

This edition of Forum explores the complex web of geopolitics and energy policy that provides the backdrop to the new gas province emerging in the East Mediterranean.

Dedicated to this single topic, the issue starts with *Trevor Sikorski's* detailed overview of the changing face of the global LNG market, the health of which will be a critical factor in the decision to sanction the development of any export-focused East Mediterranean gas projects. Sikorski points out that when these projects come on-stream in 7–10 years, the LNG market will be very different from today, with Qatar losing its pre-eminent position as the global LNG leader and Australia and the USA making major inroads. He argues that project timing will dictate the tightness of global LNG markets, with regas capacity investment running at a different speed to that of liquefaction. He projects greater competition among LNG sellers and higher volumes sold spot, improving price transparency with the desire by currently premium-paying Asian buyers to move away from oil-indexed pricing. Russia's response to these developments will be key to the state of the European LNG market,

where East Mediterranean cargoes are likely to end up, he argues.

Laura El-Katiri offers the regional context for the East Mediterranean gas revolution. Acknowledging that much of the focus for global markets will be on gas exports from the region, the author also points to the significant economic benefits that will accrue to new producer countries in terms of domestic gas supply and the ability to reduce reliance on more expensive oil-fired power, especially given the growth in domestic power demand in recent years. The author looks beyond the political issues that have so far prevented substantial cross-border energy flows, to consider the potential benefits for the growing number of regional energy-deficit countries, while acknowledging that geostrategic interests will ultimately condition these outcomes.

As the leading gas producing country in the East Mediterranean to date, Israel is a natural first country focus. *Joseph Paritzky* and *Bill Farren-Price* discuss the impact that gas is having and will have on the country's historic dependence on energy imports and the hurdles that stand in the way of gas exports, either pipeline or LNG. Domestic political opposition and technical

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and security challenges will need to be overcome if Israeli oil companies are to secure the finance needed for major resource development. Whether Cyprus can agree a liquefaction agreement with Israeli companies or opts for an offshore export pipeline to Turkey are among the choices that need to be made; but the various issues surrounding these and other options are likely to remain keenly argued.

Leigh Elston and *Peter Stewart* delve deeper into the Israeli government's decision to cap exports from major gas discoveries at 40 per cent of the proven resource, a policy decision aimed at giving a boost to gas development while keeping sufficient gas for the growing domestic market. The authors discuss the various monetization options for Israeli resource holders and the intricacies of Israeli political objections to the gas export decision.

Matthew J. Bryza argues the case for an Israel–Turkey gas pipeline as the most commercially efficient export option for Israeli gas and points to the positive impact that such a project could have on regional stability. Improved diplomatic relations between the two countries make such an option easier to reach, although private participation would be essential, he writes. While the author makes a compelling case – through comparing the CAPEX projections for alternative Israeli gas export options – he acknowledges that further political work, not least between Cyprus and Turkey, is needed before such a pipeline could be realized.

Switching, next, to Cyprus and Turkey, *Ayla Gürel* investigates the obstacles posed by the Cyprus problem to regional energy integration. Specifically, options for a pipeline carrying gas from Cyprus, and potentially from other producers, to Turkey and onwards to other south-eastern European buyers are discussed. The author explores the positions of Turkey, Cyprus, and the international community to offshore gas development as well as the issue of resource sovereignty.

The Cypriot perspective itself is provided by *Charles Ellinas*, who outlines the country's gas export strategy, projects future demand for

Cypriot gas in Europe, and explains why Nicosia has opted for LNG as its primary gas export option. He makes the case for Cyprus as a liquefaction hub for Israeli and Lebanese gas but also acknowledges the economic and competitive risks looming in terms of shale gas and the uncertain global economic outlook.

Anastasios Giamouridis looks at the intersection of Cyprus's new-found hydrocarbon prospects and its banking and fiscal crisis, examining the extent to which gas revenue could dig the country out of its economic recession. He stresses the importance of economies of scale and points out that the economics of Cypriot gas development will be better understood only once appraisal drilling and fresh exploration are undertaken.

DEPA's proposed East Med pipeline project, running from the offshore fields to Cyprus and onwards to Crete and Greece, is the subject of the next article, by *Dimitris Manolis* and *Elsa Loverdos*. The authors point out that such a project would help meet the EU's strategy of diversifying energy import sources while increasing competition among producers. They point to some of the drawbacks of LNG, not least cost, and suggest that taking the LNG route would place Cyprus in competition with other lower-cost producers feeding the Asian market.

Gerald Butt looks at Turkish energy policy and sees diversity at its heart – a strategy that for now will favour oil and gas from northern Iraq over prospective supply from the East Mediterranean. He is sceptical about prospects for the resolution of Eastern Mediterranean political entanglements and instead argues that Ankara will persist with its political and capital investments in Iraqi Kurdistan.

Turning to Lebanon, *Bassam Fattouh* and *Laura El-Katiri* analyse the country's slow progress towards its inaugural offshore bid round, one of a series of steps aimed at helping the country join the club of regional energy exporters. Strong international interest in the bid round has been shown despite political complications that include the absence of a full-time government, and the

sectarian divisions that make consistent policy formation so difficult. *Carole Nakhle*, meanwhile, assesses the legal implications of the country's upstream hybrid fiscal regime and suggests that the government will need to go further to build out its technical and administrative capacity for managing the nascent hydrocarbon sector.

Walid Khadduri looks at the challenges facing potential developers in Gaza's small offshore sector by assessing the history of BG's failed attempts to monetize its offshore discovery in Gazan waters. Finally, *Bill Farren-Price* looks at the important lessons presented by the recent history of Egypt's gas industry.

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Eastern Mediterranean LNG: a different global gas market

TREVOR SIKORSKI

While developments relating to Eastern Mediterranean gas exports around 2020 point to a boost for the economies that will be involved, the global market into which those exports will be sold will be very different from the market existing today.

Post-Fukushima Shift Towards Asian Deliveries

After a rapid expansion of liquefaction capacity in the 2005–8 period, which saw Qatari trains coming into the market and pushing that country into the role of dominant global supplier (around 33 per cent of supply in 2012), there have been few additions to change the global supply picture. The demand for LNG, though, has seen dynamic changes with the post-Fukushima demand centres in Asia rapidly expanding, so that the region now accounts for around 75 per cent of global LNG demand (up from 60 per cent pre-Fukushima).

'Fast forward seven to ten years and the LNG markets will be a different place.'

The market has balanced itself by increasingly attracting volumes away from demand areas well served by pipeline gas. Europe and North America have both seen significant reductions in LNG imports, with those volumes heading instead to Asia. While the market still largely functions on long-term contracts, spot trade has increasingly developed to ensure volumes go where their value is highest. However, the spot market is still nascent and a forward curve for, say, delivery into north-east Asia, is just beginning to develop.

Potential Supply Boom

Fast forward seven to ten years and the LNG markets will be a different place. The current moratorium on investment in new capacity in Qatar means that the country's share of global LNG supply

will begin to wane, and other countries will come forward.

The first of these will be Australia, which currently has some 62 mtpa of liquefaction capacity under construction and scheduled for operations in the period between 2014 and 2018. Another 36 mtpa is planned, although few of those projects are likely to go ahead before the end of this decade.

Second, the USA has issued full export licences for the export of 26 mtpa and has another 200+ mtpa of applications for shale gas exports pending. While not all of these will go ahead, the US DoE is coming under increasing pressure to make decisions on the outstanding applications. By 2020 we certainly think that exports of around 73 mtpa are likely (this only covers the top six applications out of 27 different projects).

The list of Canadian export projects is not as long (six so far, with export capacity of 62 mtpa), but Canada seems to have fewer concerns about granting export licences. If Canada adds another 20 mtpa or so, then North American exports could be as high as 95 mtpa by 2020. North American supply is particularly important for the market as a whole, as most of it is based on a model that does not involve direct indexation of gas to oil prices.

Aside from Australia and North America, there are further proposals for additional liquefaction in other countries, with construction underway to add some 27 mtpa of capacity. There are also plans for another 71 mtpa of capacity in regions including Russia, East Africa and Cyprus. Summing the likely increments from Australia and North America, together with a contribution from the rest of the world of another 55 mtpa or so, suggests that global LNG supply should be higher by some 220 mtpa. To put this in context, supply in the last two years was around the 240 mtpa level, so the global market in seven years could be almost double the size it is now.

Regasification

Alas, supply is only ever half the story, and while money is pouring

into liquefaction it is also pouring into regasification. There is over 100 mtpa of regas capacity under construction, with Asia boasting almost half of this (50 mtpa), Latin America (29 mtpa), and Europe (23 mtpa). The market appears more balanced when you look at proposed regas plants, which would add another 180 mtpa of demand, although a number of those proposed look very speculative and will not proceed.

Having said that, regas plants can usually be completed faster than the more complex liquefaction projects and this is particularly the case when projects involve floating storage and regasification (FSRU), a technology which is increasing in popularity (most of the Latin American projects involve FSRU). As such, there is certainly still time for more regas projects to be announced, constructed, and brought on stream by 2020.

How tight (or loose) the LNG market gets from here will be down to project timing. However, at an overall level, the ratio of global regas to liquefaction is around a factor of 2:1. Surplus regas capacity provides the holders of liquefaction capacity with greater destination optionality. By 2020, however, the increments in capacity look to favour liquefaction additions, and these will likely outstrip increments in regas. This state of affairs should help loosen the overall physical market – making more LNG volumes available for the residual LNG market that is Europe.

This has implications both for the commercial terms of the global LNG market and for the direction of regional flows. In commercial terms, a looser global LNG market will create greater competition between sellers to place volumes, and this should begin to reduce prices and stimulate demand, particularly in the power sector, as LNG-fired plants tend to operate at the high-cost end of the mid-merit power order.

Gas Trading Mechanisms

The greater levels of spot trade will help establish more transparent pricing and the old certainty of selling gas linked to

oil will begin to come under pressure. Key in this move will be the US exports that are all largely being sold into the market under contracts with direct exposure to the US Henry Hub gas price, either under a tolling agreement or under a gas-linked long-term supply contract. The one thing that is becoming abundantly clear from developments in North America is the extent to which Asian buyers of LNG find it attractive to secure gas on contracts which are not linked to some form of oil. The two US projects that have been awarded full export licences have agreed long-term supply contracts with GAIL (India), Osaka Gas, Chubu Electric (Japan), and KOGAS (South Korea). The lure of low-priced gas is real and very powerful.

If spot LNG prices become structurally lower-priced than contract gas prices, pressure will build to renegotiate those contracts and to replace them with some form of gas price indexation. This is the dynamic witnessed in Europe over the last two years and this will be increasingly seen going forward in the global LNG market. Whether the next seven years is a long enough period to see a full abandonment of oil-indexed pricing structures is a moot point, but if we do

get something like 70 mtpa of hub-linked gas spilling into the global market from the USA by 2020, such strictures that serve to keep gas as a premium fuel are likely to be fully on their way out.

In terms of directional flows, the evolving pattern of trade will mean that north-east Asian buyers will be increasingly served with, first, Australian/south-east Asian LNG and then with North American gas. Qatar will come under increasing pressure to put volumes into that market and will need to see more of its volumes swing back into Near-East Asian, Middle Eastern and European markets. The same will be true for African volumes (north, west, and east) although Algeria, Nigeria, and Angola will all be able to compete for the growing Latin American market, as will US volumes.

And What About Eastern Mediterranean Gas?

This leaves Eastern Mediterranean volumes, which will be coming online in the midst of this potential global supply boom and will probably need to look to Europe as a primary destination, given its geographical proximity. Europe has a number of LNG facilities planned,

so there will be some capacity to sell into, although this is definitely a market where hub-gas pricing is on the up and up and where hub exposure will be an important risk for the project to manage. However, where those long-term hub prices go is really a function of how Russia reacts to an increasingly competitive landscape. The importance of Gazprom's gas marketing decision-making cannot be underplayed, as by 2020 it will have the 63 bcm/year South Stream pipeline to fill up, as well as the already functioning 55 bcm/year Nord Stream. If it decides to go for market share, those gas prices could be very modest.

'... the old certainty of selling gas linked to oil will begin to come under pressure.'

What is clear is that while EU policy is clearly aimed first at minimizing the use of coal, providing a niche for gas to be a bridging fuel in that period, the competitive landscape for gas supply in the period around 2020 could well be very different from today. ■

The Eastern Mediterranean: the Middle East's final gas frontier

LAURA EL-KATIRI

The Eastern Mediterranean is in the midst of a significant energy revolution. Sizeable discoveries of over 35 trillion cubic feet (tcf) of natural gas offshore Israel and Cyprus have, since 2009, transformed the region's fate as a long-term energy importer reliant on neighbouring Arab and Russian suppliers, into that of a prospective net exporter.

US Geological Survey estimates suggest that a further 85 tcf could yet be discovered within the Levant basin (the stretch of land and sea that ranges from Syria and Lebanon in the north, down to the coast of Israel and the Palestinian territories in the south). The Eastern Mediterranean gas discoveries, therefore, mark not only the emergence of a new regional gas province, they also signify

the fall of one of the last hydrocarbon frontiers in the Middle East.

The significance of these gas discoveries extends beyond their use in the domestic energy sectors of Israel and Cyprus, for their export value gains them the attention of a range of interested potential stakeholders, including markets (such as those in neighbouring Europe) that could benefit from importing Eastern Mediterranean gas. However, the real value of Eastern Mediterranean gas, both in economic and in wider geostrategic terms, lies in its regional use. Israel and Cyprus lie close to a region defined as much by long-standing political conflict as by economic difficulty, in which low-cost, regional gas supplies could well play an important strategic role. Eastern Mediterranean gas

offers a rare opportunity for the region to re-engage in mutually beneficial trade relations that could underpin both greater economic and political stability in one of the world's most politically volatile regions.

Exploration Success with Some Future Prospects

The Eastern Mediterranean gas discoveries made since 2009 were, indeed, not the first exploratory successes in the offshore Levant basin. Gas was discovered in 1999 and 2000 at Israel's offshore Noa and Mari-B fields, as well as in offshore Gaza, although these first discoveries were small, triggering little of the notable attention the region has received more recently. The region's

first offshore discoveries were as much the result of economic stubbornness as of politically conceived economic need; Israel's historic political and economic isolation amongst its Arab neighbours having motivated the country's on- and offshore exploration efforts for decades, with the strategic aim of reducing its import dependence for energy reaching back to the 1970s.

While Mari-B provided Israel with small volumes of domestically produced gas for a limited period of time, subsequent years saw disappointing exploration results, reinforcing expectations in both Israel and the wider region of remaining reliant on energy imports for the foreseeable future. Eventually, new gas discoveries were made in 2009, again in Israeli waters, and this time they were large – amounting to some 10 tcf mostly located in Tamar, and then came the landmark discovery of the giant Leviathan field in 2010, with up to 20 tcf. Israel's offshore success was subsequently mirrored by Cypriot discoveries of up to 7 tcf of offshore gas resources in its south-east located block 12, in the Aphrodite play close to Israel's Leviathan discovery. Further exploration work is underway, with Cyprus having tendered out five more blocks adjacent to the Aphrodite play in the hope of raising the island state's recoverable resource estimates further.

'Natural gas has the unprecedented potential to change the energy landscape in the Eastern Mediterranean forever.'

With proven reserves of some 9.4 tcf by the end of 2012 and an estimate of up to 40 tcf of currently known offshore gas resources, Israel now holds resources large enough to supply its domestic market for several decades and to allow for exports. The small domestic market of Cyprus similarly allows for surplus gas to be exported, opening up the opportunity of post-2020 gas export revenues, in addition to savings made by the domestic use of its offshore gas resources in place of oil in the power sector. Israel's

offshore reserves put the country in the ironic position of overtaking all its direct Arab neighbours, including Syria, in the size of its natural gas reserves, and currently offering the Levant region's only immediately available potential export volumes of natural gas.

Lebanon and Syria, too, offer promising prospects for offshore hydrocarbon deposits, following initial seismic work, and hold high-end interest in developing and future offshore discoveries. The complicated domestic political scenes in both countries – characterized by quasi-permanent parliamentary stalemate in Lebanon and the civil war in Syria which has escalated since 2011 – have pre-empted plans by the two Arab neighbours for the exploration of their share of the Eastern Mediterranean sea. And while Lebanon now seems set to move ahead with a first offshore licensing round this year, the chaos in Syria will likely keep its offshore off the regional hydrocarbon map for longer.

Economically Well-timed Discoveries

The Eastern Mediterranean discoveries since 2009 have arguably come at exactly the right time. The Middle East and North Africa as a region has experienced tremendous growth in domestic energy demand over the past decade, a rising share of which is supplied by diminishing natural gas supplies. Regional gas reserves are highly concentrated in a few large gas producers, principally Iran, Qatar, and to a lesser extent Saudi Arabia. Of these, only Qatar is currently a stable gas exporter, albeit primarily in the form of flexible yet expensive LNG.

The Levantine economies, generally less well-endowed in hydrocarbon wealth than the oil-rich Gulf states and parts of North Africa, have for most of their histories been dependent on imports for the majority of their energy needs. Excluding Syria, this has been true not only for Israel, Lebanon, and Cyprus, but also for Jordan and, most recently, Egypt. Egypt's case dramatically illustrates what has gone decisively wrong in the region for most of the past 20 years or more – surging domestic demand. This has been driven by population growth, rising

living standards, energy-intensive industrialization policies, and a domestic energy price environment which endemically undervalues energy down to a fraction of average energy costs prevailing anywhere else in the world. This has crippled Egypt's gas export capacity over the last few years.

