

Global Energy Game Changers

*Focus on Africa and
the Middle East*

2017 (Issue 6)

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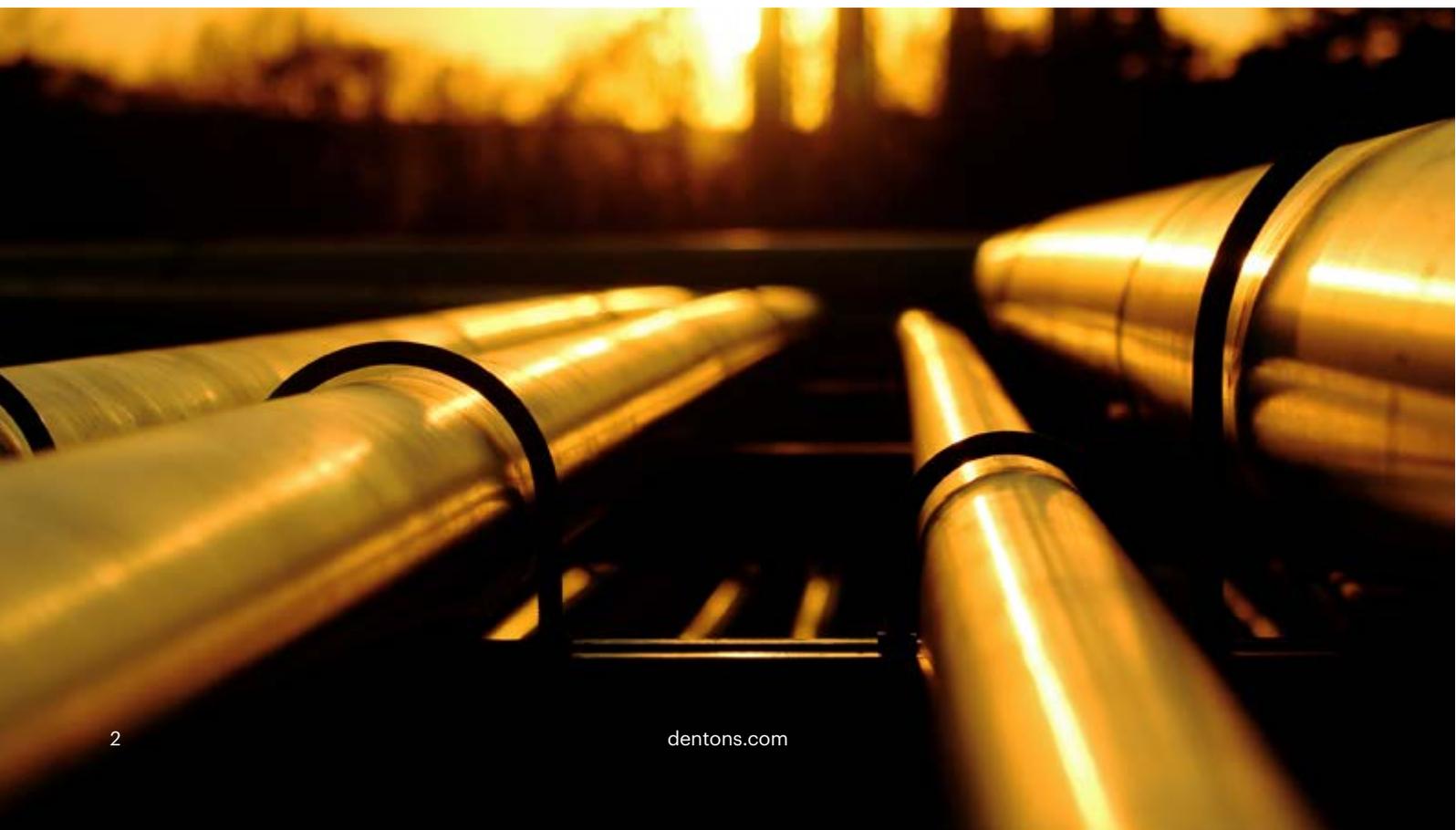
Dentons' Global Energy team is excited to present the newest edition of its Global Energy Game Changers series, a compendium of insightful analysis of the most important issues facing the energy industry. This issue is focused on key developments in Africa and the Middle East".



Quantum viewpoints

Trends and projections for the energy industry

In keeping with this edition's focus on Africa and the Middle East, we asked colleagues in our African and Middle Eastern Energy practices to share their views on what they believe are the most significant trends, issues and challenges facing the energy sector in these regions today.



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Introduction

Dentons has been working in the Middle East and Africa, often on energy matters, for more than 50 years. Of course, much has changed during that time, both in global energy markets and in individual Middle Eastern and African countries. But recently, the pace of that local and global change has accelerated significantly.

In this volume, we look at broad market trends that run across national and regional boundaries whilst also focusing in more detail on developments in a number of key regions, sectors or countries. There are plenty of comparisons to be drawn between the different ways that similar challenges and opportunities have been approached in neighbouring markets.

The rapid growth (actual or planned) of renewables in the power sector is one of the dominant themes. Competitive tender processes in both African and Middle Eastern jurisdictions have shown how cheaply large-scale wind and solar generating capacity can now be procured. In one form or another, renewables play a significant part in virtually every African country's plans for helping to meet the objectives of the CoP21 Paris Agreement: for many, wind and/or solar are now also the cheapest way of adding new capacity.

However, it will take more than the availability of cheaper renewables to solve the problems of Africa's power sector. In a series of articles, we look at some of the structural issues facing African markets and at the range of technologies they are seeking to exploit. We also consider how the unique circumstances of African power could allow it, with the right regulatory support, to lead in some of today's global trends, such as prosumerism and the rise of distributed generation. On the other hand, as centralised power still undoubtedly has a role to play in many markets, we take an in-depth look at the financing of independent power projects in Nigeria.

A number of the countries we focus on are also working hard to maximise their revenues from fossil fuels, facing varying challenges as they do so. We look at the efforts of African governments to improve their hydrocarbons regulatory regimes and at the moves towards more efficient consumption of energy throughout the Middle East. We also review the varying responses to the current challenges of the oil and gas market adopted by Iran, Saudi Arabia and Oman.

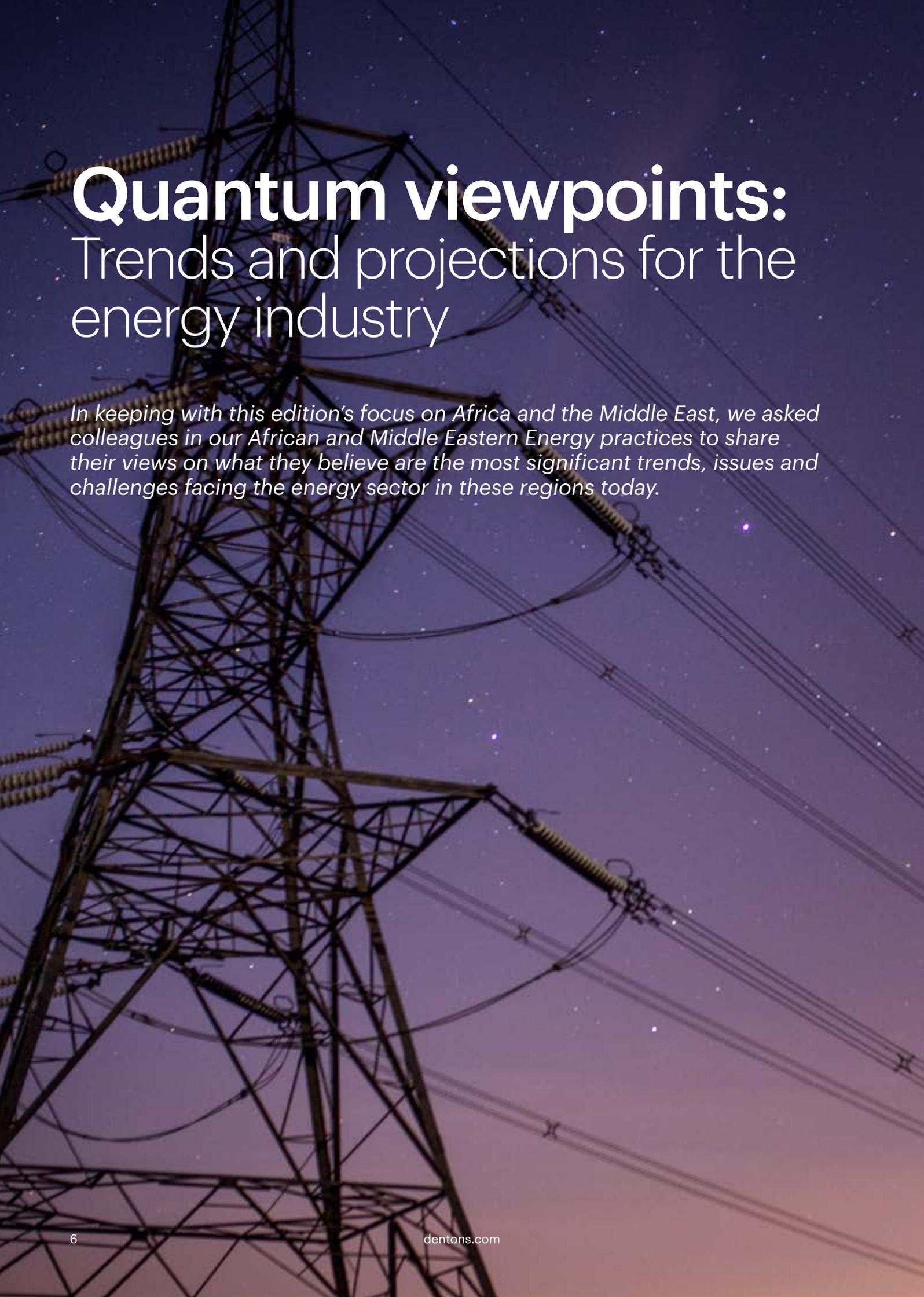
In short, we hope there is something here for everyone with an interest in the energy sectors of these diverse and increasingly dynamic regions. If you see anything that sparks your interest, please do not hesitate to get in touch.

