May 2016

Algerian Gas:
Troubling Trends, Troubled Policies

OIES PAPER: NG 108

Ali Aissaoui
Senior Visiting Research Fellow

ISBN 978-1-78467-058-0

Acknowledgements

The author wishes to thank, for their comments and feedback, Hakim Darbouche, Mostefa Ouki, Howard Rogers and Jonathan Stern.

Preface

Europe has for many years relied on multiple sources to meet its gas consumption requirements. Domestic production (Norway included) has typically satisfied 50% of European regional demand, with the remainder met by pipeline gas from Russia, Algeria, Libya, Iran and Azerbaijan (the last two to Turkey) as well as LNG from diverse supplier countries. Since the onset of the US shale gas 'revolution' in the mid-2000s and the escalation of long-running grievances between Russia and Ukraine over their gas business relations, the role of Algeria, which is both a major supplier of LNG and pipeline gas to southern European markets, has been largely overlooked.

The OIES Gas Programme's last paper on Algeria was by Hakim Darbouche in March 2011. Since then several developments have taken place which warrant timely and well informed insights. We are delighted, through this paper by Ali Aissaoui, to provide such insights on Algeria's natural gas sector trends and the outlook for its export potential. While the conclusions of the paper are not optimistic, the causal analysis has parallels in many gas resource-rich countries in the Middle East and North Africa region. Sustained government policies of low domestic prices have neither encouraged rationalization of demand nor provided adequate incentives for upstream investment, ultimately resulting in a severe deterioration of national gas balances.

We are pleased to add this paper to the list of our publications. By bringing greater clarity to pertinent issues of market supply we aim to help policy makers, researchers and commercial players better assess the future fundamentals of the wider European gas arena.

Howard Rogers

Oxford May 2016

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“Policy makers should be told not what they want to hear but what they need to hear”

Apocryphal saying

Introduction

Despite being one of Europe’s largest pipeline natural gas suppliers and the original and still very active supplier of liquefied natural gas (LNG) worldwide, Algeria has received limited serious attention as an exporter of gas in recent years. One reason may be that the country’s key role has somewhat been eclipsed by new developments in both the European gas scene and in the broader global gas arenas. On the one hand, the geo-political aftermath of the 2014 tensions between Russia and Ukraine has turned attention to the European Union's increasing dependence on Russian gas. On the other hand, the upcoming start-up of substantial new LNG supplies, with US shale gas-based LNG having already reached some markets, has brought the spotlight on the expected global gas surplus and its likely impact.

While the focus of the trade press and energy research organizations has largely been on these developments, the few current analyses of Algerian gas have, by and large, relied on the stories of the day, thereby failing to step back and recognize entrenched, inauspicious trends. To be sure, the most critical among them have revised downwards their projections of Algerian gas production on the back of slow progress in developing new sources of gas and difficulties in slowing down the decline of mature fields. [1] However, these have stopped short of offering further insight into a deteriorating supply and demand balance that is likely to seriously undermine the future of the country’s gas exports.

Opportunely for this paper, an urgently-convened cabinet meeting on 22 February 2016 has offered the context - and indeed the rationale - for revisiting Algerian gas. The meeting, which took on the character of a supreme-level policy session reminiscent of those held by the long-frozen National Energy Council (NEC), was conducted under the chairmanship of the ailing President of the Republic to review the country’s “national policy in the field of natural gas”. [2] Unfortunately, contrary to the timely and decisive NEC initiatives in the past, this meeting came too late and may achieve too little. Independent analysts and researchers have long pointed to the gas conundrum facing Algeria. In 2013, this author alerted observers to the emergence of an ‘Egypt syndrome’: a condition whereby, after a long period of denial, a government suddenly wakes up to the stark reality that production can no longer keep up with fast-growing domestic demand fueled by massive and unaffordable subsidies, ultimately leading to stranded export assets.[3] Earlier in 2011, Hakim Darbouche, then at the Oxford Institute for Energy Studies, had already warned that “a combination of subdued upstream gas development and growing domestic consumption has left the prospects of Algerian gas exports in a worse position than initially intended.” [4] Since then Algeria’s natural gas export volumes have, indeed, fallen steadily.

Adding to policy-makers’ anxieties in this area is the rapid depletion of natural gas reserves, whose estimates had been drastically revised downward. The government’s sudden apprehension in this respect stems from the fact that natural gas plays a major and critical role in the energy balance of the national economy. According to the latest comprehensive statistics available (2014),[5] it constitutes (on

[1] IEA (2015), *World Energy Outlook,* page 211.

[2] Algérie Presse Service, “Le président Bouteflika préside un Conseil restreint consacré a la politique nationale sur le gaz”, 22 February 2016 (www.aps.dz/algerie/37157).

[3] Aissaoui, A. (2013)

[4] Darbouche, H. (2011)

[5] Algerian Ministry of Energy (2016)

an oil equivalent basis) 51% of primary energy production, fuels 90% of power and power/water generation[6] and accounts for 39% of the remaining use, as both an energy source and a feedstock for the petrochemical and fertilizer industries. It further represents, when including natural gas liquids (NGLs: condensate and field LPG), 56% of export volumes.

A more pressing reason for concern is the fact that shrinking hydrocarbon export volumes have combined with falling international oil and gas prices to greatly reduce the state rent available for social support and economic development. As is commonly known and often repeated in such circumstances, Algeria's economy has remained overwhelmingly dependent on a single source of income derived from hydrocarbon exports. As a result, the country is extremely vulnerable to the instability and cyclicality of global markets. It is not surprising, therefore, that the government's concerns over the gas outlook came on the heels of much deeper worries caused by the dramatic fall in oil prices and its already-felt economic and social impact; not to mention the risk of making far worse a fraught political transition to a post-Bouteflika regime.

The total absence of information on the deliberations and conclusions of the 22 February meeting (except for a laconic communiqué)[7] makes it even more timely and topical to revisit Algeria's natural gas issues and policies.[8] Hence, this paper aims to provide further evidence of a significant and unsettling shift in the supply, demand and export of natural gas in the country and to critically analyze the relevant policy responses. As they stand, these policies, which have so far focused on the supply side and have only now started to integrate the demand side, are likely to have very little, if any, success in reversing current trends. Our arguments are developed in three parts. The first part provides a detailed analysis of declining production trends and the limits of current upstream policy measures. The second part looks at the structure and future development of domestic gas demand and the challenges facing the government as it embarks on a renewables power and a price adjustment program. The third part examines how Sonatrach is coping with both changing international gas market dynamics and shrinking availability of gas for export. Finally, we conclude by summing up the key findings and offering broader policy recommendations.

1. Declining production: an incontrovertible trend

While energy data in the public domain can be sufficient to draw attention to alarming trends, deeper analysis is needed for informed policy discussion. During the last decade since 2004, Algeria's primary energy demand grew at an average annual rate of 4.1% while domestically-sourced energy supply decreased by 0.8%/year, resulting in a contraction of total hydrocarbon export volume of 2.6%/year. Natural gas flows are no exception to such trends. Their decline is first noticeable in gross production, which dropped from 201.2 bcm in 2008 to 179.5 bcm in 2013 before slightly improving to 186.7 bcm in 2014 as Gassi Touil and El Merk (associated gas) came on-stream.

Similar trends are revealed by the evolution of the key components of gross production. In order to unravel these trends, it should be noted that wet natural gas production in Algeria is cycled for liquids content and that the bulk of this process takes place in Hassi R'Mel (Box 1). Once stripped of its NGLs (condensate and field LPG), gas is partly re-injected to maintain stable reservoir pressure and avoid retrograde condensation.[9] Dry gas in excess of re-injection requirements is then supplied to the

[6] Power generation is for the production of electricity only. Power/water generation is a combined process for producing both electricity and water.

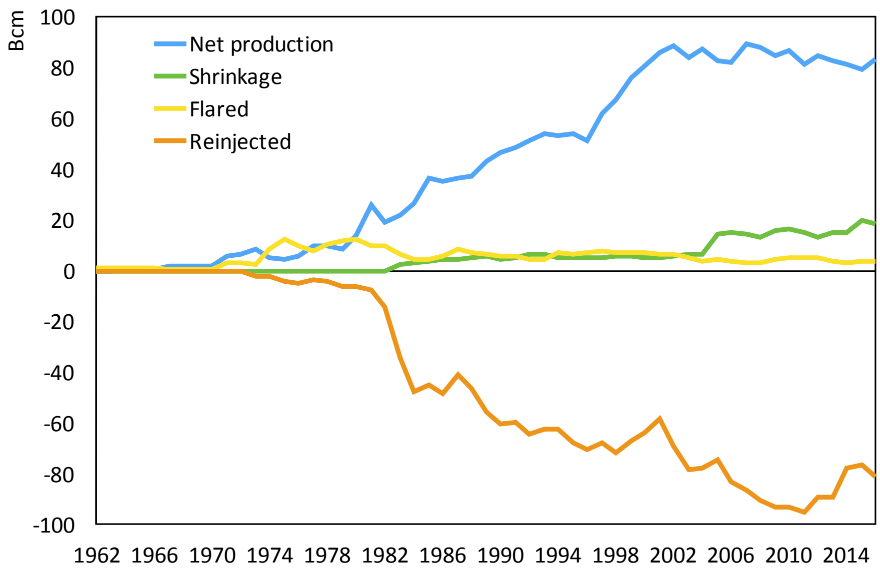
[7] See (www.aps.dz/algerie/37157)

[8] Mention should be made here of the paucity of publicly available information about Algerian gas from government, company, or conference sources, thereby making data gathering hugely frustrating and time consuming.