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Having famously cancelled its existing gas supply contract with Israel in April 2012, the Egyptian government has since struggled to fulfil its gas supply contract with Jordan – this has been recurrently interrupted by political turmoil and sabotage. Both Jordan, whose power sector is more than 80 per cent dependent on Egyptian gas, and Lebanon, which is forced to rely on oil for power generation, are arguably in a gas crisis. So is Egypt, whose current domestic situation is not only shaped by continued political turmoil and dysfunctional governing institutions, but also by insurmountable budgetary pressure, and continued fuel shortages and electricity blackouts.

... But it's the Politics, Stupid

The domestic predicament facing Syria and Lebanon regarding their lagging exploration progress, and Egypt's current gas crisis, give us a taste of the sort of dynamics which are likely to drive the direction of Eastern Mediterranean gas development. Eastern Mediterranean gas could play an economically sound and mutually beneficial role in the Levant's current energy-related economic predicament: Israeli gas, perhaps also gas from Cyprus, could supply gas-short neighbours through existing and expanded gas pipeline infrastructure. Israel's most immediate neighbours, the Palestinians, are already set to benefit from gas, albeit supplied from Israeli offshore fields. The current turmoil in Egypt – which has idle LNG facilities and unfulfilled export contracts, but has been opposed deeply to trade with

Israel on ideological grounds – finds the country's economy in disarray, with continuing negotiations for IMF loans to keep the economy from hitting the buffers. It could, commercially speaking, benefit significantly from an Israel–Egypt gas-linked entente.

Cyprus, which is divided between Greek and Turkish communities, faces controversy centred around its gas development plans. Territorial water delimitations claimed by the Turkish Republic of Northern Cyprus (TRNC) overlap with offshore blocks of the Republic of Cyprus. Turkish claims also overlap with Cyprus's Exclusive Economic Zone located in the south-west of the island, a factor which has been blamed for the continued negotiations over Cypriot blocks 5 and 6 for which bids have been received.

In spite of these political barriers, Turkey could yet offer a geographically close and economically logical export market for Cypriot gas, which would diminish Turkey's need for higher-cost Russian gas imports and the political controversy associated with Turkish alternatives to Russian gas which include Iranian gas, and Kurdish gas from northern Iraq. This could potentially contribute to Turkey's intended role as energy hub for Eastern, not Russia-based gas deliveries towards Europe. However, the absence of a settlement of the Cyprus problem renders this option highly unlikely in the near future, at the cost also of the northern Cypriot community, which would significantly benefit from a reconciliation with the Greek Cypriots in the south.

Turkish claims to defend northern Cypriot interests in the offshore Mediterranean have been met by yet

more sabre-rattling on the other side of the coastline, between Israel and Lebanon which also share disputed land and maritime boundaries. Egypt, too, is looking to reassess its offshore claims towards the east, towards what would be Palestinian waters, albeit under de facto Israeli administration. Palestinian interests in the offshore Mediterranean have perhaps been the most overlooked in recent years. Offshore Gaza offers two known plays sizeable enough for commercial development, yet deadlock between the Israeli government – keen to prevent any direct gas development revenue stream to Hamas – and shareholders has kept the discoveries from being developed.

Uncertain Outcome

Geostrategic interests in the Eastern Mediterranean are yet to shape the direction that gas development will take. Beyond impacting current development and future gas export volumes – which remain a separate domestic policy issue in both Israel and Cyprus – regional politics will most likely prove critical in determining both the extent to which Eastern Mediterranean gas will benefit the region as a whole (or only its immediate resource holders) and the eventual destination of Eastern Mediterranean gas flows. While regional options are attractive, both economically and politically, for Israel and Cyprus, political barriers to greater regional gas trade leave both countries looking at other export options.

Cyprus, with limited pipeline options, has already decided to prioritize LNG exports. The expected size of initial Cypriot exports – with some estimated

5 million tons per annum – makes the country an unlikely second Mozambique or Tanzania, but will eventually generate badly needed funds for the country, whose public finances are struggling under the terms of a multilateral bail-out. By contrast Israel, an island politically if not geographically, offers feasible regional options. In June, Israel removed the last remaining hurdle for gas exports, by approving the export of 20 bcm of Israeli gas. Still, Israel's domestic battles have not yet all been fought, and it may eventually agree to a joint LNG project in Cyprus, a pragmatic option in a region so deeply divided by politics.

Regardless of the many other challenges involved in bringing the region's gas to market (including the not yet fully resolved question of the size and nature of exports, the fiscal and regulatory regimes that are a work-in-progress, and the eventual confirmation of technically recoverable reserves), the offshore gas discoveries made since 2009 have had a tremendous effect on the regional energy power balance in the Eastern Mediterranean. Being the latest – and possibly last – gas frontier in the Middle East, the area is of no less consequence for world gas markets than East Africa and the Caspian. Natural gas has the unprecedented potential to change the energy landscape in the Eastern Mediterranean forever. ■

The author recently published a study co-authored with Bassam Fattouh and Hakim Darbouche under the title *'East Mediterranean Gas: What Kind of Game-Changer?'*, available on the OIES website.

Israel Gas: the export conundrum

JOSEPH PARITZKY and BILL FARREN-PRICE

Israel's discovery of significant volumes of offshore natural gas in the past few years will, over time, remove what has been a strategic handicap for the country: reliance on energy imported from abroad.

The fact that Israel now has sufficient gas to remove its historic reliance on oil

and coal-fired power and, potentially, to allow it to address options for the gasification or electrification of the transport fleet at some point in the future, is no mean achievement for a country that has found itself in a state of war or, at best, cold peace with its energy-rich Middle East neighbours for

decades. Delays in building a secondary north–south gas trunk line in Israel may delay domestic and industrial uptake of the increasing domestic gas supplies, but the size of the resource so far discovered means the medium- to long-term outlook for domestic gas use is strong.

But the export of gas, rather than its

domestic use, is the inevitable driver for the development of the approximate 19 tcf offshore Leviathan field, and for potential future medium- to large-scale gas additional discoveries. While the Israeli government has finally made a ruling permitting the export of 40 per cent of the country's proven gas resource base, parliamentary opposition parties have already challenged the move and are seeking a judicial review of the decision in the Supreme Court, with the aim of requiring parliament's approval for this and any future gas export deal. Whether the government wins the right to approve gas exports without the oversight of MPs or not, the dispute highlights one of the challenges faced by the Israeli gas industry, as it looks to line up buyers for future gas exports.

'The priority in all discussions will be to identify a politically durable option that will be bankable.'

Israeli explorers and their international partners know that without an export market it will be difficult to finance fresh exploration, and near impossible to secure funds for full field development. In the long term this will, paradoxically, also limit the volume of gas available to the domestic market. Israel's very public debate on hydrocarbon policy is overshadowed by the instinctive distrust felt by significant segments of the public (particularly on the left) of those industry leaders whose companies made the discoveries in the first place. Safeguarding a national strategic asset from those who would export and profit from it has become the political narrative for the opposition led by the Labour Party.

Moreover the government's green light to exporters does not, of itself, solve a raft of other problems facing Israel's upstream shareholders. The first issue for exporters is whether to opt for an expensive LNG project or a cheaper pipeline export system.

Exports as LNG

The immediate problem in this, one of the region's smallest countries, is to find an appropriate site for an LNG project.

Such a site will need to be close to the coast, sufficiently large, and not subject to security threats. The prospect of fighting a long-drawn-out legal battle to win permitting rights in a heavily congested coastal strip means that a site near the city of Ashkelon, where developers believe there is sufficient land for a two-train LNG operation, is the only real possibility, if indeed there is any option at all.

Alternative proposals to build a plant in the southern port of Eilat are not consistent with that city's limited land availability and heavy investment in tourism infrastructure. An Eilat LNG plant would, however, mean that Israeli cargoes heading to Asian markets would sail directly from the Red Sea and would not need to transit the Suez Canal – another potential security black spot for Israeli shipping, as well as that of other countries. Neighbouring Aqaba has space for a plant and Jordan would itself be a logical market for Israeli gas, but the status of regional and Palestinian politics means that it is not a realistic option for now. Floating LNG may well solve the land issue, although security concerns, cost, and the long lead time will probably keep that option off the table.

Exports via Pipeline

Piping Israeli gas to the planned LNG plant at Vasilikos on the southern coast of Cyprus is another potential solution, and one which Leviathan's partners are discussing with their Cypriot counterparts. But there are influential voices within the Israeli debate which argue against that option on the grounds that sending gas to Cyprus would simply extend security vulnerabilities, while putting a national strategic asset in the hands of a third-party country.

In terms of pipeline exports, regional geopolitics (again) rule out (at least for now) logical options such as gas sales to Egypt, which is facing its own gas supply crisis and has idled most of the capacity at its two LNG plants on the Mediterranean coast; and to gas-short Jordan. However, the prospect of a subsea pipeline to Turkey (mirroring an ENI pipeline proposal made over a decade ago) is more realistic, given the warmer diplomatic relations seen recently between the two countries.

Turkey would not only offer a long-term, assured market for Israeli gas exports, but could also serve as a conduit for onward gas transport to other south-east European markets through its existing hub connections. The same could be said of Greece, although the increased length of the pipeline required would add substantially to the cost of that option.

Decisions for the Future

The immediate challenge for prospective developers of the Leviathan field is to start a meaningful process aimed at signing a gas sales and purchase agreement, so that the final investment decision for the field's development can be made. However, the legal challenge to the government's approval for gas exports is likely to prevent progress on this front in the near term. Developers will consequently be unable to guarantee gas supplies to potential buyers until the issue is resolved. The complicated challenge of how to establish liquefaction facilities for Israeli gas will also probably mean protracted negotiations on most of the options.

Cyprus has declared that it will proceed with a minimum single-train development for its initial Aphrodite discovery, but it will be eager to improve the economics of the project by signing up another supplier such as the Leviathan consortium. Whether that can be achieved in the near term will depend upon Israel's discussions with Turkey (in which Russia's Gazprom is involved) and on the need to negotiate an acceptable route for such a pipeline, a complex task given the geopolitical rivalries and maritime boundaries in the Eastern Mediterranean.

'The first issue for exporters is whether to opt for an expensive LNG project or a cheaper pipeline export system.'

The priority in all discussions will be to identify a politically durable option that will be bankable. The Middle East's worsening geopolitical situation makes this a difficult task. But the restart of Israel–Palestine peace talks is proof that

Israel recognizes the greater regional economic integration that gas exports – whether LNG or pipeline – would represent. However, such a move would need to progress hand-in-hand with a

broader political settlement – one, in particular, that deals with the tough status issues between Israel and the Palestinians.

Israel's gas dividend has the potential

to bring both strategic and economic benefits, but there are several thorny questions that will need to be answered before gas exports can get closer to becoming a reality. ■

Israel's Cap on Gas Exports: what will it mean for Leviathan?

LEIGH ELSTON and PETER STEWART

The Israeli government's decision to cap gas exports at 40 per cent, or 320 bcm – 13 per cent lower than the export limit recommended by the interministerial Tzemach committee last year – was naturally met with disappointment by drillers in the Levant basin. However, on second glance, the government's slide to a more conservative gas policy will not necessarily restrict export options from the giant Leviathan field.

Not only will the Israeli government allow the Leviathan partners to swap gas export credits with smaller fields, but investors are hopeful that the gas reserve pie – now estimated at 920 bcm – from which the 40 per cent export slice will be cut will only grow bigger as further exploration gets underway. Nevertheless news of the 40 per cent export cap raised questions over whether Woodside Energy will withdraw from its \$1.3 bn deal to take a 30 per cent stake in the Leviathan field.

The Australian LNG player agreed to farm into Leviathan on the understanding that at least 50 per cent of the field's reserves could be exported as LNG. The new policy has led to speculation that the partners may no longer proceed with a two-train, 10 mtpa Israeli-based export project as originally

envisaged. Woodside has remained tight-lipped on whether it will proceed with its investment, stating only that the company looks 'forward to considering the detail of the gas export policy'.

But it looks unlikely Woodside will pull out of the project. The 40 per cent cap applies to the total gas reserves within Israel's Exclusive Economic Zone (EEZ), not to any one field in particular. As the Leviathan partners have the option to swap export credits with developers of smaller fields – which may only be looking to supply the domestic market anyway – it could still potentially be allowed to export up to 75 per cent of Leviathan gas (see the table 'Israel's gas export policy').

Ultimately it is the environmental and security risks of building a plant that are likely to hamper the development of an LNG plant on Israel territory, rather than export restrictions. Any major infrastructure facility will meet fierce opposition from environmentalists and residents along Israel's small but beautiful coastline, and these protests are likely to stall an already cumbersome licensing process. With Lebanon and Israel still technically in a state of war – and no agreement reached on the maritime border between the two

countries – Hezbollah is viewed as a serious threat to the safe development of Israel's offshore gas industry.

With these complications in mind, the simplest option to export LNG from Leviathan could be to pipe Israeli gas to Cyprus and liquefy it through an LNG facility there. The Cypriot government, which sees gas exports as a lifeline for hauling it out of its economic crisis, has been quick to promote the island as a potential Eastern Mediterranean LNG export hub, and to that end has already cleared a site with the potential to accommodate an initial three 5 mtpa trains at the port of Vasilikos.

'The Cypriot government ... has been quick to promote the island as a potential Eastern Mediterranean LNG export hub.'

In the meantime, Nicosia is pushing to start exports from its own block 12 gas reserves as early as 2020. Noble Energy, the operator of the licence, is carrying out appraisal drilling at the block now and should announce before the end of 2013 whether there are enough reserves to justify an LNG development.

The Texan explorer, along with block 12 partners Delek Drilling and Avner Oil, signed an MoU with the Cypriot government in June agreeing to make a decision on whether to proceed with the 5 mtpa project by the end of 2013. Although Woodside was not party to the MoU, the Australian company is reported to be interested in joining its Leviathan partners in the project. None of the block 12 partners have any liquefaction experience, and as Noble draws up a shortlist of strategic

Table 1: Israel's gas export policy

Total gas exports	380 bcm
Maximum exports for fields less than 25 bcm	0%
Maximum exports for fields of 25–100 bcm	25%
Maximum exports for fields of 100–200 bcm	40%
Maximum exports for fields of 200 bcm or more	40%
Maximum exports from any one field (using export credits*)	75%
Israel's expected gas demand over the next 29 years	540 bcm
Israel's total reserves	920 bcm
*The government sanctioned a scheme to allow export credit trading between companies, allowing producers to export beyond the limit imposed on their field.	

partners to help build the project, Woodside is, unsurprisingly, one of the likely candidates.

The Third Way

There is a third possible option for exporting Leviathan gas: building a 10 bcm/year pipeline to Israel's one-time ally, Turkey. The project is still viewed as the cheapest and quickest way of monetizing Leviathan gas. Cost estimates for the deep-water subsea pipeline vary between \$6–8 bn depending on the final route – a factor Cyprus will be pivotal in determining, as the most direct channel from Israel to Turkey would pass through its EEZ.

'Ultimately it is the environmental and security risks of building a plant that are likely to hamper the development of an LNG plant on Israel territory, rather than export restrictions.'

However, Nicosia is unlikely to grant permission for the construction of the project; firstly, because Ankara's stance on drilling offshore Cyprus has only

served to aggravate the long-running tensions between the two states; secondly because pipeline exports would undermine its ambitions to become a regional LNG hub.

On a more positive note, the potential to import Israeli gas into Turkey's booming market may have been – at least in part – a catalyst for the recent thawing in relations between Ankara and Tel Aviv. Following Israel's apology for the 2010 Gaza flotilla raid, the prospects for building the pipeline were revived. Furthermore, as the Turkish gas market is expected to grow by between 20–40 bcm/year within the next 15 years, Ankara is prepared to pay a premium to secure new gas supplies. Israel is reportedly negotiating shipping its supplies for at least \$10/mmBtu.

Waiting for the Appeal

The 550 bcm of gas now earmarked for the Israeli domestic market is, even by conservative estimates, thought to be ample to cover the country's demand for at least the next 25 years. However, some opposition MPs are lobbying for the export quota to be cut still further and four members of the Knesset and four environmental and social policy groups have appealed the government's export decision. The group petitioned

the Supreme Court for a permanent injunction against gas exports and a nullification of the government's export sanction, demanding that the Knesset, not the cabinet, be the body to sanction exports.

The Supreme Court was expected to make a decision at the end of July or early August. Until then, no further announcement on Israel's export projects is expected. So far, the only casualty of the government's policy seems to be the Tamar floating LNG project. Gazprom Marketing & Trading signed a heads of agreement to market up to 3.5 mtpa of LNG from the project in February. Noble has already signed gas supply contracts with domestic offtakers for 92 bcm of gas from the field, but the Israeli government is not counting these volumes as part of the field's 60 per cent local market quota. It is considered that 40 per cent of the remaining 190 bcm of reserves is too small to base a 3.5 mtpa LNG plant on, so it seems the project may be scrapped. Enthusiasm for Russian participation in Israel's gas sector has faded in light of President Putin's support for Syrian leader Bashar al-Assad. Relations between the traditional allies may cool still further if Israeli gas exports head towards Europe and start to nibble into the Russian gas monopoly's core export market. ■

An Israel–Turkey Natural Gas Pipeline: inter-connection of commercial and geopolitical logic

MATTHEW J. BRYZA

The export of natural gas from Israel's Leviathan field, the world's largest discovery during the past decade, could have a significant and positive geopolitical impact on the Middle East. A pipeline connecting Leviathan to the Turkish market, the most commercially efficient export option, could help resurrect a strategic partnership dedicated to regional prosperity and stability between Israel and Turkey.

