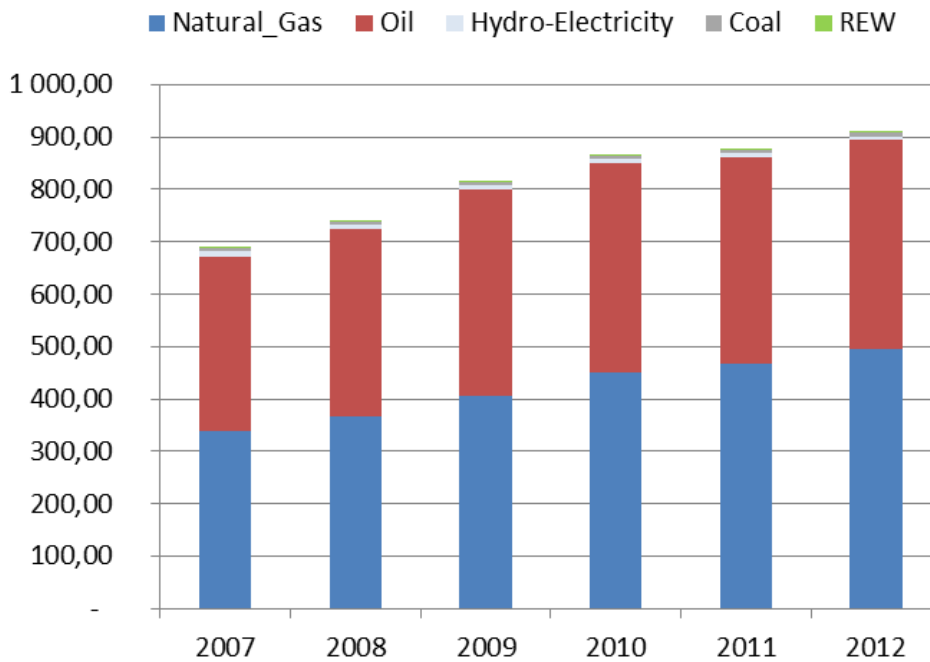
Gas has also observed an important growth in North Africa (CAGR 2007-2012: 6.8%), a growth which enabled gas consumption to catch up with the oil demand in this region, largely affected by the sharp decline of the Libyan consumption, owing to the deep crisis faced by this country since 2011.

---

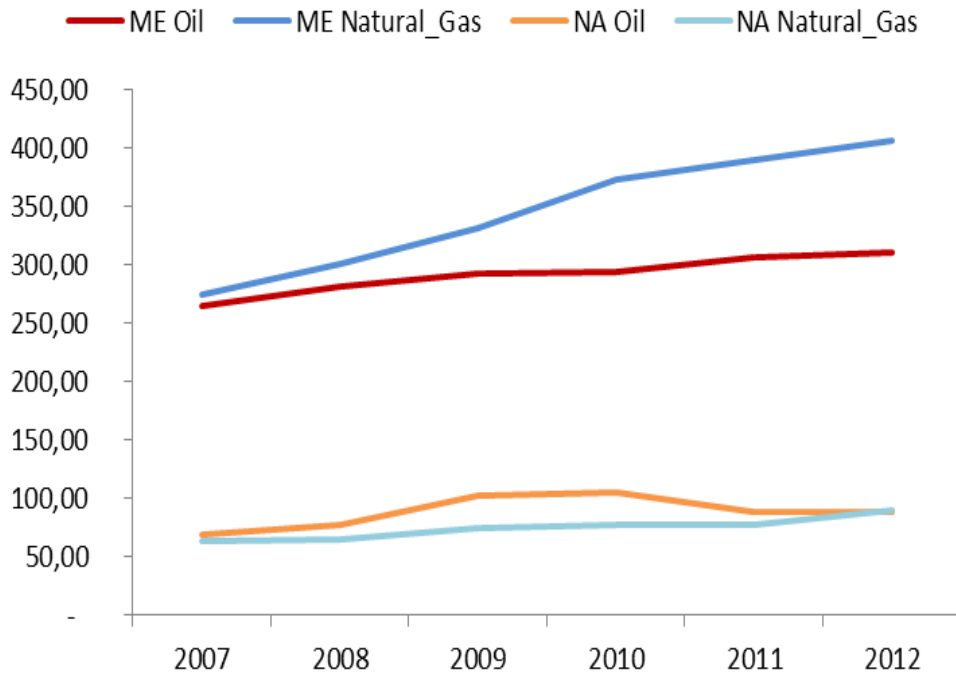
<sup>17</sup> Countries included in the MENA region are as follows: Gulf Cooperation Council countries (Bahrain, Kuwait, Saudi Arabia, Qatar, UAE and Oman), Iraq, Iran and Yemen, East Mediterranean countries (Jordan, Lebanon and Syria), North Africa (Algeria, Tunisia, Morocco and Egypt)

<sup>18</sup> OAPC statistics 2013, BP Stats for Iran

**Figure 17: Primary energy consumption in MENA Region (M. TOE)**



**Figure 18: Evolution of Gas and Oil consumptions in Middle East and North Africa (M. TOE)**



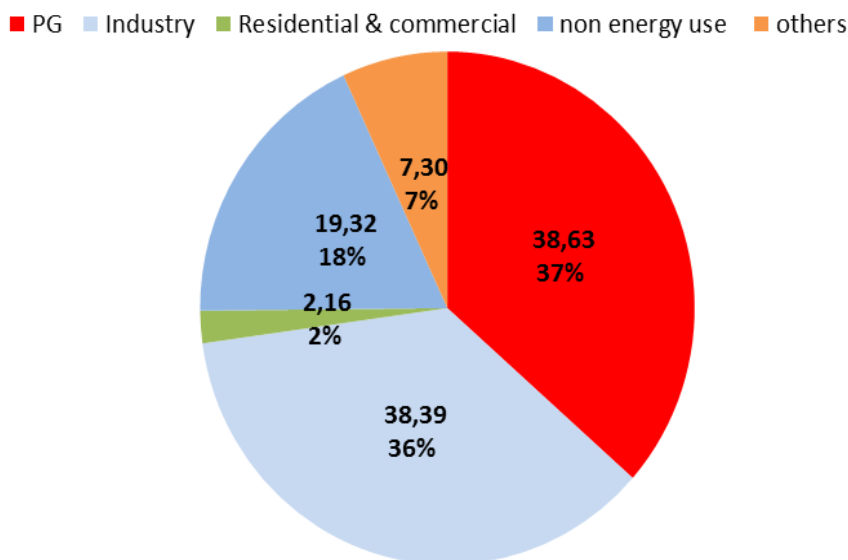
Source: OAPEC, BP stat for Iran

Renewables (excluding hydro) has experienced an increase in MENA primary energy demand, but their share remains very low (less than 1% of primary energy consumption in 2012).

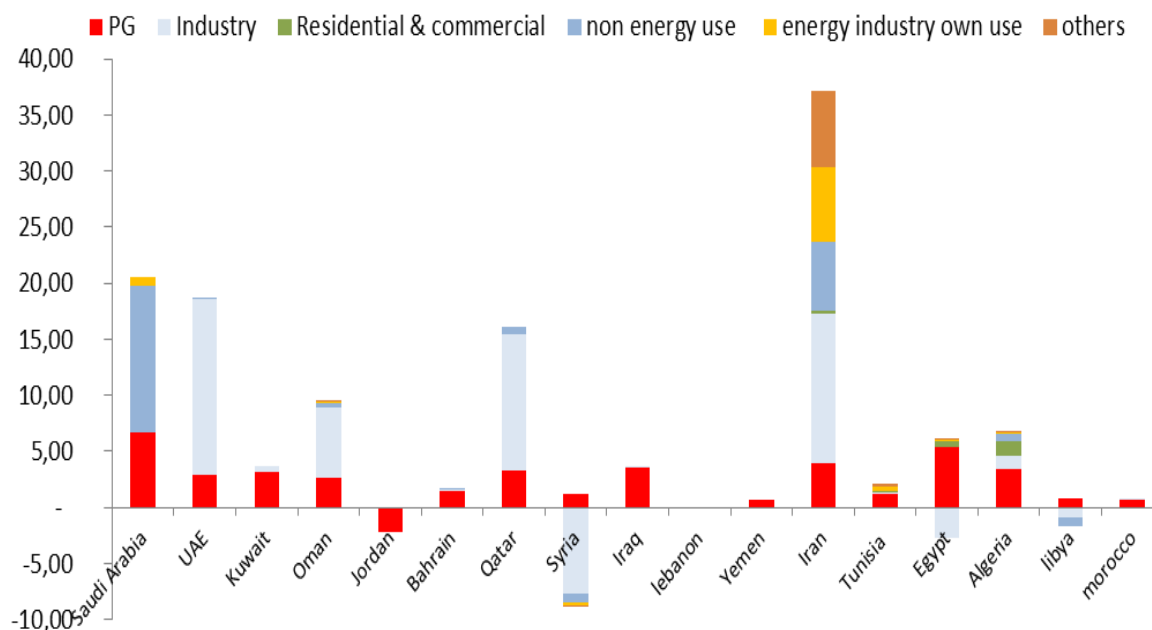
The analysis of gas consumption by sector in the MENA region shows that power generation and also industry are main drivers of growth, representing respectively 37% and 36% of

additional gas volumes consumed between 2007 and 2012. MENA Gas consumption in power generation has reached 210 bcm in 2012, increasing by about 40 bcm<sup>19</sup> from its 2007 level. Most of the MENA countries have seen a progress of gas consumption in this sector as we can see in chart below.

**Figure 19: Additional gas consumed by sector in MENA region between 2007 and 2012 (Bcm)**



**Figure 20: Additional gas consumed by sector in different MENA countries between 2007 and 2012 (Bcm)**



Source: IEA Statistics 2013

<sup>19</sup> of which 27 bcm increase has occurred in the Middle East region

With regard to the observed evolutions last years, we can say that natural gas is the fuel of choice for power generation in the MENA region, but oil continues to observe growth in this sector, , even in the context of high oil prices. The growth of oil is mainly driven by gas supply difficulties and shortages experienced by some countries, that have faced fast increase of electricity demand, particularly during the hottest summer season, and urgent needs to cope with this increase. In these cases, oil remains a relevant alternative for power generation, especially in countries with large oil resources such as Saudi Arabia and Kuwait.

The analysis of the determinants that have affected the consumption of natural gas in power generation and contributed to the observed growth of this fuel in recent years, allows us to distinguish three categories of these determinants:

- Determinants that drive **electricity demand growth**, and consequently lead to increasing needs of power generation capacities;
- Determinants that support the **share of gas fired power plants in installed power generation capacities**;
- Determinants that affect the **level of gas consumed** by the installed gas capacities, including **efficiencies of the gas power plants** and also some other factors influencing **the operating rates** of these power plants.

**1) Electricity consumption has experienced a strong growth** in recent years in the MENA region, with an average growth rate of about 6.5% between *2002 and 2012*, exceeding largely the average world growth rate, estimated at about 3.8% on the same period<sup>20</sup>. This growth has been observed in most of the MENA countries, particularly those countries with large oil and gas resources, and where high oil prices have led to significant increase in per capita revenues and also in government spending to meet the growing socio-economic needs of populations.

Growth of GDP and also growth of population associated with increasing urbanization trends, contribute largely to raise the electricity demand in MENA region, particularly household demand which represents in 2012 about 45% of final electricity demand in Middle East<sup>21</sup> and 36% in North Africa.

The commercial sector represents also a non-negligible part, with 18% of the electricity demand in 2012 in Middle East<sup>22</sup> and 14% in North Africa.