[9] Schlumberger defines 'retrograde condensation' as "the formation of liquid hydrocarbons in a gas reservoir as the pressure in the reservoir decreases below dewpoint pressure during production. It is called retrograde because some of the gas condenses into a liquid under isothermal conditions instead of expanding or vaporizing when pressure is decreased."

domestic and export markets. Figure 1, which depicts the evolution of these flow components, points to a matching decline of both marketed production and the volumes of gas re-injected (the latter being plotted in the negative region for better visualization).[10]

Figure 1: Evolution of Natural Gas Production Components



Source: Updated from Aissaoui (2001) using OPEC Annual Statistical Bulletins

The most significant evidence for our analysis is the unmistakable decline in marketed production during the last decade or so. By taking a longer-term view, we can see that production actually increased strongly during the second half of the 1990s following robust policy actions early that decade to bolster the gas sector.[11] Production then crept to a peak of 89.2 bcm in 2005, before trending downward to 79.9 bcm in 2013, improving slightly, for the same reasons invoked in the case of gross production, to 83.3 bcm in 2014 and declining once again to 82.5 bcm in 2015.[12] It should be further noted that the partial rehabilitation of the terrorist-wrecked Tiguentourine processing plant in January 2013 may also have contributed to the recovery observed in 2014. (The third and last train has taken longer to restore and is expected back in April 2016.)

Some analysts may argue that, in recent years, marketed production has actually equated to a lower call for gas, as a result of Sonatrach's exports having contracted more rapidly than domestic consumption having expanded. Indeed, while exports declined by 25.8 bcm from 2000 to 2015, domestic consumption increased by 19.7 bcm. This argument, however, is stretching the truth. It assumes that Sonatrach's exports have simply adapted to the shrinking of its main European gas markets. It can instead be inferred, from the declining trends in gross production and the volumes of gas re-injected, that there may not have been enough raw gas to maintain the cycling process at its optimum level. This in turn suggests that, notwithstanding additional volumes supplied during the last decade from Ohanet, In Salah, In Amenas, Gassi Touil, El Merk and Menzel Lejmat, production has

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(www.glossary.oilfield.slb.com/Terms/r/retrograde_condensation.aspx). In practice, retrograde condensation negatively impacts NGLs recovery, therefore the economics of the gas cycling.

[10] Originally documented and analyzed by Aissaoui A. (2001).

[11] Aissaoui A. (2001)

[12] Algerian Ministry of Energy (2016a)

at best plateaued, as a result of declining production from mature assets. As explained in Box 1, this is particularly the case with Sonatrach-operated Hassi R'Mel. Obviously, failure to prevent further decline of this super-giant field will have detrimental consequences on the level of marketable production.

Box 1: Hassi R'Mel: A Mature Supergiant in Clear Decline

Six decades after its discovery, this super-giant field has reached a mature stage. Since Sonatrach became the operator, in the wake of the 1971 nationalization of the hydrocarbon industry, the field has undergone successive developments that transformed it into a major gas-NGLs production and processing complex with a gross output gas capacity of 100 bcm/year. At the peak of its performance in the 1990s, the field produced 92 bcm/year of which 60 bcm/year were re-injected to stabilize pressure and avoid retrograde condensation. Anecdotal evidence, among informed Algerian professionals, suggests that the field, which produced some three quarters of its nominal capacity in recent years, is indeed in decline and is experiencing reduced wellhead pressures. In the absence of hard data, these guesstimates, while reasonably reliable, are difficult to interpret. This is due to the fact that Hassi R'Mel also acts as a hub for gathering, processing and cycling increased gas volumes produced further afield and delivering the resultant marketable dry gas and NGLs to the domestic and export markets.

As with any mature field, Hassi R'Mel faces many challenges. Some of the current problems have their origin in the aftermath of the 2007 collapse of the Sonatrach-Repsol partnership to develop the so-called LNG integrated Gassi Touil project, which delayed first gas from the upstream project until February 2014. To compensate for Gassi Touil's long-deferred output, cycling at Hassi R'Mel has been performed outside its optimal ranges (over-production of marketable gas to the detriment of re-injection). One apparent consequence is that some producing wells have started to yield water. As these wells were shut, the gas trapped in the corresponding areas has negatively impacted on the level of gross production. However, current challenges are not confined to recovery factors. Above-ground problems also need to be tackled, prompting Sonatrach to seek consultancy services on the diagnosis, design and optimization of surface flows. [a]

Enhancing the field's recovery, stabilizing its gross production to possibly 76 bcm/year, as reportedly indicated by Sonatrach, [b] and extending its economic life need continuous investments. New gas compressor lines (to boost wellhead flowing pressure to the separation and treatment plants) as well as other upgrading and debottlenecking facilities are being considered. However, while such investments are necessary, they are far from sufficient. Without getting too immersed in the complexities of reservoir engineering, suffice to say that innovative approaches will be needed to cope with the rapidly evolving subsurface structure and dynamics of the supergiant field, including figuring out how to release the portions of gas trapped by water encroachment. In the current uncertain economic environment, some informed sources believe that if Sonatrach fails to make rapid progress in this area, other options may have to be considered, including offering stakes in the field to major companies that could integrate the latest sub-surface technologies and help solve the field's large-scale surface optimization problems. However, this would be a politically sensitive move as Hassi R'Mel (as well as the oil supergiant Hassi Messaoud for that matter) has acquired huge symbolic significance, which is deeply rooted in Algeria's long history of asserting control over its natural resources. [c]

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[a] AFW (2015), "Amec Foster Wheeler awarded consultancy contract by Sonatrach in Algeria", Press Release dated 12 August (media.amecfw.com/amec-foster-wheeler-awarded-consultancy-contract-by-sonatrach-in-algeria).

[b] Reuters (2015), "Algeria's oil output at 1.12 mln bpd, Hassi R'Mel gas seen at 76 bcm", June 9 (http://uk.reuters.com/article/algeria-energy-idUKL5N0YV2UK20150609).

[c] Aissaoui, A. (2001), *Algeria: The Political Economy of Oil and Gas*, OUP.

Meanwhile, we can confidently infer that the fields slated for completion by 2020 (Table 1) will only just suffice to keep production roughly stable at around 85 bcm/year, especially as some of these fields are unlikely to come on stream by that date. While we should expect those being developed in partnership with international oil companies (IOCs) to finally reach completion at the delayed starting dates indicated in Table 1, i.e. by 2018, those being contemplated by Sonatrach on its own may not progress as expediently as the national oil company wishes. Even the larger and most matured Tinhert project, which has finally moved to a front-end engineering and design (FEED) phase[13] (after having long been contemplated to supply a costly, now scrapped gas-to-liquids – GTL - project), is likely to wait for financing to be sorted out before it is awarded to an EPC contractor. All such fields are part of the upstream project assets in which Sonatrach has most recently been reported to be keen to offer stakes to foreign investors.[14] However, investors will hardly take for granted Sonatrach's self-serving statements about better project engagement and fast-moving negotiations. Whatever the case, not only will the new upstream projects hardly make a difference in compensating for the decline of Hassi R'Mel and other mature fields, but most of them are tight, dry or, in the case of the southwestern formations, have high CO_2 content, therefore too costly to be able to offset the notable shortfall in government revenues.

Table 1: Gas Fields Being Developed or Contemplated for Development

	Sponsors	Estimated 2P reserves (bcm)	Expected plateau production (bcm/yr)	First production initially planned	Starting date at the time of writing
Program in partnership					
. In Salah Southern Fields	Sonatrach, BP, Statoil	65.0	(a)	2014	2016
. Touat (Adrar)	Sonatrach, Engie	68.5	4.6	2016	2018
. Reggane North	Sonatrach, Repsol, DEA, Edison	47.9	2.9	2017	2018
. Timimoun	Sonatrach-Total-Cepsa	25.5	1.6	2016	2018
. Isarene (Ain Tsila)	Sonatrach, Petrocletic, Enel	59.2	3.6	2017	2018
Sonatrach's own program					
. Tinhert	Sonatrach (originally for GTL with potential IOCs)	110.0	7.0	2015	2018
. Ahnet (b)	Sonatrach (originally involving Total and Partex)	61.5	4.0	2015	..
. Hassi Mouina	Sonatrach	..	1.4	..	..
. Hassi Ba Hamou	Sonatrach	..	1.8	..	..
. Menzel Ledjmet (periphery)	Sonatrach	..	4.4	..	..
. Bourarhat North	Sonatrach	..	..	..	..
. Gassi Touil (periphery)	Sonatrach	..	..	..	..
. Erg Issaouane	Sonatrach	..	..	..	..
. Tisselit North	Sonatrach	..	..	..	..