Yours sincerely,

Adam Brown, Editor

Dentons was named the "Energy Firm of the Year" for the second straight year by *Who's Who Legal Awards 2016*





Quantum viewpoints:

Trends and projections for the energy industry

In keeping with this edition's focus on Africa and the Middle East, we asked colleagues in our African and Middle Eastern Energy practices to share their views on what they believe are the most significant trends, issues and challenges facing the energy sector in these regions today.

Q : What is the greatest challenge for the energy sector in your region in the immediate future?

BOPAPE (SOUTH AFRICA): The limitations of South Africa’s electricity generation and transmission infrastructure and its socio-economic imperatives remain misaligned with its international commitment to reduce carbon emissions.

As a party to the United Nations Framework Convention on Climate Change (UNFCCC), South Africa has committed to limit the increase of greenhouse gas emissions to 34 percent below “business as usual” by 2020 and to peak at 42 percent below “business as usual” by 2025.

Eskom (the state-owned utility which produces more than 90 percent of South Africa’s electricity) operates coal-powered stations and has new builds (not yet commissioned) for a further 20,000 MW. Coal is available in large quantities and South Africa is endowed with 3.5 percent of the world’s coal resources, making it the cheapest and most readily available resource in the country.

A large proportion of the population have not had access to basic services, including access to electricity, because of historic racially segregated policies and spatial planning. The obligation to deliver services to these previously unserved areas remains a challenge for the government and limits its ability to migrate easily from coal as an energy source. In these circumstances, the emissions trajectory is not likely to decrease far enough and fast enough to meet the UNFCCC targets.

Alternative, renewable sources of energy, in particular wind and solar PV, have been introduced into the “energy economy” through an internationally acclaimed procurement program which uses a “feed-in” tariff system. South Africa enjoys approximately 2,500 hours of sunshine every year and has fair wind potential, especially in the coastal provinces of the Western Cape and Eastern Cape. This makes solar and wind energy ideal alternatives. However, these technologies remain fairly expensive to deploy and it is hoped that the “offset” will be derived from “new jobs” in the construction sector and in rural and peri-urban areas.

Transmission of electricity remains a challenge. Power stations are mostly concentrated inland and transmission lines are used to transport electricity to other parts of the country. The country is vast and the current infrastructure is inadequate for the purpose of delivering electricity to rural and underdeveloped areas. Long-term strategies for infrastructure expansion remain a key government priority.



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Q : What effect are global and local initiatives to combat climate change having on your clients' businesses and decision-making?



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LARRIVÉ (MOROCCO): Morocco, which successfully hosted the UNFCCC CoP 22 conference in November-December 2016, has been steadily building a reputation as one of the leading renewables markets in Africa—and, increasingly, globally. Starting from a position where its electricity-generating mix was dominated by imported fossil fuels and a certain amount of hydro power, Morocco set out in 2009 to reduce its dependence on imports, and make its energy sector more sustainable by using energy more efficiently and expanding its renewables sector through programs of large scale private sector wind and solar projects with a combined value of more than US\$12 billion. It now seems entirely credible that the country will achieve its goal of moving from 34 percent renewable electricity-generating capacity in 2015 (22 percent hydro, 10 percent wind, 2 percent solar) to 52 percent in 2030 (12 percent hydro, wind and solar each providing 20 percent or about 5 GW – with interim targets of 2 GW for each technology by 2020).

Both wind and solar projects have been competitively tendered in processes that favor the lowest per MWh bids, and with bankable long-term (20-30-year) offtake arrangements made either directly or indirectly with ONEE, the National Public Body for Electricity and Drinking Water. This has been highly successful, producing winning bids as low as US\$25/MWh for solar and US\$28/MWh for wind projects. Notable examples include the Noor I project, 160 MW of which was commissioned in February 2016 and which when complete will be the largest concentrated solar power (CSP) project in the world. The first phase can store power for up to three hours using molten salt technology; later phases, with a combined capacity of 350 MW, will be able to store power for up to seven hours using a different technology. On the wind side, the 301 MW Tarfaya onshore project has a 45 percent capacity factor.

In addition to further tenders for large-scale solar and wind projects, ONEE is also taking forward tenders for 400 MW of smaller-scale solar projects (originally described as being of 20-30 MW each). This program will be deployed in three phases until the end of 2017: the 75-100 MW Noor-Tafilalet Project, the 200 MW Noor-Atlas Project and the 100-125 MW Noor-Argana Project. The sites have been chosen according to their solar resources and their situation far from existing substations. Indeed, the 400 MW solar program is deemed a grid management tool, since it is intended to improve the quality of service provided to customers located in areas where the power supply is degraded.

These projects will be implemented in connection with EPC and O&M contracts. In total, the project cost is estimated at US\$800 million. It is supported by a loan from the International Bank for Reconstruction and Development (IBRD) and a concessionary loan from the Clean Technology Fund. In November 2016, ONEE invited the 11 prequalified bidders/consortia (representing 10 different countries between them) to submit tenders to construct either three 40 MW plants or one 120 MW plant under the heading of Noor-Tafilalet.

Further structural reforms of the power market are also planned. A decree passed in November 2015 (No. 2-15-772) provides for the progressive opening up of the “medium voltage” (5.5 to 22 kV) electricity grid to small-scale distributed renewable power projects in a carefully controlled way. The Moroccan authorities also propose to create an independent regulatory authority as well as a new system operator independent of ONEE, continuing the process of market reform that began when ONEE first lost its legal monopoly of generation in 2009.

Finally, it should be noted that, at CoP22, Morocco (with Spain, France, Portugal and Germany) signed a joint declaration agreeing to develop a roadmap for sustainable electricity trade between Morocco and the European Internal Energy Market. Taking advantage of existing partial connections and synchronization between the Spanish and Moroccan electricity grids, and of improved interconnection capacity within the Iberian peninsula and between it and the rest of Europe, this provides a starting point for the kind of large-scale schemes for supplying energy-hungry Europe with renewable electricity from sparsely populated North Africa that have often been talked about but so far not put into practice.



Q : What changes do you foresee in the energy sector in your region over the next decade or so? What will be the key drivers of those changes?



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HUSEIN (SAUDI ARABIA): If the Saudi government succeeds in realizing the ambitions set out in its *Vision 2030*, there will be major changes that go far beyond the Saudi energy sector. The intention is that the Saudi economy should become much less dominated by hydrocarbons, whilst at the same time the oil and gas sector should become significantly more “localized” (increasing local content from 40 percent to 75 percent).

But the document goes much further, including targets and objectives covering almost every aspect of Saudi life, from reducing unemployment (from 11.6 percent to 7.4 percent) and encouraging Saudis to take more regular exercise to increasing SME contribution to GDP (from 20 percent to 35 percent) and female participation in the workforce (22 percent to 30 percent); from increasing the amounts that households save and how much they spend on cultural and entertainment activities to improving the transparency and accountability of government and increasing the efficiency of the mining sector. Other targets include improving the country’s ranking in the Government Effectiveness Index from 80th to 20th and increasing foreign direct investment from 3.8 percent to 5.7 percent of GDP. There are suggestions that a range of government services, including health care and education, could be privately owned and/or delivered.

How far the architects of *Vision 2030* can be sure of turning all its aspirations into reality is unclear. In some areas it appears to scale back from earlier statements of Saudi ambitions: for example, the amount of solar generating capacity to be constructed by 2023 is a mere 9.5 GW (scheduled increases in gas or oil-fueled generating capacity in 2016-2019 are almost three times that). But it is clear that it is all to be underpinned, if not actually paid for, by the flotation and sale of a stake in Saudi Aramco, so that it becomes the world’s most valuable publicly listed company. With a target date of 2018, this is a huge task for an organization that has never issued financial statements, and whose operations, spanning a range of sectors far removed from the traditional core competences of an oil and gas company, are organically embedded in the fabric of the Saudi state.

The success of the flotation will depend in part on the establishment of a clear taxation regime. This may include tax at a materially lower level than the company has paid in the past, which would have obvious implications for government revenues – although *Vision 2030* expects non-oil government revenue to rise from SAR 163 billion to 1 trillion to compensate. The results of the promised third party audit of the

country's hydrocarbon reserves will also be important. And then there is the question of what view potential investors take of the long-term prospects for the oil price. However, there is no doubt that if and when this plan is carried through it will be a true energy sector game changer.

KAPDI (SOUTH AFRICA): South Africa has embarked on the implementation of new gas-fired power generation capacity to contribute towards energy security. There is a possibility that a variety of sources of natural gas could be economically available within a planning horizon to 2040. These sources include: the initial importation of Liquefied Natural Gas (LNG), extensive potential expansion in natural gas from shale, production from deep-water offshore fields and development of a regional gas pipeline network.

The National Development Plan (NDP) has identified natural gas as a viable alternative to coal that could potentially help reduce South Africa's carbon and greenhouse gas emissions. Coal bed methane, shale gas and imports of LNG have been identified as possible supply options. The NDP anticipates that, by 2020, LNG infrastructure will be in place that will be able to power the first combined cycle gas turbines.

In future, natural gas will provide more than just electrical power: it will also provide, amongst other things, an alternative fuel source for transport. Legislation such as the Gas Amendment Bill will introduce a mechanism allowing the Minister of Energy to direct the development of new gas infrastructure including pipelines, storage and regasification technology for imported LNG.

The Department of Energy (DOE) has developed an **independent power producer (IPP) natural gas-to-power program**, which will be a catalyst for the development of the gas industry in South Africa. In October 2016, the DOE released the Preliminary Information Memorandum (PIM) in relation to the LNG-to-Power IPP Procurement Program, thereby illustrating the government's intention to wean South Africa off coal dependency. The DOE has indicated that it plans to procure 3,000 MW of the available 3,726 MW by way of this program. The DOE has allocated the remaining 726 MW to separate procurement programs, comprised of 126 MW allocated to the Domestic Gas-to-Power Program and 600 MW allocated to the appointment of a strategic partner for a gas-fired power generation facility.

The PIM states that the LNG-to-Power IPP will be procured on an integrated basis – meaning that the successful bidder will be responsible for designing and developing the marine- and land-based infrastructure,



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including a Floating Storage Regasification Unit (FSRU) or equivalent LNG regasification and storage technology, gas transmission pipeline infrastructure and a gas-fired power plant.