Residential and commercial sectors are then the main drivers of electricity demand growth in the MENA region, with average rates estimated between *2002 and 2012* at about 6% for residential sector and 10% for the commercial one,. The demand for air conditioning strongly supports this growth, particularly in the commercial sector where a significant increase in commercial areas has been seen in countries like Saudi Arabia, Qatar or Algeria.

Electricity demand in the industry has also seen a growth in recent years, especially in oil and gas exporting countries, which seek to diversify their economies by stimulating the industrial sector, and particularly some energy-intensive industries. Qatar, Oman, Algeria and Egypt are representative cases in this regard.

The growth of electricity demand has also been encouraged by the low levels of electricity prices. Despite the differences in prices applied in different MENA countries, and within a country, between the prices charged to residential and commercial sectors and those applied

---

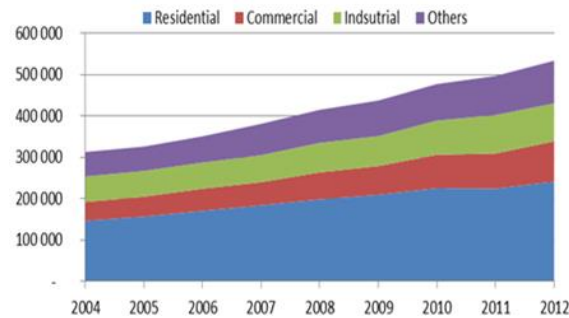
<sup>20</sup> IEA Statistics 2013

<sup>21</sup> Excluding iran, whose the share of residential sector represents 30% according to IEA 2012 statistics

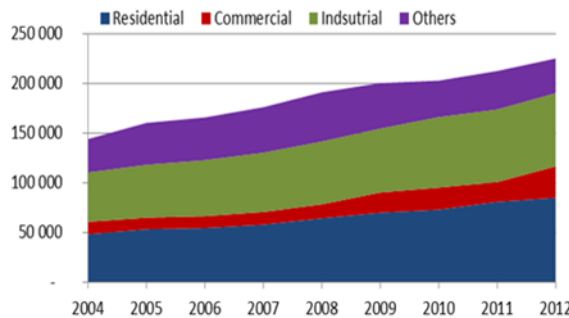
<sup>22</sup> Excluding iran, whose share of commercial sector represents 15% in 2012 according to IEA statistics

for industries<sup>23</sup>, these price levels are still very low compared to other regions in the world. In fact, average prices are below 5 cents / kwh in most MENA countries, especially oil exporting countries, compared to international prices ranging between 8 and 12 cents / kwh in the United States, 12 and 18 Europe, 18 and 26 cents / kwh in Japan (IEA estimates 2013).

**Figure 21: Final Electricity Consumption by sectors in Middle East (excluding Iran) (GWH)**



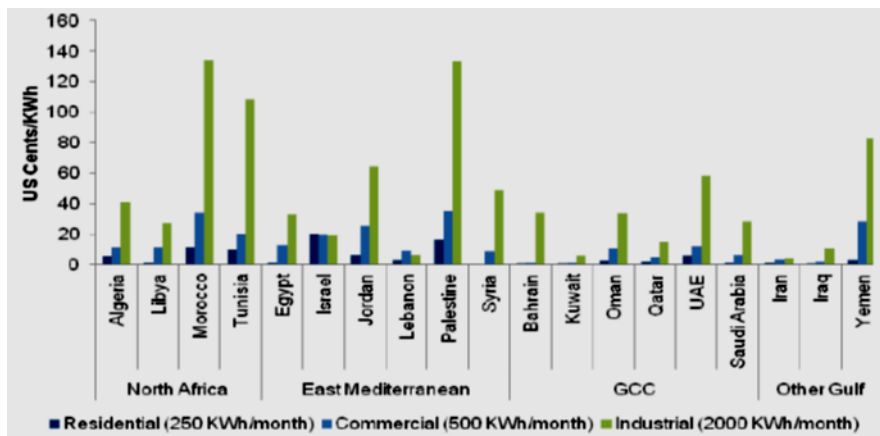
**Figure 22: Electricity Consumption by sectors in North Africa (GWH)**



Source : Arab Union of Electricity 2013

In the Middle East, prices charged to households are, for the majority of countries, less than 2 cents / Kwh, with completely free electricity for Qatari citizens

**Figure 23: Electricity prices by sector and by MENA country (US cents/Kwh)**



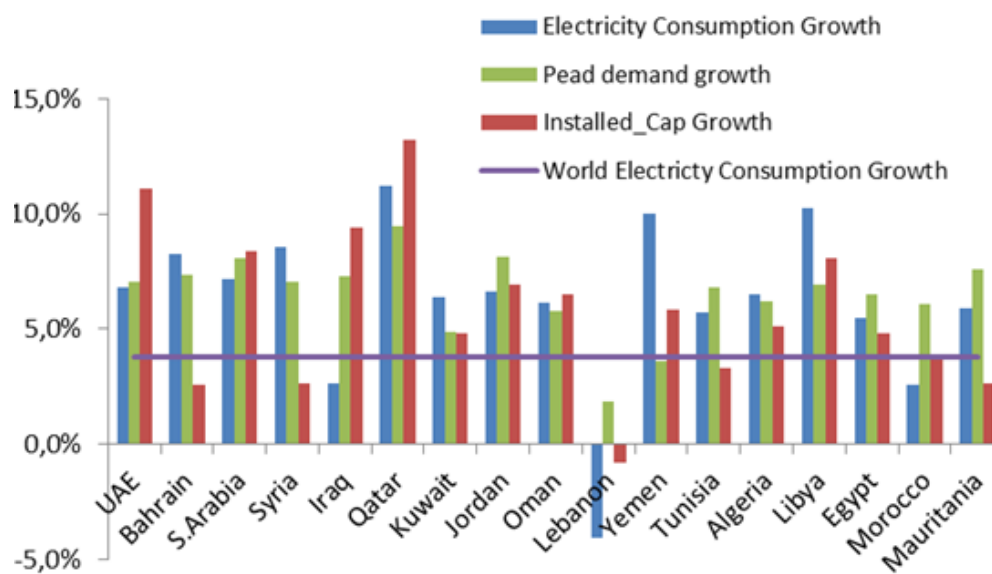
Source : L. Elkhatiri, 2014

<sup>23</sup> Energy intensive industries in particular

Power generation capacities have observed a significant growth, particularly in the Middle East region<sup>24</sup>, in order to cope with the increase in electricity demand and particularly the increase of peak demand. The peak demand pace of growth was higher for electricity peak demand than for annual electricity demand in many MENA countries.

At the level of individual countries, and if we compare the growth rate of installed power generation capacity to the growth of electricity peak demand between 2002 and 2012 (see chart below), we can notice that GCC oil exporting countries (except Kuwait) have increased their PG capacity at a relatively higher rate than peak demand. The growth of power generation capacities was however lower in other MENA countries, which would suggest an additional investment effort to catch up with rising demand.

**Figure 24: Average annual growth between 2002 and 2012 of Electricity consumption, Peak demand and Installed capacities in MENA countries (%)**



Source: Arab Union of Electricity, OAPEC + IEA for Iran 2013

**2) Natural gas share in power generation capacities** has significantly progressed during the last decade. Several factors could explain this progression:

- The emergence of Gas Combined Cycle (CC): Along with the observed trends in other parts of the world, combined cycle progression in the MENA region was favored by factors related mainly to lower investment costs; CC plants' efficiencies, environmental benefits, and particularly the relatively short lead time for CC power plants' construction, which is a response to urgent needs of additional power generation capacities in many MENA countries.
- The cost of the gas fuel: Electricity generation from natural gas is widely advantaged by the cost of gas as a fuel, which is usually administered and subsidized by governments.
- The gas cost advantage and economic attractiveness of gas power plants could be appreciated in the fact that gas represents a large part of the new capacities developed by private investors,, whose share has increased following power sectors' reforms undertaken in many MENA countries.

<sup>24</sup> CAGR 2001-2011 of PG Capacities are estimated respectively at 7.5% and 6% in Middle East and North Africa

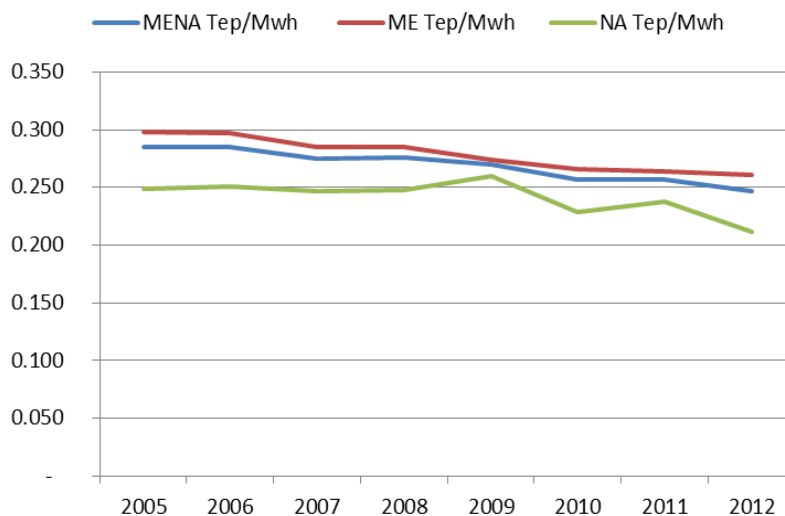
- Rising prices of oil: natural gas has also become the fuel of choice to substitute, to some extent, the use of expensive oil in power generation, both in oil importing countries that seek to reduce the cost of fuel, and also in exporting countries whose objective is to maximize the value of their exports.
- Energy policies promoting natural gas in power generation: Policies and measures that promote Gas in power generation are adopted in order to meet several expectations and objectives for the MENA Region, including mainly: i) Development of significant gas resources to support a growing local demand (such as in Qatar, Algeria and Iran), ii) Replace oil in power generation to reduce greenhouse gas emissions and to increase revenues from oil exports; iii) Development and monetization of associated gas to oil production and whose produced volumes are often conditioned by OPEC quotas (the case of the main oil-producing countries in the Middle East); iii) Reduce gas flaring (as it is the case of Iraq, where about 60% of associated gas production is flared); iv) Deal with the uncertainties characterizing the evolution of international markets, these uncertainties could prevent the development of capital intensive export's projects and encourage domestic use of gas resources; v) Exploit synergies between seawater desalination and power generation. Indeed, the energy intensive seawater desalination plants are often installed with gas fired power plants, with the aim to combine and optimize the energy produced and consumed. The cogeneration of power, steam and water provides significant technical and economic advantages, especially in the Gulf countries where technologies based on thermal water distillation (especially the Multi Stage Flash Distillation technology), have been advantaged , because of the low cost of energy consumed, the convenience of these technologies with regards to the quality and high salinity of the seawater in this region, and also their viability for large scale designed desalination plants. .
- Gas power plants flexibility: The electricity load curves in MENA region are characterized by large fluctuations, which are mainly related to the dominance of commercial & residential sectors in the electricity demand and also to the climate characteristics of this region. Therefore, there is an important need of operational flexibilities in power generation to cope with demand variations. Gas power plants are in this regard very convenient to provide this flexibility.
- The MENA flexibility needs could be appreciated in the increasing share of gas turbines in many countries despite their lower efficiency than gas combined cycle. This is mainly because of the short response time gas turbines could provide, as well as their competitiveness to operate in peak load regime.