(a) Dry gas fields developed to maintain the planned plateau production of 9 bcm at In Salah - Started in Feb 2016

(b) Following Total's exit from Ahnet, Partex Oil & Gas, which hold a 2%-stake in the venture, remains a virtual partner

Source: Companies' Annual Reports and Official Web-posting

The cost of producing gas in Algeria remains an elusive area of research. This author has tentatively estimated them through a Delphi survey.[15] A panel of peer, well-informed experts were asked to assess individually the plausibility of preliminary estimates of the economic cost of production of 17 existing and planned fields (the latter having secured a final investment decision at the time of the survey). Except for a few cases, associated gas from oil fields was assumed re-injected for enhanced oil recovery (EOR). The panel was first presented with initial wellhead costs, which were worked out as full-cycle costs of exploration, development and production. Cash flows included as debits: yet-to-be amortized CAPEX, OPEX and expected royalty (on both natural gas and liquids valued at opportunity costs); and as credits: expected revenues from liquids. Unit costs were computed as a quotient of NPV of net cash flows over NPV of production. The discount factor was 10%. The survey's results are shown in the form of a cost curve, which has been approximated by ranking each field's

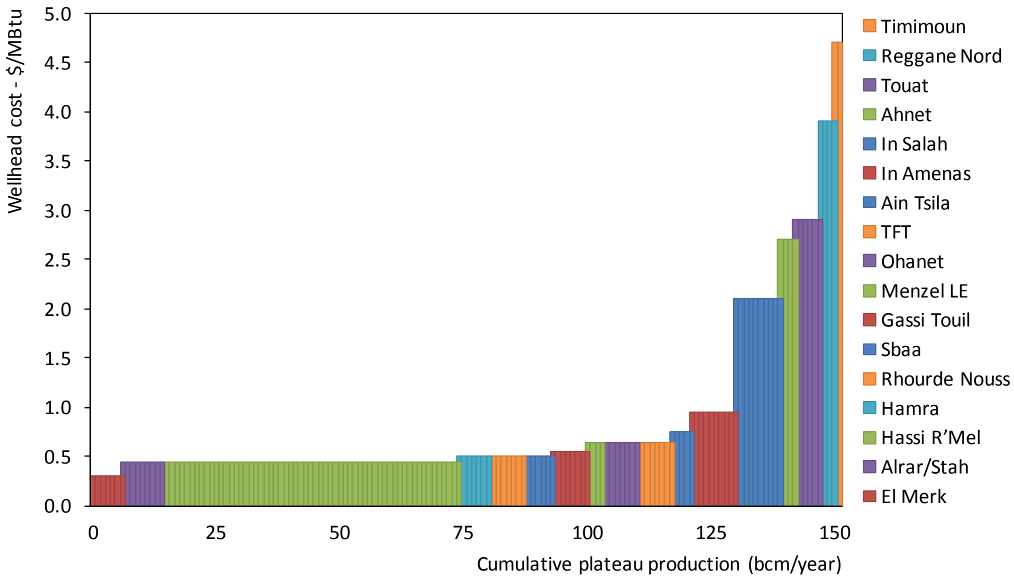
[13] Sonatrach, 2014 Annual Report.

[14] Reuters (2016), "EXCLUSIVE - Oil revenues down, Algeria woos energy investors", March 23 (uk.reuters.com/article/algeria-energy-idUKL5N16U52A).

[15] Aissaoui, A. (2013)

plateau output from lowest cost to higher cost. Accordingly, and as shown in Figure 2, estimates range from \$0.30/MMBtu for El Merk (gas associated with oil) to \$4.70/MMBtu for Timimoun (tight gas).

Figure 2: Natural Gas Wellhead Cost Curve



Source: Estimated through a Delphi survey - First published by A. Aissaoui in APICORP's Economic Commentary dated Jul 2013

Limiting our scope to existing fields at the end of 2015 and assuming that these fields produce at plateau levels, results in a weighted-average unit cost of production of \$0.60/MMBtu. Obviously, the cost is higher – up to \$0.70/MMBtu - if we assume lower production rates from depleting mature fields, which is closer to reality. As for the long run marginal cost of supply it may be approximated by the unit cost of production from the upcoming, most expensive tight-gas project, i.e. Timimoun, at \$4.70/MMBtu.

The alarming trends in both volumes and costs detailed above have raised concerns over the depletion of easy and cheap gas and prompted a serious review of the country's reserves and resources (Box 2) and how to further expedite exploration and development. In this context, the main policy measure so far has been the February 2013 revision of the prevailing hydrocarbon law, which provided new incentives to stimulate upstream investment including, for the first time, unconventional resources. Unfortunately, this potentially strong supply response, which comes on top of increased emphasis on the promotion of new and renewable energies, has failed expectations. So far, the only post-revision bidding round (September 2014) has auctioned 31 licenses. However, the fact that only five bids were submitted, of which four were awarded, speaks loud and clear about investors' dissatisfaction with the offering. It is worth noting in this respect that IOCs generally assess project portfolios on the basis of multiple investment criteria, including reward, control and risk. Those involved in the bidding must have perceived problems with either the reward factor (modest returns on investment), the control factor (Sonatrach's majority stake), the risk factor (perceived security weaknesses) or, more plausibly, all three. In addition, companies anticipating a 'lower-for-longer' oil price environment must have increased their hurdle rate of return or put more value on the option to wait for better opportunities in the future.[16]

[16] Aissaoui A. (2015)

Box 2: Gas Endowment: Still Larger Than Commonly Assumed

Until recently, Algeria's natural gas production was believed to be supported by a relatively large conventional proven reserve base of 4,500 bcm. However, this figure, which has been repeatedly reported by the international statistical agencies, is no longer valid. Indeed, in November 2015 the government announced that proven conventional reserves now stand at 2,745 bcm.[a] This drastic revision confirms, to a large extent, that, contrary to prevalent assumptions, Algeria's reserve replacement ratio (RRR) has remained below one for some time. Accordingly, the ratio of reserves to production (R/P) has fallen to 33 years. Although this latter ratio is static, and therefore potentially misleading, it constitutes a common indicator of how long the revised reserves will last at current annual production rates of 83 bcm.

There is, however, a non-negligible potential for conventional reserves expansion. This is supported by the 2012 assessment conducted by the US Geological Survey (USGS),[b] according to which technically recoverable undiscovered conventional gas resources in the three "priority" geological provinces of the Trias/Ghadames (stretching a little beyond Algeria's borders into Tunisia and Libya), Illizi and the Grand Erg/Ahnet are estimated at 1.1 tcm (mean), with a probabilistic range of 0.6 tcm (95%) to 1.6 tcm (5%). As exploration and discovery history data are a critical part of the USGS methodology, resources could be higher if the non-assessed Algerian offshore province, for which there is no public data available, is included. Furthermore, adding future growth of known reserves could ultimately lead to a slightly larger gas endowment.[c]

While conventional reserves and resources appear after all modest, a much larger potential for expansion of reserves and supply is offered by unconventional gas. According to a 2013 review of the world's shale resources, commissioned by the US Energy Information Administration (EIA) from Advanced Resources International (ARI),[d] Algeria's technically recoverable shale gas reserves could amount to 20.3 tcm. These reserves, which could be produced using current technology, but without reference to economic profitability or environment impact, constitute more than seven times the country's revised proven conventional reserves.

[a] www.aps.dz/en/economy/8839-hydrocarbon-exports-expected-to-grow-by-4-1-in-2015
[b] USGS (2012).
[c] Aissaoui, A.(2013a)
[d] US EIA (2013

It is also the case that the January 2013 terrorist attack on Tiguentourine (In Amenas), which is operated by Sonatrach, BP and Statoil, has increased the cost of operating in the Saharan provinces and introduced a greater element of risk assessment in new ventures.[17] The Algerian military has surely devoted considerable resources to protect key hydrocarbon assets. However, the additional measures taken in the aftermath of the attack could not prevent a recent (mid-March 2016) firing of explosive munitions on Krechba - part of the In Salah gas scheme. As if the security in the Saharan provinces is not enough cause for worry, the government was also caught by surprise by another form of disruption in the region caused by anti-shale protests. These far-reaching campaigns were initiated by local residents expressing concerns for the lack of information and participation as well as deep worries over the impact of shale fracking on the region's scarce and precious water resources. The irony, if it is, is that none of the potential shale blocks (about half among the 31 offered in September 2014) were bid for by IOCs. Instead, what triggered the protests was drilling work on Sonatrach-sponsored pilot wells in the shale-gas prone part of the Ahnet Basin, nearest to In Salah. While these

[17] Aissaoui A. (2013b)

protests have disrupted the pilot, the lack of social acceptance is expected to be one among many potential barriers to shale development.[18]

What is at stake is the development of Algeria's huge technically recoverable shale gas reserves, which could, according to an EIA/ARI study - amount to 20.3 tcm (Box 2). However, these and other estimates from studies commissioned by Sonatrach itself, are highly uncertain and will likely remain so until Algeria's shale basins are extensively tested with actual production wells. Therefore, at the same time as embarking on pilot test wells in the Ahnet basin, Sonatrach drafted an ambitious 20-year investment plan of some $70 billion aiming at a production of 30 bcm/year starting progressively in 2020. The pilots, which were implemented in an ad hoc partnership with IOCs and oil service providers, eager to have a foot in the door, have been designed to assess productivity and liquids content, as well as the economic viability and environmental impact of the undertaking. Accordingly, horizontal drilling and fracking were carried out on the first well in 2014. Preparations for the second well in early 2015 triggered the protests.

One apparent consequence of the protests, which turned into a sustained political challenge to the country's authorities, was a shift in the government's energy administration (May 2015) and an inflexion of its upstream policy. Although there has been no significant statement yet in this respect, the few public comments by Mr. Salah Khebri – the current minister of energy – have shed some light on what seems to be a fast and focused exploration and development strategy.[19] Prior to the high-level policy meeting of 22 February, he had been reported by the local media as saying that "Algeria aims to rapidly increase production", therefore "maintaining its priority for the upstream sector". He went on to explain that, in order to pursue and develop any findings to the market, efforts will be directed towards exploration schemes in proximity to producing areas. His argument is that many (small) discoveries have been made over time that could not be economically exploited due to their geographical remoteness from processing facilities. When taken together, Mr. Kherbi's statements (or the lack of them on specific issues) point to the likelihood that he would strive to avoid getting distracted by the controversial shale policy of his predecessor. Instead, he would focus Sonatrach's efforts on conventional low risk ventures and rapid results. However, this should not be taken to imply that longer-term-oriented exploration in less accessible areas, which involves partnership with higher risk-taking investors, would not be supported. In this regard, and in preparation of the upcoming bidding round (expected for the end of 2015 but, as of April 2016, still not decided), the Agence Nationale pour la Valorisation des Ressources en Hydrocarbures – the state licensing body, ALNAFT – has been fine tuning its contractual terms and procedures to make them more appealing. However, whatever the extent of such a review, it is unlikely for the time being that it would involve changes in the prevailing fiscal and regulatory framework.