The DOE has identified Coega, in the Eastern Cape, and Richards Bay, in KwaZulu-Natal, as the feasible sites for an LNG-to-Power IPP. Multinational companies including Total, Shell and Cheniere have expressed interest in South Africa's LNG-to-Power IPP program confirming that this is now a major global gas project.



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MCGEE-OSBORNE (LONDON): There will be a wave of further structural market reform. Many governments across Africa and the Middle East took the first step towards liberalizing their electricity markets in the 1990s or soon after that by introducing competition for the market, i.e. by implementing a program of independent power projects (IPPs). Some, such as Abu Dhabi and Oman, also unbundled their vertically integrated markets to establish functionally separate structures specifically to facilitate later liberalization and privatization of wires and supply functions. Few have yet taken the step of completing that work by doing so.

A driver here will be that the contracts for IPPs will start to expire. They are typically between 15 and 30 years. But plants have a longer life and governments will need a mechanism to balance efficiently the deployment of new, more efficient, generation technology against the easier, but perhaps less efficient, option of extending IPP contracts. Oman is tackling this issue – the Authority for Electricity Regulation, Oman (AER) has announced that rules are being developed for the inception of a generation spot market. When developing those rules, other drivers, such as the desire to see more renewables and greater diversity in the generation mix, to tackle efficiency on the demand side and to consider harnessing the benefits of retail competition (AER has also reported that the market is sufficiently developed for retail competition), will also no doubt be at work. These challenges face many governments across the region and a wave of structural reform therefore seems inevitable.



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MKOKWEZA (ZAMBIA): Over the last two years, challenges arising from the El Niño-induced drought in the region, as well as the lack of maintenance of power stations and over-dependence on hydro resources for electricity generation, have contributed to the immense energy crisis currently facing Zambia. Load shedding for periods of between eight and 12 hours is not uncommon. Although Zambia was one of the first African countries to legislate for a liberalized energy sector, with the Energy Regulation Act of 1994, there is still only one principal supplier of electricity, ZESCO Limited, for household end users. Thus, in the National Budget for 2017, government strategy to alleviate national energy challenges focuses on introducing more cost-reflective tariffs, with a view to increasing private sector involvement in the generation and distribution of electricity.

It is against this background that, within the next decade, the Zambian energy sector will undergo immense restructuring. The governing Patriotic Front included in its manifesto for the 2016 elections a policy of unbundling ZESCO Limited such that generation, distribution and customer service are separated from transmission, which will remain under the government's jurisdiction. At the same time, a draft Renewable Energy Feed-in Tariff, developed by the Energy Regulation Board, has been published: this should provide an increased opportunity for IPPs to access the transmission grid.

Micro-grids are likely to feature in the new landscape of the Zambian electricity sector. A micro-grid is a localized electricity network comprised of a generation unit which is connected to the end-user through a localized distribution network. Globally two types of micro-grids are employed: (i) off-grid to provide rural electrification, often in developing countries, and (ii) on-grid to provide back-up power, including in developed countries. Technological advances in type (i) micro-grids have provided a business model for type (ii) micro-grids, such as [Zengamina Power Limited](#) in the North-Western Province of Zambia, creating a solution in the event of supply challenges.

Zambia has a limited amount of fossil fuel resources, but abundant renewable resources (including solar, hydro and some geothermal and wind potential). For commercial users of power in particular (for example in the mining sector), micro-grids powered by renewables can now compete on price with power from the grid or a traditional off-grid fossil-fueled solution. If the renewable source does not provide power continuously (as is the case with solar, for instance), back-up will be required. Traditionally this would simply take the form of a diesel unit, but increasingly battery banks are also being included to optimise the use of renewable resources and keep diesel fuel consumption to a minimum. The government's regulatory reforms should aim to facilitate the development of such hybrid micro-grids and the benefits they can bring in terms of energy security and reduced costs.





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MUGAMBI (KENYA): Kenya is eager to accelerate its economic development towards achieving the country's Vision 2030 and in that context particular attention is currently being paid to the energy sector. A new Energy Bill is currently under discussion and is forecast to be adopted in 2017 following consideration by the Senate. Among its key provisions is the introduction of changes to the national energy entities, including the introduction of a Nuclear Energy Institute. The proposed creation of this institute suggests a keenness to exploit nuclear power, which is an emerging trend in East and Southern Africa.

The Ministry responsible for energy is also looking to implement an energy auction policy, as an alternative to the existing feed-in tariffs, for the uptake of electricity generated from renewable energy. The government anticipates that energy auctions will increase both competitiveness and transparency, to result in cheaper energy. The current per kWh feed-in tariff for solar plants is easily double the kind of price that could be expected to be successfully bid in an auction-based system, and it is reasonable to expect that there would be competition both from established players on the Kenyan market and new entrants with international solar experience. A recent [government announcement](#) highlighted how increases in the share of power in Kenya produced from renewable sources have allowed tariffs to be reduced substantially for many customers as a result of reduced expenditure on fossil fuels.

It is also intended that new energy projects involving private investors will fall within the larger public private partnerships framework and will be subject to similar processes and government involvement to other infrastructure projects. The National Treasury is also in the process of reviewing the government support measures provided to investors for energy projects: it is noticeable that energy sector projects dominate in the table of contingent liabilities in the Treasury's [draft Budget Policy Statement 2017](#). It is expected that support measures will become more standardized across projects, based on feedback from stakeholders on the acceptability and adequacy of proposed measures to achieve bankability.



Q : How can energy companies and governments in your region cooperate to address the most pressing issues facing the global energy sector?



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BRADFIELD (LONDON): One area where greater cooperation between governments would be welcome is in relation to disputed borders and oil and gas fields that straddle national boundaries. Increasingly, offshore oil and gas projects in African waters face problems where blocks allocated by one state may fall wholly or partly within areas claimed (with more or less justification) by another. Examples include ongoing disputes between Ivory Coast and Ghana, Kenya and Somalia, and Tanzania and Malawi. There are many other unsettled boundaries in Africa and globally.

Inevitably, where these disputes go to international arbitration or the International Court of Justice, the process of resolving them is slow and costly, but there is a final outcome. On the other hand, while negotiation between the States is preferable, solution under this procedure can take decades, if one can actually be reached. As it is, uncertainty over boundaries can inhibit the development of some potentially valuable hydrocarbon reserves due to uncertainty over whether the commercial parties involved are entitled to exploit them and which regulatory regime will be applicable.

The risk for countries is that, by inflexibly pursuing an agenda that pushes their territorial claims to the maximum, they end up blighting the prospects of anyone making any money out of resources in and around the disputed zones. Some States have recognized this issue and resolved it via establishing joint development zones, such as East Timor and Australia, and Nigeria and São Tomé and Príncipe. But, whatever approach the governments concerned decide to take in a given case, energy companies can (with government buy-in) help to facilitate a successful outcome. To do so, they need to be prepared to invest in developing robust and creative contractual or regulatory proposals.



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DE SILVA, LUCILLE (LONDON): Some 10 years after Ethiopia and Kenya signed a memorandum of understanding to pave the way for the interconnection of their power systems, construction finally began in 2016 on a 1,045 km, 500 kV HVDC line with a capacity of 2,000 MW connecting the two countries at a projected cost of US\$1.26 billion. This is Ethiopia's largest such project to date, but it already exports some power to Sudan and Djibouti and has plans to export to Yemen, South Sudan, Somalia and Tanzania. It is reported that 7 percent of the country's GDP already comes from power exports, which it would like to boost from their current level of 223 MW to 5,000 MW. For the importing countries, the availability of an additional source of power from Ethiopia boosts security of supply and reduces costs (to the extent that imported renewable power is displacing electricity generated domestically from fossil fuels).

Ethiopia is not alone in having renewable power generation resources with the potential to produce more power than its own consumers are likely to use. This project is just one example of the potential for win-win outcomes in the development of new physical and legal links between the power industries in neighbouring African countries. There are plenty of others, such as the clutch of projects involving Uganda, Rwanda, Kenya, Burundi and the DRC that are currently under construction, with US\$415 million of funding from the AfDB, the European Union, and governments or development agencies in Germany, Japan, the Netherlands and Sweden. Although regional power pools exist in the North, South, East, West and Center of Africa, the quantities of power traded within them are currently very small proportions of their members' combined output. There are gaps in both the regulatory and physical infrastructure needed to make the most of the opportunities for resilient regional power markets to develop and achieve their potential. On one estimate, sub-Saharan Africa as a whole could save US\$50 billion on capital costs of generation projects and US\$10 billion in consumer spending on electricity bills if it spent an additional US\$9 billion on interconnection.

CUTHBERT (DUBAI): The "One Belt One Road" (OBOR) project is China's ambitious economic roadmap to link Asia and Europe and points in between or adjacent such as the Middle East and North Africa. It covers more than 65 countries and more than 65 percent of the world's population. Once fully fledged, it will give rise to everything from technology sharing and flows of financial capital to wider economic, political and social cooperation along six "economic corridors," of which the most relevant for present purposes are perhaps the New Eurasian Land Bridge and the China-Central Asia-West Asia Corridor.

OBOR seeks to make the most of the opportunity provided by the fact that so many of the countries involved have a chronic lack of (or need to replace) infrastructure in sectors such as energy and transport and limited domestic resources to finance the necessary investments, whilst, at the same time, China has huge amounts of capital and an economy that is capable of producing more in some sectors than global markets are able to consume without an additional stimulus.

The attraction for OBOR countries is obvious: China can offer a one-stop-shop solution to their infrastructure needs, including debt or equity finance, construction expertise, provision of raw materials and goods and operational services. For those countries that want



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to retain state ownership in infrastructure projects or have them controlled by a domestic entity, Chinese companies, which have become familiar with PPP structures both at home and abroad in recent years, are likely to be willing to agree on a structure that provides all parties with what they need.

OBOR will accelerate trends such as the internationalization of the renminbi and the development of Dubai (where four of the biggest Chinese banks are already established and issuing bonds) as an international finance hub. OBOR has so far included several large power projects in Pakistan (coal-fired, hydro and nuclear) and other countries in the region may be expected to benefit in a similar way.