Such a pipeline could, if coupled with political will and diplomatic deftness, also help Cyprus finance a liquefaction facility to export its own significant natural gas reserves from its offshore

Aphrodite field. These optimistic scenarios require political breakthroughs that seem out of reach today. However, a modest amount of political re-alignment could enable their realization, which could then catalyse new political momentum toward a negotiated Cyprus settlement and broader stability in the Middle East.

Historic Relationships Between Israel and Turkey

Israel and Turkey have a long history of partnership, though with periodic ups and downs. In 1949, Turkey became the first Muslim-majority country to

recognize the state of Israel. Tensions emerged between the two countries during the Six Day War in 1967 and again following Israel's annexation of East Jerusalem in 1980. But Israel–Turkey relations got back on track each time, reaching a zenith in the late 1990s when both countries acknowledged the existence of their strategic partnership based on military and intelligence cooperation.

Relations between Israel and Turkey have also waxed and waned over the past decade, during the government of Prime Minister Recep Tayyip Erdogan and his Justice and Development Party (AKP).

Initially, Erdogan pursued a pragmatic approach toward Israel. On a visit to Jerusalem in 2005, Erdogan laid a wreath at the Yad Vashem Holocaust memorial, called anti-Semitism ‘a crime against humanity’, and dubbed Iran’s nuclear ambitions ‘a threat to (the) entire world’. In 2006, Turkey led efforts to establish a Palestine–Israel industrial park, while Israel’s President Shimon Peres visited Turkey (and did so again the following year). Israel–Turkey relations began to deteriorate in late 2008, when Israel moved troops into Gaza at the very moment Ankara believed it was on the verge of negotiating a breakthrough in Israel–Syria relations. Feeling diplomatically betrayed, Erdogan erupted in anger before a packed audience at the World Economic Forum in Davos in January 2009, accusing Peres of being a ‘killer’, and then storming off the stage.

‘... the most promising export options for East Mediterranean gas are an Israel–Turkey pipeline (the cheapest route) and a liquefaction facility on Cyprus (which provides the greatest marketing flexibility).’

The Mavi Marmora Incident

Relations continued to sour into 2010 when, on 31 May, a flotilla of boats carrying protestors from several countries, led by a Turkish passenger ferry the *Mavi Marmara*, decided to break through what they termed Israel’s blockade of Gaza. Israeli commandos intercepted and boarded the *Mavi Marmara*, leading to an armed struggle in which nine passengers were killed, eight of whom were Turkish citizens. The *Mavi Marmara* incident resulted in the breakdown of Israel–Turkey relations, with each country withdrawing its ambassador.

More recently, both countries have hinted at their willingness to put the *Mavi Marmara* incident behind them. On 22 March 2013, Israel’s Prime Minister Netanyahu apologized for the deaths of the *Mavi Marmara* passengers during a phone call with Prime Minister

Erdogan (brokered by US President Obama). Two rounds of official negotiations on compensation followed in April and May. The normalization process appeared stalled as of July 2013; tension increased with statements by some senior Turkish politicians attacking Israel (as well as the international Jewish community) for Palestinian deprivation in Gaza and for provoking major protests across Turkey in June 2013 over government plans to replace Istanbul’s Gezi Park with a shopping mall. Still, senior officials in both countries continued privately to signal their desire to reinvigorate bilateral relations, with a natural gas pipeline potentially at the centre of the process.

Hope for the Future: Israel–Turkey Pipeline

If Ankara and Jerusalem can weather this latest political storm and finalize their diplomatic normalization, an Israel–Turkey pipeline would provide a critical tool to deepen this reconciliation into a renewed strategic partnership. Israel has already taken a major conciliatory step in Netanyahu’s apology for the *Mavi Marmara* deaths. Ankara’s two remaining criteria for normalizing relations are compensation for the families of those killed on the *Mavi Marmara* and the end of Israel’s ‘blockade’ of Gaza. If diplomats from both countries can negotiate understandings on these two issues, their top political leaders will likely embrace an Israel–Turkey gas pipeline as a way to turn words into concrete elements of a new strategic partnership. The geopolitical significance of such a partnership – between the Middle East’s only Muslim-majority country with a secular democracy and the world’s only Jewish state – would be enormous.

Regardless of geopolitical benefits, an Israel–Turkey natural gas pipeline will be realized only if private companies decide to invest in it. Private investors will indeed probably favour such a pipeline, since it would provide the most commercially competitive way to export Israel’s gas from Leviathan. According to feasibility studies conducted by the Turkish energy company Turcas Enerji Holding (on whose board the author serves), capital expenditures (CAPEX)

of \$2.5bn would be required to construct a 470 km subsea pipeline from Israel to Turkey. The pipeline would consist of twin 24-inch lines, each pumping up to 8 bcm of gas per annum, for a total of 16 bcm. The twin pipelines would run from the Leviathan field through Israeli waters, then across Cyprus’s continental shelf into Turkish territorial waters, landing onshore at either Ceyhan or Mersin on Turkey’s eastern Mediterranean coast. An additional \$83 million would be required to build a 40 km pipeline on land to connect the landfall at Ceyhan to the Turkish national gas grid.

More ambitious plans to integrate Leviathan gas into the EU-supported Southern Corridor project (which will initially connect Azerbaijan with markets in Turkey and the EU), would require either: \$647mn for a 470 km connection from Ceyhan to the Trans Anatolian Natural Gas Pipeline Project (TANAP); or \$1.93bn for a 1,215 km pipeline from Ceyhan to the start of the Trans-Adriatic Pipeline (TAP) on the Turkey–Greece border, for a total of \$4.4bn to connect Leviathan gas directly with the EU.

Other Options for Exports of Leviathan Gas

The CAPEX estimate for even this maximalist export of 16 bcm from Israel to the EU is considerably lower than estimates for the three other options that are under serious consideration by the Israeli government and the private companies leading development of the Leviathan field – Israel’s Delek and the US company Noble Energy.

Floating LNG in Israeli waters: IN FAVOUR – provides maximal marketing flexibility, allowing Leviathan gas to reach Asia’s higher priced markets; allows Israeli government to maintain physical control over export facility; avoids politically contentious permits for a land-based liquefaction terminal in Israel. AGAINST – no floating liquefaction facility has yet been deployed, with the world’s first example, Shell’s Prelude project, now under development for Western Australia; both CAPEX (see below) and operational expenses (OPEX) are estimated at more than three times those of an Israel–Turkey pipeline. Estimated CAPEX: \$7 bn to \$9 bn.

LNG onshore in Cyprus: IN FAVOUR – provides the same maximal marketing flexibility and avoidance of contentious permitting as does floating LNG. AGAINST – denies Israeli government physical control over gas export facility; will require a decade or longer to develop; difficult to finance without revenue from early gas exports, (which an Israel–Turkey pipeline would generate). Estimated CAPEX: \$4.5 bn to \$6 bn.

Pipeline to Cyprus, Crete, and mainland Greece: IN FAVOUR: provides direct access to EU market; avoids potentially contentious Turkey–Cyprus debate over access to the Cypriot continental shelf (see below in relation to Israel–Turkey pipeline). AGAINST – prohibitively expensive. Estimated CAPEX: \$11 bn to \$14 bn.

In theory, onshore LNG terminals in Israel and Egypt could provide additional export options for Leviathan gas. In practice, however, liquefaction facilities onshore in Israel, either on the Mediterranean Sea or at Eilat on the Red Sea, are unlikely to secure governmental permits due to environmental and security concerns. As for Egypt, it is politically inconceivable that the Israeli government would allow the country's gas export facilities to be located in an Arab state, particularly since the turmoil in Jerusalem's relations with Cairo following the ouster of former Egyptian President Mubarak.

Israel–Turkey Pipeline Plans

In light of the full range of political and commercial factors discussed above, the most promising export options for East Mediterranean gas are an Israel–Turkey pipeline (the cheapest route) and a liquefaction facility on Cyprus (which provides the greatest marketing flexibility). The government of the Republic of Cyprus is indeed intent on constructing an LNG terminal on the island, regardless of the economic risks posed by the relatively low level of gas reserves proven thus far in Cypriot waters: Aphrodite's proven reserves are now only one third of Leviathan's 900 bcm, (which equates roughly with Azerbaijan's total proven reserves, a volume that is necessary to launch the EU-supported Southern Corridor

but not sufficient on its own to have a major geopolitical impact). The Cypriot government is confident that additional exploration will significantly expand the country's proven reserves, which could be complemented by gas from Israel and (a decade later) Lebanon. But, securing financing under such conditions of uncertainty would be considerably easier if backed by revenues from exports of Israeli natural gas via a more easily financeable Israel–Turkey pipeline.

'... realization of an Israel–Turkey pipeline is currently blocked by the lack of political alignment among the parties.'

The government of Cyprus, however, may hold a significant trump card with regard to an Israel–Turkey pipeline. According to the United Nations Convention on the Law of the Sea (UNCLOS), while no country can prohibit an international pipeline from being laid across its continental shelf, any country can impose conditions on its construction. While UNCLOS is thus ambiguous on whether Nicosia could block construction of the Israel–Turkey pipeline along its continental shelf, the Cypriot government may be able to argue its case with sufficient skill to secure political support among its EU allies, which in turn could raise the financing costs of such a project.

A Cypriot attempt to block construction of an Israel–Turkey pipeline would carry significant risks for all parties, perhaps most of all for those who favour a negotiated settlement of the Cyprus question. The United Nations is leading a diplomatic process to negotiate a political agreement between Cyprus and Turkey, which aims to reunify the island into a bi-zonal, bi-communal federation. That process has stalled since 2009. But the election of Cypriot President Nicos Anastasiades in February 2013 renewed hope for progress towards a settlement, given Anastasiades's strong public support in early 2003 for the Cyprus settlement plan proposed by former UN Secretary-General Kofi Annan. During the first half of 2013, such hope seems to have prompted the Turkish government to

signal its readiness to re-energize its approach to political settlement negotiations with Cyprus.

Understandably, President Anastasiades has focused most of his energy on the Cypriot banking crisis during his initial months in office. But with some renewed progress in UN negotiations over a Cyprus settlement, political conditions could emerge to allow a collaborative approach between Nicosia and Ankara, as well as Jerusalem. A consequence of such an approach could see revenues from an Israel–Turkey pipeline facilitating the financing of an LNG terminal on Cyprus. This could involve early monetization of Aphrodite gas through its export via an Israel–Turkey pipeline, during the decade required to develop and construct the considerably more complex LNG terminal on the island.

The Way Forward?

Unfortunately, realization of an Israel–Turkey pipeline is currently blocked by the lack of political alignment among the parties. Normalization of Israel–Turkey relations remains stalled; and Cyprus and Turkey have treated future East Mediterranean natural gas exports as a reason to harden their positions on the Cyprus Question rather than to generate new momentum towards a negotiated settlement. These developments underscore the fact that major economic projects – such as hydrocarbon pipelines – cannot on their own generate political reconciliation. Rather, political conditions must first align sufficiently to allow two states to conceive of an economic project that can carry their political reconciliation further.

An Israel–Turkey pipeline will therefore never be realized as a 'peace pipeline'. Rather, it will emerge as the most commercially attractive export option for Israeli gas, after Israel and Turkey have normalized their political relations. Such a pipeline may then prove to be a key financial enabler of an LNG terminal on Cyprus. If the governments and private companies exploring these two projects proceed this far, they will generate further political momentum that could catalyse historic political breakthroughs regarding Cyprus, together with broader geopolitical issues in the Eastern Mediterranean. ■

The Cyprus Problem as an Obstacle to Regional Energy Cooperation

AYLA GÜREL

The discovery of natural gas, together with the prospect of further hydrocarbon finds offshore Cyprus, carries a promise of prosperity for the island. Most experts agree that rapid realization of this promise, with maximum benefits for all stakeholders, is possible if there is cooperation between Cyprus and Turkey. Specifically, this refers to a project which involves export of Cypriot gas via a pipeline to Turkey, where it could be consumed in the latter's consistently growing domestic market or be transported to European markets (via the planned TANAP plus TAP pipelines).

Naturally such a project requires an understanding between the Greek Cypriots (who are at the helm of the Republic of Cyprus – RoC), the Turkish Cypriots (who have, in the northern part of the island, their separate *de facto* state, the Turkish Republic of Northern Cyprus – TRNC), and Turkey (which, while not recognizing the RoC, is the only country that recognizes the TRNC).

More generally, analysts do not dispute that optimal solutions (both economic and political) for monetizing Eastern Mediterranean gas call for regional cooperation, e.g., involving Turkey, Israel, and Cyprus.

However, Cyprus–Turkey cooperation over gas appears to be difficult, if not impossible, without a political settlement in Cyprus or, at least, some loosening of the involved parties' positions vis-à-vis the Cyprus problem. The political impasse between the Greek Cypriots on the one hand, and the Turkish Cypriots and Turkey on the other, also creates difficulties for other possible regional cooperation projects. For example, an Israel–Turkey subsea gas pipeline is being mooted by the two governments and promoted by various companies from both sides. Such a pipeline cannot, for obvious reasons, go through the Exclusive Economic Zones (EEZs) of Lebanon and Syria, and will have to go through the EEZ of Cyprus, which means Turkey and Israel will require Greek Cypriot consent.

Such cooperation proposals are mired

in difficulties. These arise generally from the Cyprus problem and, more specifically, from the fact that the positions of the two Cypriot sides and Turkey, in respect of the issue of hydrocarbons, are informed by their perceptions of what is *politically* at stake in Cyprus.

Greek Cypriot Position

The Greek Cypriots argue that their actions are compatible with international law because under the present circumstances their government, as accepted by the international community, is the legitimate government of the RoC – the recognized state which formally encompasses both Greek and Turkish Cypriots. As such, the RoC is entitled to an EEZ, can sign delimitation agreements with other states, and enjoys exclusive sovereign rights to explore for and exploit the natural resources in its EEZ.

There is agreement between the two Cypriot sides (in the context of UN-sponsored negotiations between them) that in the event of a settlement natural resources will be a federal competence, to be jointly exercised by Greek Cypriots and Turkish Cypriots. However, the Greek Cypriots say that pending such a settlement, the RoC's sovereign right to explore and extract hydrocarbons lying in its EEZ is 'inalienable and non-negotiable' and is not conditional on a Cyprus solution. More specifically, the exercise of this right is not a bi-communal issue for negotiation with the Turkish Cypriots at present – i.e. before a settlement.

'However, Cyprus–Turkey cooperation over gas appears to be difficult, if not impossible, without a political settlement in Cyprus.'

It is universally accepted that the island's offshore natural resources belong to all Cypriots, Turkish as well as Greek. Yet, as regards sharing of revenues from these resources, the Greek Cypriots

say that will come after a solution, i.e. the Turkish Cypriots, as citizens of the Republic, will enjoy the benefits of any natural resource wealth *within the framework of a united Cyprus*.

Position of the International Community

The Greek Cypriot position that (pending a solution of the Cyprus problem) their government represents the RoC and therefore has the right to explore for natural resources in Cyprus's EEZ, has the strong backing of the international community (including the EU and the five permanent members of the UN Security Council). On the issue of revenue sharing, however, the position of the international community is somewhat unclear. For example, in his Cyprus reports to the UN Security Council in June 2012 and January 2013, the UN Secretary-General noted: 'It is important to ensure that any new-found wealth, which belongs to all Cypriots, *will benefit both communities*' (emphases added). It will not be too far-fetched to interpret this statement as an implicit recognition that the Greek Cypriot approach – that there can be no revenue sharing before a settlement – is a problem. Nevertheless, this Greek Cypriot approach has not been questioned by either the EU or by the permanent members of the UN Security Council, with the recent exception of Russia, whose foreign minister Sergei Lavrov stated in April 2013: 'In respect of Cyprus [hydrocarbons] ... any prospecting for natural resources must envisage an agreement that each and all Cypriots gain from it.' It must be said, however, that this statement is at odds with the interest shown by Russian energy companies – e.g. Novatek and Gazprom Bank (a subsidiary of state-owned Gazprom) – in participating in the RoC's emerging hydrocarbons industry.

Positions of Turkish Cypriots and Turkey

The Turkish Cypriots, together with Turkey, dispute the perception (held by

the Greek Cypriots and the international community) of the present political status quo in Cyprus. Their fundamental contention is that the Greek Cypriots alone cannot legitimately represent the RoC, as this would be contrary to the 1959–60 Cyprus Accords and Constitution. In their view, since the 1963 breakdown of the bi-communal power-sharing structures of the Republic, no single authority, constitutionally competent to represent Cyprus as a whole (i.e. Greek Cypriots and Turkish Cypriots together) has existed on the island. On this basis, they object to all RoC actions relating to EEZs and offshore hydrocarbons development. The Turkish Cypriots, together with Turkey, regard such actions as involving the exercise of sovereign rights at the international level, which, they maintain, Turkish Cypriots and Greek Cypriots possess jointly, by virtue of their being the equal constituent communities of the 1960 Republic. For the same reason, Greek Cypriots and Turkish Cypriots are co-owners of the island's natural resources and should both benefit from any exploitation of such resources. From this perspective, any RoC action in this field now – at a point where the Cyprus problem is still unsolved – amounts to ignoring the legitimate rights and interests of the Turkish Cypriots.