**3) The important increase of the gas demand in power generation** has been somewhere counter-balanced by the improvement in average gas power plants' efficiency. Between 2005 and 2012, the gas consumed per Mwh produced in MENA gas power plants has decreased from 0.285 Tep/Mwh to less than 0.246 Tep/Mwh.

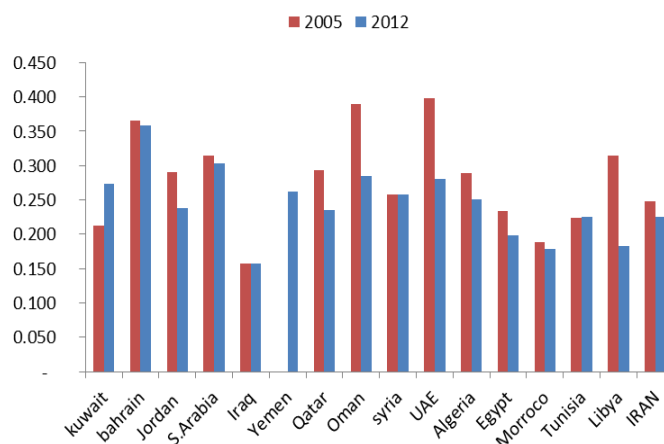
Despite this non negligible decrease in gas consumed per unit of electricity produced, it remains largely higher than the world average estimated by IEA at about 0.162 Tep/Mwh in 2012. Consequently, there is a potential for further improvement in average gas power plants' efficiencies in the MENA region.



**Figure 25: Gas consumed per unit of electricity produced for MENA, Middle East and North Africa (Tep/Mwh)**



**Figure 26: Gas consumed per unit of electricity produced for MENA Countries (Tep/Mwh)**

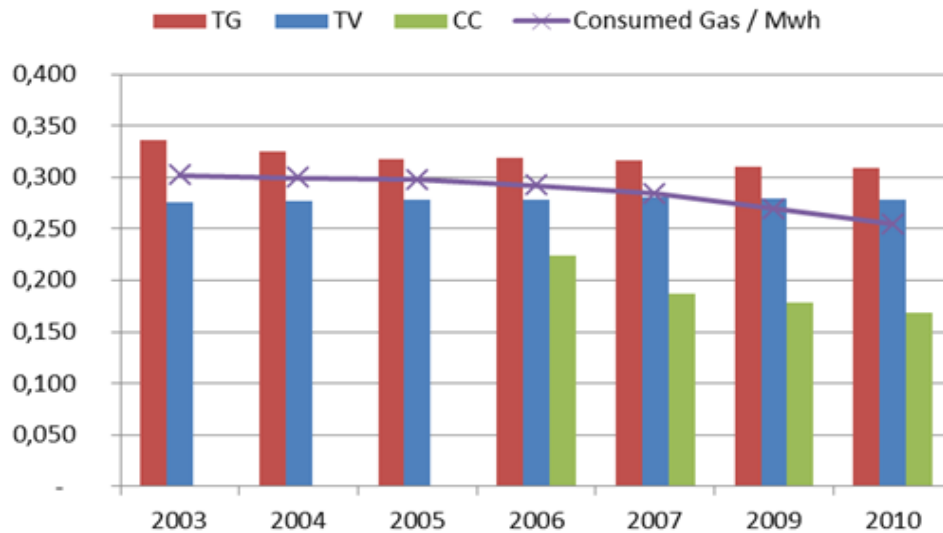


Source: IEA Statistics 2013

The decrease of gas consumed per Mwh produced has been observed in most of the MENA countries, particularly in UAE, Oman, Algeria and Libya. This improvement of average gas power plants' efficiency is largely attributed to the commissioning of new power plants (mainly Combined cycles) with better performance.

We can illustrate the algerian case (Graph. 9) where the average efficiency has increased by about 16% between 2003 and 2010, this improvement is due to the commissioning of new power plants, essentially Combined Cycles that are showing better performance.

**Figure 27: Gas consumed per unit of electricity produced by type of gas power plant in Algeria (Tep/ Mwh)**

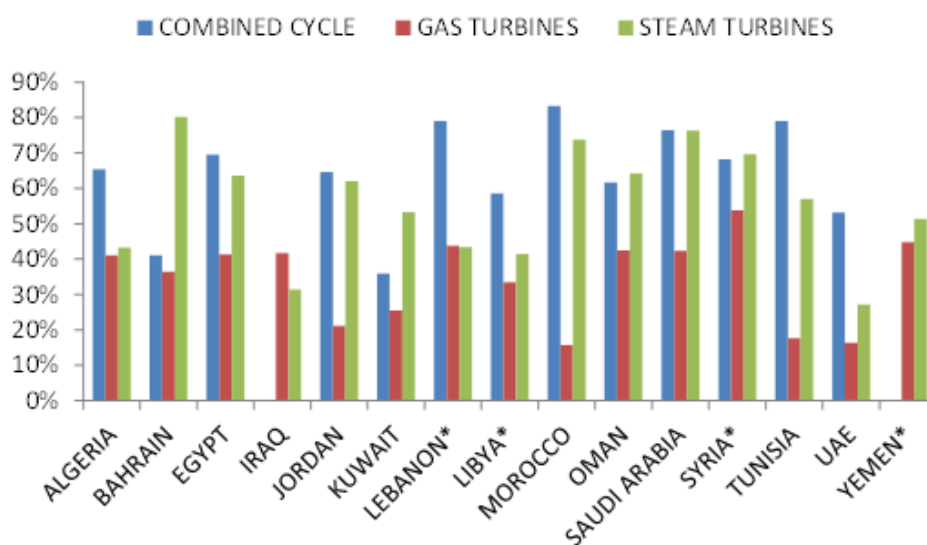


Source : COMELEC 2011

Demand for natural gas depends strongly on the operating rates of gas power plants, and in particular the functioning regime of these plants (peak load, intermediate load or Base load).

The operating rate of gas power plants, or usually named capacity factor, could be appreciated for the 3 existing types of thermal power plants (Steam Turbine ST, Gas Turbine GT and Combined Cycle CC). The chart below displays the operating rate of thermal power plants by type in the MENA region for 2012, and we can notice that Combined Cycles (essentially fueled by gas) have average operating rates exceeding 70% in most of MENA countries, indicating that these plants run mainly in base load regime.

**Figure 28: Thermal power plants' operating rates - 2012 (Electricity generated/ Electricity generated for full year functioning)**



Source: Arab Union of Electricity 2013

In 2012, the lowest CC operating rates are observed in the United Arab Emirates and Kuwait, which have recently experienced gas supply difficulties, and which have turned to other alternatives, mainly generation from oil (Oil Boilers -Steam Turbines), in addition to gas imports, to compensate their deficit in gas for power.

Gas turbines however, don't operate in most of cases in base load regime, with average operating rates below 40% in almost all MENA countries. These rates are particularly low in gas importing countries (Morocco, Tunisia for instance), which could be explained by the allocation of the bulk of gas imported volumes to CC power plants, having higher efficiency and operating in base load. In addition, gas is imported through contractual arrangements with defined quantities that support the allocation of important share of gas to the Base load power plants. Flexible gas turbines are more reserved to manage the balancing needs and thus operate mainly in peak load regime.

Gas turbine often use oil or oil products, in MENA Region, with important share of Gas turbines running on oil in Saudi Arabia and also in Iraq. According to ECRA<sup>25</sup>, around 40 .% of Saudi gas turbines are based on oil and oil products.

The average operating rate of the steam turbines are ranged for almost all the MENA countries between CC and Gas turbines, witnessing that these power plants can run in base load (such as in Saudi Arabia, 76%, Bahrain 80%) or out of base load (intermediate load mainly).The technical and economic characteristics of these plants make them less advantaged to operate in peak load<sup>26</sup>.

It is also worth noting that the non-availability and outage for maintenance of aging steam turbine power plants in many MENA countries are important factors affecting the operating rate of these plants

Steam turbines can run on gas, coal or on oil products (HFO in particular). Often, plants are designed to use both natural gas and oil products.

The analysis of the power sector in different MENA countries enables to identify a number of factors that affect the operating rates and functioning regimes of gas power plants including: i) The structure of power generation mix; ii) The cost of generating electricity and economic arbitrage between different types of power plants, iv) The structure of power markets and the modes adopted for power transactions (for instance: the existence of Take or Pay in power purchase agreements (PPAs)<sup>27</sup> with some generators, requires the provision of defined amounts of electricity and consequently affect the operating rate of plants), iii) the available power generation capacity compared to the required demand that affect the use and the load solicitations of the existing power plants' and expose them to high load solicitations in order to meet the demand; v) Balancing needs of MENA countries' power systems, which are dependent particularly on fluctuations of demand and also on variations of supply, requiring the use of flexible power plants to meet these balancing needs.

The evolution perspectives of the above mentioned factors determine the future operating rates of gas power plants and thus the amount of gas consumed.

Natural gas provides significant advantages in the Balancing of power systems with gas turbine emerging as a major contributor in this Balancing. Indeed, gas turbines usually offer

---

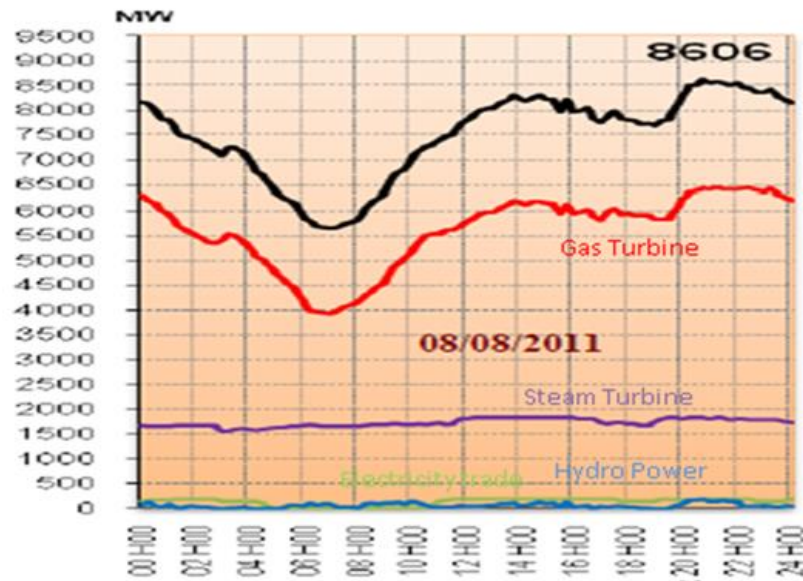
<sup>25</sup> Electricity & Cogeneration Regulatory Authority

<sup>26</sup> Regarding the Steam Turbines Efficiencies, costs and also their less operational flexibilities

<sup>27</sup> This is the case of BOOT contracts with independent power producers, adopted in several countries in the context of power sectors' reforms.

a lower cost for low operating rates, higher flexibility and shorter time response in starting and ramping up phase. This can be illustrated for the case of Algeria where Gas Turbines bring the great flexibility needed to cope with load curves;

**Figure 29: Algerian load curve for a summer day**



Source: OS 2011

Although some measures have been adopted in countries like Egypt for the conversion of Gas Turbines to Combined Cycles in order to improve power plants' efficiencies, the additional investment cost could reduce the attractiveness of these plants to operate in peak load regime.