Has shale gas been removed from the government's agenda? Judging from comments and feedback by Algerian energy professionals whose views were solicited by this author, the answer is that the government's hopes that shale gas might rapidly become commercially available have simply evaporated. Referring to the meeting of 22 February, these experts argue that while strong concerns were expressed about the depletion of natural gas reserves, there was no specific mention of shale gas among the policy options listed in the official communiqué, i.e. upstream development, demand rationalization and a push to renewables, which the meeting deemed a "national priority". The reasoning according to these experts is that, taking account of the high cost of developing shale gas and the lack of social acceptance, adopting renewables on a large scale, as already formulated in a 2015 development program, would be a long-term stop-gap solution, something that can ultimately virtually preserve natural gas reserves and the state rent derived from it. Meanwhile, an opportunistically-oriented approach to reining in domestic gas demand has become the focus of

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[18] Boersma, T, et al. (2015)

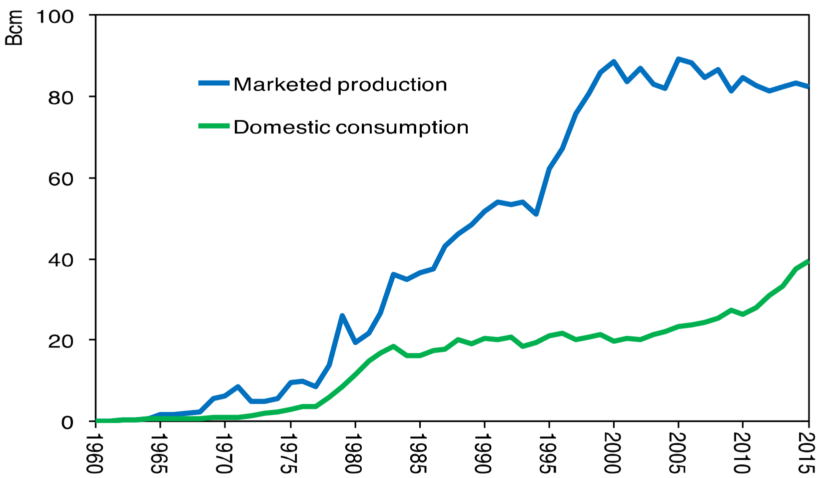
[19] Aissaoui, A. (2015a), "Algeria's Energy Policy: What to Expect", LinkedIn Post, July (www.linkedin.com/pulse/algerias-energy-policy-what-expect-ali-aissaoui?trk=prof-post).)

policy. Indeed, the current fiscal crisis has offered a way to legitimize very long-awaited energy pricing reforms.

2. Domestic demand and the pricing challenge

The weakness of the production outlook contrasts with the strength of domestic demand. During the last 10 years or so, while natural gas production appears to have stagnated at best as discussed previously, domestic consumption has grown at 5.2%/year from 22.6 bcm in 2004 to 39.5 bcm in 2015.[20] Figure 3 shows how consumption has been running ahead of production, absorbing an increasing share of it, to the obvious detriment of exports. With this share reaching 47.9% in 2015, the domestic market has indeed become the major and sole growing component of the national gas balance.

Figure 3: Marketed Production and Domestic Consumption



Source: Algerian Ministry of Energy and CREG

The structure of gas consumption has been evolving rapidly. As the public distribution sector (household, pubic administration and commercial activities) took the lead in driving demand, the share of the power and power/water generation sector sector has declined from 62% in 2004 to 42% in 2014 (Figure 4). However, the fact that the power sector is 90% fueled by natural gas means it remains the dominant sector in the domestic gas market. With rapid depletion of reserves, this raises major policy issues, particularly with regards to the adoption, on a large-scale, of an electricity-based renewables program. This program aims to install 22 GW of power generation capacity by 2030, of which 18.6 GW would be from intermittent solar photovoltaic (PV) and wind, and 2 GW from solar thermodynamic systems with storage, the remaining 1.4 GW being from biomass, renewable-based cogeneration and geothermal. Taking account of the future size and structure of the Algerian electricity grid, whose peak load is projected to be 31 GW at that horizon, the emphasis should rather be on thermodynamic solar systems with storage. Otherwise the cost of backing up intermittent electricity output would be exorbitant. This drawback, which must have originally escaped policymakers' attention, will certainly lead to a revision of the current design of the renewables program as implementation progresses.[21]

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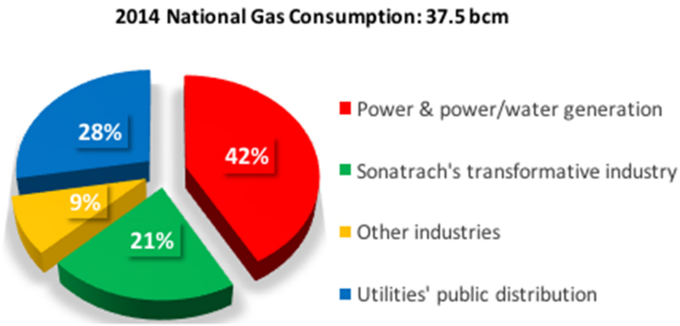
[20] Algerian Ministry of Energy (2016)
[21] Boutarfa, N. (2016)

Figure 4: Structure of Gas Consumption in 2014



Source: GREG, Ministry of Energy and Sonelgaz

Whatever the design and outlook of the renewables program it will surely affect the volume of gas used by the power sector, therefore the size of the domestic gas market in the long term. Current official projections – those released by the Electricity and Gas Regulation Commission (CREG) in 2015 for the decade 2014 - 2023 – take into account the impact of the renewables program, but in its original 2011 version. As the new program adopted by the government in Feb 2015 has not changed the overall target of 22 GW by 2030 questioned above,[22] we assume that CREG's projections are still valid in this respect. These projections anticipate an acceleration of domestic gas demand growth to 5.2%/year in a central scenario, resulting in a demand of 54.6 bcm in 2023 (Table 2). The acceleration is primarily due to a catch up in power capacity investment over the period 2013-17. Assuming that the renewables program is implemented successfully, growth would only start moderating significantly post 2023.

It should be noted that Algeria's domestic gas consumption in 2014, which is the base year of the above projections, was estimated by CREG at 34.6 bcm while the actual figure turned out to be higher by 8.4% at 37.5 bcm (Table 2). Furthermore, the figure of 39.5 bcm released for 2015 confirms the strong growth of recent years that CREG seems to have missed. However, in order not to divert our focus, we still stick to the CREG original central (moderate) projection scenario, assuming that any adjustment of the projected demand profile to a higher base year will most likely be counterbalanced by the impact of slower economic growth caused by the collapse of oil and gas prices. It is on this basis that we have extrapolated domestic gas demand from 2023 onward. The resulting level of nearly 70 bcm in 2030 appears too close for comfort to current marketed production; unless final demand for both electricity and gas is moderated through a policy of aggressive price increases.

[22] Algerian Ministry of Energy (2015)

Table 2: CREG's Natural Gas Demand Outlook in a Moderate Scenario

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

Source: CREG 2015 (Power generation demand in 2017 and corresponding growth rates corrected from source)

As already noted, the current fiscal crisis has opened an opportunity to justify a long-due increase in energy prices. Caught by surprise by the collapse of international oil prices and realizing that the current down cycle in global energy commodities is likely to persist, the government has had little choice but to adopt measures, promptly though very prudently, to contain a widening budget deficit. In addition to increasing various end-use taxes to improve revenues, the government agreed to several austerity measures including a reduction in public spending on social transfers and energy subsidies.

In this context, CREG was finally empowered to adjust electricity and gas tariffs. Given the complex structure of such tariffs and the large amount of relevant data published on that occasion,[23] the outcome of CREG decisions can be difficult to present concisely. Suffice to say that tariffs have been increased for all consumption brackets except for the lowest ones in order to protect limited-income households. Actually, to provide incentives for rationalizing energy use, the tariff structure for households and commercial activities has been made progressive i.e. the unit price of electricity or gas increases progressively from one bracket to the next. The percentage increases, which vary from 15% to 41% depending on the energy form, end-use sector and usage level, seem impressive. The reality is that they are from a very low, a decade-long frozen base. Inferring from estimates produced by Sonelgaz (the group of generators of electricity and retail suppliers of gas and electricity), the additional revenues that will be generated by the new tariffs would cover only 14% of the deficit the utilities companies said they registered in 2015, which amounted to $1.8 billion.[24] This means that tariffs will have to increase much more substantially to generate enough revenue to even recoup costs, let alone mention self-financing of new investment. As Sonelgaz put it "the path to charging the true cost is still a long one".[25] What Sonelgaz has refrained from anticipating, however, is that prices of the upstream gas resource may need to be adjusted in turn, as examined next.

Before proceeding further, we need to explain the prevailing pricing framework at both the institutional and conceptual level. At the institutional level, in addition to the Ministry of Energy in its capacity as the policymaking entity, Sonatrach, in its capacity as the primary supplier of natural gas, and Sonelgaz Group of companies, in their capacity as the retail suppliers of both gas and electricity, two other bodies oversee and regulate energy prices. While CREG sets and notifies retail electricity and gas tariffs, as analyzed above, the hydrocarbon regulating authority (ARH) is in charge of setting and notifying primary gas prices. At the conceptual level, primary gas prices (exclusive of taxes) consist of a supply price ('prix de cession') – uniform across the national territory on the basis of the 'perequation' principle [26] – and a wholesale price ('prix de vente'). The wholesale price results from the supply price once transportation costs through Sonatrach's pipelines are added. Current regulation specifies that the supply price is based on the "cost of economic returns" plus a "premium

[23] CREG (2015)
[24] Boutarfa,N (2016a)
[25] Boutarfa,N (2016a)
[26] 'péréquation' is an economic concept (of French origin) used to indicate that a price/tariff is uniform across a country. It is largely used by the World Bank in its English-version literature to indicate a financial cross-subsidy mechanism.

to cover the additional cost of mobilizing new resources to meet long-term demand". Although forward-looking, these cost concepts may not be consistent with the precepts of mainstream economics, which tend to favour the 'long-run marginal cost of supply' (LRMC) to emphasize both economic efficiency and sustainable investment. Furthermore, pursuant to the February 2013 amendments of the hydrocarbon law, Sonatrach's foreign partners may be required to relinquish their share of gas to the domestic market and be remunerated on the basis of an export-based opportunity cost. Therefore, for domestic supply prices to evolve towards that level, a 'depletion premium' should be added to LRMC to account for the opportunity cost of consuming an exhaustible resource today rather than tomorrow.