With Greek Cypriots determined to continue exploring for hydrocarbons on their own, the Turkish Cypriots and Turkey collaborated in restoring the political balance, as they saw it, by taking 'reciprocal steps of equal significance': an agreement was signed demarcating the continental shelf between the island's northern coast and Turkey. The Turkish Cypriot authorities also granted hydrocarbons exploration licences for sea areas in the north, east, and south of Cyprus (with some areas in the south and east partly overlapping the Republic's exploration blocks) to the Turkish national oil company TPAO. These 'reciprocal steps' amount to a claim by the Turkish Cypriots to what they consider to be their equal share with the Greek Cypriots in rights concerning maritime jurisdiction and hydrocarbon exploration, notwithstanding the lack of a negotiated settlement.

Alongside counter-plans for their own

hydrocarbon exploration, the Turkish Cypriots also invited the Greek Cypriots to cooperate over hydrocarbons. They did this through the UN Secretary-General to whom they submitted two proposals, in September 2011 and September 2012. Both proposals were rejected by the Greek Cypriots without consideration. The latter proposal, called 'Hydrocarbons plan regarding exploration activities (north and south)', related to establishing a bi-communal technical committee which would be mandated to: (a) obtain the mutual consent of both sides on agreements concluded and licenses issued unilaterally by either side; (b) determine each side's share of revenues from hydrocarbons offshore Cyprus; and (c) manage the total revenue of hydrocarbons.

Turkey itself has another reason for opposing the Greek Cypriot pursuit of hydrocarbons: its claimed continental shelf in the Eastern Mediterranean covers almost all of the EEZ proclaimed by RoC in the island's west and partially overlaps RoC exploration blocks 1, 4, 5, 6, and 7 in the south-west. This is a maritime delimitation issue which, Turkey says, can be settled only after a solution in Cyprus.

Security Implications

As regards action it is likely to take against RoC exploration, Turkey seems to be making a definite distinction between how it would react (a) to exploration in parts of blocks 1, 4, 5, 6, and 7 which it claims to be part of its continental shelf; and (b) to exploration in blocks which are licensed by the TRNC to TPAO and which overlap with RoC blocks 1, 2, 3, 8, 9, 12, and 13.

In the case of (a), Turkey has made it clear that it would step in to halt any activity in the overlapping areas, implying that it would, if necessary, even take military action. An incident which took place in November 2008 indicates what might happen: two foreign-flagged exploratory ships conducting surveys on RoC's behalf in the relevant areas were intercepted by a Turkish warship and 'forced ... to cease their operations and withdraw within the territorial waters of the RoC'. It is worth noting that the RoC has not, to date, licensed blocks 1, 4, 5, 6, and 7.

For case (b), Turkey seems to have settled on using its navy to monitor activities without intervening – as happened during Noble's first drilling in Aphrodite in 2011 and again recently with Noble's seismic surveys in block 12 – and, of course, on the policy of reciprocal steps. The latter entails Turkey's continued support to the Turkish Cypriots in their 'activities to protect their ... rights over the [island's offshore] natural resources' including the provision of 'necessary assistance for the completion of seismic researches and proceeding with drilling ... within the license areas granted to ... TPAO by the TRNC in the south of the Island' (Turkish MFA statement of 14 June 2013).

Hydrocarbons and the Sovereignty Issue

Pending a solution of the Cyprus problem, the hydrocarbons controversy appears to have fuelled the more fundamental disagreements between the two sides regarding (a) where sovereignty lies in Cyprus and (b) the related question of how 'a new state of affairs would come into being' under a political settlement.

'The hydrocarbons controversy is perceived by both sides as yet another episode in the fundamental conflict of principle between them.'

According to the Greek Cypriot view, a new state of affairs in Cyprus will be created by the writing of a new constitution for the *existing, internationally recognized, and continuing* RoC, which will be transformed into a bi-communal, bi-zonal federation, the Turkish Cypriot community essentially being reintegrated into that state.

The Turkish Cypriots, on the other hand, maintain that a new state of affairs in Cyprus will be established through the founding of a new state by the two pre-existing sovereign states or entities (i.e., the two separate administrations that now exist on the island). These entities will devolve some of their sovereignty to the new state but

will otherwise retain their sovereignty. Turkey, of course, supports the Turkish Cypriots on this.

The presumptions that the two sides use to defend these entrenched positions are essentially the same as those that inform their stances vis-à-vis the hydrocarbons issue.

Hence the Turkish Cypriot proposal – calling for cooperation between the two sides on hydrocarbons, pending a Cyprus settlement – appears to the Greek Cypriot side as being aimed at nothing but strengthening the hand of the Turkish Cypriot side at the negotiations. It is perceived as an attempt to challenge ‘the sovereignty

of the existing RoC’ and to put ‘on an equal par the unrecognized TRNC with the legitimate state, the RoC, which is internationally recognized’.

Conversely, the Turkish Cypriots perceive the determination of the Greek Cypriots to continue in their unilateral exploration for hydrocarbons as being linked: (a) with the Greek Cypriot desire for further confirmation that the status of the present – i.e. solely Greek Cypriot-run – RoC as a sovereign independent state is unproblematic (as happened when the RoC was allowed to join the EU in 2004); and (b) with the Greek Cypriot position that the RoC should be preserved under a settlement.

Conclusion

The hydrocarbons controversy is perceived by both sides as yet another episode in the fundamental conflict of principle between them. It has thus turned into a ‘zero-sum game’, ruling out possibilities of inter-communal or regional cooperation. Given the accelerated political unrest in much of the Eastern Mediterranean region at the moment, one can only hope that the international community will be able to persuade the two Cypriot sides that now is a time for compromise rather than for any further aggravation of their own traditional animosities. ■

Cyprus LNG: optimizing the export options

CHARLES ELLINAS

The advantageous geographic location of Cyprus – at the crossroads of major international energy routes to Europe and the Far East through the Suez Canal – makes the island a natural regional energy hub in the Eastern Mediterranean and the natural location to develop a liquefied natural gas (LNG) plant.

The Growing Importance of Gas

The new Eastern Mediterranean gas discoveries have happened in a period when global demand for gas is increasing. ExxonMobil’s *The Outlook for Energy 2013* predicts that global energy demand will grow by 35 per cent, even with significant efficiency gains, as the world’s population expands from 7 billion today to nearly 9 billion by 2040, led by growth in Africa and India. Energy demand in developing nations (non-OECD countries) will rise 65 per cent by 2040 compared to 2010. The fuels used to meet the world’s growing demand for energy are changing. Oil will remain the number one global fuel, while natural gas will overtake coal for the number two spot. Also, over the same period, global gas demand is expected to grow at about 1.6 per cent per year – more than twice the rate of oil. Within that, LNG demand growth is expected to be even stronger. Between now and 2020, average annual growth is expected to be

5 per cent, decreasing to about 2 per cent per year after that as demand shifts to the more price-sensitive markets of China and India who have other energy sources of their own.

Gas will see strong growth and will constitute nearly a third of fuel inputs for electricity generation by 2040. In OECD countries, ExxonMobil sees an ongoing transition from coal to gas in the following 15 years. Today, coal is a very competitive economic option for generating electricity. However, as costs arising from greenhouse gas policies are considered, natural gas becomes increasingly competitive, due to the fact that it emits 60 per cent less carbon dioxide than coal in electricity generation. Thus, gas demand will grow faster than any other major fuel source, rising 65 per cent by 2040. In Europe, despite the effects of the economic crisis, gas demand will remain fairly stable or slightly increase in the coming years, to reach 550–600 bcm/year by 2020.

For the next 10 to 20 years, Europe will require substantial growth in both oil and gas imports, because indigenous production of gas in the EU is decreasing rapidly. As a result, by 2025 the EU will require an increase of about 100 bcm in gas imports per year, in comparison to 2010. Over the same period China will need another 140 bcm/year of new gas, despite increasing production of

shale gas. China is actively securing long-term gas supplies, both by pipeline from central Asia and as LNG imports. However, shale gas is expected to change China’s energy landscape significantly after 2020. Driven by China and India, global gas imports are expected to increase by 450 bcm/year by 2025.

Eastern Mediterranean Gas and Energy Security in Europe

Europe is heavily dependent on Russia for its energy supplies and is currently the largest market for Russian energy exports, with about 35 per cent of the EU’s gas coming from Russia. The EU has made it clear that in order to satisfy current and future demands, it wants to diversify its imports away from Russia and inflexible long-term contracts indexed to oil, towards alternative reliable gas suppliers. This diversification is also supported by the USA. A report by the US Congressional Research Service on Europe’s energy security in 2012 states that successive US administrations and Congresses have viewed European energy security as a US national interest. This has included promoting diversification of Europe’s natural gas supplies, especially in recent years, through the development of a Southern European Corridor, as an alternative to Russian natural gas.

For Europe, Eastern Mediterranean gas has a strategic value as an alternative to Russian and North African imports. But Russia's ability to adapt and protect its markets, even by reconsidering the pricing of gas if required, should not be underestimated.

'For Europe, Eastern Mediterranean gas has a strategic value as an alternative to Russian and North African imports.'

With potential gas reserves exceeding 1.1 tcm in the six leased blocks and a very small domestic gas demand (of the order of 1 bcm/year), Cyprus is developing an export strategy. Of the possible export options, LNG provides the flexibility to serve several markets and customers, providing the strategic advantages that Cyprus needs. Pipelines do not offer flexibility in the selection of markets. Also, the water depth in the eastern Mediterranean (2000 m+) limits the size of pipeline, and thus throughput. Given the amount of gas that Cyprus expects to be exporting by 2025, pipelines do not offer a practical solution. The decision to build an LNG plant in the south of the island at Vasilikos was reconfirmed by the President of the government of Cyprus, Mr Anastasiades, in April 2013. The land has been secured initially for three trains with 15 mtpa of LNG export capacity, possibly expanding up to a total of eight trains in the future.

Cyprus as Regional LNG Hub

With the timely establishment of an LNG plant, Israel and Lebanon should also be able to bring their gas to Cyprus for liquefaction, making it possible to create a world class LNG hub at Vasilikos. However, Israel still has other options, which include Floating Liquefied Natural Gas (FLNG); geopolitics, cost, and time will be key factors in the final choice. By 2025 Cyprus could be in a position to export 25 million tonnes LNG (35 bcm) per year, starting with 5 million tonnes (7 bcm) by 2020. This could rise to 35 million tonnes (50 bcm) per year if

Vasilikos becomes an LNG hub for the region.

Even with only 50 per cent of this gas going to Europe, by 2025 Cyprus and the Levantine Basin could supply 25 per cent of the additional gas needs of the EU, which is far more than the 10 bcm of gas currently planned for the Trans Anatolian Natural Gas Pipeline Project (TANAP) per year, making the Eastern Mediterranean a much larger potential gas supply source. Cyprus's membership of the EU also offers the added incentive of fiscal and regulatory oversight. It also satisfies the EU Commission's intent to promote development of new onshore and offshore indigenous sources of energy.

The East Med Gas Corridor could form a new independent and secure supply of LNG which could contribute substantially to the EU's future energy security. This is in line with the European Council's May decision to intensify the diversification of Europe's energy supply and develop indigenous energy resources to ensure security of supply, reduce the EU's external energy dependency, and stimulate economic growth. Furthermore, a Cyprus-based LNG plant would give access to the attractive markets of Asia, especially those of the Far East, where demand for gas supplies keeps growing and LNG prices are particularly high – and are expected to remain so in the 2020s.

Alternative Global Supplies and Risks

Over the long term, Cyprus offshore gas will have to compete with production from lower-cost supplies from East Africa and unconventional gas sources such as shale gas from North America. In addition to the above, there is a wave of large projects coming to fruition from 2014 onwards in Australia. These will expand LNG supply from 25 mtpa to 88 mtpa and Australia is expected to become the largest LNG supplier in the world by 2018.

Global LNG demand is expected to continue increasing and by 2025 an additional 160 mtpa will be needed. Even allowing for new projects currently under planning, the LNG supply gap is expected to be about 70 mtpa. However, over 25 countries are proposing a number of new projects

which, by 2020, could amount to about a third of world LNG demand. A key factor in their realization will be their ability to attract investment in what are currently uncertain times, which will limit the number reaching a Final Investment Decision (FID). This may also lead to shortages of skilled contractors and labour, which may lead to higher project costs.

New pipelines and interconnectors, both to Europe and the Far East, will compete with LNG. Examples are the TANAP pipeline – expected to transport 10 bcm/year to Europe – and Turkmenistan to China pipelines which will carry up to 60 bcm/year.

New unconventional gas developments are also having an impact on global energy prospects. Currently, only the USA, Canada, and Australia are exploiting their unconventional gas (particularly shale gas) resources. In Europe, shale gas development may take much longer and is unlikely to become a game changer. The same applies to India. However, China is making progress with its own developments and should benefit from these increasingly from 2020 onwards. Unconventional recoverable gas resources (mostly shale gas) have now grown to over 44 per cent of the 752 tcm world total and are bound to capture some of the world's gas demand, in competition with LNG. When shale gas is included in the global total reserve base Cyprus's estimated 1.1 tcm recoverable reserves are put into context – at only 0.16 per cent of the world total.

'... the World Bank expects gas prices in Europe and the Far East to drop by more than 10 per cent by 2020, in comparison to current prices.'

Another major risk for LNG demand is the erratic state of the world economy. Economic growth is uneven and uncertain – particularly in the developed world – impacting other world markets, with concomitant effects and uncertainties on future energy demand growth. Ineffective fiscal, legal, and regulatory systems may also slow LNG project development.

Gas Pricing Structures

In the recent *EIA Outlook*, the USA is seen as being a net gas exporter by 2020. Even though actual US net export volumes, even by 2025, are expected to be relatively low (around 40 bcm), Henry Hub pricing is influencing other gas markets and, especially in the Far East, is contributing to the pressure on gas pricing to move away from oil price indexation. For example, a recent LNG supply contract between BG and CNOOC is based on a blending of oil-linkage and gas-on-gas market pricing. Going forward, LNG sellers will eventually have to face pricing reality to remain competitive, but equally, LNG prices will have to reflect construction costs. However, with the number and volume of projects proposed post-2020, buyers will have more choice and sellers will need to be competitive.

Many of the currently planned LNG projects would find it difficult to achieve FID if they are forced to sell at hub pricing. Even though such a shift is a few years away, LNG buyers, especially those in Europe (which has to compete with very low US gas prices), will focus on cost-competitive supplies with as low a level of oil price indexation as possible. This may be assisted by future US hub-priced LNG exports to Europe, as part of its policy to play a bigger role in European energy security and global natural gas markets.

A number of Japanese, Chinese, and Korean companies have already signed

contracts to purchase LNG from the USA and Canada at gas market-related prices. They have also begun to invest in upstream and midstream assets to enable their LNG supply, something which is of interest to Cyprus given the need for investment in its LNG plant.

Another major factor is that pricing in Asia and the Far East is expected to be influenced by the upcoming cost-competitive North American and East African LNG projects, especially for post-2020 LNG supplies. An ever-increasing number of projects is targeting this market, seeking long-term sales contracts post-2020. In addition to Australia, North America and East Africa may be supplying an additional 60 mmtpa to the Asian LNG markets by 2025. As a result, those projects which are delayed, or are unable to find buyers soon, may face increasing pricing risks with time. Cost-competitiveness is the other major factor.

As a result, it is expected that Henry Hub, shale gas in China, and East African LNG project economics will set pricing levels both in Europe and in Asia for post-2020 LNG supplies. Bearing in mind the above developments, competition, and global demand in the years to come, the World Bank expects gas prices in Europe and the Far East to drop by more than 10 per cent by 2020, in comparison to current prices. Predictions for 2020 are: \$13.7/mmBtu for Japan, \$10.5 for the EU, and \$5.7 for Henry Hub.

Potential for LNG from Cyprus

Thus, with Cyprus planning to start exporting in 2020 the Far East, as well as the EU, remains an attractive market. The main competition will be projects in North America and East Africa, which are expected to start exporting LNG at about the same time, but they could have an advantage cost-wise. As a result, controlling costs and completing the Vasilikos LNG plant as early as possible will be key factors in its success. There have been many unsettling announcements of cost escalations and project development delays over the last few years.

With the large capital investment required to support new liquefaction projects, it is important to secure attractive long-term commercial arrangements to underpin project returns and financing sooner in the planning process rather than later. LNG projects can also be selective – by selling to those who can assist in securing finance to underpin project development. This also applies to Cyprus.

In view of the above, the key driver for Cyprus should be the acceleration of the LNG project in order to be in a position to start construction as early as possible – hopefully early in 2016 – and to begin exports by early 2020. This should then enable Cyprus to benefit from the window of opportunity it now has to negotiate long-term LNG sales contracts at favourable prices to underpin its project development. ■

Fast Forward for Cypriot Gas

ANASTASIOS GIAMOURIDIS

Until recently, few people considered offshore Cyprus or Israel to be areas of significant prospectivity. However, through a process that was neither easy nor one that should be considered complete, the picture has changed very dramatically for both countries over the course of the past decade.

In the case of Cyprus, the first steps to that end were taken in the early 2000s when the Cypriot government hired Petroleum Geo-Services (PGS) to proceed with a preliminary assessment of

the country's offshore potential through seismic surveys. PGS's results were largely favourable, and on the basis of this the government attempted to award exploration and production licences for 11 offshore blocks in the Cypriot EEZ in February 2007. However, it was able to attract only three bids, with no interest from some of the larger IOCs.