Oil and oil products keep an important share in producing electricity in MENA region. Despite high oil prices and a clear willingness to reduce oil consumption in this sector, a large part of oil-fired power plants (steam turbines in particular) continues to operate in base load or intermediate load with an average operating rate often exceeding 50%. (~80% for Saudi Arabia). Oil products is also consumed in diesel group generators which are often used to supply remote locations (Algeria) or provide electricity in countries exposed to high power shortages and discontinuity of supply (the case of Iraq)

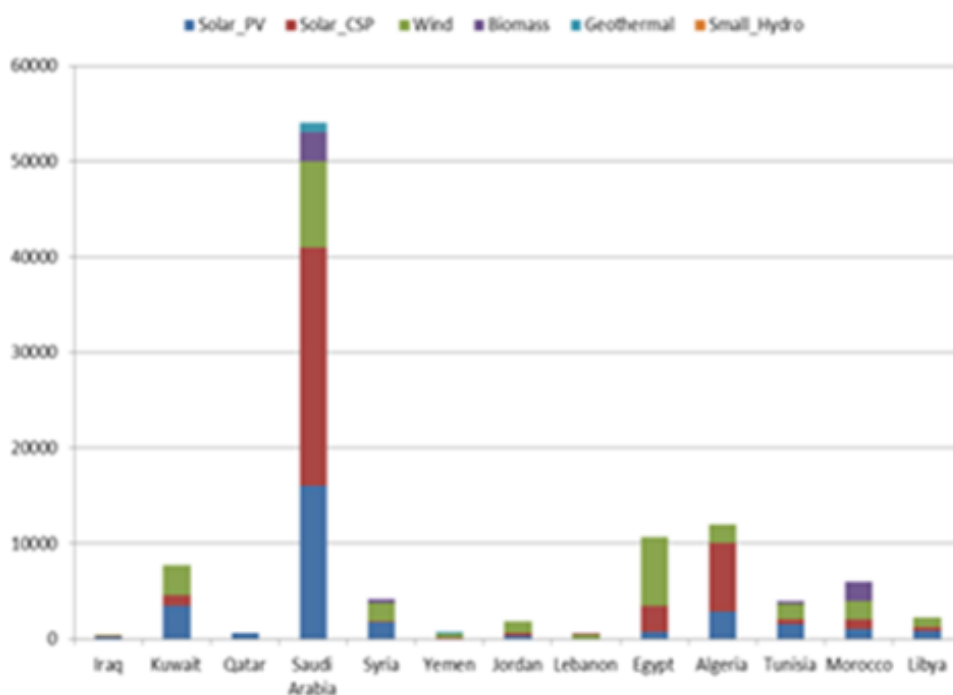
The existence of fuels' flexibility (oil / gas, ) in thermal power plants, particularly the steam turbine and gas turbine power plants allows to manage between the use of oil and gas, but the gas supply constraints observed in a number of MENA countries has contributed to increase the consumption of oil in power generation. The case of Saudi Arabia is very representative in this regard. Indeed, the available gas is often allocated in priority to industry (petrochemicals in particular) leading to increase the use of oil in power generation, particularly during the summer season where the consumption of oil to power could reach more than double of its level in winter..

The hydropower dependence on seasonal availability of water resources and on the regulation of dam discharges, mainly because of the irrigation needs, leads to high outputs' variability that requires thermal power plants to assume balancing role (it is mainly the case of Egypt and Morocco where hydropower represents more than half of the MENA hydro installed capacity)

Despite the low share of renewables (excluding hydro) in MENA, the expected increasing trends of these sources in power generation mix, according to the ambitious targets announced in many MENA countries, would affect significantly the operating rates of thermal power plants and could also increase the balancing needs because of the renewable intermittence.

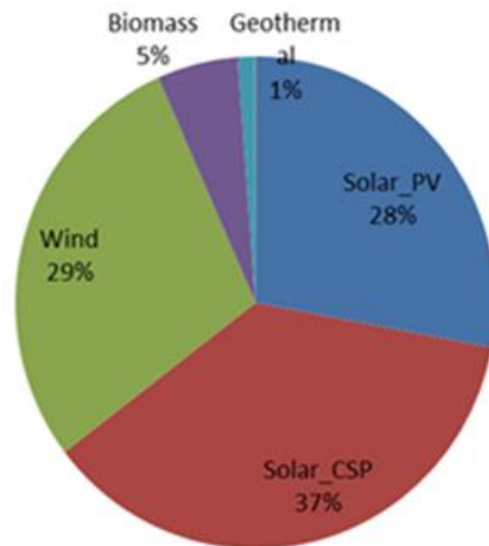
However, the important planned share of CSP power plants, usually associated with storages which provide some flexibility to manage CSP output variability, would play against increasing the needs of thermal balancing for renewables power plants. In addition, it is worth noting that higher levels of renewable power generation in MENA countries (including even the wind power generation profiles observed in some countries<sup>28</sup>) often coincide with periods of high electricity demand and thus high load of power networks.

**Figure 30: Renewables capacities' perspectives according to the countries targets by 2030 horizon (MW)**



**Figure 31: renewables capacities per type by 2030 horizon (%)**

<sup>28</sup> According to the observations in countries with installed wind capacities like Morocco and Egypt



Source: RECREEE 2013

National electricity companies have a dominant share in installed power generation capacities, and they continue to play a key role in the provision of operational reserves and flexible capacities to ensure the balancing and safe operations on the power systems. These companies usually support the additional costs related to keep and maintain power plants which run at relatively low operating rates in order to provide balancing flexibilities.

Independent producers are often bound by Take or Pay purchase agreements that require them to deliver defined quantities of electricity to the single buyer. This has a direct effect on the operating rate of gas power plants owned by independent producers which usually run in base load regime. It is worth to note that the single buyer model (or variants of this model) is the scheme adopted in almost all MENA countries that have undertaken some reforms of their power sectors.

### 3. Future role of gas in power generation: an uncertain outlook

Despite the strong growth of gas in MENA power generation experienced in the past, which is driven by a number of determinants mentioned above, many uncertainties are characterizing the continuity of this growth and the role natural gas will play in the future of the power sector. These uncertainties would affect i) electricity demand perspectives and the additional capacities to be installed, ii) the share of gas in future power generation mix and iii) the operating rates of the installed gas fired capacities. So, what are the main uncertainties that we can identify to draw future prospects for gas for power in MENA region?

Beyond the geopolitical risk that characterizes many countries in the MENA region, we can identify a number of uncertainties with potential high effects on the role of gas for power generation:

- **Economic growth** in MENA region and particularly the **GDP structure of the resource-dependent economies**. The success of diversification policies is a major challenge for these economies;
- **The progress of liberalization reforms** which has been undertaken in many MENA countries and whose main objectives are i) to increase the contribution of private sector in financing new power generation capacities, in a context of a huge investment required to satisfy growing electricity demand; ii) to improve efficiency in the management of power

sector through the introduction of competition and unbundling of activities, iii) to focus the efforts on managing and strengthening power networks and infrastructure, in order to reduce inefficiencies and large power losses, iv) to enhance and strengthen the regulation of power sectors.

- Many analysts have pointed out that the power sectors reforms engaged in MENA countries have achieved an important progress but have not reached the targeted structure of power market, which is to build a wholesale competitive market. Almost all the MENA countries having undertaken reforms of their power sector have adopted a single buyer model or variant of single buyer model which could be an intermediary stage, and thus there is a possibility for further progress. Some countries like Egypt or Saudi Arabia have announced their strong willingness to make more progress in liberalization reforms.

The investment for the development of new power generation capacities (such as renewables) and for the strengthening of electricity networks, constitute a major challenge in MENA region, particularly in some countries where public power sectors are very indebted. In this regard, the progress of reforms, the evolution of the structure of power markets and the future role of different actors in these markets, including independent operators and national companies, will be important drivers affecting significantly funding and investment levels in power generation.

- **The evolution of domestic electricity prices** and more generally of domestic energy prices<sup>29</sup>, with regards to the measures announced or already adopted in many countries (Iran, Egypt or Jordan), aiming to reduce large subsidies granted to energy sector. It is worth noting that although the engaged measures to increase prices in some MENA countries were more focused on levels of prices than on the structure of pricing, more progress in the power sector liberalization reforms if it will occur in some MENA countries could also affect the electricity pricing structure and consequently the levels of electricity prices
- **Effect of energy efficiency measures** which are announced or under implementation in many MENA countries. Indeed, energy efficiency is increasingly becoming an important topic, even in the oil rich GCC countries (Saudi Arabia and UAE in particular). This marks an increasing awareness of the need to change energy consumption patterns, that are not compatible with sustainable development
- **The development of alternative sources of electricity generation**, mainly renewables but also nuclear energy and even coal which has been announced in countries like Egypt.
- **The development of electricity trade and of networks' interconnection**, within MENA region and also between Europe and MENA region, in the framework of different proposed initiatives for regional integration (GCC Integrated Network, Maghreb Integrated Network , DESERTEC<sup>30</sup>, and Mediterranean Solar plan (MSP)).
- **The evolution of MENA gas supply**, and essentially the evolution of production profile in producing countries, which could have a significant effect on gas demand in power generation, both in gas producing and gas importing countries, since an important share of gas is sourced within the MENA region. Gas supply difficulties have led some MENA countries to use other than gas in power generation. For instance: Saudi Arabia has opted for the continued use of oil as important source of electricity generation because of gas challenges<sup>31</sup>.

---

<sup>29</sup> Energy subsidies are usually as a package including electricity and other energy sources .

<sup>30</sup> Desertec is an important Deserts' power project aiming to develop large electricity exports' capacities, based on renewable energy (solar in particular and wind), from the deserts in North Africa and Middle East to Europe. The project has been supported by the Desertec Industrial Initiative (DII) which includes big industrial partners and the Desertec foundation. Desertec foundation has however withdrawn from the DII initiative in 2013, following difficulties in communication and coordination between the partners. Desertec Foundation and DII representatives are nevertheless saying that they keep their projects and initiatives.

<sup>31</sup> For example: Royal decree was established in 2006 to transform in oil fired power plant one of the biggest power plants in country planned initially to run on gas,

#### 4. Gas supply in the MENA region

It is often cited that the MENA region is experiencing a paradox<sup>32</sup>: On the one side, very large gas resources, with recent optimistic estimates of gas potential in this region which remains under explored, and on the other side, domestic gas availability concerns to satisfy the rapidly growing domestic needs and exports, leading some producing countries to turn to imports, particularly of LNG.

It should be noticed that several factors have affected the pace of MENA domestic supply evolution, especially in the countries experiencing gas shortages and difficulties. These factors include i) the level of Exploration & Production investments, which is considered by many experts, as not in line with the potential and requirements of MENA region, ii) delays observed in the development of major projects and iii) the substantial increase in the cost of upstream projects.

According to Barclays Research estimates, Exploration and Production expenditures in Middle East and Africa have observed a significant decrease after the peak of 2008<sup>33</sup>. Nevertheless, The E & P spending rebounded from 2011/12, driven by the Middle East investment growth with Saudi Arabia taking the lead of this growth.