In any case, the cost and premium used by the Algerian regulator are normally reviewed every four years. In between, the price is set according to an indexation formula (Box 3), which combines a nominal exchange rate index and an inflation rate index. This formula seems to have been devised to magnify inflation through the exchange rate channel. As Algeria relies heavily on imports, the 'pass-through' of exchange rates and import prices to domestic inflation is substantial. Most frequently, a decrease in the exchange rate (depreciation) and a rise in the prices of imported goods and services leads to an increase in domestic prices in nominal terms.

The Algerian regulators are independent in law. In reality, they are subject to political expediency and policy-making imperatives. This is particularly true of CREG, which, as noted previously, had been unable to adjust retail prices for a decade since 2005. As for ARH, it has managed, as explained in Box 3, to amend the relevant decree to adjust the indexation formula of supply price upward. However, the price it last notified in 2011 was kept below what the formula actually calculated (Figure 5). In addition, rather than annual as provided by law, ARH's notifications have been episodic. Of the three price notifications made so far the first, which came in decree 2005, set a dual supply price, one at Dinar780/1000m^3 ($0.28/MMBtu) for the power generators and public distribution, the other at Dinar1,560/1000m^3 ($0.56/MMBtu) for the industrial sector. The second notification, which was made in 2008, set the supply price at Dinar828/1000m^3 ($0.33/MMBtu) and the wholesale price at Dinar1,203/1000m^3 ($0.48/MMBtu). The third in 2011 set the supply price at Dinar1,024.27/1000m^3 ($0.37/MMBtu) and the wholesale price at Dinar1,404.30/1000m3 ($0.51/MMBtu).[27]

Box 3: Domestic Supply Price: Lagging Behind the Prevailing Formula

The supply price (prix de cession) is to be determined, exclusive of taxes, on the basis of current and anticipated costs and indexed to both the exchange rate and inflation rate along the following formula:

$$P_{t+n} = P_t * \frac{FX_{t+n}}{FX_t} * (1 + r)^n$$

Where:

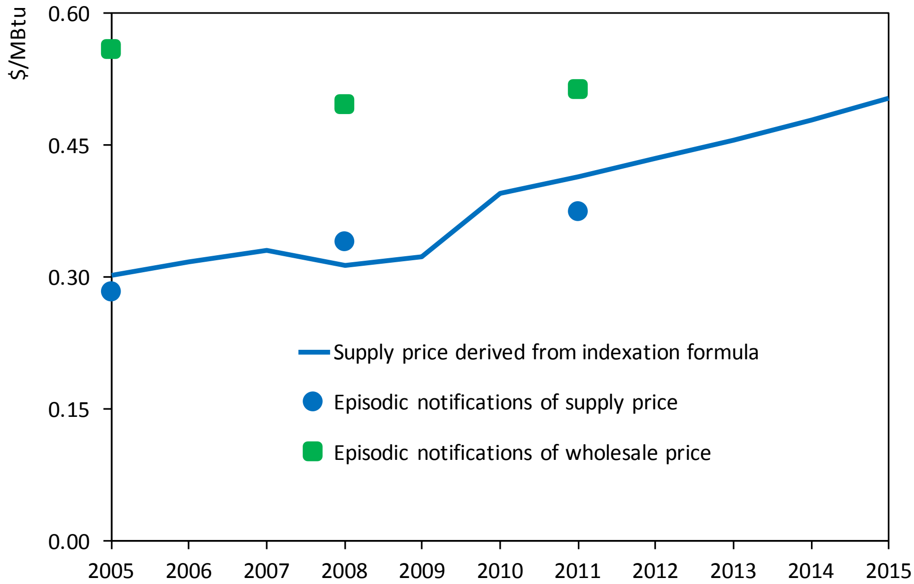
- P_{t+n} is the supply price at year (t+n) in DZD/1000m^3
- P_t is the supply price on the date of application
- FX_{t+n} is the USD-DZD parity on 1st January of year (t+n)
- FX_t is the USD-DZD parity on the date of application
- r is a constant rate of inflation
-

This formula, first introduced by decree dated 24 April 2005, was amended twice, in two respects. First, the inflation rate has been adjusted downward in decree dated 12 April 2007 from 5% to 3% then readjusted back to 5% in decree dated 12 January 2010. Second, starting with the latter decree, the exchange rate index only applies if $FX_{t+n}/FX_t > 1$, that is when the Algerian dinar (DZD) depreciates against the US dollar (USD).

Source: Aissaoui, A. (2013)

[27] ARH's third price adjustment as currently (April 2016) posted on its website (www.arh.gov.dz/index.php/fr/espace-operateurs/tarifs/gaz-naturel).

Figure 5: Evolution of Supply and Wholesale Prices



Source: Updated from Aissaoui A. (2013)

Whatever the extent and pace of these revisions, primary gas prices in Algeria have remained very low by any standards. Should ARH adjust supply prices for 2016 using the prevailing formula, that price would be $0.50/MMBtu - a 35% increase relative to what was notified in 2011. Still, this level would be below the weighted average wellhead cost of production that we have estimated at $0.70/MMBtu in the first part of this paper, not to mention the LRMC of more than $4.70/MMBtu suggested in the same. The revised supply price would also remain the lowest across the MENA region, where pricing policies and measures have resulted in a growing cross-country trend. This trend currently ranges between the most recent increase of up to $1.75/MMBtu (from $0.75) for the industrial and petrochemical sectors in Saudi Arabia, which has embarked on a broader program of subsidy reforms, and a staggering, up to $8/MMBtu (from up to $6) for the energy-intensive industries in Egypt[28], where the government has been compelled to reflect the cost passed on by IOCs operating in the country as well as the cost of gas from newly imported LNG. It would require domestic prices to be increased by at least 5 times for Algeria to catch up with this trend. Meanwhile, we should expect domestic demand to continue growing unrelentingly and only moderate once the renewables program gains sufficient traction. As we expect production to be stagnating at best, this growth will inevitably continue to be to the detriment of exports.

3. Gas Exports: Issues and Implications

The decline in Sonatrach's gas exports, which was already perceptible in the early 2000s, has accelerated in the aftermath of the global financial crisis of 2008-2009 and subsequent economic slowdown. This is particularly the case of exports to Europe and more dramatically in parts of the recession stricken Southern periphery where Sonatrach's markets have tended to be concentrated. We have seen in the first part of this paper that, with declining (stagnating at best) domestic production, exports have been contracting more rapidly than domestic consumption has been expanding. While this observation points to the domestic factors as being significant in curbing

[28] Government of Egypt (2014), Decision no. 1162 dated 3 July 2014 (Arabic) (www.petroleum.gov.eg/ar/Laws/PricingLaws/Laws/قرار%201162%20لسنة%202014.pdf).

exports, it leaves open to discussion the possibility that the national company may have been slow to adjust to changing market conditions and competitors' evolving marketing strategies.

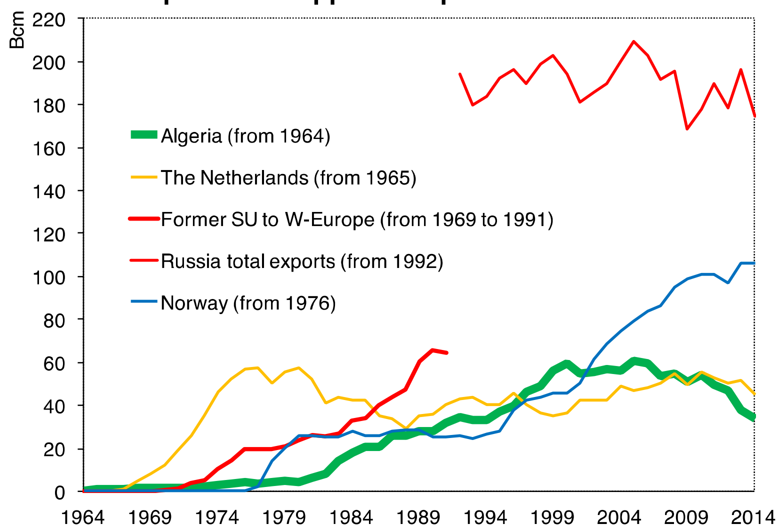
In recent years, continental European gas markets have been in a state of flux. Emulating the UK pattern, major reforms have been articulated by the European Commission aimed at restructuring, liberalizing and integrating national markets into one single market. A key objective of these reforms has been to foster competition. As a result, long-term gas contracts and their key clauses of take-or-pay for minimum quantities, link to the oil market for price formation and fixed destination clauses have become unsustainable. To be sure, in guaranteeing the continuity and stability of bilateral trade relations, these contractual structures have been instrumental in the development and expansion of the gas industry. However, as argued by Stern and Rogers, these structures have become 'anathema' to a market, which has grown more competitive; by the same token they have also become 'untenable' for buyers exposed to that competition.[29] In this context, suppliers, most of them are still locked in a logic of an oligopoly-based contractual framework, could no longer garner support for their arguments that the traditional long-term contracts are most effective in enabling investment, securing funding and, in the absence of vertical integration, hedging transaction risks. Today, buyers are increasingly holding back from signing anything that is not in line with the new realities of the marketplace.