For a more detailed discussion of OBOR, see our briefing: [*One Belt One Road: PPP Alchemy – is the Silk Road paved in Gold?*](#)





Q : How are emerging mega-trends such as big data, proactive consumers and non-traditional competitors impacting the energy landscape in your region?



Adam Brown is a senior associate in Dentons' London office. He focuses on the regulatory aspects of energy and infrastructure projects.

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BROWN (LONDON): It is hard to generalize meaningfully about the impact of global trends on the large number of diverse national energy sectors covered in this publication, but some patterns emerge at a high level.

Some of today's mega-trends are to be seen as clearly in Middle Eastern and African economies as anywhere in the world. The sharp fall and subsequent partial recovery in oil prices during 2014-2016 have their origins in the Middle East and their effects have been felt very sharply in many countries in the region as well as in major African hydrocarbons exporters such as Nigeria. In some cases, the fall in oil prices has helped to trigger a reappraisal of the traditional approach of subsidizing domestic consumption of fossil fuels, which could have far-reaching economic and social consequences. As noted elsewhere in this volume, the global shift from oil to gas is also conspicuous in both regions.

In just a few years, a number of factors have combined to transform the market for renewable energy in these regions: the falling price of wind and solar technologies, the abundance of renewable energy resources and (in some cases) the desire to maximize revenues from fossil fuel reserves by exporting them rather than consuming them at home. Individually large renewable electricity generation projects have been developed and increasingly a substantial renewable energy sector has grown up in a number of African and Middle Eastern countries with little or no previous history of such projects (apart from some hydro power).

In some of these countries, we are seeing renewables develop in almost exactly the opposite way to how the wind and solar markets in, for example, Europe have grown. They have started with large rather than small projects, and governments have begun by selecting projects on the basis of competitive bids, rather than starting off with a potentially over-generous feed-in tariff and only moving to auctions later. So far, the penetration of intermittent renewable technologies has yet to reach the point in any African or Middle Eastern country when it starts to cause the sorts of problems that policymakers in EU countries are now grappling with, but maybe they can learn from others' experience and start to anticipate some of these.

Another global trend strongly in evidence in Africa, for example, is the rise in distributed electricity generation. This is considered in more detail elsewhere in this volume: the underdeveloped or dilapidated state of many African countries' transmission networks, coupled with their size

and often relatively low population density, means that smaller-scale generation projects (renewable or conventional) are ideally suited to their needs and the sector looks poised for growth.

One trend that is less dominant in Africa and the Middle East is climate change mitigation as a driver of energy policy. Many countries in both regions will be significantly at risk if global temperature rises are not kept within the targets set by the Paris CoP21 Agreement. But equally, for many, the move to renewables, for example, is prompted as much if not more by the other horns of the energy trilemma – affordability and security of supply – as by concerns about CO₂ emissions (and in any event, for many African countries, power generation is not the major cause of such emissions).

Other global trends are also seen to some extent. There is, for example, concern about network security, but perhaps more often in relation to physical than cyber threats. Finally, as noted elsewhere in this volume, when it comes to the relationship between utilities and their customers, there is scope for Africa to become a trend-setter, or at least close to the leading edge, in terms of the adoption of new technologies and the active participation of consumers in electricity markets.





Energy Efficiency: the new Middle East mantra

By Jon Nash, Kanishka Singh, Udayan Mukherjee

The transformation of the energy environment in the Middle East over the last decade has been remarkable. The region has grown beyond its historical role as a major energy supplier, to become a substantial demand hub with its own increasing energy requirements, driven by substantial population growth and diversification of the region's economies.

The per capita electricity demand in the GCC countries continues to increase at a faster rate than that of their counterparts in the US and most other leading countries in the world.¹ In a matter of a few years, residents of developed countries in the Middle East could well be outright leaders in the use of electricity and water on a per capita basis.

This has focused the minds of the governments in the region. We have all read of the high-profile move to regional investment in renewable and alternative energy production. However, the revolution goes way beyond that and has revealed itself in many other ways, all of which we discuss below under the broad label of "energy efficiency." As a result, the nature and scope of work in Dentons' Energy practice across all of our regional offices from Amman to Muscat have transformed from advising on the staple fossil fuel based power developments to a broad range of services involving a multitude of lawyers across our full service offices in the region.²

Renewable and alternative energy in the Middle East

Background

The growth of the renewables industry in the Middle East is very recent. The Middle East is a region that has traditionally depended on hydrocarbon sources for both energy and revenue and initially interest in renewals was driven by a desire to export "US\$100" oil for profit rather than burn it for domestic consumption. However, with an ever-growing population and a decline in oil prices, there has been a recognition across the region of the need to diversify into other energy sources and to tap into the private sector to sustain growth. There is also a focus on making government budgets stretch further by reducing and even eliminating energy subsidies in regional fuel and electricity prices as well as a government focus on economic diversification.

While the region has been slow to shift away from the traditional hydrocarbon sources for power, the renewable source that is garnering more and more attention is solar energy in particular.

Solar energy

One result of the new approach referred to above has been a significant increase in solar power development in the region as part of a growing desire to diversify energy production. While the region has always had solar potential, until recently it had not been a priority for it to develop renewable sources. The Middle East solar fleet has gone from a couple of hundred megawatts in 2013 to almost 3,000 MW being tendered and developed in 2015, while the forecast for 2016 has been an additional 4,000 MW. A significant proportion of these projects were initially in Jordan, where 12 ground-mounted projects were awarded as part of Jordan's first round of solar

1 Deloitte white paper on "Energy on demand: the future of GCC energy efficiency"

2 Dentons' Middle East offices are located in Abu Dhabi, Dubai, Cairo, Doha, Amman, Riyadh, Jeddah and Muscat.



IPP tenders. However, more recently we have seen Kuwait, Qatar, Egypt, Dubai and Abu Dhabi enter the market with several projects of their own and more on a “utility scale.” After several years of eager anticipation it would appear solar energy has finally taken off across the GCC region.

Dubai has recently concluded a major solar IPP – the 800 MW Sheikh Maktoum Solar Park Phase 3. It will be the GCC’s largest solar facility when completed. It was the first solar project in the UAE concluded on the basis of a competitively tendered IPP and recorded the lowest ever levelized cost tariff, at below 3 cents per kilowatt hour. This tariff prompted Dubai to increase its target of providing energy from renewable sources from 5 percent to 25 percent by 2030. More astonishingly, just recently in Abu Dhabi, the government received a lowest bid of 2.42 cents per kilowatt hour for its 350 MW Sweihan solar project by the Marubeni/Jinko consortium. Just a few years ago, costs as low as 3-6 cents per kilowatt hour might have seemed unthinkable; now they are becoming the norm.

The usual trend with the introduction of solar power to new markets is relatively high tariffs due to a lack of technical expertise and technological capability. However, the MENA region has defied this trend for various reasons, which include, but are not limited to, tough competition, plentiful land giving rise to expansion opportunities, and government commitment to achieving renewable energy targets.

However, with this increased competition there is a growing concern that the tariffs are reaching a level that may be unsustainable and unrealistic. The low tariffs have seen various companies decline to bid on new projects as the project costs would be too great for developers to be able to sustain and deliver on the low tariffs. This was seen recently in Jordan, where various companies underbid just to survive and then could not execute. Furthermore, bidders and sponsors struggle to get internal approval in regard to the low tariffs, as market expectations do not always translate to attractive investments for developers using a PPP model. There is also concern about the long-term solvency of panel manufacturers, and expectation of consolidation in the industry in the future.

Also such a low-cost model may not necessarily be an appropriate benchmark for other regions of the world as Middle East markets operate on substantially different commercial and technical terms. Project development and land costs are significantly lower; most Middle East economies offer a substantial tax advantage with low or no corporate tax and zero income and withholding taxes. In addition, the risk and responsibility for interconnections usually remain with the government. Further, concessions are often structured on a 25-year term where other markets adopt comparatively shorter terms of 10 years, 12

years or 15 years. The success of the recent tenders in the region means that governments will be looking to implement more projects in the future. The next big opportunity is perceived to be Saudi Arabia, the largest market in the GCC, where a tender process for 300 MW of solar is expected to begin soon. If these are successful, then it is likely that the development of the Saudi market will accelerate and create major new opportunities for market players.

In addition to low tariff rates, there are a number of other key factors fueling the sharp rise in solar power development in the Middle East. First, the price of solar systems has dropped dramatically since 2009, when the first large-scale solar project in the Middle East was unveiled by Masdar (an Abu Dhabi based energy company). The installation cost of utility-scale solar PV power plants has also fallen from roughly US\$7.00/watt (in 2008) to less than US\$1.50/watt (in 2014).³ This amounts to more than a 75 percent cost reduction. It means that a plant four times larger than the same 10 MW solar PV power plant in 2008 can be built today without incurring any extra cost.

As a result of this cost reduction, solar energy is now competitive with the wholesale price of electricity in many jurisdictions in the Middle East. But, beyond cost, renewables have become the new growth sector because of the volatility of oil and gas prices and the continued diversification of the region's economies. The diversification is aimed at reducing the dependence of the Middle East economies on sales of hydrocarbon resources, with the goal being to enable more resilient and sustainable economic growth. Economic diversification has taken the form of socioeconomic plans such as the Strategic Plan 2021 in the United Arab Emirates, or Vision 2030 in the Kingdom of Saudi Arabia. These socioeconomic plans have far-reaching consequences for the power sector with a push towards renewables being encouraged for reasons of cost efficiency and to keep up with growing infrastructural needs.

Additionally, for some countries, such as Jordan and Morocco, renewable energy is seen as an opportunity to achieve greater energy independence.

Finally, the reduction in oil prices has put pressure on government budgets, which are no longer able to sustain significant subsidies in the electricity price for industry and residential consumers on an ongoing basis. Governments are very focused on alternative and more lucrative uses for their oil and gas as they continue to diversify their economies. It appears the era of cheap fuel for domestic consumption is behind us.