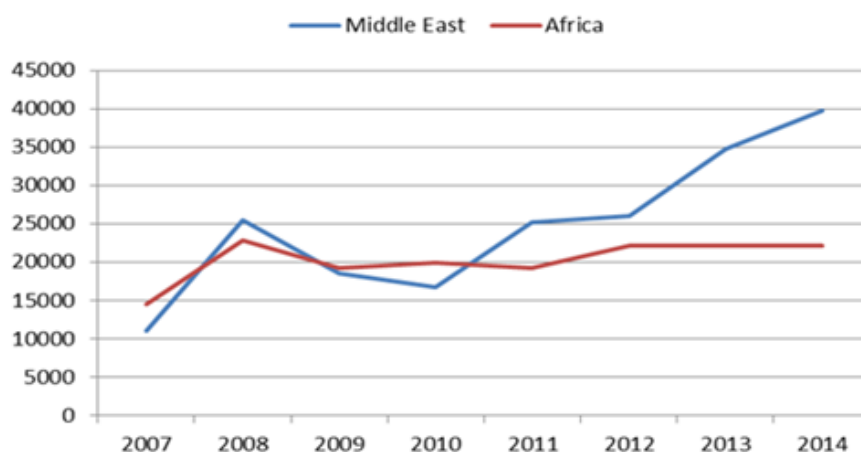
---

<sup>32</sup> Weems, Philip & Midani, Farida, 2009, A Surprising Reality: Middle East Natural Gas Crunch

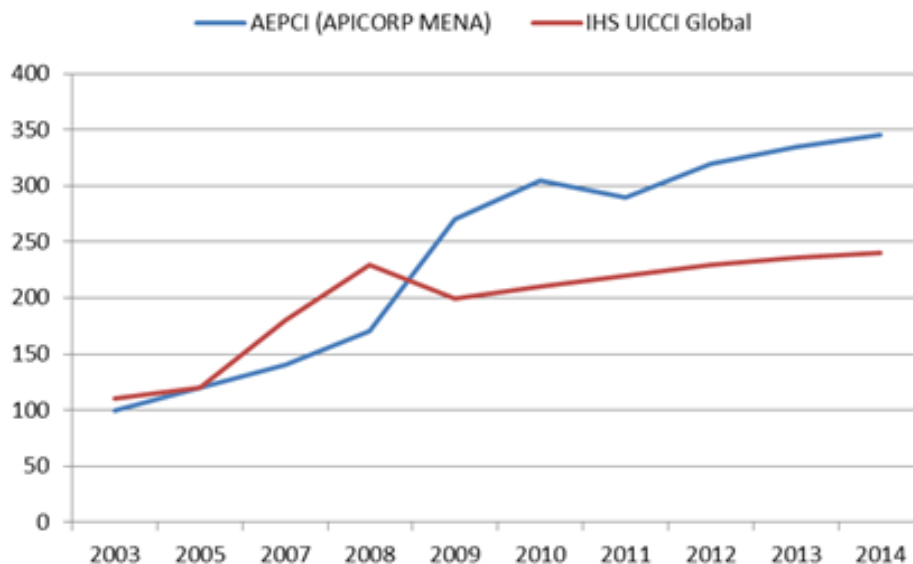
<sup>33</sup> This peak has been driven by the high oil and gas prices' increase experienced on the international markets on 2007.



**Figure 32: E&P spending in Middle East and Africa (M.\$)**



**Figure 33: Upstream costs index (World Vs. MENA Region)**



Sources: Barclays Research 2012, Apicorp (set at 100 in 2003), CERA IHS (set at 100 in 2000)

Exploration & Production capital expenditures were also affected by cost inflation of upstream projects. Indeed, a significant part of the increase in E & P capital spending is related to the increase of projects' costs, which has had a non-negligible effect on the expected development of additional gas production capacities in MENA Region and also led many investors to revise sharply their investments' budgets.

The cost inflation of upstream projects is driven mainly by the significant increase in EPC costs, raw materials costs as well as constraints on skilled labor.

If we refer to the IHS global upstream capital cost index (UCCI) which is an indicator of the evolution of average upstream projects' costs on global scale, we can see that these upstream costs almost doubled over the last decade. However, MENA upstream costs has more than tripled last decade, according to MENA upstream Cost Index published by APICORP, showing, showing a much larger increase than global average upstream costs. This increase is mainly

linked<sup>34</sup> to high risk investment premiums applied by upstream contractors, and to additional costs owing to the observed delays and costs overruns of some major MENA upstream projects.

The future of natural gas production profiles in the MENA region depends mainly on **the potential resources available in different MENA countries**, as well as on **E&P investment efforts made by these countries** in order to renew and consolidate their reserve base and also to develop the existing potential.

The potential of conventional gas resources in the MENA region remains very high with, proven reserves estimated at 88.4 tcm<sup>35</sup> (45% of world reserves), and technically recoverable undiscovered resources estimated at 26.6 tcm by the USGS<sup>36</sup> (representing 17% of potential worldwide resources that remain to discover). In addition, the potential of reserve growth and increasing recovery from discovered deposits is estimated at about 29 tcm (USGS). In addition, the potential of reserve growth and increasing recovery from discovered deposits is estimated at about 20 tcm (~20% of the known reserves estimated by USGS)<sup>37</sup>.

Basing on USGS assessments, the technically recoverable conventional resources are then estimated at about 144 tcm. However, APICORP<sup>38</sup> estimates this level of resources at about 163 tcm; these estimates include the undiscovered potential from other basins which was not assessed by USGS. If we consider the cumulative MENA gas production from origin (around 10 tcm in 2012), the remaining technically recoverable conventional resources is estimated at 134 tcm by USGS and 162 tcm by APICORP, representing more than 93% of MENA ultimate gas resources.

Adding to these technically recoverable resources, MENA region is well endowed with unconventional resources including shale gas, estimated at about 28 tcm according to EIA estimates. Most of this estimated potential (nearly 20 tcm) is located in Algeria, which is the 3<sup>rd</sup> country in the world in terms of shale gas resources after China and Argentina. It is worth noting that the boundaries between conventional and unconventional resources are often difficult to identify and could be significantly revised with the technology progress.

Despite high potential of conventional and unconventional gas resources in the MENA region, significant dipartites do exist between different countries and we can see in the chart below estimates of gas potential by country:

---

<sup>34</sup> According to APICORP, Investment for Energy: Looking Beyond Conventional Determinants - Economic Commentary Vol 8 No 11, 09/ 2013

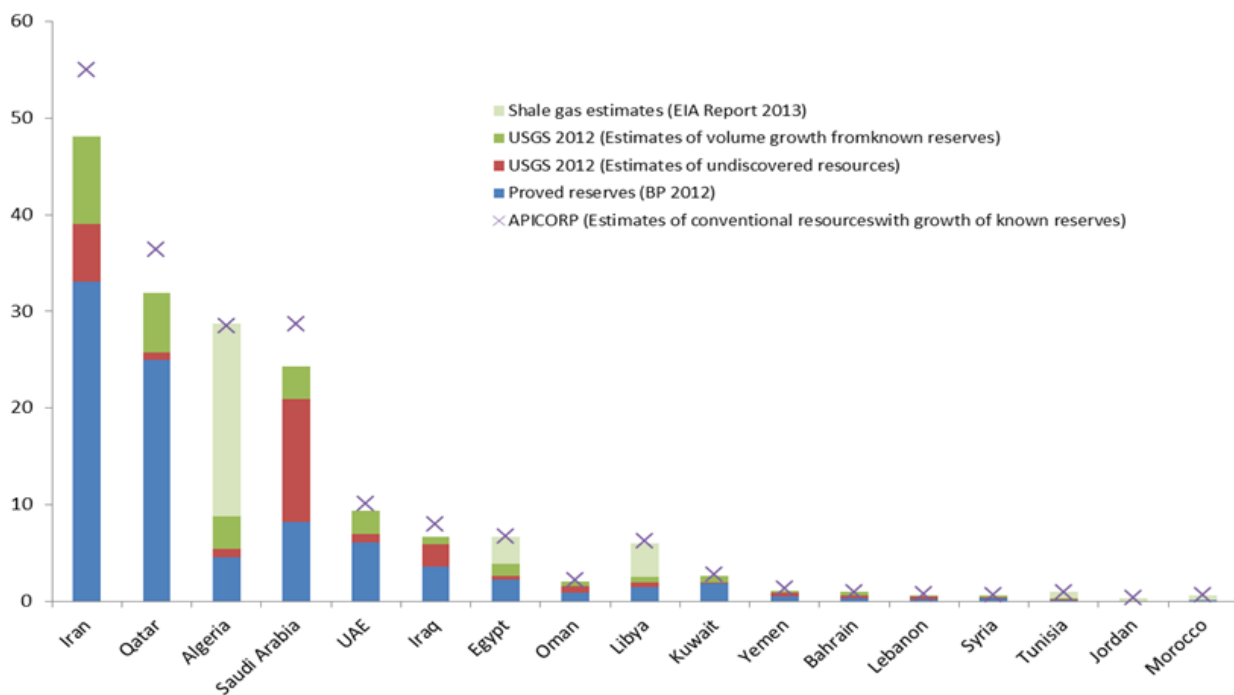
<sup>35</sup> BP Statistical Review 2012

<sup>36</sup> The U.S. Geological Survey 2012 World Assessment of Undiscovered Oil and Gas Resources

<sup>37</sup> Vol 7 No 12, Dec 2012: MENA Natural Gas Endowment Is Likely To Be Much Greater Than Commonly Assumed

<sup>38</sup> Vol 7 No 12, Dec 2012: MENA Natural Gas Endowment Is Likely To Be Much Greater Than Commonly Assumed

**Figure 34: Gas resources in MENA countries (TCM)**



Source: Estimations USGS, APICORP 2012

It is appropriate to note that many factors and uncertainties are playing against investments in exploration and production in the MENA region, and their evolution will affect significantly the gas production developments. Therefore, gas production scenarios can be drawn according to the evolution of the main uncertainties characterizing E&P perspectives and results.

Beyond geopolitical problems and risks characterizing some MENA countries, principal uncertainties affecting the prospects of E&P investments perspectives are:

- **Uncertainties on international oil and gas prices** and on the conditions of valuation of MENA countries hydrocarbon exports;
- **The Lack of visibility on international gas demand**, with recent markets' evolutions, particularly in Europe, that have increased the investment risks of the upstream capital intensive projects;
- **Low level of gas prices on the MENA domestic markets** that are experiencing a significant demand growth and which are often given priority in gas supply;
- **Project financing constraints** with on one side the tightening of external financing, including loans and the capital contributions from international investors, and on the other side, uncertainties on internal financing that includes national companies' equities, governments' loans and contributions, depending essentially on hydrocarbon revenues;
- **The technical complexity of new non-associated gas projects and their costs;**
- **Attractiveness of the regulatory environment for investment:** For example, we can notice in this regard that the change of rules and of upstream conditions and their renegotiation in countries experiencing governance change in the context of Arab spring, are important factors affecting 'investments decisions and leading to delay in the execution of upstream projects.

- **Evolution of upstream investment environment and role of different actors and companies in the development of resources:** An important share of exploration and production investments in MENA region is carried out by the MENA national oil and gas companies (NOCs), which have recently stepped up efforts to develop the gas resource potential. A non-negligible portion of these resources is complex and technically challenging, whose development and exploitation would generate higher costs and risks than those previously experienced in the region.
- The development of these complex resources may therefore require the use of advanced technology and international expertise. In this regard, the resources' accessibility and the attractiveness of MENA countries to foreign investments would be an important factor, enabling rapid and efficient development of these resources. This upstream investment attractiveness of MENA region is more and more important since the region would have to compete with other regions in the world having the potential resources and the environment to attract these investments.
- In order to meet the development challenges of their gas resources and to attract foreign investors who provide necessary funding and technical expertise. MENA countries need to improve the project profitability conditions and also the investment environment by providing facilitations and incentives that allow risk compensation, especially in immature and still under explored areas. We see that many efforts have been done by MENA countries in this regard. For instance, Saudi Arabia whose the upstream domain is not used to be open to foreign companies, have invited these investors to prospect in the region "Rubh El Khali" with the aim to bring expertise and share the risk. Abu Dhabi also have signed with international companies for the exploration and development of a sour gas project. Algeria has also done efforts by giving more incentives<sup>39</sup> for the development of challenging projects. Algerian National Company Sonatrach has even taken on its own the development of important transport infrastructure in order to enable the evacuation of gas produced in remote areas in the south west of the country.