By way of further background, it should also be mentioned that, since 2008, gas demand has declined considerably. The larger European gas market (defined here as involving Scandinavia, Western Europe, Eastern Europe and Russia) has shrunk by 11%, losing nearly 130 bcm. In the EU, where the aftermath of the financial crisis has been the most severe, the market has sunk deeper by 22% during the same period. As a result, its size has shrunk by some 110 bcm. In addition to the impact of the recession and subsequent economic restructuring, the fall in demand has been driven by gains in efficiency use and, in the power sector, by a significant deployment of lower-(variable) cost renewables and, in part, the use of imported cheap coal displaced by shale gas in the US. As the fall in EU gas demand has been larger than the fall in production, gas imports have declined less dramatically, though significantly by some 55 bcm during the same period (since 2008). With European LNG imports virtually stagnating, the decline has mostly been through pipelines.

It is in these unsettling circumstances that Sonatrach has had to compete, first with the main traditional suppliers, i.e. Gazprom (Russia), Statoil (Norway) and GasTerra (The Netherlands), all of them pipeline exporters. It has had also to deal with an aggressive LNG exporter – QP of Qatar. Ultimately, Sonatrach appears to have failed to defend its market positions. As shown in Figure 6, except GasTerra whose exports to Europe have declined most (mainly because the Dutch government has imposed a cap on the output of the super-giant Groningen gas field, which it has blamed for causing earth tremors), both other suppliers seem to have largely coped with slowing market conditions. Undeniably, this is the case of Gazprom, despite apparent fluctuations in reported gas flows from Russia. Notwithstanding the adverse geopolitical and economic consequences of the annexation of Crimea and the EU's push for diversification of gas imports away from Russia, Gazprom has managed to largely maintain demand for its exports.

[29] Stern J. and Rogers H., (2011)

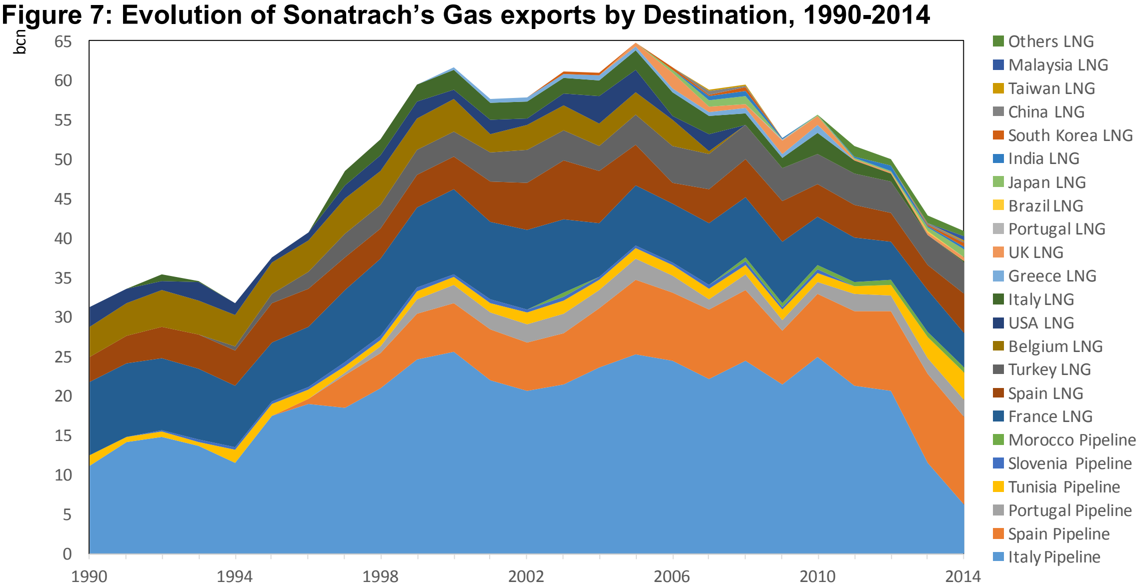
Figure 6: Natural Gas to Europe: Main Suppliers Export Paths



Source: Updated from Aissaoui A. (1999)[30] using BP

As illustrated in Figure 7, since reaching a total export peak of 65 bcm in 2005, Sonatrach has lost a huge portion of its market, which we estimate at more than 30 bcm. This loss has hardly been compensated by the gains of some 6 bcm the national company made during that period. The gains have resulted from a relatively significant increase in flows through the Etap (Tunisia) contract through the Transmed, enhancement of deliveries to the Spanish market through both the GME and Medgaz, as well a slight increase in the Botas contract (Turkey). Also, substantial spot sales to different Asian countries contributed to the gains. The losses have mostly been the result of terminations or suspensions of contracts, including the Distrigaz Belgium contract, US LNG contracts and many small Italian contracts – both LNG and pipeline. Losses have also stemmed from curtailments of the Engie (formerly GdF Suez) LNG contract, and most recently of the Eni contract through the Transmed.

Figure 7: Evolution of Sonatrach's Gas exports by Destination, 1990-2014



Source: Author's compilation using BP Statistical Review (several years)

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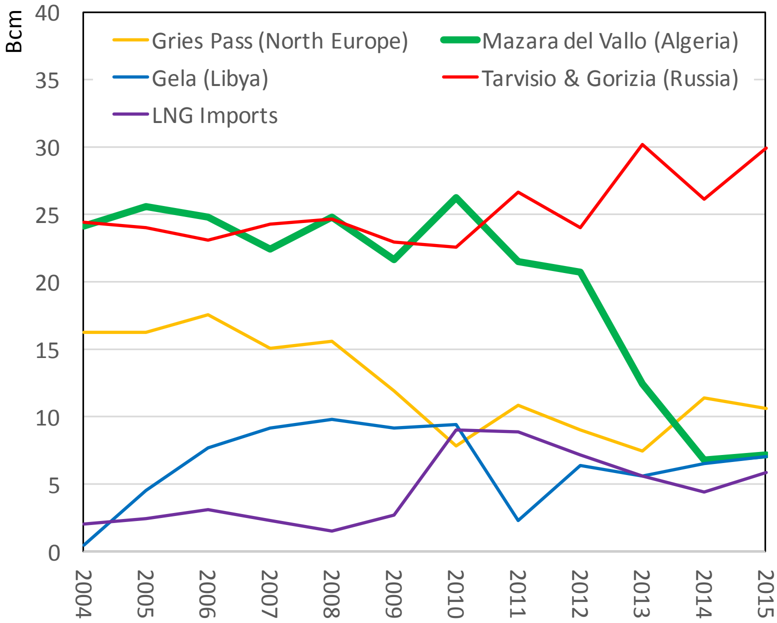
[30] Aissaoui A (1999)

Lost market ground is particularly severe in Sonatrach's nearest, biggest and long-standing Italian market where Sonatrach used to compete head to head with Gazprom (Figure 8). Until recently, each of the two companies accounted for about a third of Italian imports, with Gazprom having supplied a yearly average of 24 bcm over the 5-year period up to 2012 and Sonatrach a yearly average of 23 bcm over the same period. Since then, imports of Algerian gas dramatically decreased to 12.5 bcm in 2013, 6.8 bcm in 2014 and only slightly improved to 7.2 bcm in 2015, thereby equating gas imports from troubled Libya. Extraordinarily enough, during that time, imports at Tarvisio and Gorizia entry point, as reported by Snam Rete Gas, jumped to 30.3 bcm in 2013, 26.2 in 2014 and 29.9 bcm in 2015. Even if these volumes include some spot trading from the Austrian VTP hub (Virtual Trading Point) to Italy, the bulk of them are Gazprom's supplies under long-term contracts.

Figure 8: Natural Gas Imports into Italy during the Last Decade



Source: Extended and updated from ISPI (2015), [31] Using Snam Rete Gas

Gas imports into Italy from Algeria through the Transmed (at the Mazara del Vallo entry point in Sicily) involve several Italian buyers whose annual maximum supplies added up to some 25 bcm in the peak year of 2005 (Figure 7). Among these, Eni Gas & Power is by far the major offtaker with annual contractual quantities of 19.5 bcm. Except Eni and Enel, most supplies to other buyers have been suspended in recent years. Therefore, the bulk of the decline analyzed previously stems mainly from the apparent failure of both Eni and Sonatrach to honour their obligations: Sonatrach could not supply and Eni could not take the quantities stipulated in their contract, at least not at the prevailing oil-indexed prices. To better understand how the pattern of this tricky relationship has evolved, it is important to first try and lift some of the veil of secrecy surrounding their complex contractual arrangements. [32]

In recent years, Eni and Sonatrach have amended their long-term contact twice, first temporarily in May 2013 then on a more definite base at the end of 2015, while looking forward to renew (or not renew) their contact at the expiry date of 2019. In 2013, after nearly two years of discussions, both companies agreed on a "package solution for 2013 and 2014" to "reduce certain quantities of the

[31] Verda, M. ISPI (2015), Italian Institute for International Political Studies