The government accordingly awarded only one licence (block 12) in October 2008, to Noble Energy, a medium-sized E&P company from the USA, which

already had strong interests in the region (Israel). Following considerable preparatory work, which included rather more detailed seismic data assessment, Noble Energy moved forward with drilling its first exploratory well in block 12 in September 2011. This indicated a 5–8 trillion cubic feet (tcf) natural gas deposit in deep water of about 1700 metres, with an intermediary estimate of 7 tcf.

The confirmation of Cyprus's gas potential in 2011, together with growing

interest from industry, prompted the country to push forward quickly with a second licensing round in 2012. This round, in sharp contrast to the first, saw good participation from IOCs, upstream independents, gas buyers, gas and LNG traders, and smaller regional players seeking to benefit from potential synergies and market positioning. Licences were awarded for a total of five offshore blocks out of 12 on offer (of which nine received bids) in 1Q 2013. This was earlier than previously anticipated and took place before the presidential election of February 2013. Offshore blocks 2, 3, and 9 were awarded to a consortium led by Italian major ENI and the world's largest LNG buyer KOGAS from Korea; while blocks 10 and 11 were awarded to French supermajor Total. A bid for block 9 by a consortium which was led by Total and included Novatek and Gazprom Bank of Russia was initially favoured, but was later dropped in favour of the ENI-KOGAS consortium bid.

'The challenge for Cyprus and its partners is to develop its hydrocarbons potential as fast as possible, while at the same time ensuring that they maximize economic benefits ...'

This news gave birth to great expectations of economic and, potentially, geopolitical gains in Cyprus. Indeed, even without any further additions from new gas discoveries to this estimated resource basis, Aphrodite (the name given to Noble's offshore field) is large enough to allow Cyprus to surpass the (proved) reserve basis of some relatively established gas producers in the EU such as Poland, Romania, and even the UK – albeit in certain cases this would largely be a result of field depletion. Moreover, if the more speculative figure of 60 tcf – which Cypriot authorities believe its EEZ probably contains (roughly 40 tcf of this figure being in the new contract areas) – were to be confirmed, Cyprus's reserve levels would approach those of Norway – a major European gas producer and exporter. Importantly, this excludes potential

oil prospectivity, which is likely to be assessed by Noble, ENI-KOGAS, and Total in their respective licences and could dramatically improve profitability.

The Intersection with the Economy

But the good news on the hydrocarbons front was soon overshadowed by problems in the economy. By March 2013, Cyprus was faced with the spectre of uncontrolled default including Eurozone exit, with potentially far-reaching negative consequences for the country's economy, and even politics. Against this background, the new centre-right administration of Nicos Anastasiades, which had taken over only a few weeks earlier from the nominally communist administration of Demetris Christofias, accepted a rescue loan from the European Union (EU) and the International Monetary Fund (IMF). The EU/IMF loan to Cyprus amounted to €10bn and was offered on strict conditionality, including a requirement to more than halve the size of the Cypriot banking sector, a major source of income for the country, by 2018.

This challenging economic environment has raised the stakes for successful hydrocarbons exploitation, as a means of both offsetting some of the short-term recessionary pressures, as well as facilitating the restructuring (and diversification) of the Cypriot economy away from its current focus on banking. The challenge for Cyprus and its partners is to develop its hydrocarbons potential as fast as possible, while at the same time ensuring that they maximize economic benefits on each level of the value chain. Cyprus and Noble Energy are targeting early 2016 for agreeing a final investment decision (FID) on a 5 mmtpa liquefaction facility, which could kick-start gas infrastructure development and total investment by a figure upwards of \$10bn in a \$23bn economy. Additionally, cheaper indigenous gas could substitute for expensive oil imports, and export revenue could start benefitting Cyprus's national accounts some three to five years later.

This timeframe is possible but not a given, and is largely conditional on Aphrodite being a commercial discovery.

Uncertainties (still perfectly normal at this stage) that have yet to be determined include: the specific resource basis in Aphrodite and more broadly in block 12; production costs and gas quality at Aphrodite; and the potential existence of liquids credits (condensate or deep oil) to support upstream economics. Indeed, under such a scenario, gas recovery costs can decline dramatically – and even turn negative – as the extraction of natural gas becomes a technical necessity of (the more profitable) oil recovery.

The Value of Economies of Scale

If the economics at Aphrodite alone do not work, then Cyprus will need to seek wider economies of scale, with the aim of driving unit costs down to support the viability of such a capital-intensive project. However, economies of scale should be pursued irrespective of whether Aphrodite is viable or not, as a means of boosting project profitability and, by implication, also revenues for the government (operational efficiency, financing terms, and market skill being some other key profitability drivers; these will be directly linked to Noble's ability to deliver them, alone or with a suitable partner).

'... calls to make the development of Cypriot hydrocarbons conditional on a prior solution to the Cyprus dispute, a problem which has failed to make any real breakthrough over the past 40 years ...'

The potential source of such economies of scale for Cyprus include further prospectivity in block 12, new gas discoveries by Total and the ENI-KOGAS consortium in the five blocks awarded to them, and joint monetization under which Israel and/or others liquefy their gas in an onshore plant in Cyprus. Cooperation with Israel could also include unitization agreements – an established industry practice which optimizes production across contract areas and thus helps reduce upstream production costs.

All the above options are theoretically feasible, but still need to overcome some important obstacles. For example, the confirmation of further prospectivity beyond Aphrodite in block 12 and/or in the new licences awarded in 2013 under Cyprus's second licensing round, require further seismic surveying and drilling. By the same token, achieving economies of scale by means of joint LNG monetization with Israel presupposes success in overcoming the serious legal, commercial, and political complications which could emerge in relevant negotiations, in a successful and timely manner. These complications could in fact be aggravated by a lack of prior experience – this will be the first arrangement in the world whereby gas from one country is transported for liquefaction to another, and is then jointly exported from that latter country (although not directly applicable to the Eastern Mediterranean, problems between Timor Leste and Australia, in relation to the Sunrise LNG project, are a case in point).

It is thus possible that, if results from Noble Energy's ongoing appraisal drilling (expected end-2013) fail to indicate a sufficient level of prospectivity that would allow development on the basis of Aphrodite alone, then there will be delays in taking a FID until such economies of scale have been successfully achieved. Still, if Total and ENI proceed, as they have suggested, with an aggressive exploration programme in offshore Cyprus over and above their contractual obligations – and

prove successful in firming up new prospectivity – then a FID could still be taken reasonably close to the present target of 2016. This would thus allow gas exports to start at some time in the early 2020s (and domestic use one to two years earlier).

Politics and Gas

Besides normal commercial uncertainties and relevant challenges that may delay progress, development can sometimes be inhibited by extraneous non-commercial factors, including political risk. This includes calls to make the development of Cypriot hydrocarbons conditional on a prior solution to the Cyprus dispute, a problem which has failed to make any real breakthrough over the past 40 years, and which could prevent project implementation whilst these complex political negotiations lasted.

Similarly, calls for Cypriot exports via a subsea pipeline to Turkey are based on the (false) premise that this is necessarily a commercially superior monetization option compared to a liquefaction plant; and that development of such a Cyprus–Turkey link could thus help both solve the Cyprus dispute and allow the Cypriot authorities and other stakeholders to maximize economic returns. On the contrary, Noble has already indicated its interest in LNG as being able to capture premium Asian markets, while Total, ENI, and KOGAS have similarly shown interest and have positions in the global market. These players may therefore be unwilling

to commit to the inherently more limited pipeline monetization options (to Turkey or elsewhere), which could accordingly lead to further, unnecessary project delays.

Meanwhile, a number of objections which relate directly to the aforementioned Cyprus dispute – put forward by Turkey with reference to hydrocarbons exploration and production operations in Cyprus – seem to have been ignored both by the government of the Republic of Cyprus and key IOCs. The significant capacities brought by these IOCs (Total and the ENI-KOGAS JV) to Cyprus suggest that there will probably be adequate levels of technical and commercial expertise in the coming years for the country to realize its maximum hydrocarbons potential across exploration, production, and monetization. However, the speed with which Cyprus will move towards capturing the much-needed economic benefits from its hydrocarbons potential will depend on the favourable clarification of a number of relevant factors. These include: various technical variables impacting gas commerciality; the ability to achieve efficiencies and favourable arrangements such as midstream economies of scale; and the ability to move forward with licensing, exploration operations, and monetization decisions free from political interference and constraints which undermine profitability – or outright viability. ■

The East Med Pipeline

DIMITRIS MANOLIS and ELSA LOVERDOS

This article focuses on the Eastern Mediterranean pipeline project proposed by DEPA (Greece's public gas corporation), which is one option for the export of Eastern Mediterranean gas to Europe.

The political factors which influence investment decisions are beyond this article's scope, which is based on the premise that sufficient gas for exports to Europe will be available. (The US Geological Survey has estimated a mean

of 122 trillion cubic feet (tcf) of recoverable gas in the Levantine basin and although the Israeli government's decision – limiting export quantities to 40 per cent of the country's projected reserves – is higher than the Tzemach recommendations and the size of the resource base isn't constant, it still provides about 540 bcm for export.) We shall argue that Europe needs this gas and is a window for gas sellers, and that the pipeline: creates an additional

gas corridor in conformity with the EU's external energy strategy, is eligible for development within the EU's infrastructure framework, is technically and financially viable, and is competitive with other export options.

Outline of the East Med Project

This project consists of a reverse-flow 26-inch pipeline, initially carrying 8 bcm but scalable, and consisting of

three sections: (a) a pipeline from the fields to Cyprus, (b) a pipeline connecting Cyprus to Crete, and (c) a pipeline from Crete to mainland Greece with compressor stations at Cyprus and Crete. There are two routing options for section (c): a 1,700 km pipeline (1,200 km offshore and 500 km onshore) to the Greek Adriatic coast, which could then connect to Italy via the IGI Poseidon, the 210 km, 10 bcm offshore pipeline between the Greek Adriatic coast (Thesprotia) and Italy (Otranto); or a 1,550 km pipeline (1,530 km offshore and 20 km onshore) to the gas network in northern Greece, which could connect to Bulgaria via the IGB (Interconnector Greece–Bulgaria, the 180 km, 5 bcm interconnector between Komotini in north-eastern Greece and Stara Zagora in Bulgaria).

The EU's Natural Gas Requirements: a significant window for gas sellers

Europe continues to be a valid market. The historically low rates of gas consumption – which, according to the European Commission's Directorate-General for energy, dipped by 4 per cent in 2012 registering a 14 per cent decrease relative to 2010 – fell with the contraction of GDP, raising doubts about the market's enduring attraction to sellers of gas.

'... a pipeline delivering gas from the Eastern Mediterranean would be well-placed to tap into both the SEE's markets and those further afield in Europe.'

However, according to European Commission staff, trends have shown marked growth overall and import dependency rose from 43.5 per cent in 1995 to 62.4 per cent in 2010. Moreover, although previous projections have had to be revised downwards, forecasts commissioned by the EU to take into account the flagging economy indicate that the share of gas among fossil fuels is still expected to increase up to 2030. For, as the 'cleanest' fossil fuel, gas

is integral to the EU's Low-Carbon strategy, constituting an essential backup supply to balance the increasing use of variable renewables. This, coupled with dwindling conventional reserves and uncertainty regarding the extent of shale production in Europe, indicates that Europe's reliance on imports will increase to 80 per cent, according to EU figures.

The adverse impact of the Eurozone's recession on foreign direct investment and external demand in the south-east European (SEE) economy has also raised doubts about this regional market's potential. However, a recent report from the World Bank notes an emerging recovery, with projected growth of 1.7 per cent, ending the double-dip recession and the Commission estimates an increase in gas demand during 2012–25. For example, projected demand (in bcm/year) in Romania is expected to increase from 13.67 to 16.79 (while its production declines from 10.33 to 6.22) and in Bulgaria from 2.75 to 4.99; Serbia's consumption is expected to increase from 2.30 to 4.07, FYROM's from 0.43 to 0.88 and Bosnia-Herzegovina's from 0.33 to 0.95.

Apart from economic ills, pricing and regulatory uncertainties have also triggered doubts about the SEE's attraction as a destination market. However, while reforms are certainly necessary, the region's states – as Energy Community members – are legally obliged to establish the EU's legal/regulatory framework. This, and aspirations for EU membership, bodes well for the Commission's efforts to improve implementation of the EU's acquis and consolidates the SEE's attraction as a destination market by virtue of it being the closest to the new sources of gas, and in urgent need for resources to diversify its supplies.

Moreover, the selection of the Trans-Adriatic Pipeline (TAP) by the SDII Consortium is excellent news for the development of the region's gas market, potentially triggering further investments – a prerequisite for market growth – in various interconnectors including the IAP (Ionian Adriatic Pipeline) and those between: Bulgaria–Romania (1.5 bcm, 25 km) and Bulgaria–Serbia (1.8 bcm, 150 km).

The Objectives of the EU's External Energy Security Strategy for Natural Gas: diversification

Supplies from the Levant would contribute to the EU's energy goals: Europe's major gas imports are from Russia (34 per cent), Norway (31 per cent), and Algeria (14 per cent), with extensive single-source dependency in northern and eastern Europe, while 90 per cent of Russian exports transit Ukraine or Belarus. With its increasing reliance on imports for the energy it consumes, the EU's priority is to overcome dependency and minimize the risks associated with reliance on a small number of suppliers/routes, through diversification. Apart from ensuring uninterrupted supplies, this goal is pursued in order to increase competition which, with gas costing European industry four times more than its US competitors, is increasingly urgent.

'... where there are precedents for cross-border pipelines, a new commercial framework needs to be devised for an LNG project sourcing from more than one country.'

The Southern Gas Corridor (SGC) has been the EU's strategy cornerstone, and the selection of TAP constitutes a milestone. However, the 10 bcm associated with the SDII consortium represents only 2 per cent of the EU's consumption and, according to European Commissioner for Energy Günther Oettinger, is just the start of Europe's diversification process.

But Where From?

Europe's options are limited. Despite hopes for the Trans-Caspian Pipeline, Turkmen gas will not be available in the near future, due to disputes over the Caspian Sea. Iranian gas is another hostage of politics and Iraq's will initially be allocated domestically. Additional supplies from existing North African suppliers seem doubtful. Apart from the ramifications of the Arab Spring,

this is due to factors including: ageing infrastructure and delays in bringing new upstream volumes online (Algeria); technological challenges facing new discoveries (Libya); and supplies being focused on the domestic market (Egypt).

Mediterranean gas is therefore attractive and a pipeline delivering gas from the Eastern Mediterranean would be well-placed to tap into both the SEE's markets and those further afield in Europe. According to Commissioner Oettinger 'For the EU, this region [the Eastern Mediterranean] could become a potential plank of energy security'.

EU's Infrastructure Policy

Europe's resolve to diversify is reflected in its new infrastructure strategy for 2020 and beyond. This emphasizes the need for transit infrastructure to link up with new suppliers, as well as cross border interconnections to ensure delivery. The Commission estimates a 30 per cent increase in the volume of transmission capacity is required.

The Eastern Mediterranean has already been integrated into the EU's strategy. Regulation 347/2013 incorporates it within the SGC and cites it as a source for diversifying central eastern, and south-eastern Europe's supplies. Priority corridors have been designed with the integration of SEE markets in mind.

Work is underway to establish the list of PCIs by the end of 2013 and Commissioner Oettinger has stated recently that 'we take a particular interest in proposals for transporting East Mediterranean gas into the EU'. Apart from the proposed East Med pipeline a similar project, the TransMed a 1,400 km (approximately) pipeline from Cyprus to the Greek mainland (near Athens) via Crete, has been proposed by Cyprus. While the ultimate objective foresees their merger, currently both projects have been scoring well in the evaluation process and seem set to be labelled PCIs.

The East Med pipeline meets a series of EU criteria: it contributes to competition inter alia by facilitating access to sources of supply taking into account diversification of sources, counterparts, and routes; it promotes market integration and interoperability

by enabling the connection of Cyprus to the EU mainland; and it potentially impacts security of supply beyond Cyprus and Greece to Italy, Bulgaria, and the SEE. It establishes a new route, in addition to the one via Turkey, for Caspian gas, thus satisfying Europe's quest for alternative routes. Memories of the 2009 Russia-Ukraine crisis (which also disrupted supplies coming through Turkey) serve to underline the significance of this. Moreover as a reverse-flow infrastructure, the East Med could also provide supplies from Italy and North Africa towards the south-east.

The East Med's Technical Feasibility

Studies show that the project is technically feasible. While the maximum water depth (2,873 m) is challenging, the engineering required is similar to projects – such as the planned Galsi and Medgaz – already completed. Even the approach to Crete, complex due to a rough sea bed, does not represent insurmountable difficulties and a marine survey scope has been defined.

The East Med's Economic Viability

Major energy infrastructure is expensive. The EU estimates that to cover gas needs from 2010 to 2020, investments of €70bn are required; this sum includes import pipelines, interconnectors, reverse flow, storage, and LNG. It is not surprising, therefore, that one of the criteria for PCI status is for the project's overall benefits to outweigh its costs. The costs for creating a new corridor from the Eastern Mediterranean to Europe will be high whether considering LNG or a pipeline. The East Med's costs (from source to Italy) are estimated at €6bn and would be realized with project financing probably consisting of 70 per cent debt and 30 per cent equity.

As potential sources for facilitating financing, European institutions have increasingly focused on energy, with the European Bank for Reconstruction and Development having contributed around €8bn since 1991 and the European Investment Bank more than €55bn since 2000 (27 per cent on gas).