## 5. Gas exports' potential Vs. Gas for power growth in MENA Region

Despite the great potential of gas resources in the MENA region, we can notice if we look at the gas exports' level in 2013 that two countries, Algeria and Qatar, provided around 3/4 of the MENA exports' volume, estimated at about 217 Bcm<sup>40</sup>.

For the other MENA exporting countries, the share of exports in gas supply<sup>41</sup> is significantly lower than internal gas consumption (See chart below). This share usually reflects a strategic choice, particularly in the cases of oil rich GCC countries and Iran, to dedicate gas resources for the domestic market in order to make more oil available for exports and thus increase exports' revenues. **However, gas demand growth perspectives and the development of export opportunities on the international markets could highly encourage these countries to significantly develop their gas exports' potential.**

The imports of gas by some MENA countries, including those countries that are well endowed with gas resources, allow them to cope with the rapid development of internal gas demand, especially in power generation. In 2013, MENA gas imports have reached 33 bcm of which about 82% came is imported from within the region. Qatar has provided around 23 bcm (mainly volumes exported via the Dolphin pipeline estimated at 20 bcm) followed by Algeria which supplied 3.2 bcm to its neighbors (Morocco and Tunisia).

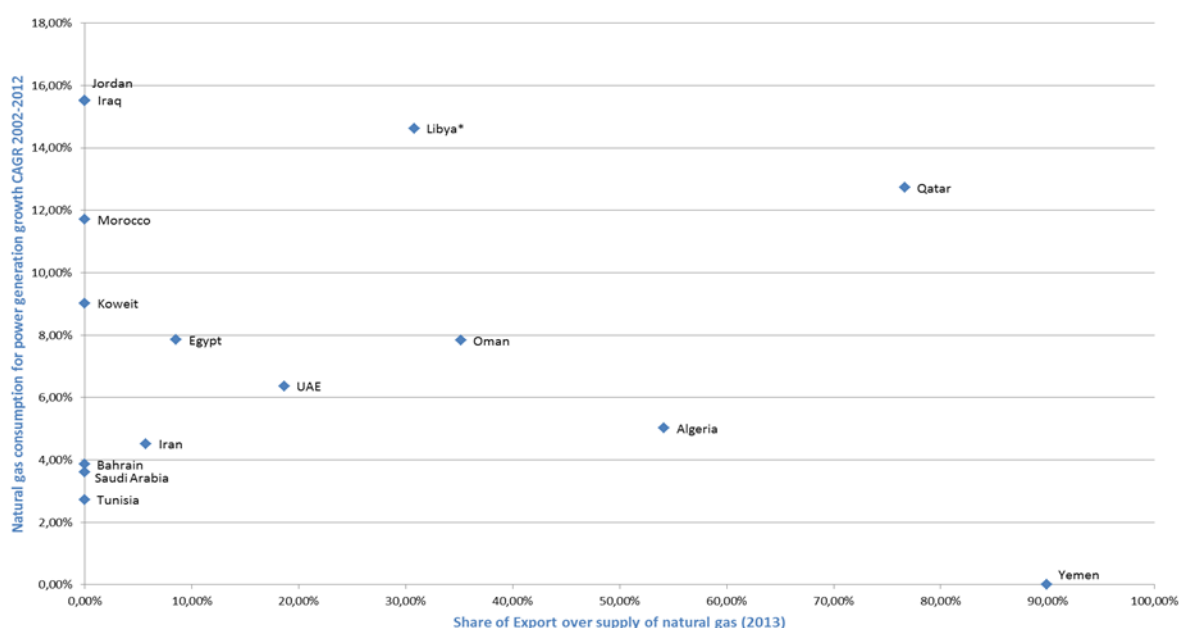
---

<sup>39</sup> In the context of the amendments of the Algerian Hydrocarbon Law

<sup>40</sup> BP statistics, CEDIGAZ 2013

<sup>41</sup> Gas supply includes both domestic production and imports.

**Figure 35: Share of exports in MENA countries Vs. gas for power growth**



Sources: BP statistics, CEDIGAZ 2013 for production & trade – IEA statistics for gas for power growth -\* 2011 numbers used for Libya

It is worth to note that 3 MENA countries are both importers and exporters of natural gas (Iran, UAE, Oman). These countries imported in 2013, 27 bcm (of which 20 bcm imports for UAE) and exported 28 bcm (of which 19 bcm as LNG exports from UAE and Oman).. Egypt will be soon the fourth country joining this category of MENA countries

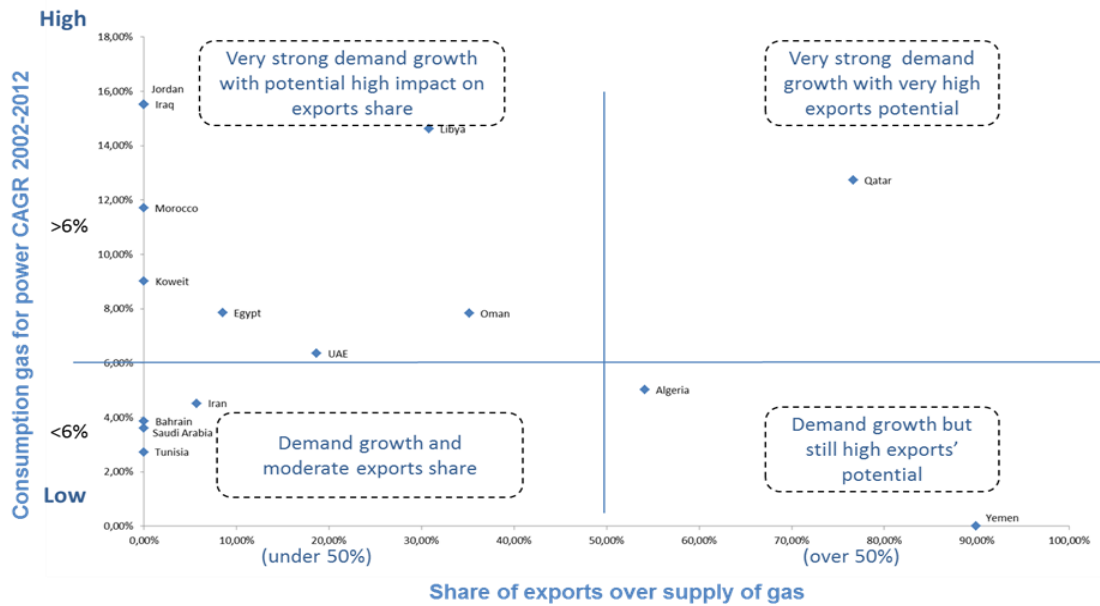
The consideration of a matrix confronting the MENA countries’ export potential<sup>42</sup> and the demand growth in power generation allows to identify four categories of countries (Chart below):

- Very strong gas for power growth (annual growth over the last decade higher than 6%) with very high export share (export share > 50%): Qatar emerges alone in this category.
- Gas for power growth but still high exports' potential: this group includes Algeria, which has a large export potential and also Yemen with a small size of its domestic market, and gas dedicated mostly to exports.
- Very strong gas for power growth with high potential impact on exports' share: this category includes several exporting countries in the MENA region, whose export potential is challenged by the domestic gas market and some of these countries are considering the option to import gas to meet the rapid growth of gas demand, mainly in power generation.
- Gas for power growth and moderate exports' share: Iran is part of this group with on one side, a gas for power growth which is below than what have been observed in other MENA countries, and on other side, an export share which remains relatively low because of most of gas is oriented to domestic market.

In addition to the gas exporting countries, other countries in the MENA region have seen a steady growth in gas for power demand. Some of these countries are important producers like Saudi Arabia and to lesser extent Bahrain; the others are gas importers sourcing their gas mainly from MENA exporting countries like Jordan, Tunisia and Morocco.

<sup>42</sup> expressed as a share of exports in the available gas supply (production + imports)

**Figure 36: Share of exports over supply of gas in MENA countries**



### MENA Scenarios

In order to identify future scenarios for the MENA region, we consider two strategic axes: i) Gas for power growth and ii) Gas exports' potential. So, scenarios can be described according to the future growth dynamics of gas demand in power generation and to the potential gas exports of the MENA region. Uncertainties and determinants characterizing the demand and supply of natural gas in various MENA countries could then be appreciated and assessed for each scenario<sup>43</sup>.

#### Scenario 1: High Exports share with sustained gas demand growth in Power Generation ("MENA Gas Optimistic scenario")

- This scenario is characterized by a significant development of the huge MENA gas potential, making available important gas supply which enables to support both high exports' volumes and growing gas domestic demand, particularly in the power generation. This scenario is therefore driven by the availability of supply that allows to sustain the priority of growing gas domestic markets in the MENA region.
- Gas producing countries with a high potential for resource development, such as Iran, Qatar and Algeria are the drivers in this scenario. These countries would increase their gas production, and would generate large gas surpluses for exports.
- Iraq and Saudi Arabia, which are not yet gas exporters, will be able to increase their production and to play a significant role as supply centers in the MENA region. These countries would export part of their production surpluses. It is also assumed that Iraq can recover a large share of associated gas whose significant part is currently flared.

<sup>43</sup> It is clear that in reality, the MENA countries could be in different future situations or scenarios, because of the characteristics and evolutions' dynamics of these countries. However, our main objective is to clarify the conditions that allow different MENA countries to be in a specified scenario and to assess the potential effect on MENA gas supply/demand balance and thereby on the gas exports' potential.

- UAE, Egypt, Oman, Kuwait, and even Bahrain maintain a significant level of production and also will have gas imports' capabilities, which give them additional flexibility to supply their domestic markets and also international markets.
- Exporting countries in the MENA region continue to provide a significant share of gas volumes imported by the MENA importing countries (Tunisia, Kuwait, UAE and even Egypt), but at prices which are significantly affected by international gas prices, given that MENA exporters' would have to arbitrage between exporting gas to these MENA markets or to other profitable markets.
- Scenario 1 will observe a significant increase of E & P investment, especially in countries with substantial resources. Thereby, the conditions supporting this upstream development of gas resources and also gas exports are met, including mainly oil and gas prices perspectives, gas demand in consuming markets and exports' opportunities, and MENA investment environment

### **Scenario 2: High Exports share with moderate gas demand growth in Power Generation: ("Reduced MENA Gas demand scenario")**

- This scenario is characterized by positive development of the MENA domestic supply, following efforts led by MENA countries, especially those endowed with significant gas resources, in order to ensure the replacement and sustainability of their hydrocarbon reserves. However, a slowdown of natural gas demand over the long term will be the key driver leading to generate significant surpluses for exports.
- In this scenario, the slowdown of gas demand is mainly resulted from the efforts deployed and the success of many MENA countries in improving energy efficiency and reducing gas consumption, particularly in the power generation which has a huge potential for efficiency improvement and fuel Mix diversification<sup>44</sup>.
- Gas producing countries in the MENA region, particularly those which have initiated policies and measures to curb energy demand growth and to diversify power generation mix such as Iran, Algeria, Egypt and also Saudi Arabia and UAE (Emirate of Abu Dhabi in particular), will be able to significantly reduce the demand for natural gas particularly in power generation. This will allow them to have large gas surpluses that could be allocated to exports. The slowdown of gas demand enables also some MENA gas importers (or potential importers) such as UAE, Kuwait and Egypt to reduce the call for imported gas to satisfy their demand. Gas imports could be however used by these countries for optimizing and valuing the flexibility they have to import and export gas volumes.
- On the other side, the reduction of gas demand and the possibility to monetize more gas in attractive international markets will contribute to attract more upstream investors, leading to positive development of supply, in particular from complex and challenging resources

### **Scenario 3: Moderate / low exports share with sustained demand growth ("Gas for growing MENA domestic markets scenario")**

- This scenario is characterized by, on one side a sustainable increase of gas MENA domestic demand, driven mainly by the power generation needs and, on the other side an evolution of gas production profiles which doesn't provide large gas surpluses for exports. In this scenario, gas exports' opportunities are highly reduced with regards to international gas markets evolution, and also oil and gas prices environment that will not provide revenues and incentives to develop gas value chains and to ensure expected profitability for upstream projects.