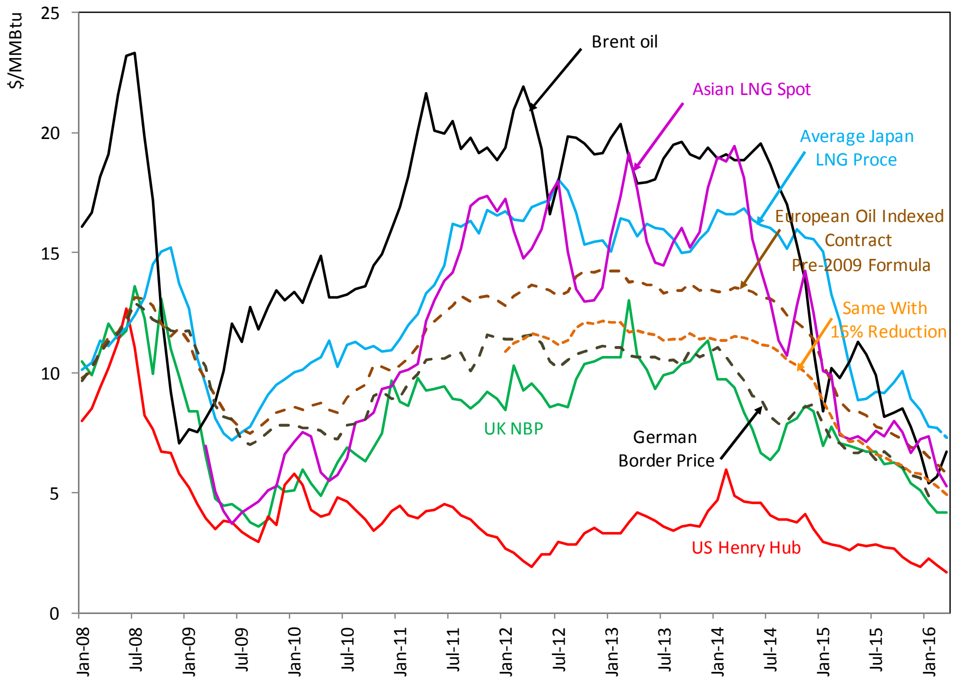
[32] In order to not inadvertently breach the strict confidentiality requirements of commercial contracts, to which he has no access anyway, this author has had only recourse to facts in the public domain as well as relevant anecdotal evidences.

contractual gas volumes delivered into Italy."[33] It is striking indeed that, while Eni was publicly declaring that its objective was to reduce its take-or-pay obligations and bring oil-indexed prices in line with hub prices, only the take-or-pay clause was revised substantially while the gas price formula, which is fully linked to oil, seems to have been upheld. As the aforementioned statistics of imports into Italy attest, the agreements resulted in a sharp reduction of contractual volumes. Furthermore, while possibly maintaining some degree of daily flexibility, the two companies agreed on a pipeline-to-LNG swap. In this latter respect, some traders have been reported as saying that some of the undelivered gas had been diverted under the swap agreement to Algeria's newly commissioned LNG train at Skikda (GL1K), while others suggested it was rather being diverted by pipeline to Spain.[34] Both alternatives seem to be corroborated by Sonatrach's data on exports to other destinations.

During that period, in a context where buyers started to litigate their price review disputes, which resulted in a record series of high-profile arbitration cases involving Sonatrach among others,[35] Eni also entered negotiations with its other long-term pipeline suppliers. In contrast to Sonatrach, which would not compromise on oil-linked prices (unless taken to arbitration), Gazprom, GasTerra and Statoil each agreed to some degree of flexibility in their pricing while focusing on maintaining volumes. In a context where oil prices were at $100+/bl and oil-indexed pipeline gas prices around $12/MMBtu, the new arrangements must have yielded significant price discounts, with prices ending closer to to the prevailing European hub prices at that time of about $9/MMBtu (Figure 9).[36] As a matter of fact, at the moment of writing, virtually all Norwegian and Dutch contracts have been converted to hub prices, while Russian contracts to major European markets have been adjusted to something close to hub prices (even if in a complicated manner[37]).

[33] ENI Press Release dated 28 May 2013 (www.eni.com/en_IT/media/press-releases/2013/05/2013-05-28-Eni-Sonatrach-reached-agreement.shtml).
[34] Argus (2013), "Eni, Sonatrach reach deal on gas supply contracts", 28 May (www.argusmedia.com/pages/NewsBody.aspx?id=848890&menu=yes).
[35] Power, R. (2014), "Gas price reviews: is arbitration the problem?", Global Arbitration Review, 6 March (available on: www.blplaw.com/expert-legal-insights/articles/wp-content/uploads/2014/03/6-3-14_Gas_price_reviews-_is_arbitration_the_problem.pdf).
[36] Rogers, H. (2015)
[37] Stern, J. (2015)

Figure 9: Evolution of Natural Gas Prices in the Main Regional Markets (as of End-March 2016)



Source: Howard Rogers, OIES (using Platt's, EIA, Argus and CME)

These outcomes must have swayed Sonatrach as it and Eni resumed their unfinished discussions. In addition, this time the talks between the two companies took place in a completely different context. The decline of oil prices since mid-2014 and their subsequent collapse caused oil-indexed gas prices to dip to the current level (if not below) of the Italian PSV hub price of 20 Euro/MWh (equivalent to $6.40/MMBtu).[38] According to public comments by Claudio Descalzi, Eni's CEO, on the occasion of a presentation of Eni's 2016-2019 Strategic Plan to the financial community in London, in March 2016, the agreement finally reached with Sonatrach at the end of 2015 involves this time both volumes and, more significantly prices. [39] Our understanding is that, while volumes were set to increase, the parameters of the oil-linked gas price formula were adjusted to fit the prevailing price environment.

It is hard, in the absence of further disclosure, to provide a clear-cut interpretation of the two successive agreements between Eni and Sonatrach. What the first provisional agreement probably entails is that with rapidly declining Algerian export volumes and massively decreased Italian gas demand, both Sonatrach and Eni got what they wanted: the former kept oil-linked prices but reduced volumes without incurring penalty; the latter paid higher prices for lower volumes while avoiding take-or-pay liability. The reduction of imports from Algeria (and from Libya for that matter) allowed Eni to meet its take-or-pay commitment for Russian gas while being more aggressive in its price negotiations with Gazprom.

Equally difficult to interpret is the extraordinary shift in the trade between the two companies. Given the European geopolitical context noted above in relation to Russia, the reason provided by Italian IPSI researchers for such a shift seems at first far-fetched. Referring to the temporary agreement of 2013-2014, they asserted that:[40]

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[38] PSV: Punto di Scambio Virtuale (Virtual Trading Point).
[39] Platt's (2016), 18 March.
[40] Verda, M. IPSI (2015)

> The reason of this shift can be traced back to a decision of Eni, which holds long-term contracts with both the Russian Gazprom and the Algerian Sonatrach, to give the priority to the flows from Russia, while reaching an agreement with its Algerian supplier to postpone part of its withdrawals.

Yet this reason is plausible when these researchers, who were probably sharing their insight into what appear to be Eni's thinking, further contended that:

> In fact, Italian decreasing demand translated mainly in a reduction of imports from Algeria. Besides reducing Italian oversupply, the agreement eased the pressure on Algerian production by growing domestic consumption, winning time for a much-needed increase in upstream investments in the country and thus contributing to the long-term reliability of the exports from the country.

From Sonatrach's side, a different reason for the shift can be found in the national company's recent tendency to engage in opportunistic market behavior. As a matter of fact, this tendency has its origin in the period before the global financial crisis. As noted by Hakim Darbouche, [41] under the influence of the policymakers of that time, Sonatrach turned to the LNG spot market for some 15% of its LNG output. In a context of tightening markets, the move stemmed from the belief that spot and short-term contract trades could generate more value than long-term contract sales.

Similarly, when Sonatrach and ENI started their talks in 2011, the context was that of soaring spot LNG prices in Asia, a direct consequence of the Fukushima meltdown caused by a devastating earthquake and tsunami, and the subsequent shut-down of all Japanese nuclear plants. At that time, Sonatrach must have been comfortable to see ENI postponing its gas take, therefore offering it the possibility of diverting whatever surplus gas was available to the booming premium spot LNG market through its expanding LNG capacity at Skikda (GL1K) and Arzew (GL3Z) (the latter being built without securing any long-term, take-or-pay contract). Unfortunately, Sonatrach could not long take advantage of that market condition. When, finally, GL3Z was commissioned in November 2014, depressed oil prices weighed on oil-indexed gas prices, which, as noted above, have since collapsed to currently less than $5/MMBtu. Morten Frisch's observation about the outcome of Sonatrach's opportunistic move during the second half of 2000's is still valid: "Sonatrach's strategy ultimately proved to be unsustainable". [42] Finally, with the LNG spot market losing its attractiveness, Sonatrach has diverted the bulk of whatever surplus gas it has available towards Spain through both the GME pipeline and the newly built Medgaz, as well as towards its neighbouring, gas transit countries – Tunisia and Morocco through the Transmed and GME respectively. It is worth noting in this respect that without Sonatrach's additional deliveries, Tunisia, which has long elected to receive its gas transit royalties in kind, could have suffered a serious supply shortfall in its domestic market.

As noted above, Italian gas imports statistics for 2015 indicate that Sonatrach's supplies through the Transmed have not significantly increased compared to 2014. We may therefore infer that Sonatrach and Eni have de facto extended their 2013-2014 provisional agreement while advancing their talks. Following conclusion of these talks at the end of 2015, exports to Italy have virtually doubled during the first quarter of 2016 compared to the same quarter of 2015. They further soared during the first week of April (at the time of finalizing this paper).[43] Obviously a week of data, or even a quarter, cannot be extrapolated to suggest a sustained high level of exports. This could rather be a response to nominations by Eni, which has great short-term flexibility to price-optimize its supply portfolio; all the more so as Algerian gas must now be cheaper. In any case, any increase in Sonatrach's pipeline exports would come at the expense of re-injection at Hassi R'Mel (Box 1) as well as for enhanced oil recovery (EOR), the domestic market or liquefaction plants. Therefore, for this increase to be sustained, Sonatrach, and Algerian policymakers for that matter, need to reconcile all such competing demands.