Moreover, as a PCI the East Med's development would be facilitated by

the provisions of Regulation 347/2013 which – by addressing obstacles related to granting of permits, regulatory issues, and financing – was designed largely to attract investments. To boost investment, it provides a series of advantages: preferential treatment for PCIs, streamlined permit procedures, a clear regulatory framework, long-term incentives for investments including the obligation on national regulatory authorities to grant risk-related incentives through tariffs (anticipatory investments, early recognition of costs incurred, additional return, etc.), and appropriate cost allocation to enable investments with cross-border impact.

Furthermore as a PCI the East Med would potentially be eligible for financial support (grants for studies and financial instruments from the new Connecting Europe Facility, CEF). Although the Commission's original proposal of €41.2bn for CEF has been slashed to almost €30bn (€5,126 million to the energy sector), its instruments will assist projects to leverage additional private investments.

Of particular relevance for investors, however, is the analysis showing that the East Med would offer competitive tariffs – lower than those of an LNG plant – rendering this project less prohibitive than has been suggested. For example, regarding exports to Italy and SEE, the pipeline's average transportation tariffs would be about a third of the costs associated with LNG. Whereas the tariff of LNG to Italy and SEE would range between 54 per cent and 100 per cent, the corresponding pipeline tariff to Italy via Greece would be between 43 per cent and 51 per cent. Indeed, this is comparable to the case of gas from the Caspian to Europe via Turkey and Greece, where the tariffs range from 31 per cent to 68 per cent.

Pipeline versus LNG

There is no denying the advantages inherent in a liquefaction facility, as proposed for the Vasilikos area for gas from Leviathan, Tamar, and block 12. This would be the first in the EU and the world's second cross-border facility, and an MOU regarding its development was recently signed between Cyprus and the Noble, Delek,

and Avner companies. LNG is more flexible, offering greater opportunities for expansion, export orientation versatility, volume adaptation, and client base diversification. By eliminating the physical connectivity of pipelines, LNG may reduce supply risks for Europe – which imports 80 per cent of its gas via pipeline – constituting an alternative energy route.

The drawbacks of LNG are well-known; it is susceptible, as are pipelines, to physical (both technical and political) threats, and it requires large coastal sites, leading to resistance from environmentalists. However, the most important variable determining the choice between pipeline and liquefaction for the monetization of gas is the cost of LNG facilities. Liquefaction costs from greenfield projects have increased dramatically: according to estimates, the case for LNG depends on containing costs at \$1,050/ton – difficult in light of cost inflation and the cost overruns

from which projects sanctioned in recent years have suffered. Higher liquefaction costs render LNG less attractive than gas delivered via pipeline – even assuming a pipeline cost that is 25 per cent higher relative to the base. With energy prices increasingly being a critical political issue, the end price for consumers, and price affordability, will be key factors in the decision for a liquefaction plant.

Moreover, where there are precedents for cross-border pipelines, a new commercial framework needs to be devised for an LNG project sourcing from more than one country. This could cause delays.

Commercially, pipelines offer more competitive tariffs. Furthermore, experience shows that European companies hesitate to commit to long-term LNG, potentially rendering a project dependent chiefly on Asian buyers for sanctioning, whereas a pipeline option would be more likely to secure the participation of European

buyers through long-term contracts, bolstering the investment's viability. Moreover, the Asian market experiences intense competition from alternative suppliers. By 2025 these will include new sources in Mozambique and Tanzania, capitalizing on their proximity to this target market which by that time may be balanced, if not over-supplied.

However for DEPA, on the premise that sufficient gas is available, LNG together with a pipeline working in parallel would provide a win-win situation. Ultimately, although political factors are not in the scope of this article, national security concerns and security risks resulting in a higher risk premium will be decisive factors for the choice of market and infrastructure. Indeed the ultimate investment decisions will disclose the extent to which these resources constitute a vehicle for international cooperation, regional integration, and for greater energy security in Europe. ■

Northern Iraq Eclipses the Eastern Mediterranean in Turkey's Energy Diversity Plan

GERALD BUTT

One word encapsulates Turkey's core energy strategy: diversity. To meet the demands of a rapidly expanding economy and a growing population, Ankara needs not only to build out its energy imports, but also to diversify the sources of those imports.

'Turkey decided to focus on this region for the simple reason that it offers the nearest and cheapest source of oil and gas and has significant sub-surface resources ...'

At present Turkey is uncomfortably reliant on Russia, Iran, and Iraq, all of which have agendas on the Syrian conflict and other issues that are at variance with Ankara's views. Up to the middle of 2012 (when sanctions were imposed on Tehran), Iran was Turkey's

main oil supplier (51 per cent of the total), followed by Iraq (17 per cent). Since then, imports from Iran have fallen sharply, while those from Iraq have risen accordingly, leaving these two countries accounting for more than half of Turkey's oil requirements. Russia remains the chief provider of natural gas (57 per cent), followed by Iran (18 per cent).

While Turkey will target the expansion of current domestic energy sources – such as coal – and the development of new ones – like shale gas and nuclear power – it will still need to increase imports of oil and gas to meet the rise in domestic demand. Enjoying a long Mediterranean coastline, Turkey might seem best-placed to benefit from the arrival of offshore gas in the Eastern Mediterranean. However, the tangle of geopolitical disputes in that region means that a windfall from this direction is unlikely in the near future. The controversy over the divided island

of Cyprus, in particular, shows no signs of being resolved, thus eliminating the simplest and cheapest way of taking Eastern Mediterranean gas via pipeline to Turkey and onwards to Europe. Improving relations between Turkey and Israel are giving greater credibility to talk of a subsea pipeline connection under the Mediterranean. But a number of diplomatic and technical hurdles need to be crossed before this project can proceed.

Over the coming five years, Turkey will seek to increase natural gas imports from Russia, and widen its search for new suppliers of LNG, to meet the expected growth in domestic demand. In 2018, the Trans Anatolian Natural Gas Pipeline Project (TANAP) will deliver 16 bcm of Azerbaijani gas to Turkey; 6 bcm of this will be consumed domestically, with the remainder being destined for Europe. Looking further ahead, Turkey is hoping that natural gas from Turkmenistan can be fed into the

TANAP venture. In June 2013 Turkey and Turkmenistan signed a cooperation framework agreement on Turkmen gas supplies.

Economic/Political Ties with Irbil

But for now, with Eastern Mediterranean gas being off limits, Ankara's sights are set on another region much closer to home as a new and expanding source of oil and natural gas: northern Iraq. A strategic decision was taken by the Turkish government in 2008 to develop economic and political relations with Irbil, with a view to the area of Iraq governed by the Kurdish Regional government (KRG) providing an increasing share of Turkey's energy requirements. Senior energy officials in Ankara believe that Turkish firms failed to exploit energy openings in Azerbaijan and Kazakhstan and were determined not to make the same mistake in northern Iraq, when the potential there became clear. Today, some 1,200 Turkish companies of all kinds are operating in northern Iraq.

Turkey decided to focus on this region for the simple reason that it offers the nearest and cheapest source of oil and gas and has significant sub-surface resources: the KRG aims to produce 1mn b/d of oil by the end of 2015 and 2mn b/d by 2020. At present, Turkey is importing 60,000 b/d by truck.

There is, of course, a tricky and sensitive political dimension to Ankara's focus on the KRG region. The Baghdad government deems the export of oil from northern Iraq to Turkey in the absence of supervision by the state marketing firm, SOMO, as illegal and unconstitutional. This is one of several issues that have led to strained relations between Ankara and Baghdad.

For its part, the Turkish government is keenly aware of the sensibilities, but insists that it is proceeding in a legal and ethical way, and without any desire to become a party to the disputes between Irbil and Baghdad over oil and territorial claims. How successful Turkey has been in persuading Baghdad of its case could become clear in 2014 after the completion of a pipeline from Khurmala Dome in the KRG region to Fishkabur near the Turkey–Iraq border. From here,

there are plans for a new pipeline to carry KRG-produced oil across Turkey to the Dörtyol Oil Terminal, east of Ceyhan, for onward shipping to Turkish refiners or other buyers.

Pipeline Awaits Political Decision

The option exists to inject KRG crude into the Ceyhan pipeline, but the KRG authorities are only prepared to take this step if all the operating costs of the international oil companies (IOCs) involved are met by Baghdad – which is the subject of an ongoing dispute between Irbil and Baghdad. Also, capacity constraints at Ceyhan terminal mean that a new Dörtyol pipeline is the preferred long-term plan for KRG crude. No decision has been made yet on this pipeline, but government officials are confident that construction will start within 12 months. The KRG and the IOCs operating in the region are awaiting word from Turkey's Energy Market Regulatory Authority (EMRA) on whether work can start on a new direct export pipeline.

The decision will be a political one which the Turkish government will take when it feels it has presented the best possible case to Baghdad, explaining why it feels justified in proceeding with the deal. The following are key elements in Turkey's justification:

- The application for the licence for the export pipeline has been made by a private Turkish firm. So this is not a Turkish government venture – which might have implied recognition of the KRG region as an independent country. Turkey also has effective control of the line.
- IOCs operating in the KRG region would become partners in the pipeline, which would be built on a Build-Operate-Own (BOO) basis.
- The revenue from the oil would be split according to the Iraqi Constitution, with 83 per cent going to Baghdad and 17 per cent to Irbil, after deduction of the IOCs' production costs. Therefore the central Iraqi government stands to benefit from the proposed scheme.

Despite the political sensitivities and the delays that might arise (a final decision is unlikely before the 2014 Iraqi parliamentary elections), one can expect KRG-produced oil to be flowing into Turkey by end-2014 or early 2015. If the new pipeline project receives a green light, construction will take six months.

Turkey has further underlined its commitment to energy ties with the KRG through the acquisition by a state company of six blocks in the region. Two (Jabal Kand and Pulkhan) straddle areas disputed by both Irbil and Baghdad. When asked if this was not a sign of Turkey taking the KRG's side in the territorial dispute, senior government officials were clear that the border issue was an internal Iraqi matter, and until they resolved it, Ankara saw no harm in exploring for oil and gas in those areas.

Domestic Diversification

Even as Turkey's diplomats concentrate on finessing the proposed KRG pipeline project, its energy officials are seeing what further potential lies inside the country itself to help meet rising fuel demand. To help cope with an annual rise of 7–8 per cent in electricity demand, more and more coal/lignite is being mined and burned, with the intention that this will account for 30 per cent of power generation by 2023. At the same time a Russian firm is to construct a 4,800 MW nuclear power plant at Akkuyu, near Mersin on the Mediterranean coast on a BOO basis, with commissioning scheduled to begin in 2020 – although critics say this will only increase Turkey's reliance on Russia as an energy partner. A second nuclear plant is planned for Sinop on the Black Sea, with a third option being studied.

'Potentially the brightest light on Turkey's domestic energy horizon is shale gas.'

Potentially the brightest light on Turkey's domestic energy horizon is shale gas. Energy Minister Taner Yildiz said in 2013 that 'there is huge potential of shale gas reserves', especially close to

the Central Anatolian cities of Ankara, Konya, and Nevşehir, and in the Thrace Basin in the west of the country. Shell and Turkish Petroleum Corporation

(TPAO) began exploration work close to Diyarbakir in the east towards the end of 2012. By the point at which shale gas becomes a key player on Turkey's energy

stage, it is hoped in Ankara that the political problems blocking the country's access to the Eastern Mediterranean gas bonanza will have been cleared. ■

Lebanon: The Next Eastern Mediterranean Gas Province?

BASSAM FATTOUH and LAURA EL-KATIRI

Lebanon is the Levant's most recent candidate to launch an offshore bidding round, the first in the country's drive to become yet another gas province in the Eastern Mediterranean. Lebanon's waters are believed to hold significant hydrocarbon potential, for both natural gas and oil, making offshore Lebanon a potentially attractive location for gas explorers.

'If the discoveries are large enough, there will be plenty of gas to meet both domestic and export requirements by the middle of the next decade.'

A long-term energy importer, Lebanon's faltering economy could benefit tremendously from hydrocarbon wealth. Current plans are to import short-term LNG to replace oil in power generation, but the successful development of Lebanon's offshore resources could reverse this trend within less than a decade, turning Lebanon into a self-sufficient producer and a potential exporter of natural gas.

The development of gas projects across the Eastern Mediterranean faces a large number of geopolitical, regulatory, and commercial challenges which, if unresolved, would undermine the development of these resources altogether, let alone the export projects. Most of the Western media's focus has been on the geopolitical landscape surrounding the development of Lebanon's reserves. This is not surprising. The inter-state conflicts and rivalries that have for so long formed part of the region's geopolitical landscape have been revived, and in some cases intensified, by these recent exploration developments. However,

we believe that Lebanon's complex geopolitical landscape is likely to play a secondary role in the development of the country's natural gas resources. Instead, the pace of the development of gas reserves will be mainly driven by local political dynamics and energy policies.

Delayed Take-off

Lebanon's history as a potential hydrocarbon province has been a relatively short one. While the first offshore studies were conducted back in 2006, the most likely impetus for Lebanese offshore plans can be linked to neighbouring Israel's offshore discovery of its 9 tcf Tamar field in 2009, followed by subsequent large discoveries amounting to some 35 tcf in Israeli and Cypriot waters. With some Israeli discoveries lying in immediate proximity to Lebanese waters, the prospects for Lebanon's own offshore resources suddenly seemed glaringly obvious. With no history of domestic oil and gas production, Lebanon has, since then, been very much at the beginning of its own industrial hydrocarbon development, which has yet to produce the country's own share in the Eastern Mediterranean's regional gas revolution.

Initial policy hurdles were overcome in August 2010 with the passing of Lebanon's long-awaited hydrocarbon law, which provides the basis for the establishment of a hydrocarbon industry and its institutional framework. After months of political infighting, the government eventually appointed Lebanon's Petroleum Administration (PA), a key committee constituted by the Offshore Hydrocarbons Law, in December 2012. The appointment of the PA paved the way for a prequalification round at the beginning of 2013, followed by the launch of Lebanon's first bidding round, for up to four offshore blocks, in May 2013.

Lebanon's prequalification round in early 2013 underlined the commercial attractiveness of the Lebanese offshore for international investors: some 50 international companies, including many of the region's sought-after IOCs, registered interest and 46 companies have now been qualified, including 12 operators. After lukewarm IOC interest in neighbouring offshore Israel and Cyprus – primarily attributed to their political sensitivity – this is positive news and, if initial interest is followed up by investment bids, it may help the prospective hydrocarbon producer monetize its yet unconfirmed hydrocarbon resources relatively rapidly.

Elephant in the Room

Despite this year's successful prequalification round, the Lebanese timeline for the finalization of a fiscal system to guide investment into its hydrocarbon sector, and for the award of its first offshore blocks, is ambitious. With bidding expected to close in November, the government will need to issue a final investment framework (including a Model Exploration and Production Agreement and the Tender Protocol) binding on all parties no later than September this year. The decision on what terms to offer companies for their long-term investments is unlikely to be an easy task. A draft proposed scheme, reportedly combining production-sharing contracts with royalties paid to central government, was presented for consultation with bidding companies in May. Consultation will be followed by what is likely to be a painstaking task of responding to and discussing fiscal amendments, and obtaining approval by the different ministries involved. Before the Lebanese government issues a final binding decree, it also needs to approve the draft decree on block delineation,

which was submitted to the council of ministers before its resignation earlier in March this year.

Lebanon's political situation may yet complicate the next steps in the schedule considerably. The country's deep political and sectarian divisions, together with the fragility of the political system, have prevented successive governments from formulating a clear energy policy. The sectarian nature of Lebanon's political system has already delayed the formation of the PA, and hence the country's first bidding round, by more than a year. The six-member PA, now in charge of managing the country's emerging hydrocarbon sector, is composed of members of different religious groups – the result of a one-year drama around names and sectarian affiliations – reflecting the secondary role played by economic objectives behind Lebanese institutional appointments. While the formation of the Petroleum Administration last year was a welcome development, and the resignation of the government has not affected the PA's work so far, the highly uncertain and volatile political environment could delay the bidding round as all the laws and decrees require cabinet approval.

More fundamentally, the underlying political and institutional dynamics that delayed the bidding round in the first place are still in full swing: sectarian tensions, which have led to outright violence, have indeed intensified over recent months, partly in response to neighbouring Syria's gradual descent into sectarian civil war, with repercussions on its next-door neighbour Lebanon. With parliamentary elections now postponed from June this year until the end of 2014 due to rising security concerns, it remains unclear if Lebanon will have a functioning government and cabinet in place in time to review fiscal proposals and to issue the much-awaited fiscal law that will guide hydrocarbon exploration, by this September.

Yet another elephant in the room is Lebanon's historically plagued relations with neighbouring Israel, as part of the long-standing Arab–Israeli conflict. Of most immediate concern are overlapping Lebanese and Israeli maritime claims over a territory of some 854 square kilometres along the working line that has become the de facto border between

the two countries since the 1980s. Negotiations over the territory are unlikely any time soon given the continued status of de facto war with each other. Neither of the two parties has yet announced any suspected resource discovery that straddles the territory in question, a factor that has likely contributed to both sides' apparent lack of interest in an escalation of conflict over the issue, apart from occasional rhetorical attacks on both sides. However, the as yet unresolved issue has kept Lebanon from agreeing its maritime borders with third party Cyprus, which borders both Israel and Lebanon; and is likely to complicate future exploration and exploitation efforts of the disputed area, while rendering potential cooperation over infrastructure and trading routes between the two neighbouring states out of the question. Furthermore, although there have been various attempts to demarcate the maritime borders with Syria, very little has been achieved on that front.