Wind energy

In the Middle East, wind power is much less prominent than solar power. There are ambitious projects in wind power being undertaken in the Near East (particularly Jordan) and North Africa, where wind speeds are more suitable for power production. In North Africa, Egypt and Morocco are leading the charge and have continued to push forward on renewable energy despite facing political turmoil in their respective countries. The Red Sea has been the focus of a transformation led by Egypt, as seen with the Zaafarana and Elsewedy wind farm projects. That said, Qatar and the United Arab Emirates (UAE) are also giving serious consideration to develop their own wind energy resources. Saudi Arabia is also looking to take advantage of the Red Sea coastal areas in establishing potential wind farms to help boost its renewable energy output.

Interestingly, Masdar (Abu Dhabi's renewable champion) has taken a lead in investing in wind projects overseas. After wind-mapping most parts of the GCC, it is also scouting possible locations for turbines at home.

Nuclear energy

Several countries in the Middle East have announced plans to embrace nuclear power as part of their future energy supply. The UAE is currently ahead of its peers in building the first Arab nuclear power plant. It is the first country in nearly 27 years to start constructing its first reactor.

Over the next decade or two, new nuclear power plants are scheduled to be operational across the MENA region. Abu Dhabi's Barakah flagship project,

3 Mena Solar Outlook Report 2015



if completed in accordance with the current official program, will have a total installed capacity of 5.6 GW representing some 25 percent of the UAE's energy needs. The project is scheduled for full operation in 2020 should it receive timely safety approval from the Federal Authority for Nuclear Regulation.

Dubai is also considering its own nuclear power initiative. In 2009, the task of overseeing all matters relating to alternative and renewable energy in Dubai (including nuclear energy) was assigned to the Dubai Supreme Council of Energy. A separate permanent sub-committee (the Dubai Nuclear Energy Committee) has recently been established to focus on nuclear energy. Rosatom, the Russian state nuclear corporation, has also recently established its regional headquarters in Dubai.

Saudi Arabia, too, is set to follow suit with ambitious nuclear plans, involving 16 nuclear reactors to be built by 2032 with a total capacity of more than 17 GW (expected to meet 15 percent of the country's electricity needs).⁴ The first reactor is expected to be operating in 2022.

Beyond the Middle East, in the Levant region, Jordan is moving towards the use of nuclear energy (signing a deal with Russia's Rosatom to build Jordan's first nuclear power plant, with a capacity of 2,000 MW scheduled to be operational in 2022).⁵

The biggest impediment, however, to harnessing nuclear energy in the GCC remains the shifting geopolitical environment in the region. This makes nuclear power an even more controversial issue than elsewhere: states are suspicious that civilian nuclear programs could be used for military ends. This, combined with the already stretched government budgets in the region and the difficulties of procuring third party financing for nuclear projects, raises questions about GCC governments' ability or desire to make the substantial investment needed to implement nuclear power. That said, unlike most other nuclear energy users around the world,



many Middle Eastern countries have the advantages of being oil and gas rich, which gives them more time to consider the role nuclear power should play in meeting their energy needs.

Water production and reuse

Without major action on the part of the regional governments, water supplies are set to deteriorate across the Middle East over the coming years, threatening economic growth and national security and forcing more people to move to already overcrowded cities. With rapidly diminishing groundwater stocks, governments of most Middle East countries are resorting to technology to produce usable water supplies. Desalination of seawater and wastewater treatment are two such alternatives being explored by governments in the region.

Desalination

Desalination is becoming an increasingly important matter for countries in the Middle East which have experienced rapid rises in demand for water on the back of strong economic and population growth, and where groundwater supplies are depleting at a disturbing rate. As oil revenues (and therefore government budgets) decrease and the issue of continued reliable water supply has risen up the political agenda, governments have acted to try to reduce capital and operational expenditure. Experts forecast that the GCC will increase its total seawater

desalination capacity by nearly 40 percent by 2020 in an effort to meet the rapidly increasing demand for potable water in the region.⁶

Investments in desalination have been on the rise and confidence in various technologies is growing. Technology is playing a pivotal role in this situation. The use of advanced water technologies is at an all-time high in the GCC. Most of the best available water treatment and reuse technologies are being used in this region.

Historically, due to the high energy consumption of desalination plant technology (MSF and MED), development of desalination resources has been based around the concept of co-production of power and water. However, that has recently changed to a focus on reverse osmosis technology. Even this technology is power hungry. Clearly, a focus on making energy use more efficient will pay huge dividends in the future and it is inevitable that governments will look at renewable power based desalination. Saudi Arabia is already heading down that path.⁷ Renewable desalination has consistently been a major topic of discussion at recent World Future Energy Summits in Abu Dhabi.

Also in Abu Dhabi, Masdar has launched a pilot program to test and develop advanced energy-efficient seawater desalination technologies,

4 <http://uk.reuters.com/article/uk-saudi-russia-nuclear-idUKKBN0OZ10R20150619>

5 <http://www.reuters.com/article/us-jordan-nuclear-russia-idUSKBNOMK2QD20150324>

6 <http://www.arabianbusiness.com/gcc-forecast-raise-desalination-capacity-by-40-by-2020-610159.html#V-tOwYh96Uk>

7 <http://www.prnewswire.com/news-releases/abengoa-and-awt-to-develop-the-worlds-first-solar-powered-desalination-plant-in-saudi-arabia-289273681.html>



such as reverse and forward osmosis, suitable for integration with renewable energy production.

The desalination solution presents its own problems. Roughly 70 percent of the world's desalination capacity sits in the Middle East. Apart from the energy-intensive nature of its operation, these plants emit brine by-product into the regions' seas (in particular the almost entirely enclosed Gulf waters) thereby increasing saline levels and threatening the viability of existing desalination technology. It is clear that further innovation will be required but the opportunities for technology companies are huge.

Wastewater treatment

While desalination remains the primary solution for governments to address water supply challenges in the region, increased adoption of wastewater treatment and reuse represents another significant opportunity for governments to address the ever-increasing demand for water.

We have already seen significant developments in the fields of water production and reuse and these developments are gathering pace. We have seen an increasing volume of contracts for wastewater treatment and transmission and distribution contracts awarded in recent years. The next few years will be crucial as much will depend on timely completion of these planned projects and overcoming the challenges of financing and operational delays.

Qatar's Public Works Authority (Ashghal) is planning to roll out significant wastewater treatment projects in a bid to increase the production of high-quality treated water in the country. These include the Sewage Treatment Plant project in Al Thakhira, the fifth package of expansion works for the Doha West Sewage Treatment Plant project, the Doha North Sewage Treatment Plant project, and the second package of the expansion works for the Industrial Area Sewage Treatment Plant project.

In the UAE, Abu Dhabi previously let four private concessions for treatment plants in the Emirate, which have now been operating for a few years. A high-tech AED 16 million plant in the Al Ain region became operational in 2013 and is treating 700,000 liters of water a day. Abu Dhabi is building a deep-level sewage interceptor tunnel, following the model used in Singapore. It is the first time the tunneling method has been used in Abu Dhabi.⁸ The tunnel is part of the Strategic Tunnel Enhancement Program (STEP), a 40km-long wastewater tunnel intended to address rapidly growing needs for the collection and transport of used water generated by the growth of the city. In 2030, when fully operational, the plant, featuring wastewater pumps, will be able to treat up to 70,000 cubic meters of wastewater every hour.

Saudi Arabia has announced plans to reuse over 65 percent of its water by 2020 and over 90 percent by 2040 by transforming its existing and planned wastewater treatment assets into source water suppliers across all sectors.⁹

Kuwait has recently joined the drive to treat wastewater. Bids on its Umm Al Hayman wastewater treatment project were submitted very recently.

Demand side management

The severe drop in oil prices has forced GCC governments to take austerity measures as slumping revenues have resulted in inflated budget deficits. Governments are reacting to the squeeze on their incomes with a mixture of strategies, drawing down reserves and taking on debt on the one hand and imposing spending cuts on the other. As part of this initiative, governments have looked carefully at the subsidies they provide in energy and natural resource provision to consumers and have taken the decision to withdraw them steadily over time.

The UAE in an unprecedented move cut fuel subsidies in a bid to strengthen the Gulf state's finances and limit spiraling car usage in the country. The policy is aimed at decreasing consumption and encouraging the use of public transport and fuel-efficient vehicles, including hybrid and electric cars. The UAE has also hiked electricity and water rates. Recently, the government of Abu Dhabi imposed water tariffs for the first time for UAE nationals (while increasing existing prices for expatriate users) as a means of decreasing subsidies and lowering demand.

To finance shortfalls, Qatar has recently implemented measures such as hiking utility rates and doubling fines for wasting water.

Oman recently announced that electricity subsidies available for large consumers, mainly government, commercial and industrial users, will be cut and a higher revised tariff structure will be effective from 1 January 2017.¹⁰

On a very positive note, GCC governments are continuing to invest in public transport infrastructure to help reduce levels of energy consumption and ease traffic congestion. Although the ambitious US\$200 billion GCC-wide railway network has been suspended due to the sustained low oil prices, contracts worth billions of dollars have been awarded for metro line construction in Kuwait, Jeddah, Mecca

and Medina. Substantial public adoption of public transport is critical if such infrastructure is to improve energy efficiency.

Waste to energy (W2E)

Total waste generated in the GCC is likely to increase from 94 million tonnes in 2015 to 120 million tonnes by 2020.¹¹ The surge in the amount of waste generated can be attributed to a high rate of population growth, urbanization and economic expansion. This has resulted in rising consumption and, consequently, an increase in the generation of all types of waste. Naturally, such increases have placed a significant additional burden on existing waste management infrastructure and increased the demand for power. Consequently, the region's waste management sector presents "untapped opportunities" in the years to come.

Historically, GCC countries have placed reliance on landfill for waste disposal and on conventional power production for meeting energy demands. However, these options are becoming undesirable and unsustainable for economic, environmental and practical reasons. W2E is an environmentally-friendly way of disposing of waste and provides a clean and renewable source of power as a by-product.

Over the past decade, many of the GCC states have embarked on several policy-led initiatives to evaluate the various options available to address the growing waste management issue. This has included Saudi Arabia's commissioning of the World Bank to undertake a comprehensive study on waste management in the Kingdom. In the UAE, the government of Dubai has focused on waste management in the "Dubai Strategic Plan 2021" and the "Dubai Integrated Energy Strategy 2030" and Abu Dhabi launched a "Waste Management Master Plan 2040" in 2015.