---

<sup>44</sup> The slowdown of gas demand may be also linked to unfavorable evolutions (geopolitical, economic difficulties) with a sustained negative impact on demand, but our focus in this scenario is on the impact of gas demand reduction through energy efficiency improvement and energy sources substitution in power generation.

- Gas producing countries will allocate significant portion of their gas production to their domestic markets, especially for power generation sectors, in order to support economic and population growths and also to create more value for their internal resources. Gas exports would go down, especially for countries with lower gas potential and which have already experienced supply difficulties to cope with the rapid development of the domestic market.
- The recourse to gas imports would be an increasingly considered option in this scenario, leading to increase gas imports' capacities. In this regard, the priority of domestic markets in the supply of MENA gas producing countries could be supported by reducing exports to international markets or also by increasing gas imports.
- For MENA gas importers, the diversification of supply sources through the development of LNG capacities is used as a lever to secure gas supply, but cooperation agreements with well gas endowed MENA countries, could be privileged, in order to benefit from price advantages. The gas rich MENA countries could see these agreements as a good deal in order to avoid selling gas to less attractive markets observed in this scenario, with weak demand growth and less price levels than what is expected by MENA exporters.

#### **Scenario 4: Moderate / low exports share with moderate demand growth (MENA gas pessimistic scenario)**

- This scenario is characterized by significant and sustained slowdown in the development of the MENA gas resources, leading to a relatively pessimistic supply evolution, which would not allow many countries to generate large surpluses for exports.
- In this scenario, investments in exploration and production do not reach the expected levels and results. The various constraints that hinder these investments would persist over the mid to long term. Several producing countries with gas resources potential would not increase their production, in a context of gas valuation conditions which are less than their revenues' expectations. Indeed, international oil and gas prices' levels will not encourage gas value chain developments as well as the upstream investments aiming to make available new gas supply, particularly from complex and challenging gas deposits.
- Faced with gas availability constraints, the MENA countries would support the priority to supply their domestic market by reducing their exports to international markets, and also by increasing their efforts to reduce internal gas demand, especially in electricity generation which has a large potential for gas use reduction and fuels' substitution.
- The pessimistic evolution of gas supply will encourage some MENA countries to consider more and more gas imports option, especially in the context of moderate international gas prices characterizing this scenario, but these gas imports would be affected by the moderate growth and fluctuations of gas for power demand.

**MENA Scenarios' assessment:** In order to assess the different identified scenarios, we have considered a number of assumptions on the various uncertainties affecting gas demand and supply. These assumptions are consistent with the characteristics of each scenario.

In addition, we have elaborated a simulation model allowing to estimate for each MENA country future gas demand in power generation, on the basis of electricity demand perspectives, required capacities to satisfy this demand<sup>45</sup>, share of gas in power generation installed capacities<sup>46</sup>, gas power plants' efficiencies and also gas power plants' operating rates,

---

<sup>45</sup> Réf. Previous part describing various gas to power determinants.

<sup>46</sup> Required power generation capacities represent capacities to be installed taking into account, capacities' retirement, peak electricity demand perspectives, marginal reserves and also net trades of electricity



In our scenarios' assessment, we consider the 10 MENA Gas producers<sup>47</sup>, representing nearly 95% of regional gas production and also 95% of regional gas demand.

**Figure 37: Gas production Vs. Gas demand in different scenarios**



## 6. Role of gas in power generation

The comparison of gas demand levels in the considered scenarios shows significant gap between the gas optimistic scenario (Scenario 1: 1033 Bcm in 2035) and the most pessimistic scenario (scenario 4: 630 Bcm). The power generation is the sector which contributes the most to this gas demand gap<sup>48</sup>, showing therefore the great sensitivity of this sector to the various changing conditions that characterize different scenarios.

### Scenario 1 (“Gas optimistic”) and scenario 3 (“Gas for domestic markets”): Strong growth of gas demand in power generation

- Scenarios 1 and 3 will see the strongest growth in gas for power demand, owing mainly to the dominance of gas fired power plants in installed power generation capacities in most of the MENA countries (considered in our assessment). Power generation capacities will indeed experience an important development to cope with the strongly growing electricity demand forecasted for these two scenarios.
- For scenario 1 (“Gas optimistic” scenario), the high availability of gas supply provide large competitive advantage to this fuel in power generation. Gas prices and electricity continue to be administered at low levels compared to international prices.
- For scenario 3 (“Gas for domestic markets” scenario), natural gas maintain globally an important share related to, in addition to the gas techno-economic and environmental advantages, the willingness of MENA gas producers to use gas for their internal markets, in power generation and also in industry. However, gas demand in the power generation is lower in this Scenario 3 compared to Scenario 1 (“Gas optimistic”); this difference is mainly related to less abundant gas supply, in the context of less attractive oil and gas international prices and less exports’ opportunities, affecting negatively upstream projects’ profitability in scenario 3 (“Gas for domestic markets”).

<sup>47</sup> Algeria, Egypt, Saudi Arabia, Qatar, Kuwait, Iran, Bahrain, Iraq, Oman, UAE

<sup>48</sup> Scenario 1: 424 bcm Vs. Scenario 4: 192 bcm, repres

- The difference between gas for power demand in “Gas optimistic” and “Gas for domestic markets” scenarios is estimated to more than 100 bcm, this difference is observed particularly in countries experiencing gas development challenges like Egypt, Saudi Arabia and UAE, which will see more use of alternatives to gas power generation capacities, including oil fired power plants.
- For the two above considered scenarios, Natural gas is used in the increasing CC and Gas Turbines power plants’ capacities, the latter offer cost’ benefits, short lead times and also operational flexibilities. They are also used for the balancing needs driven mainly by highly fluctuating load curves, especially in “Gas optimistic scenario”, where the residential and commercial sectors continue to dominate the MENA electricity demand, leading to important fluctuations in load curves.
- The national power companies in the main MENA countries will play important role in the development of power generation capacities, although these companies would face funding challenges in Scenario 3 (“Gas for domestic markets”) in a context of lower hydrocarbon exports’ revenues characterizing this last scenario, which put strains on the MENA governments’ financing supports and encourage them to push for more progress in power sector reforms. In this regard, scenario 3 would observe more capacities operated and developed by independent power producers, especially gas based capacities

**Scenario 2 (“Reduced gas demand”) and scenario 4 (“Gas pessimistic”): slower progression of gas for power demand, with a decrease by 2035 in scenario 4**

- Scenario 2 would experience slower growth in gas for power demand, driven mainly by MENA countries efforts to reduce this demand, through the development of alternatives to gas in power generation (renewables in particular) as well as through the improvement of gas power plants’ efficiencies. Gas to power demand would be reduced in this scenario by more than 1/3 comparing to “Gas optimistic” scenario (Scenario 1).
- The MENA power systems and infrastructures would see a significant improvement in this (“Reduced gas demand” scenario), with the reduction of energy losses, enhancement of efficiencies both in the energy processing and energy end use. These improvements will be particularly achieved in countries like Algeria, Egypt, the United Arab Emirates, Saudi Arabia and Iran. These countries have already set up energy efficiency policies with a number of measures and actions already launched.
- Development of power generation alternatives and improvement of energy efficiency in the power value chains are largely supported by the significant increase in electricity and gas prices, following the important subsidies’ reduction which would be implemented in several MENA countries.
- In addition, power system reforms will see significant progress and positive results in many MENA countries, particularly those showing a strong desire to make progress in these reforms (Egypt, Saudi Arabia, UAE), leading to enhancement of power systems’ performance, more participation of independent and private investors in the development and operation of power generation capacities, and higher penetration of market mechanisms in the formation of electricity prices.
- The scenario 4 (“Gas pessimistic” scenario) will see the slowest growth, and even a decrease in gas for
- power demand over the long term. Indeed, it’s forecasted that gas consumption in power generation in 2035, will be less than the current levels, representing a reduction of about 30% comparing to this demand in scenario 2 (“Reduced gas demand” scenario) and nearly 60% comparing to the MENA “Gas optimistic” scenario.
- This scenario is characterized by a pessimistic evolution of MENA gas supply, which will be largely below the important resources’ potential of the region. This evolution is driven by low oil and gas prices’ environment and by significant decrease in gas exports’ opportunities

- Faced with limited gas supply, several MENA countries would switch to other alternatives to gas in power generation and would reduce gas fired power plants shares in the installed capacities. The development of these alternatives is more important than in scenario 2 (“Reduced gas demand”), and many countries would exceed their announced targets leading to greater exploitation and development of their renewable potential.
- In the “Gas pessimistic” scenario, conditions that support rapid development of non-hydrocarbon power generation capacities are satisfied, including significant increase in domestic prices of electricity and fossil resources, significant participation of independent investors in the development of these capacities, high government and institutional support with successful implementation of several incentivizing mechanisms for renewables’ development.
- Renewable electricity exports are also strengthened; allowing diversification of export revenues, This scenario will see then a significant increase in intra and inter MENA power trades to support exports’ diversification and also to exploit complementarities between power networks.

## 7. Gas demand in other than power generation sectors

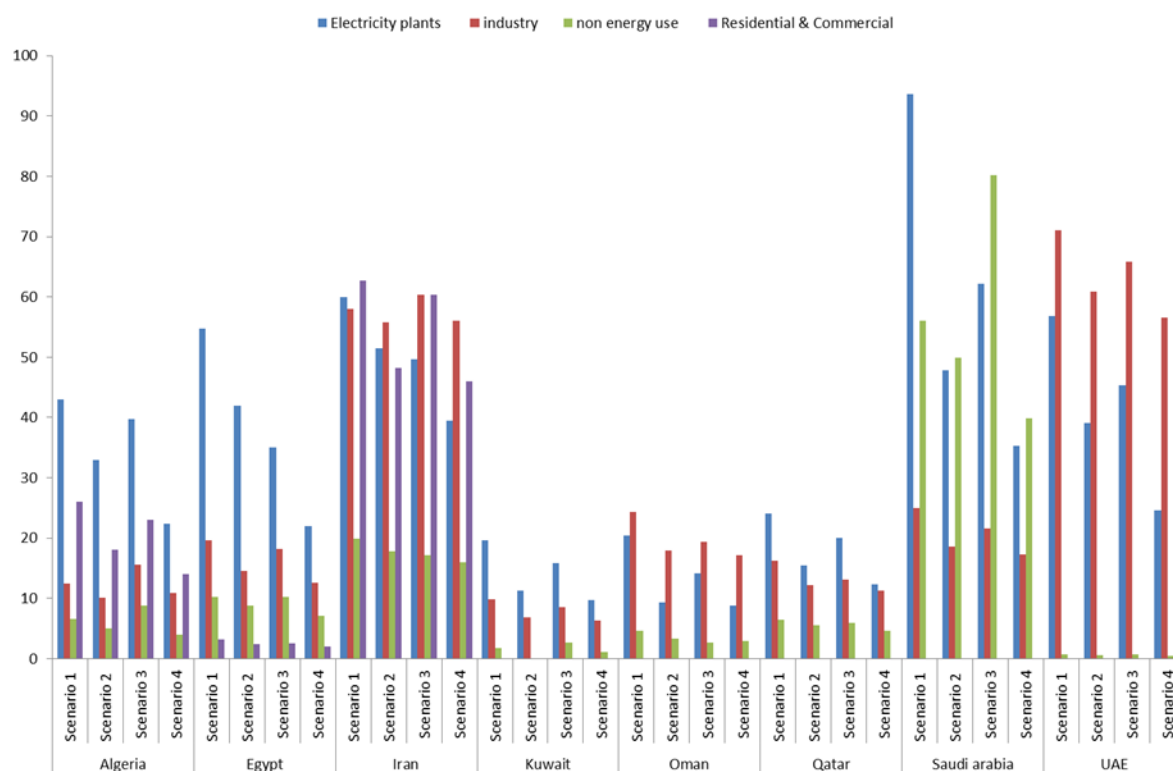
### **Scenarios 1 (“Gas optimistic”) and Scenario 2 (“Reduced gas demand”): large gas supply availability would support gas demand growth in different economic sectors.**