Lebanese Long-term Options

A key issue likely to face Lebanon in the future (post 2020) is whether it should pursue an aggressive export policy to monetize its potential gas reserves. Care needs to be taken, for the current debate surrounding Lebanese reserves-to-be is based on no confirmed numbers. Although not a single well has been drilled so far in Lebanon's EEZ, this has not prevented some politicians from throwing around some big numbers about the potential size of Lebanon's hydrocarbon resources. Caretaker Minister of Energy and Water, Jibril Basil, put Lebanese estimated reserves in May 2013 at 30 tcf of natural gas (around 850 bcm) and 660 million barrels of oil in its EEZ, hypothesizing that exports could begin in as little as four years. In August 2012 Spectrum, the Norwegian company in charge of Lebanon's first 3D seismic survey, estimated recoverable dry gas reserves for Phase I of its survey at 11.6 tcf, with an initial estimate of 25.4 tcf for both phases covering Lebanon's EEZ.

The basis upon which these estimates have been derived is not clear, and Spectrum has since been criticized for what some observers have called highly speculative estimates for Lebanon's

offshore reserves. More can be said about the credibility of the numbers suggested by Lebanon's Ministry of Energy and Water, though perhaps the extent to which the ministries' own reserve estimates reflect reality does not matter in a country where there is low trust in politicians' statements anyway. Statements such as that by Jibril Basil, however, reveal the extent of the hype in this resource-poor country and the desire to be part of the 'small gas revolution' currently being experienced in Israel and Cyprus, the two Eastern Mediterranean countries with the most advanced plans in offshore gas exploration.

'The road towards Lebanon becoming a gas producer is very long and it is still very early for the government and politicians to start planning on how to spend the gas revenues.'

If and when offshore work confirms commercially recoverable offshore resources in Lebanon, the balance between the use of gas to meet domestic demand and for export purposes will ultimately determine the companies' profitability, together with their incentive to develop the reserve base. Meeting domestic demand, especially in the power sector, should assume top priority in government policy. But this requires that Lebanon has a clear policy regarding the pricing of gas for the domestic market, which is potentially a contentious issue in negotiations between government and companies. Furthermore, since gas demand is strongly interlinked with the evolution of electricity demand, it is essential that the government embark on the reform of the power sector and electricity prices. The challenge is grave. Électricité du Liban (EdL) suffers from huge financial and operating losses, which constitute between 20 per cent and 25 per cent of the government's primary expenditure. EdL also suffers from chronic underinvestment, which has so far prevented it from modernizing its grid and expanding power generation capacity. In addition, increasing the penetration of gas in the power mix requires heavy investment in the gas

grid, including the planned project to build a coastal gas pipeline from the north to the south of the country. This project has faced many hurdles in the past, and there is always the risk that gas could start flowing from offshore fields without the government putting in place the necessary infrastructure to move it around onshore.

The most likely outcome for Lebanon is the adoption of a balanced approach between meeting domestic demand and allowing companies to export. Gas demand is estimated to reach 2.6 bcm in 2020, increasing to almost 4 bcm by 2030. If the discoveries are large enough, there will be plenty of gas to meet both domestic and export requirements by the middle of the next decade. But this raises another set of questions: Should Lebanon aim at directing its exports towards regional markets by pipelines, or should it invest in the more expensive liquefaction facilities? Ultimately, the complex geopolitical landscape will impact Lebanon's choices over possible monetization options and hence will be pivotal in determining the future direction of gas trade flows. The long-term border conflicts across the region serve as impediments to the realization of synergies and the optimization of resource development. However, Lebanon is in a better position than its neighbours as it has more options – such as pipeline gas exports either to Turkey through Syria or to Jordan and Egypt through the Arab Gas Pipeline – to monetize its reserves in the long term.

It is important to stress that while there is much hype about Lebanon's gas potential, the country is not expected to produce any natural gas by 2020 and

thus it will have to import all of its gas requirements in the short to medium term if it is to achieve its ambitious objective of increasing the share of natural gas in power generation. Due to rising demand in their own markets and limited potential to expand supply, pipeline gas from Syria and Egypt is unlikely to be forthcoming any time soon, at least not in large quantities. Recently, Iran and Lebanon agreed to build a gas pipeline through Iraq and Syria to supply Iranian gas for Lebanon's power plants. This project, however, is unlikely to materialize due to a number of factors, which include: instability in Syria, sharp political divisions within Lebanon regarding the role of Iran in the country, the financial sanctions on Iran that limit the options for financing the project, and the limited availability of Iranian gas for export.

Thus, Lebanon faces little choice over the short term but to rely on LNG imports. The question then is: should Lebanon wait until gas reserves are brought on stream, and in the meantime continue to rely on expensive liquids to fuel its power sector, or should it pursue the LNG option? While LNG imports are likely to be less costly than liquids, especially at currently high international oil prices, the infrastructure cost of switching fuels could be high.

An Uneasy Road Ahead

The road towards Lebanon becoming a gas producer is very long and it is still very early for the government and politicians to start planning on how to spend the gas revenues. In the next few years, the government will be confronted

with many complex decisions. Like other countries, Lebanon will realize sooner rather than later that the key challenges to be faced in developing its hydrocarbon reserve base will probably not be found underground, in the form of resource and technological constraints, but above ground, in formulation of a gas promoting national legislative and fiscal policy, appropriate and effective institutional structures, and the management of gas revenues.

In the current context of political polarization, the regulatory environment is likely to be highly volatile and key policy decisions (and their implementation) are likely to be subject to constant delays. The Energy Ministry has promised 'full transparency in the evaluation process through the bidding round', but given the weak institutions, the lack of a clear governance structure, and the absence of accountability, it is doubtful whether such transparency will ever be achieved, especially in an industry where the size of the rents can be very large and the competition for rents fierce. Also, if Lebanon is to meet its ambitious target of joining the family of gas producing countries soon, it has to overhaul its general business practices – including the processes of obtaining permits and customs and security clearance. These measures are essential to shelter the gas industry from the corruption and red tape that currently characterize Lebanon's business environment.

The way Lebanon deals with these above ground challenges will determine whether the promised 'gas revolution' will ever materialize and whether it will prove to be a revolution for the country as a whole or just for the privileged few. ■

Lebanon Oil and Gas: what is on offer?

CAROLE NAKHLE

It has been said many times that Lebanon is at a crossroads. This has never been truer than now. The Lebanese economy is often associated with banking and tourism. But this perception could dramatically change if Lebanon succeeds in unlocking its oil and gas potential and, more importantly, increases

its commitment to transparent and efficient management of the sector.

International Interest

The Ministry of Energy and Water (MoEW) officially launched Lebanon's first ever offshore licensing round in April 2012.

Around 52 international oil companies submitted prequalification applications and 46 companies were shortlisted. These included major oil companies such as Shell and ExxonMobil, which satisfied the country's relatively strict financial and technical prequalification requirements. However, there is a difference between companies that

prequalified; those that will actually bid; and the number of contracts awarded – the numbers will shrink as we move towards the latter category.

While such a high level of international interest is surely a positive development, it is also not unusual. Oil and gas companies are constantly looking for new opportunities. Lebanon's key target, however, has to be to capitalize on these expressions of interest, in other words, to lock in foreign capital in a way that maximizes the benefits to the whole nation.

Uncertain Plan

According to the Ministry's original plan, bidding was supposed to start in May 2013 and was expected to continue for six months. Various bid evaluations would then take place between November 2013 and January 2014, with the first exploration and production agreement (EPA) scheduled to be signed in February 2014.

However, the resignation of the Mikati government in March 2013 took many by surprise and left the future of the round in doubt. At the time of writing, no new government has been formed. If the issue is not resolved by September, it is likely that the round will be postponed.

'While such a high level of international interest is surely a positive development, it is also not unusual. Oil and gas companies are constantly looking for new opportunities.'

The problem is that, prior to the government's resignation, two important decrees still had to be approved by the Council of Ministers, as required by the Lebanese Offshore Petroleum Law: first, the model EPA which includes the fiscal terms (which have not been defined in the law); second, the delineation of the 10 offshore blocks in question (out of which four are likely to be offered in the first bid round).

In principle, a caretaker government does not approve such decrees. However, the MoEW has repeatedly said that, under special circumstances, an exception could be made. The robustness of such

an option is a question for the legal community to decide – except that it is doubtful whether, in a country where political rivalries are so vibrant, a lasting legal settlement can be achieved.

The late Lady Thatcher once said 'always expect the unexpected and be prepared for it'; her wisdom is particularly pertinent in Lebanon's context.

Fiscal Regime

Meanwhile, the Petroleum Administration (PA) shared the draft EPA with the shortlisted oil companies as part of a closed consultation workshop, and received around 1,500 comments, some of which were incorporated in the preparation of a new draft EPA. The terms are yet to be disclosed to the wider community.

The fiscal regime includes various tax and non-tax instruments that affect both government take and investor return. Getting the regime right is central for Lebanon.

The volatility of oil and gas prices, the large development and operating costs, the high level of uncertainty associated with petroleum geology, the specific characteristics of individual oil/gas fields, and the long-time horizons, all add to the challenge of designing and implementing an appropriate petroleum tax system that can achieve a balance between the interests of both government and industry. This challenging task should not be underestimated.

Striking the right balance is the critical factor. If the government take is too high, it can lead to sub-optimal investment and, therefore, to less tax revenue in the long run. If it is too low, then too much of the nation's resources are given away to the investor. Part of the problem, however, is that the right balance keeps shifting, driven by many factors including price volatility, knowledge of the geology, technological advances, and competitive behaviour.

According to Lebanese officials, the country has adopted a hybrid arrangement which combines a tax and royalty (concessionary) scheme and a production sharing mechanism (contractual). However, it is common to find the former in production sharing arrangements (PSA) where contractors often pay a royalty (as a percentage of revenue or

production) in addition to income tax on their share of profit petroleum. Such a model is widespread in developing countries.

The type of regime, whether concessionary or contractual, is not a central issue from an economic point of view since, for a given oil or gas price, the government take can be made equivalent for the different types of regime. Furthermore, judging a fiscal regime from its 'headline tax' rates is very simplistic – the devil surely lurks in the detail and a meticulous assessment of various terms is therefore required.

According to the PA, the royalty will apply at a flat rate on gas (around 4 per cent) and in the case of oil, on a sliding scale (between 5 and 12 per cent), mainly varying with daily production. The attractions of a royalty scheme from a government perspective are that it is relatively simple to administer (especially for oil), predictable (as it varies with production, not profits), and it provides an early revenue stream (as soon as production starts).

However, because a royalty is imposed irrespective of cost (and therefore of underlying project profitability), it has the effect of a regressive tax – one which imposes a heavier burden on the least profitable fields, even if it is imposed on a sliding scale. A sliding scale simply strips royalty of one of its advantages: its simplicity.

A sliding scale royalty scheme also fails to address the fundamental limitation that it is imposed irrespective of cost, knowing that in oil and gas projects, significant cost variations among individual projects do exist. An additional problem with any sliding scale scheme is how to determine the scale. Furthermore, a higher royalty rate reduces the amount of petroleum available for cost recovery, which in turn lengthens the cost recovery period.

Another instrument that a government can use to achieve early returns is one of putting a ceiling on cost recovery. If the ceiling is, say, 70 per cent in any given year, contractors can recover 70 but not 100 per cent of their costs; the rest is carried forward to the following year.

Just like a royalty, a cost recovery ceiling also has a regressive impact. The definition of which costs are

recoverable can vary across countries, hence the need to have a clear understanding of recoverable costs.

According to the PA, the cost recovery ceiling will be one of the biddable parameters. Profit sharing will be another, and it will be on a sliding scale related to profitability (R factor). The latter should make the regime more progressive, but the final outcome will depend on the rates and interaction of different instruments, especially if, for instance, in future rounds, the government decides to enact the state participation option which is provided in the law.

Good Practice

While at first sight, there is nothing peculiar about the above terms, one area of concern is the fact that two important instruments that will shape the government take – cost recovery ceiling and profit sharing – are biddable.

According to international good practice, biddable items should be limited. Typically, they include the work programme and signature bonus. The latter does not apply in Lebanon, although if the potential of the country

is proven and international interest is high, this could be an option in the longer term.

When cost recovery or profit sharing is used as a biddable item, it is recommended that the government pre-set by law the range within which bids can be placed. The Lebanese government can also consider fixing the lower band of its share of profit petroleum and allow companies to bid for two more upper tiers.

'The fiscal regime includes various tax and non-tax instruments that affect both government take and investor return. Getting the regime right is central for Lebanon.'

The advantage of this more prudent approach is that it allows the government to achieve a greater predictability of potential rewards. This in turn helps more generally with budget planning – minimizing discrimination among investors and reducing the administrative burden of managing

different fiscal structures – especially important in a country like Lebanon where administrative capacity is very limited.

Furthermore, some companies may offer very generous terms to the government – for instance a higher share for the government from profit petroleum when the R factor exceeds a certain limit. However, cost overruns (very common in the oil and gas industry) would of course imply that the higher tier would never be triggered.

A legislative, contractual, and fiscal framework that is robust and clear remains the main device on which the government should focus to ensure a sustainable development of its oil and gas sector. Building in-house expertise and administrative capacity to manage the sector is essential. Progress has been 'so far, so good', but the remaining to-do list is long and requires close collaboration between various ministries – mainly the MoEW, Ministry of Finance, and Ministry of Environment. The real test will be in the implementation. The coming years will tell whether Lebanon is able to give itself a good deal. ■

Gaza Gas: challenges versus opportunities

WALID KHADDURI

The discovery of natural gas in the Eastern Mediterranean presents opportunities to exploit a clean domestic energy resource and to reduce imports. However, it also resurrects chronic regional political conflicts. In the case of the Gaza Strip, the problem is that of Israeli occupation of Palestinian territory, and the attempt to maintain influence and pressure over the occupied Palestinian entity.

The geology of petroleum fields does not recognize political boundaries between states. Under normal political conditions, diplomacy prevails to resolve these conflicts. This is not the case throughout the new petroleum province of the Eastern Mediterranean, which has seen the Israeli occupation of the Gaza Strip, followed by the Israeli marine blockade on Gaza. There have also been the legal and financial demands by Israel

that, so far, have made it impossible to develop Gaza gas resources.

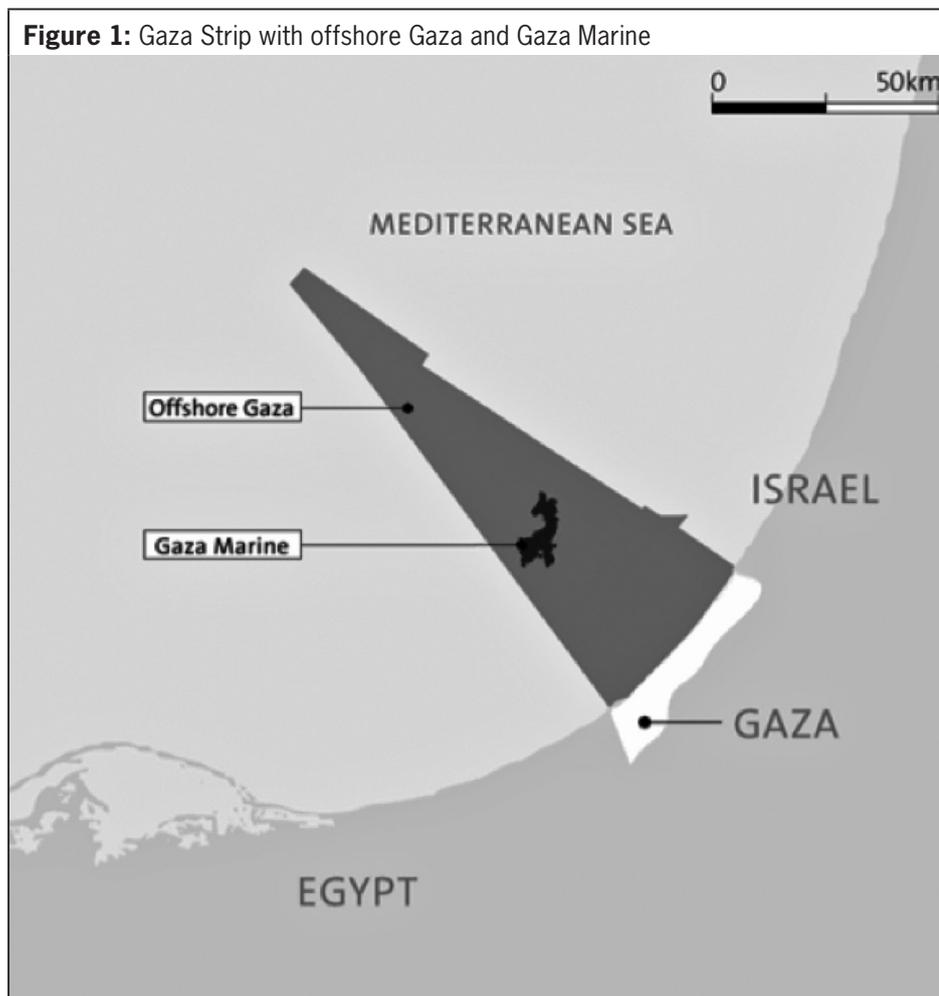
Further north lies the disputed territory between Lebanon and Israel. This represents a dispute that cannot be negotiated bilaterally, because the two countries are still technically at war, and therefore fields straddling the border cannot be unitized.