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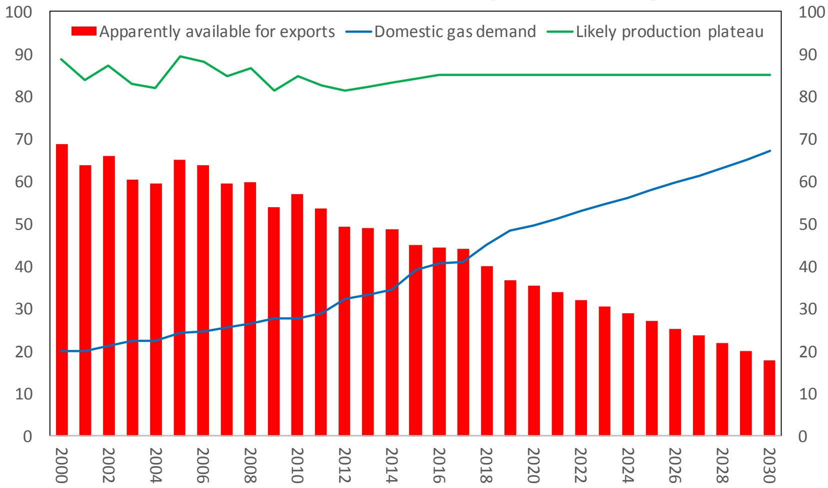
[41] Darbouche (2011)

[42] Frisch, M (2010)

[43] Platt's (2016), "Algerian gas exports to Italy, Spain soar, Libyan flows slump", 7 April.

However, consistent with our analysis so far, we take the view that Sonatrach's export outlook is not likely to improve beyond the above positive short-term fluctuations. When considering arguments to the contrary we should remember the long-heralded export targets of 85 bcm/year by 2010 and 100 bcm/year by 2015, which have been misleadingly overhyped by successive policy makers.[44] Today, even the lower figure of 60 bcm/year, which is being considered as a more reasonable target, may also become irrelevant. As assessed in the first part of this paper, marketed production is likely to plateau at best. Therefore, in a central, moderate scenario of domestic demand growth, Sonatrach's exports will likely be reduced to a trickle of some 15 bcm/year by 2030 (Figure 10). Obviously, the fall in exports would be even more dramatic if we consider a higher demand growth scenario, which would put demand on a par with production at 85 bcm in 2030. In such a case, exports would be almost eliminated.

Figure 10: Outlook for Production, Domestic Consumption and Exports in a Central Scenario



Source: Extrapolated from CREG (for domestic demand) and author's assumptions for production

Today, Sonatrach's portfolio of running contracts totals 69 bcm/year with nearly one quarter in the form of LNG and a little less than three quarters through pipelines. Key contracts in this portfolio are coming up for renewal within the next few years and all of them have clauses for periodic price reviews and price re-openers. With the above export outlook, it seems unlikely that Sonatrach would meet full delivery under these contracts. It remains to be seen whether or not the amended (2015) Eni-Sonatrach contract and their new trade relationship pattern will serve as a paradigm for future negotiations.

Before concluding this paper it is important to note that as a result of the decline analyzed above, Sonatrach's utilization of export capacity has collapsed to 52% through both LNG plants and pipelines (Table 3). This means that, if production continues to stagnate as assumed and domestic consumption to grow as projected, part of Algeria's gas export facilities would have to be considered as stranded assets; that is to say assets ceasing to operate to the full extent of their economic life. In which case, they should be recorded on Sonatrach's balance sheet as a financial loss. With this perspective, it would be arrant nonsense to talk about investment in new export capacity. Therefore, whatever the perceived potential strategic benefits of the 8-bcm Galsi pipeline to Italy through Sardinia, Sonatrach and its Italian partners (Edison, Enel and Hera) should definitely scrap the project without further discussion. Sonatrach should also consider decommissioning the obsolete, gas-

[44] Darbouche H. (2011a)

intensive liquefaction trains at Arzew (GL1Z and GL2Z).[45] Otherwise, the higher fixed cost resulting from lower capacity use will continue combining with lesser value of exports to further worsen the loss of the hydrocarbon rent accruing to the Algerian state.

Table 3: Algerian Gas Export Capacity and Capacity Use in 2014

	Nominal capacity (bcm)	2014 exports (bcm)	Capacity use
Pipelines			
. Transmed	33.5	10.2	30.4%
. GME	11.5	10.5	91.3%
. Medgas	8.0	6.9	86.3%
Total pipelines	53.0	27.6	52.1%
LNG			
. GL1Z	10.6	6.0	56.6%
. GL2Z	10.7	5.1	47.7%
. GL3Z	6.3	0.8	12.7%
. GL1K	6.0	5.6	93.3%
Total LNG	33.6	17.5	52.1%
Grand Total	86.6	45.1	52.1%

Sources: Sonatrach, Snam Rete Gas, Cores, BP

4. Conclusions

Algeria is faced with serious challenges in its natural gas sector. Confronting these challenges requires more aggressive policy responses to both supply and demand. As far as the supply side is concerned, we have established that declining (at best stagnating) natural gas production is, under prevailing conditions, an incontrovertible trend. As similarly observed during the last decade or so, anticipated developments of small and costly reservoirs would hardly stem the decline of Hassi R'Mel and other mature fields unless such a decline is rapidly contained. The Feb 2013 amendments of the hydrocarbon law, which have come on top of increased emphasis on the promotion of renewables, could have created new opportunities for investment. However, as demonstrated by the disappointing results of the only subsequent licensing round, the investment climate and a number of other issues have had a detrimental effect.

In addition, the shale gas initiative, which is a key provision of these amendments, has been frustrated by unexpected anti-fracking protests stemming from deeper grievances and aspirations. But even limiting the scope to conventional resources, the potential for reserve expansion could be higher than commonly assumed. However, this expansion will not happen without policy makers radically improving the enabling environment for investment and the incentives needed to attract and retain new investors, on a scale akin, if not more, to what was carried out in the early 1990s. Recent trade press reports, sourced to Sonatrach, alleging that the national company is looking to offer stakes in its own upstream project assets, including possibly Hassi R'Mel, to be conducted on the basis of bilateral deals, could well be a welcome sign of fundamental changes in the making. However, these reports have to be confirmed by policymakers with details of what might be offered to investors and on what terms; otherwise they will only add to the investment uncertainties prevailing in the country.

[45] The prospect of retiring the existing LNG capacity, both at Arzew and Skikda, once the new plants come on stream was first raised by Hakim Darbouche in unpublished, internal OIES material in 2011-12. Most recently, Nazim Zouiouèche, former Sonatrach CEO, explicitly suggested it on the occasion of an interview with Radio M (Maghreb Emergent), as reported by Selma Kasmi in Al Huffington Post dated 30 March 2016 under the title “GNL1 et GNL2 gaspillent du gaz, il faut les fermer!” (www.huffpostmaghreb.com/2016/03/30/zouioueche-gnl1-gaz_n_9570572.html).

Meanwhile, on the demand side, a rapidly growing domestic gas market has long become a major issue. The tardy government policy response to curb such growth has been twofold: substituting in the long run renewables for natural gas in the dominant power generation sector and, in the short to medium term, adjusting tariffs for gas and electricity to rationalize their consumption. As far as renewables are concerned, the Government's target seems ambitious and challenging. To be realizable, it needs to be underpinned by more effective policy tools, particularly in the form of incentive schemes that are both transparent and easily accessible to investors. Also, implementation strategies should include coordinated public support programs and public-private partnerships aimed at developing and disseminating local industrial content. As for domestic pricing policy, it should be reviewed at both the design and implementation levels. While dealing with retail gas and electricity prices is necessary as a matter of urgency, it is not sufficient. Primary gas supply prices, which are far divorced from the upstream costs they are supposed to reflect, should be addressed as well. Furthermore, building on these measures, a broader framework should be in place to tackle energy price and subsidy reforms in a progressive, coordinated and coherent manner. Unfortunately, in this complex and politically sensitive area, Algerian policymakers should be expected to continue inching forward very prudently taking care not to upset the precarious social and political balance of the country. Therefore, while policy changes will continue to be slow and incremental, the snowballing domestic demand risks is continuing relentlessly.

It is beyond doubt that the above supply and demand factors have been the main reasons for the dramatic decline in Algeria’s gas exports. Adding to this are the structural and cyclical shifts in international oil and gas markets which have ended up undermining Sonatrach’s marketing strategies. In a context where natural gas buyers are resolutely seeking to shorten their long-term contracts, increase the flexibility of quantities they purchase and adjust pricing formulae to reflect competitive market conditions, we have focused on the latest round of contract re-negotiations and price reviews to try and learn what new trade patterns and relationships the resulting adjustments could reveal. Whatever these might be, they are likely to have been influenced by the realization that Sonatrach is increasingly being perceived as structurally short on gas supply. Looking ahead, we have challengingly assumed that gas production will be stagnating at best. Therefore, in a moderate demand scenario, Algeria would be left with only 15 bcm/year to export by 2030. In a lower production or high demand scenarios, it will cease exporting all together, therefore importing gas beyond any such a point. With this conceivable perspective, policymakers should consider shifting their focus away from commodity trade, as the foremost way to monetize Algeria’s gas resources and ponder a different energy/industrial strategy. Renegotiations of Sonatrach’s gas contracts should reflect this alternative perspective. Instead of uncertain quid pro quos they are no longer in a position to ask for, Sonatrach and its governing policymakers should create ground for new win-win situations and partnerships in all areas of hydrocarbon development activities. Such a course of action may stand a better chance of success in reversing the troubling trends we have duly highlighted and creating more diversified value for Algeria’s future.

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