A number of W2E projects have been announced in the GCC over the last couple of years. The key projects include:

- the Kabd Municipal Solid Waste project in Kuwait (bids were just submitted in September);

8 <https://www.meed.com/sectors/construction/abu-dhabi-step-sewer-project-sets-standard-in-gulf/3134561.article>

9 <http://www.wateronline.com/doc/saudi-arabia-sets-sites-on-wastewater-reuse-0001>

10 <http://timesofoman.com/article/94118/Business/Higher-tariff-for-large-electricity-consumers-in-Oman-from-January-2017>

11 <http://www.constructionweekonline.com/article-40454-gcc-to-produce-120-million-tonnes-of-waste-by-2020/>



- the upgrade of the Domestic Solid Waste Management Center in Doha, Qatar;
- the integrated waste management project in Bahrain;
- various industrial waste management projects in the Royal Commission of Yanbu in Saudi Arabia;
- the Bee'ah and Masdar strategic partnership to develop a W2E "Center of Excellence" in Sharjah;
- the Al Warsan W2E plant in Dubai; and
- the Northern Emirates W2E projects.

In many respects, the difficulties and challenges facing GCC governments in launching W2E projects are not dissimilar to those faced in other sectors, including utilities and social infrastructure. Early initiatives suffered because W2E was seen as an energy project rather than a waste processing project. This approach inevitably leads to difficulties. Now those early mistakes are behind us, W2E will undoubtedly play a very significant role in providing a long-term solution to the rising waste management problems of the region and contribute to the production of electricity at the same time.

[Expansion or upgrade of existing plants](#)

Building a new plant is expensive and time consuming. Investment decisions are linked to economic growth, availability of finance, fuel costs, the regulatory regime and market incentives as well as likely future demand for energy. If developers are to build a new plant they need finance for the land and plant as well as resources to navigate the hurdles of regulation and planning permissions. Not surprisingly, in an economic climate of sustained low oil prices, the option of upgrading existing plants rather than building a new facility is proving to be more attractive.

The concept applies equally to power and water production as to industries consuming those utilities.

On the utility generation side, operators (both government and private sector) are now looking to extend the operating range, increase their ramp rates, achieve higher efficiency at low power ratings and deliver on fuel flexibility. As a result of this demand from their customers, original equipment manufacturers are now offering a range of retrofit options that can enable asset owners to further optimize operational performance, respond rapidly in a far more dynamic marketplace, cut commercial risks and keep operating costs to a minimum. There is a range of options for renovating and improving an existing plant, which can extend life expectancy, increase output and flexibility and help meet environmental and emissions regulations. In the case of power production, changes in the dynamics of the power markets in the region (witness Oman's recent push towards a "spot" market, on which we are privileged to be advising) will reward the more efficient production plants in the country's fleet.

On the production side, one case in point is the Saudi Electricity Company (SEC), which recently announced the expansion of the Qassim II & III power plants. The project will generate additional power without using significantly more fuel. This comes at a time when Saudi Arabia is seeking to improve its power generation efficiency. The power plant is being expanded to meet the increasing demand of power in the region through a conversion from simple cycle operation to combined cycle operation.

Similarly, Dubai Electricity and Water Authority (DEWA) has commenced work for the expansion of the utility's gas-fired M-Station power and desalination plant in Dubai. The 2,060 MW combined-cycle plant, completed in 2013, is to receive two new gas turbine generators, two heat recovery steam generators and one back press turbine, which will increase its power capacity to 2,700 MW and its thermal efficiency rating from 82.4 percent to 85.8 percent.¹²

On the consumer side, Dubai Aluminium (Dubal) has recently been engaging in an ongoing US\$600 million plan to upgrade its smelter facility to reduce its consumption of electricity and mitigate recent and future increases in the unit cost of utilities. The Dubai entity reportedly produces 1.1 million tonnes of aluminium per year, with the planned upgrade set to enhance output by 100,000 tonnes when completed.

Oman's Solar Refinery is being upgraded as part of the Solar Refinery Improvement Project (SRIP) aimed at maximizing the value of the country's oil resource.¹³

Bahrain's state-run oil firm, Bahrain Petroleum Company (BAPCO), recently opened the bidding process for an expansion project at its Sitra refinery. The refinery currently has a processing capacity of 260,000 barrels per day, but BAPCO plans to increase this to 360,000 barrels per day in due course.

In Saudi Arabia we have seen the petrochemical industry move to make its processes more energy efficient to minimize any increase in the unit cost of utilities.¹⁴

Uncertainty over economic growth and prolonged low oil prices mean utilities and developers are deferring major investment decisions. Where the option exists, upgrading existing plant can enhance plant lifetime, improve efficiency and give increased output for a fraction of the cost of building a new plant. At a time of constrained budgets, this option will continue to be attractive. This has created a specialist market for legal services examining the complex legal aspects associated with such projects (intellectual property licensing, brownfield construction risk and health and safety). This has resulted in our firm offering up multidisciplinary teams to support our clients' need for this specialist advice.

Building standards and energy auditing

Due to historical low utility prices and a focus on upfront capital cost (rather than whole of life cost), the energy efficiency of buildings in the Middle East has been low on a developer's priority list. While

12 <http://www.powerengineeringint.com/articles/2015/02/siemens-wins-contract-for-dubai-gas-fired-power-plant-expansion.html>

13 <http://www.hydrocarbons-technology.com/projects/sohar-refinery-improvement-project/>

14 <http://newsbase.com/topstories/sahara-sipchem-press-ahead-development>

the recent increase in utility prices will help to change attitudes, energy efficiency can be most successfully encouraged through a regulatory drive. For instance, creation of an effective regulatory framework around building energy audits, sub-metering, energy conservation, energy supply and benchmarking and facilitation of an ESCO-like market (something that is still missing in many countries in the Middle East) will go a long way in laying a solid foundation for energy efficiency in the region. Benchmarking and incentives could further show customers what they can achieve. These approaches need to take into account the intricacies and specific requirements of each country and need careful analysis to achieve their full potential. With the right regulatory framework, the benefits of implementing energy efficiency measures would far outweigh the costs.

That said, significant steps have already been taken. The Middle East is starting to see a shift towards adopting energy-efficient building and construction practice. A few key recent developments in some of the GCC regions are:

- **Abu Dhabi, UAE** – Estidama (meaning “sustainability” in Arabic) is one of the first organic sustainability frameworks in the Middle East. Introduced by Abu Dhabi in 2009, Estidama seeks to ensure that all new development in Abu Dhabi is undertaken in a sustainable manner. This includes the imposition of requirements on the planning process and the imposition of a green building code under the “pearl” rating system. New developments are subject to a “Development Review Process,” where the applicant must set an Estidama vision for the project. Once planning permission has been received, the development must be constructed in accordance with the pearl rating system (noting that there are different requirements in place depending on the type of construction, for example a building, a villa or a whole community).

The government of Abu Dhabi has encouraged this initiative by requiring that all government buildings have a minimum of a two pearl rating. All other new buildings must meet a minimum of a one pearl rating. Currently the focus of Estidama is on new developments; however, it is likely that this ambitious scheme will be expanded in the future to ensure that existing buildings are retrofitted to meet such sustainability standards.

- **Dubai, UAE** – Etihad ESCO is a DEWA venture that was established in 2013 to make Dubai’s built environment a leading example of energy efficiency. Etihad ESCO is aimed to jumpstart the creation of a viable performance contracting market for energy service companies by executing building retrofits, increasing penetration of district cooling, building capacity of local energy service companies and facilitating access to project finance. The primary aim is to develop energy efficiency projects by targeting more than 30,000 buildings in Dubai.

Dubai has also recently made a “green” approach mandatory when constructing new buildings. The Dubai Municipality introduced its “Green Buildings Specifications” in 2011, when they became mandatory

for all new government buildings. From March 2014 the specifications became mandatory on all developers for all new buildings. The regulations seek to improve the performance of buildings in Dubai primarily by ensuring that the way they are built acts to reduce the consumption of resources as well as improve the welfare of their inhabitants. In practice this has meant, amongst other things, the use of solar reflective materials and advanced insulating material in construction. Recently we saw the award to Enova of a contract for the largest energy retrofit in the Middle East at Jebel Ali. The works aim to save 26 GWh of electricity and 900,000 m³ of water annually.

- **Saudi Arabia** – Steps to reduce energy demand have been taken by the Saudi Arabian Standards Organization (SASO) with standards for the use of high-tech insulating materials in the construction of new commercial buildings, and by restructuring electricity tariffs by the Saudi Electricity Company.

The National Energy Efficiency Program (NEEP) has conducted programs on energy audits to focus attention on the concept and benefits of energy efficiency by providing demonstrable “proof of concept”. The energy audits are believed to have increased corporate awareness regarding energy efficiency measures and technical and economic recommendations have been made available for policymakers.

- **Bahrain** – Bahrain is working on several environmentally-friendly building projects as part of its sustainable development initiative aimed at reducing power and water consumption, besides carbon emissions. The green building initiative is one of the most important strategic objectives for the country’s Ministry of Works, Municipalities Affairs and Urban Planning. It is being implemented on all the existing and new construction projects for various governmental ministries and entities in Bahrain, which are being designed, supervised or maintained by the ministry. The Ministry’s Construction and Maintenance unit has put in place a model list for the green buildings specifications, including six main elements, namely locations, materials, quality

of internal environment, energy efficiency, water and management.

After decades of construction with a focus on cheap costs of construction and little focus on energy efficiency, these new measures are welcome and ensure a lower “lifetime cost” of a building.

District cooling

Today, air conditioning in the GCC accounts for 70 percent of annual peak electricity consumption. Such high cooling demand is expected to nearly triple by 2030. By then, the fuel needed to power air conditioning in the GCC will be the equivalent of 1.5 million barrels of oil per day.¹⁵

District cooling should be the technology preferred for new high-density buildings, as it is considered the environmentally-friendly alternative to traditional air conditioning. Over the last five years, the Middle East markets have witnessed a staggering growth, mainly fueled by the construction sector in big cities of the UAE, Saudi Arabia and Qatar. At present, district cooling is one of three main systems used for air conditioning in the region (the two others include conventional window units or split systems as well as central air or water-cooled chillers). In contrast to conventional systems, district cooling is centralized, and involves central plant supplying chilled water through a network of pipes to multiple buildings within a local area.