Finally, Turkey has used its occupation of northern Cyprus to assert its interests in Cypriot waters, demanding petroleum royalties on behalf of the Turkish community in the occupied Cypriot territory, and requiring the resolution of the Cyprus conflict in accordance with its own terms. Accordingly, Eastern Mediterranean petroleum discoveries, while offering new economic opportunities, are creating new conflicts and exacerbating old ones.

Discovery of Gaza Marine

This article focuses on Palestinian attempt to develop a gas field, Gaza Marine, discovered offshore Gaza. In 1999, the president of the Palestinian Authority, Yasser Arafat, signed a 25 year exploration licence covering the entire marine area offshore the Gaza Strip with the British Gas Group (BG) – which formed a consortium, acting as operator in which it held 90 per cent equity. This figure was reduced to 60 per cent as the Athens-based Consolidated Contractors Company (originally a 10 per cent partner) and the Palestinian Investment Fund exercised their options at development sanction. In 2002, an outline Development Plan was approved by the Palestinian Authority.

BG discovered the Gaza Marine gas field in 2000; it was 17–21 nautical miles

Figure 1: Gaza Strip with offshore Gaza and Gaza Marine

Key to operations

■ gas ■ BG Group-operated block

Source: www.bg-group.com/OurBusiness/WhereWeOperate/Pages/AreaofPalestinianAuthorityoperationsmap.aspx

off the Gaza coast and had estimated reserves of around one trillion cubic feet (tcf) with high methane. However, the field has not yet been developed.

'The geology of petroleum fields does not recognize political boundaries between states.'

Meanwhile the US firm Noble Energy, in partnership with Israeli oil companies, made several finds in 2000–4. These were small discoveries, made in southern Israeli waters adjacent to Palestinian waters. These initial discoveries were not sufficient to meet domestic Israeli demand, obliging Israel to import gas. But much larger discoveries (one a giant field) were made in 2009–10 in northern waters (Tamar and the Leviathan fields, as well as

others), close to Lebanese and Cypriot waters. These northern discoveries were large enough to provide sufficient gas reserves for Israel to meet domestic consumption and allow for exports.

The Oslo accords, in particular the 1994 Gaza–Jericho Agreement, confirmed by the 1995 Oslo II interim agreement, gave maritime jurisdiction up to 20 nautical miles from the coast to the Palestinian Authority. This allowed fishing, recreational, and economic activities (which includes petroleum exploration and production). The accords also gave Israel the right to forbid maritime traffic within the zone for security reasons.

Obstacles to Development of Gaza Marine

BG work in offshore Gaza encountered several Israeli hurdles soon after the Gaza Marine discovery. First, there

were legal objections by the Israeli Yam Thetis consortium, which operates small southern Israeli fields. The consortium petitioned the Israeli government to stop BG from exploring off Gaza, asserting that the Palestinian Authority is not a sovereign entity to benefit from the Law of the Sea Treaty. Second, the 2006 naval blockade of the Gaza Strip made work difficult, if not impossible. Third, the different opinions held by successive Israeli prime ministers on how to deal with Gaza Marine exports led BG to withdraw from negotiations with the Israeli government for the sale of gas to Israel in 2007. In 2008, BG closed its office in Israel.

Prime Minister Ehud Barack initially allowed BG to proceed with drilling. The decision was considered a political gesture, not a legal one that would recognize the well as being under Palestinian Authority jurisdiction. BG succeeded in making a discovery, Marine-1, in 2000, some 36 km offshore the Gaza coast – three-quarters of the field thus being in Palestinian waters. The company proceeded, with Barack's approval, to delineate the field and it drilled two further successful wells in 2000, confirming the commerciality of the discovery.

Obstacles and delays were also encountered as a result of Palestinian political developments that delayed negotiations. The discovery of the field was announced in late September 2000, on the eve of the second intifada. This was followed by: Israel's unilateral redeployment from the Gaza Strip in September 2005; Hamas rule of Gaza since 2006; Israel's war against Lebanon during summer 2006.

Potential Markets

Not only did negotiations between BG and the Israelis not proceed, but the economics of the project indicated that Palestinian gas consumption was too small (45mn cubic metres or 0.001 tcf annually) to dedicate Gaza Marine production exclusively to the Gaza Strip. Accordingly, BG explored new markets, among them Egypt (where BG was already a big gas player) and Israel (with an annual consumption of 0.04 tcf). Negotiations between BG, the Palestinian Authority, and the Israeli

government started as early as 2000. The terms of reference for the talks were the Oslo Accords, with the recognition that Israel needed to import gas, while BG and the Palestinian Authority were seeking a larger market for Gaza Marine gas. In the course of the negotiations, BG offered a larger package, combining gas supplies from Gaza Marine and gas it produces in Egypt, together with gas from an Israeli field near Ashkelon. The gas was to be sold to the state-owned Israeli Electric Corporation (IEC).

However, the proposal encountered several challenges, including one from the Yam Thetis consortium (three Israeli firms with the US Samedan Oil Corporation) which was also proposing a long-term supply contract to Israel. The second was from East Mediterranean Gas (EMG), owned by the Israeli firm Merhav, the Egyptian General Petroleum Corporation (EGPC), and the Egyptian businessman Hussain Salem. The arguments against BG were: BG had no right to drill in Palestinian waters as the Palestinian Authority is not a state and cannot grant such a right to drill in offshore Gaza. Second, BG cannot have a monopoly supply deal with the state-owned IEC.

The Israeli government had its reservations about exporting gas directly to the Gaza Strip. It wanted to have control over the money that would be at the disposal of the Hamas-led government in Gaza in order 'not to fund the terrorists'.

'Eastern Mediterranean petroleum discoveries, while offering new economic opportunities, are creating new conflicts and exacerbating old ones.'

Israel demanded that the pipeline from the Gaza Marine field had to land at Ashkelon before proceeding to Gaza and that Israel would have the right to lift as much gas as it required. The gas had to be offered at a discounted price – less than that for gas imported by Europe. BG and its partners refused these demands. What has transpired since is that EMG carried influence with the former president of Egypt, Hosni Mubarak, and his family. EMG was able to secure Egyptian gas exports to

Israel at a considerably reduced price. There was a furore in both the Egyptian parliament and the local media against the low-price formula during the Mubarak regime. Former President Mubarak and his two sons are now being tried because of this deal and other accusations. EMG's Hussain Salem is a fugitive. Since the overthrow of Mubarak, the export pipeline from al-'Arish has been bombed several times. Gas exports to Israel ceased as of 2012.

A Possible Future?

While development of Gaza Marine ceased over a decade ago, the Israeli economic publication *Globes* reported in March 2013 that development talks between BG and the Israeli authorities – but without the participation of Palestinian representatives – had been taking place for several months. Nonetheless, the field remains shut down and BG has not resumed operations. Meanwhile, the Gaza Strip continues to receive sporadic fuel supplies either from Egypt (smuggled through the Rafah tunnels) or from Israel. ■

Egypt's Gas Industry: the urgent need for planning

BILL FARREN-PRICE

Egypt's political crisis has exposed a weakening Egyptian pound, a balance of payments problem, and a sliding economy hit by reduced tourist numbers and collapsing foreign direct investment (FDI) flows. The state has relied upon treasury transfers from Gulf states and has also announced several energy bailouts. But it is important not to confuse cause with effect: the political crisis has simply crystallized some of the systemic problems that would have been faced by the Mubarak government, or any other, in due course. One of the most urgent problems has been domestic energy – in particular the gas and power sector.

The past 20 years have seen Egypt's natural gas sector boom and bust, presenting an object lesson in why strategic planning is critical to long-term

management of gas supply and use. Despite a surge in gas exploration and development in the 1990s, Egypt has not been able to simultaneously meet its overseas gas commitments and its fast-growing domestic demand for gas since 2007, forcing the curtailment of pipeline exports and the progressive slowdown in LNG exports as the domestic sector is prioritized.

Domestic Demand

The country's increasingly gas-reliant economy – driven in equal part by gas-burning power generation and gas as an industrial feedstock for petrochemical and energy-intensive industries such as cement – has been driven by artificially low gas prices. Government attempts at reform have been piecemeal at best and have targeted specific industrial sectors,

while some adjustments have been made to the prices paid to IOCs for gas produced from more expensive and challenging deep-water fields.

'The past 20 years have seen Egypt's natural gas sector boom and bust, presenting an object lesson in why strategic planning is critical to long-term management of gas supply and use.'

During the first decade of the century, and following on from the rash of successful Nile Delta gas discoveries in the 1990s, Egypt established a basic three-way split for its gas allocation policy: one third would be devoted to

exports; one third to the domestic sector; and the final third kept in the ground for the benefit of future generations. In principle, this appeared to be a conservative and sound policy that safeguarded domestic consumption at heavily subsidized rates, while allowing the export projects that would ultimately drive further upstream spending by IOCs. But it was not based on any serious economic forecasting of domestic demand growth which, at the time the policy was formed, was only moderate.

'The immediate challenge will be to reform the pricing of gas, power, and transport fuels to reflect import prices and to moderate demand growth.'

Even as new gas discoveries were being developed and brought on stream, Egypt faced an emerging two-fold problem: the growth in proven gas reserves slowed dramatically; while the growth in domestic gas consumption accelerated. Initially, Egyptian policy-makers from within the oil ministry and state-owned gas company EGAS responded to the challenge by borrowing gas allocated to future generations and reallocating it to domestic demand, on the expectation that fresh success with the drill bit would allow that gas to be 'paid back' and those blurred lines allocating reserves to be redrawn more sharply. Unfortunately, upstream success became even more patchy in the key production areas (offshore the Nile Delta and the Western Desert) and never again emulated the successes achieved in the 1990s.

All the while, the country's power demand continued to surge higher as Egyptians increasingly adopted air conditioning, and electrification spread to remote areas. Government schemes to create town gas networks around the main urban centres spread throughout the country as far as Upper Egypt. In fact, Egypt has been a regional leader in putting gas at the heart of its economic growth, with town gas and compressed natural gas (CNG) having been adopted in parts of the transport sector.

The Need for Imports

Cairo's policy commitment to building an economy on cheap, gas-fired power came unstuck when it became clear that the country did not have the gas reserves to underpin the strategy. Like several Gulf countries, Egypt now faces the prospect of becoming an importer of LNG in order to meet peak seasonal gas demand (the country saw a similar transition in the oil sector after production peaked at 900,000 b/d in the 1990s, becoming a net oil importer in 2008).

Responding to the need for additional gas, Cairo launched LNG import tenders in late 2012 with the aim of drawing 3–5 bcm/year of gas via a floating regas and storage vessel, but problems over financial guarantees and import infrastructure have delayed progress. As part of an aid package, Qatar has agreed to supply five LNG cargoes as part of an aid deal that would see Qatari LNG meet some of the export obligations of Egypt's sole functional LNG project at Idku, with gas feedstock normally used by the plant being diverted into the domestic sector. But whether this agreement will survive the ousting of President Morsi – or indeed the leadership changes in Qatar – is unclear.

Until LNG can be imported, Egypt will have to rely upon imported fuel oil and diesel to meet its power needs which, with oil prices still hovering above \$100/bbl, will put further strain on an already huge energy trade deficit, which accounts for around 20 per cent of the fiscal budget. But even when new supplies of gas are made available, unless prices can be liberalized – and there has been no enthusiasm for that course of action since President Mubarak was toppled – additional gas supply will simply release more pent-up demand. Consumption data shows that gas and power consumption are rising at an even faster rate since the start of the Egyptian political crisis in 2011, despite a weaker economy.

The Search for Gas

BG's experience in Egypt – as a gas explorer and producer of a third of the country's gas – highlights the supply-side challenge in Egypt. The company played a major role in exploring the offshore Nile Delta and produces gas and liquids from two core areas: the Rosetta concession and the West

Deep Delta Marine concession, both of which feed the domestic market and the Idku LNG plant. Despite new phases of development on these assets BG, like other major gas producers in Egypt, has seen gas production fall over the last few years.

Energy Subsidies and Price Reform

Annual gas demand growth, meanwhile, has risen from a rate of around 6 per cent in the years since 2007, to over 12 per cent in the past year. Power demand accounts for 60 per cent of Egyptian gas consumption, with most of the remainder being used in industry. Power demand in the industrial sector has risen by nearly 40 per cent in the period 2005–12, while overall power generation has risen from 101 billion kWh to 157 billion kWh in the same period.

The essential problem is the gap between the subsidized prices for gas paid by power generators, industry, and household consumers and the price paid for imported LNG, once imports start. Talks between potential LNG sellers and the government have focused on prices in the \$8–10/mmBtu region, in contrast to domestic wholesale tariffs of \$3/mmBtu for major industrial users and \$1.25/mmBtu for household consumers.

Pressure for the rolling back of energy subsidies, which account for some 20 per cent of the state budget, has come from the IMF as part of its discussions on a standby facility; but there was no movement by the Morsi government to address this issue and the interim military-led government is unlikely to risk rocking the boat further by liberalizing energy prices at such a politically delicate time.

Egypt now boasts two under-utilized LNG plants with a combined capacity of 12 mtpa, a pipeline export system to the Levant that is barely seeing throughput reach 50 million cubic feet/day, and an exploration sector that has failed to draw serious participation in recent bid rounds. The immediate challenge will be to reform the pricing of gas, power, and transport fuels to reflect import prices and to moderate demand growth. Longer-term efforts will require a more investor-friendly upstream regime and special consideration for existing IOCs, particularly in the resolution of payment arrears now estimated at a total of \$5bn. ■

Asinus Muses

Stone axe or dodo?

Peak Oilism has been declared dead, slain by rising oil output in the USA. But since no industry dies without a fight, a flurry of outraged rejoinders have sprung up on the internet to denounce these pronouncements, some claiming that global oil production has already plateaued. But the concept 'oil' is, well, slippery. We have a variety of volatile fossil fuel-based liquids, on a sliding scale from something that would not look out of place in a wine glass next to your chateaubriand, proceeding by gradual degrees of gloopiness to stuff you could walk on, stickily. Conventional oil production may no longer be on the up, but when you include unconventional oil we have a way to go yet.

Our own Robert Mabro, in a previous edition of this very publication, has cleared up some of the confusion, pointing out that there is no disagreement over the proposition that oil will run out eventually. That, after all, is why it is called an exhaustible resource. Mabro is also known for the quip (which he attributes to an oil executive) that 'the stone age didn't end because we ran out of stones, and the oil age won't end because we run out of oil'. For this reason, Peak Oilism is not the obvious proposition that oil is finite and will some day run out: it is the proposition that its end is nigh, with the corollary that there will, lo, be much weeping and gnashing of teeth.

So is oil like the stone axe? Or is it, rather, on the dodo track? On Asinus's reading, neither. While oil production continues to rise, high prices tell us that it is not rising faster than oil demand. Since such a grand topic deserves more

than one metaphor, let us also state that oil is neither going gentle into that good night, nor does it rage, rage against the dying of the light. It will, indeed, make its way out not with a bang but with a whimper.

Asinus would like to be clear that Peak Oil Is Bogus: those who claim oil's end is imminent have been wrong for decades, and continue to be wrong. But that does not mean that oil presents no problem. As one blogger put it, we are not transiting to something better than conventional oil, as from the stone axe to the iron axe. We are, instead, transiting to something worse than conventional oil, in the form of dirty, polluting, and expensive unconventional oil. We are poorer for it, the atmosphere will heat up quicker for it, and pictures of the lakes of sludge created by the Canadian tar sands industry have in the past put Asinus off his dinner. Yuck, yes. But Mad Max it ain't.

Druids and Barons

Key to these developments is the fact that nowadays any old fracker can get hydrocarbons out of the ground. That is, unless the druids stop you. Such was the (temporary) fate of fracking company Cuadrilla in Balcombe village in West Sussex, whose path to their drilling ground was blocked by locals dressed in traditional shamanic garb. Given the success of Nimby-ist opposition to wind farms, one might imagine that people power in this affluent and Tory-voting rural idyll would win the day. But with Chancellor of the Exchequer George Osborne giving special tax breaks to the shale gas industry, and establishment stalwart Edmund John Philip Browne, Baron of Madingley, former CEO of BP,

in position as chairman of the board of said frackers, one fears that arguments against polluting our drinking water (and the occasional minor earth tremor, as Asinus has previously reported) are less likely to win the day than complaints about unsightly wind turbines in fields. Asinus, whose grazing grounds are not so far from Balcombe, will be sipping bottled water while enjoying the uncluttered view.

Representatives and representativeness

Shale gas is also Obama's 'transition fuel' of choice as he ponderously gears up US efforts to reduce carbon emissions. The president's perennial problem is the pro-fossil fuel fossils who occupy so many seats in Congress. His great wheeze is to bypass Congress altogether by instructing the Environmental Protection Agency to curb carbon emissions by power plants.

Confirming his credentials as a climate science-hater, John Boehner, Republican Speaker of the House of Representatives, described the plan as 'absolutely crazy'. But according to a new 'bipartisan poll' of voters under 35, 37 per cent of these youths described climate change deniers as 'ignorant' and 29 per cent as 'out of touch'. Throwing Boehner's epithet right back at him, 7 per cent said they were simply 'crazy'. Asinus, who is not totally ignorant of statistics, is puzzled by this poll: he naively thought that a representative sample was a representative sample, and was not aware that there was such a thing as a 'bipartisan poll'. But then Asinus expects to never fully understand either the science or the politics of a country where views on evolution correlate strongly with views on social security taxes.

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