- In these scenarios, the availability of a large gas supply will support gas demand increase in different economic sectors, particularly in the industry which is expected to see a positive dynamic in many MENA countries, in line with economic diversification efforts.
- The “Reduced gas demand” scenario 2 is characterized however, by less gas demand in the other economic sectors than in “Gas optimistic” scenario 1, owing to large efficiency improvement, which will affect both the consumption of gas and of electricity. In our MENA countries’ assessment, gas demand in industry (including petrochemicals) is forecasted to be around 17% (~60 bcm) less in scenario 2 comparing to “Gas optimistic” scenario 1 by 2035. This difference is however significantly reduced (around 20 bcm) in residential and commercial sectors, since gas is mainly consumed in 3 MENA countries namely Iran, Algeria and Egypt.

### **Scenario 3 (“Gas for domestic markets”) and Scenario 4 (Gas pessimistic”): less gas exports’ revenues encourage the internal use of gas in creating more added values for MENA gas producing countries**

- In these two scenarios, gas exports’ revenues are below the expectations of gas projects’ developers, encouraging MENA producing countries to use gas in sectors creating added values for their economies, such as industrial sector and particularly energy intensive sectors including petrochemicals. This internal monetization of gas enables to support economic diversification and to compensate less hydrocarbon exports revenues considered in these scenarios.
- Therefore, internal gas demand growth in scenarios 3 and 4 are forecasted to be relatively high, especially in scenario 3 characterized by a greater availability of gas supply than the pessimistic scenario 4.
- In the latter scenario 4, the industrial sector would experience a significant growth in many MENA countries, despite less availability of supply. This could be explained by the allocation to this sector of the gas volumes that can be issued from less use of gas in power generation. Indeed, the industry and petrochemical (N. energy use of gas) are forecasted to represent in scenario 4 more than 45% of gas demand in 2035 in our MENA countries’ assessment, against 30% in 2012.

**Figure 38: Gas demand in different economic sectors by 2035 in MENA gas producing countries**



Source: Study assessment

## 8. The evolution of the natural gas supply

The level of gas production can change significantly between different scenarios. In our assessment, the production in 2035 could be from 630 bcm in the most pessimistic scenario (Scenario 4) and more than 1300 bcm in the optimistic scenario (Scenario 1). This difference marks the great uncertainty regarding the evolution of gas production over the long term, depending on the changing upstream investments determinants and conditions considered in the different scenarios.

### **Scenarios 1 (“Gas optimistic”) and scenario 2 (“Reduced gas demand”): Development of significant gas production in the context of favorable upstream investments’ conditions.**

- Production in “Gas optimistic” and “reduced gas demand” scenarios would observe significant growth, driven mainly by the growth in the most promising MENA countries namely Iran, Qatar, Saudi Arabia, Algeria and Iraq. However, the production would increase more in “Gas optimistic” scenario comparing to the “Gas reduced” scenario, given the need to satisfy a much more significant domestic demand for natural gas, while maintaining important export levels. The estimated production gap between the two scenarios is more than 200 bcm.
- In the “gas optimistic” scenario which is characterized by gas abundance, high international prices of gas and also of oil will encourage MENA countries to seize gas and also oil exports’ opportunities. Indeed, significant substitution of gas to oil would be undertaken, which would further support gas demand in power generation.
- Scenario 2 (“Reduced gas demand”) would observe a relatively greater participation of foreign investors than ‘gas optimistic” scenario, which allow significant gas resources’ development, including complex resources, unconventional and sour gas. This participation is encouraged by the lower domestic gas demand growth which increase investor confidence to

allocate significant gas volumes toward international markets. Therefore, in many countries, the share of gas exports is more important in the “reduced gas demand” scenario, despite lower production levels. It’s worth to note that lower production levels considered in this last scenario is a way to factor more cautious development of gas export-oriented resources, compared to Scenario 1 (“Gas optimistic”).

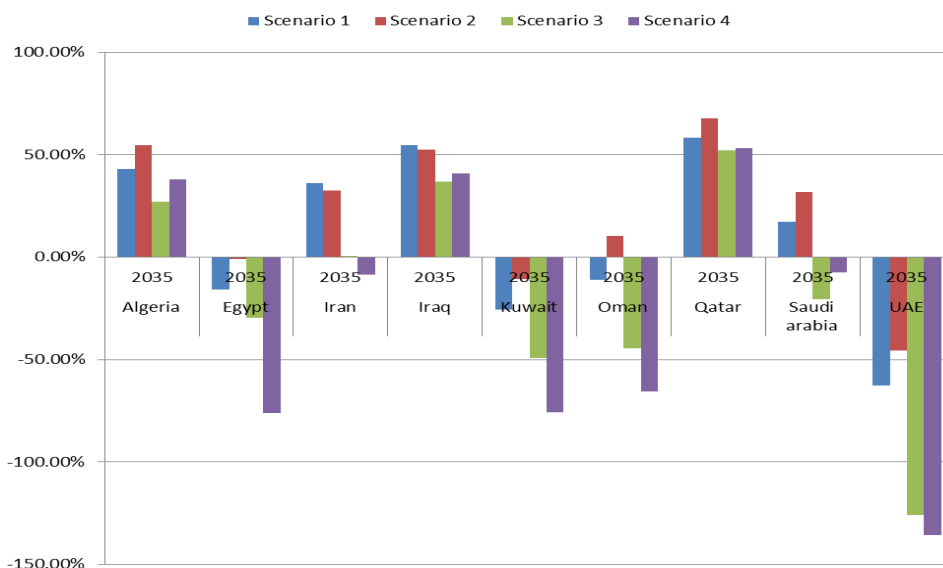
**Scenario 3 (“Gas for domestic markets”) and scenario 4 (“Gas pessimistic”): MENA gas production would not allow generating long-term surpluses; most of the production is consumed locally**

- In these two scenarios, MENA region will face conditions that do not support the development of large production capacities, particularly in the pessimistic gas scenario. Its status of gas net exporter on the long term is then largely disrupted, even that there would be significant disparities between countries.
- Despite that the “Gas for domestic markets” scenario would observe increasing production trends; this production is primarily directed towards the domestic markets in order to provide further supports to the MENA economies and incomes’ diversification. Scenario 4 (“Gas pessimistic”) is, however, characterized by a decline in regional natural gas production by 2035, driven by the production decrease in several countries, especially those which have recently experienced gas supply difficulties.

**MENA gas production Surplus Vs. Deficit**

- The “Gas optimistic” and “Reduced gas demand” scenarios are characterized by large gas production surpluses available for exports, estimated for the whole countries considered in our assessment, at about 25% and 33% for the two scenarios respectively by 2035.
- At the country level, we can notice (see chart below) that beyond the large gas surpluses generated by the traditional gas exporters (Algeria and Qatar), significant gas exports’ potential would be available on the long term in Iraq, Iran and also Saudi Arabia. The latter could seize interesting opportunities for gas exports, especially to meet the demand of some neighboring countries in the gulf region such as in Bahrain and UAE.

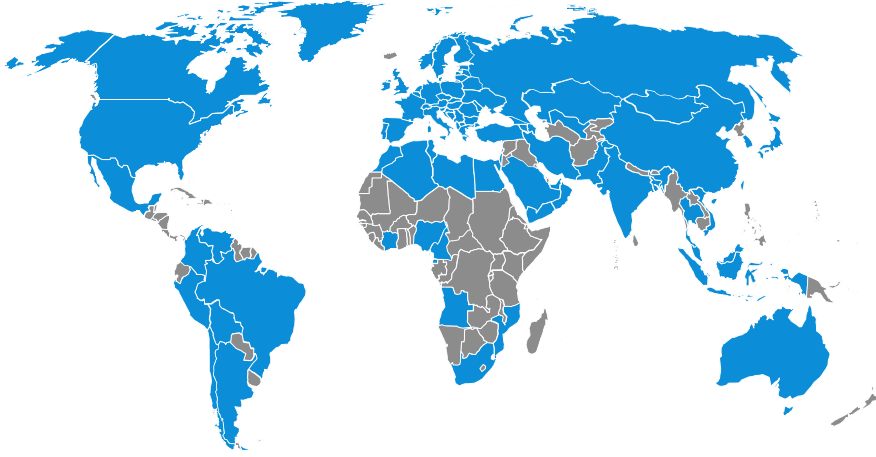
**Figure 39: Gas production surplus Vs. Deficit**



- Despite a lower gas production in “Reduced gas demand” scenario, comparing to “Gas optimistic” scenario, gas surplus is significantly higher. Indeed, we can notice this higher surplus in most countries except Iran, largest gas reserves holder in MENA, and also Iraq. For these countries, it is estimated that the difference in production levels between scenario 1 and 2 exceeds potential gas savings.

- For scenarios 3 (“Gas for domestic markets”) and 4 (“Gas pessimistic”), gas production deficits would be observed in several countries, leading to increase the needs for gas imports, particularly in the “ Gas pessimistic” scenario, where gas production would not provide the necessary volumes to meet the gas demand, despite an important slowdown in this demand .

In our assessment, gas deficits are greater in “Gas pessimistic” scenario 4 except for Saudi Arabia, where the “Gas for domestic demand” scenario 3 displays higher gas production deficit, since it’s estimated that gas production cannot keep pace with highly growing demand in this last scenario, which is supported by the size of the Saudi economy, the enormous need to replace gas in power generation and the role of energy-intensive industries.



The International Gas Union (IGU) was founded in 1931 and is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. The IGU has more than 142 members worldwide and represents more than 97% of the world's gas market. The members are national associations and corporations of the gas industry. The working organisation of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit [www.igu.org](http://www.igu.org)

**Address:** Office of the Secretary General  
c/o Statoil ASA, P.O. Box 1330, Fornebu, Norway

**Telephone:** +47 51 99 00 00

**Email:** [secrigu@statoil.com](mailto:secrigu@statoil.com)

**Website:** [www.igu.org](http://www.igu.org)



This publication is produced under the auspices of the International Gas Union (IGU), which holds the copyright. This publication may not be reproduced whole or in part without written permission of the IGU. However, irrespective of the above, established journals or periodicals shall be permitted to reproduce this publication, or part of it, abbreviated or edited form, provided that the credit is given to the IGU. This document contains strictly technical information to be distributed during the 26th World Gas Conference in Paris, France and has no commercial intent.