Current market structures in the GCC make it difficult to recognize and capitalize on the benefits of district cooling. Historically, power prices have been low, making district systems appear uncompetitive with conventional cooling systems other than in cases of high levels of cooling density. Moreover, property developers often fail to appreciate the advantages of combining their cooling demand and are wary of the technology as it requires significant initial investment. Also, despite GCC countries’ high temperatures and levels of humidity, most governments in the GCC have not regarded the provision of air conditioning as a matter requiring public policy and planning. Instead, they have permitted an unregulated market to determine when and where to use different cooling systems, and to decide how to pay for them.

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<http://www.strategyand.pwc.com/media/file/Unlocking-the-potential-of-district-cooling.pdf>

Over time, district cooling has become the preferred choice of cooling solution for planned and newly-established major developments in the GCC (large malls, hospitals, residential buildings, amusement parks etc.). As the region plans for an increasingly urban future, there seems to be an increasing awareness amongst the industry participants and governments of the substantial benefits of district cooling. Providing considerable increases in environmental protection, comfort, operational efficiency, and cost advantages, there is no doubt that this technology brings superior cost-effective and sustainable solutions – albeit ones that necessitate significant government intervention to encourage.

This suggests that GCC governments should promote district cooling as a central element of new energy conservation strategies. GCC governments subsidize transmission lines to remote areas that the private sector would never finance. There seems, therefore, to be no reason why similar measures should not be applied to district cooling. The easiest first step is to make district cooling mandatory for all new appropriate developments. This could then be extended quickly to all retrofit projects. We are seeing the progression of regulation for district cooling in both the Emirates of Abu Dhabi and Dubai. To the extent this regulation promotes the use of district cooling and sets mandatory standards of delivery, it is very welcome and probably overdue.

Concluding remarks

There is no question that, after decades of relatively carefree enjoyment of its vast and valuable natural resources, conditions have changed, probably for good, in the Middle East, requiring regional governments to change their approach to one of careful management. The Middle East has joined the rest of the developed world in focusing on efficient use of those resources. Energy efficiency has become a dynamic sector in the region and shifted the focus for the energy and natural resource sector. It is a welcome step and an exciting time for energy lawyers to be living and practicing in the Middle East.



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Iran: Unstoppable progress?

By Humphrey Douglas, Lucille de Silva, Alistair Black

Politics in the US, Iran and elsewhere means that there is still some uncertainty around the position of Iran in world energy markets. But agreements reached on international sanctions in 2015 and policy decisions taken within Iran itself have triggered major positive developments in both the oil and gas and power sectors of Iran's economy. In this article we explore the opportunities for growth as well as some of the remaining constraints that foreign businesses seeking involvement in Iranian projects can still face.

Iran: potential hydrocarbons superpower

Huge international interest in Iranian oil and gas has been stimulated by the partial lifting of international sanctions against Iran and the development of a new model contract for foreign investors in Iranian upstream projects (for comments on the "principles" of which see our [April 2016 briefing](#)). The reasons for this interest are obvious. Iran's proven reserves of oil have been estimated as the fourth largest in the world, more than those of Russia and the US combined, but its production of crude oil and other liquids in 2015 was less than a third of that produced by either of those countries individually. When it comes to natural gas, Iran may actually have the world's largest reserves (roughly three times those of the US and four times those of Saudi Arabia): if not, it runs Russia a close second. Its annual gas production in 2015 was less than half of Russia's and barely a quarter of the US's, but the majority of Iran's recoverable reserves have yet to be exploited.

The prospect of "lower for longer" oil prices suggests that maximizing market share from relatively low-cost basins such as Iran is the key to success. At the same time, an increasing number of forecasters see global oil demand peaking by 2030, and the drive to reduce global CO2 emissions, favors a shift to gas as a fuel for power generation and other areas where coal or oil products currently dominate. Against this background, the need for Iran to develop and exploit its hydrocarbon resources more effectively, and the opportunities for international capital and know-how to help Iran to do so, could not be clearer.

Politics

It is politics, as much as the size of its reserves, that makes Iran a special case. It is still too early to predict the full significance for companies seeking to do business in Iran following the US elections of November 2016 and the inauguration of President Trump. Also in November 2016, Iran succeeded in securing an exemption from OPEC production cuts in recognition of the impact that sanctions have had on its production: it is even permitted to increase production slightly while others are meant to cut back. How either of these factors will affect the outcome of the Iranian presidential elections in May 2017 is of course unknowable at this stage.

There is no lack of anti-Iranian sentiment in the newly-elected US Congress, with some Republicans already introducing anti-Iranian bills. There are also concerns that a change of tone and/or policy from Washington could tilt the balance of power towards the hard-liners in Tehran (particularly given the death of Ayatollah Rafsanjani) in a way that would be unhelpful to external commercial interests, that rely on the current relaxation of sanctions against Iran. At the very least, it would appear that the final details of the terms on which foreign

companies participate in Iranian oil and gas projects may be shaped to a significant degree by domestic political calculations.

However, at the time of writing, subject to all these qualifications, a mood of guarded optimism continues to prevail among those who wish to invest in Iranian projects.

Partial relaxation of sanctions: enabling Iran's re-integration into global energy markets

US and EU sanctions against Iran were relaxed under the Joint Comprehensive Plan of Action agreed by the five permanent members of the UN Security Council and the EU. However, it is important to be aware of the possibility of "snap-back" of sanctions, and to be aware of other techniques for mitigating other political risks of dealing with Iranian counterparties.

- Any party to the JCPOA can refer another to the Security Council if it thinks another party is not meeting its JCPOA commitments and the Joint Commission provided for under the JCPOA dispute resolution procedures does not resolve it in 30 days.
- On such a referral, sanctions will "snap back" unless the Security Council positively votes to continue to lift sanctions.
- Snap-back does not invalidate contracts already entered into as such but, if the contract is with a previously sanctioned entity such as NIOC, it can freeze performance of the contract.
- Contracts need to make careful provision for these possibilities.
- Quite apart from snap-back issues, there may be a need to protect against other aspects of Iranian political risk. Bilateral investment treaties are worth considering if one of the counterparties comes from a country that has such a treaty with Iran (not e.g. the UK or US), as they give investors the opportunity to appeal against unfair treatment by host governments to an independent arbitral tribunal applying international law principles.
- Domestic, Iranian protection of investments (e.g. the Foreign Investment Promotion and Protection Act) and enforcement considerations are also highly relevant.

See further our briefing on [Iranian Investment Protection: BITs, DTTs and JCPOA](#).

Upstream oil and gas: Total leads the way for returning IOCs

A major milestone in the process of capitalizing on IOC interest in Iran came on November 8, 2016 with the announcement that Total, China National Petroleum Corporation and the National Iranian Oil Company



(NIOC) had signed heads of agreement to develop phase 11 of the 24-phase South Pars gas field – the largest in the world and the location of some 40 percent of Iran’s proven gas reserves. The project is expected to produce 1.8 billion cubic feet, or 370,000 barrels of oil equivalent per day. Total, which previously developed phases 2 and 3 of South Pars, will be the operator with a 50.1 percent interest, with NIOC subsidiary Petropars and CNPC taking 19.9 percent and 30 percent respectively.

In the words of Amir-Hossein Zamaninia, Iran’s deputy Oil Minister for international affairs: “This is an icebreaker and we shall see more multibillion-dollar oil and gas contracts with other companies including Russians and Europeans soon. ... The next agreement might be in a few weeks.”

It was recently announced that Poland’s PGNiG and Denmark’s DNO are to carry out studies on Iran’s Sumar and Changuleh oil fields respectively. Among major IOCs which have been mentioned in connection with potential Iranian deals are Shell, Lukoil and Eni. All the IOCs mentioned above were on the list of companies published by NIOC in January 2017 as having qualified to bid for new Iranian oil and gas contracts, as were (amongst others) CNOOC and Gazprom, KOGAS, Maersk, Mitsui, OMV, ONGC Videsh, Perenco, Pertamina, Petronas, Sinopec and Wintershall.

A further encouragement to potential IOC participants in Iranian projects came on November 26, 2016 when Iran signed the International Energy Charter declaration, paving the way for foreign investors in the Iranian energy sector to enjoy the investment protections offered by the Energy Charter.

Iran’s sixth Five-Year Development Plan is explicit about the country’s ambitions for its oil and gas sector, and about the need for foreign, private sector investment to achieve them. Amongst the priorities it outlines are:

- developing new fields and rehabilitating old ones (more than a half of the country’s output comes from 70-year-old fields whose output is shrinking by 10 percent annually);
- increasing crude oil and gas exports (by over 80 percent overall between 2014 and 2020, including more than doubling gas condensate production and improving the balance between light and heavy crude);
- quantity-quality improvement of petroleum products (including a 50 percent increase in refinery capacity by 2021, with projects such as the Persian Gulf Star Refinery); and
- decreasing the volume of associated gas flaring (Iran is currently the world’s third largest flarer of associated gas).

Some potential participants in Iranian projects now have more information than was set out in the “Principles of the New Contract Model” released by the Iranian government in 2016. However, the full picture of all the arrangements that will underpin foreign participation is still emerging.

What to do with all that oil and gas?

Iran currently imports significant amounts of both natural gas and refined oil products, notably gasoline, to satisfy domestic demand. The development of new refinery capacity would help to make Iran more self-sufficient in oil products. Iran aims to treble the output of its refinery sector, relative to its current capacity, by 2025, with plans including the upgrading of three existing refineries and the construction of three new ones. Iranian Oil Minister Bijan Namdar Zanganeh has estimated that the country needs to attract some US\$52 billion in investment to develop its petrochemical sector. Iranian officials have recently stated that negotiations are in progress with Spanish, Danish and German counterparties on lines of credit of several billion euros for petrochemical projects.

There is plenty of scope for some of the additional gas which is extracted from new developments, or more efficiently recovered when extracting oil, to be consumed in Iran’s domestic market. But Iran’s oil and gas fields are located predominantly in the western part of the country and its territorial waters. The National Iranian Gas Company has noted the need to develop its distribution network in those parts of the country that it does not currently serve. Iran also has energy intensive manufacturing sectors, such as the largest steel industry in the Middle East, to supply and develop. Although the government is keen to improve the efficiency of power use and generation, the wider development of Iran’s economy will require a significant increase in gas-fired generating capacity.

Approximately 80 percent of Iran’s electricity comes from fossil-fuel plants, with demand for power in the country growing by more than 5 percent a year. The government accordingly wishes to increase installed generating capacity by some 33 percent (or 25 GW) over the next five years. Much of this will be achieved by improving or replacing existing gas-fired power stations (for example, moving from simple to combined cycle) or constructing new ones: the government has set a minimum standard of 58 percent efficiency for new CCGT plants.

In March 2016, Siemens signed an MoU with Iran’s MAPNA Group that includes both the initial provision Siemens’ F-Class turbines for the Bandar Abbas power station and a licensing arrangement that will allow MAPNA to manufacture the turbines in Iran. The MoU also covers the development of “a roadmap for the extension and optimization of the overall Iranian power and electrification system [including] not





only power generation, power transmission and distribution topics, but ... also ... necessary solutions including EPC ... [and] financing options.” Complementing this, in October 2016, Wärtsilä signed a co-operation agreement with the Industrial Development and Renovation Organization of Iran to develop “decentralized power generation in Iran, including power plant operations and maintenance services and related liquefied natural gas (LNG) infrastructure.”

But the real prize, and a major infrastructure investment challenge, is to facilitate exports: by pipeline to neighboring countries such as Turkey, Iraq, Oman, Kuwait and Pakistan, and – if LNG capacity can be developed in Iran – potentially much further afield. In the medium term, Iran considers that it should be able to supply 10 percent of global gas demand.

There may be geopolitical as well as engineering and financing issues to be resolved to achieve this, but any significant increase in Iranian gas exports, either within the Middle East or to Europe or Asia, could service currently unmet demand or change the conditions of competition in particular markets. In May 2016, Kogas signed a cooperation agreement with Iran covering LNG exports, gas market cooperation and gas trading knowhow. Along with Shell, Kogas has also been linked with the proposed Iran-Oman pipeline development project. As regards exports to Europe, current Iranian thinking seems to be to favor the development of LNG capacity over a long-distance pipeline, since this would enable sales to be made direct rather than through a hub in (for example) Turkey. A further potential site for developing LNG export facilities may be the port at Chabahar, which India has agreed to help refurbish as part of a joint strategy to develop trade within Central Asia.

Not just fossil fuels: Iran’s renewable ambitions

At present, renewables contribute little more than 1 percent of Iran’s total primary energy consumption, and only a small fraction of that

consists of non-hydropower renewables. Yet estimates of the total potential wind power capacity in Iran range from 30 to 100 GW. Most of the country has 300 days of sunshine. The country's geology could support the deployment of significant amounts of geothermal energy. There are substantial waste streams that are currently not used for energy purposes. Moreover, renewable energy now has the backing of the Supreme Leader; the Iranian power utility Tavanir expects renewables to provide 10 percent of Iranian power by 2021, with 5,000 MW of renewable generating capacity potentially to be added by 2018; and the government appears to be prepared to offer significant financial support to renewables developers.

The Iranian Ministry of Energy, acting through the Renewable Energy Organisation of Iran (SUNA), is obliged to purchase renewable electricity from approved private sector projects at specific rates. These feed-in tariffs are denominated in Iranian Rials. There are a number of different tariff bands according to capacity and technology and the Ministry of Energy has a policy of gradually reducing the guaranteed price to be paid for renewable power (although reductions in price should only apply to new contracts). The rates published as current on SUNA's website at the time of writing, although slightly reduced in some cases from those available earlier, are still quite generous by international standards (see the examples below).

Technology	Rials/kWh	US\$/MWh (US\$1 = 32,229 Rials)
Biomass (landfill; digestion; incineration)	2700 / 3500 / 3700	89.98 / 108.60 / 114.80
Wind (bands for below 1-50 MW, above 50 MW)	4200 / 3400	130.32 / 105.50
Solar (bands for ≤10 MW, ≤30 MW, >30 MW,),	4900 / 4000 / 3200	152.04 / 124.11 / 99.30
Geothermal	4900	152.04

Note that these rates do not last for the whole period during which guaranteed tariffs apply to a project. They apply for the first 10 years of the 20 year period during which the feed-in tariff regime applies. For the second 10 years, lower rates apply, with the amount by which support reduces depending on technology, size and capacity factor. For technologies other than wind, there is a straightforward reduction of 30 percent. For wind, projects with a capacity factor of less than 20 percent in each band are not reduced at all; those with a capacity factor of more than 40 percent are reduced by 60 percent, with proportionate reductions for those in between.

The template form of contract between the generator and SUNA, under which feed-in tariffs are paid, provides for RPI indexation. Additional support of up to 15 percent can be provided where equipment of Iranian design and manufacture is used.

The Iranian government has set the tariffs at levels that are designed to attract investors, both domestic and foreign, and to build up the sector, as has happened in many other jurisdictions. For those prepared to be among the first movers, the potential financial rewards are clear. Those who prefer to let others go first may well find that they will not earn such high returns, as it is anticipated that – as elsewhere – tariff rates available for new projects will reduce as deployment increases.

For more detail, please see our [briefing on Iranian renewables, with a focus on solar projects](#).

Overall, then, opportunities abound in Iran across the energy sector for those who are prepared to engage with the additional complexities of doing business there.



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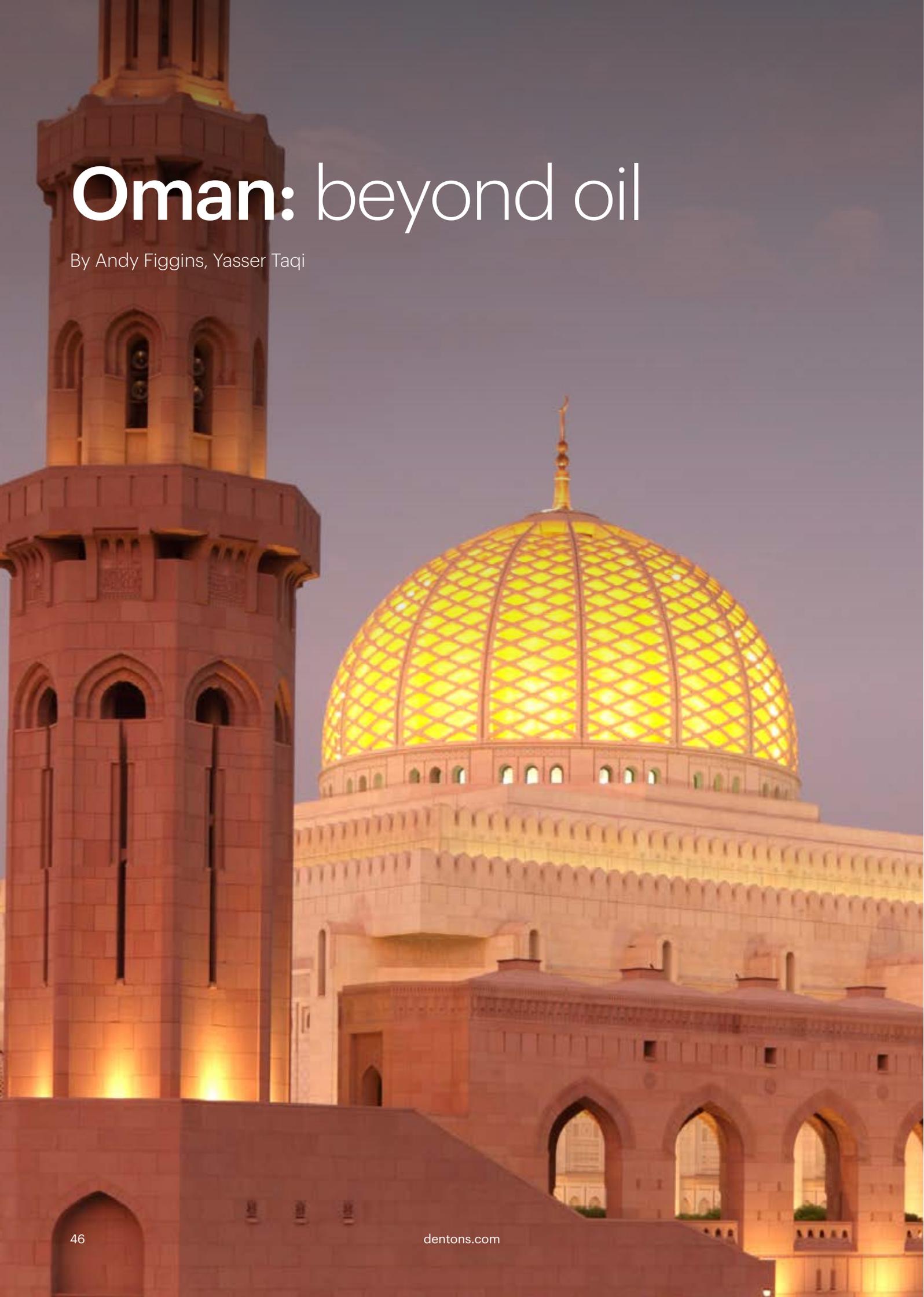
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Oman: beyond oil

By Andy Figgins, Yasser Taqi

Prompted by the sustained lower oil price, Oman, a country where oil revenues make up 45 percent of GDP, has announced a major step towards reducing its oil dependency. The government is ramping up its economic diversification plan in a bid to preserve the notable success it has achieved over the last five decades.

Like its neighbors making up the Gulf Cooperation Council of the Arab States of the Gulf (Saudi Arabia, United Arab Emirates, Kuwait, Qatar and Bahrain) the Sultanate of Oman has witnessed an unprecedented social and economic transformation in the last few decades. Oman's transformation was triggered by the accession of His Majesty Qaboos bin Said al Said to the throne in 1970, when he began an aggressive social modernization program. It has won several UNDP Public Services awards, including the "nation most improved during the preceding 40 years," and has been widely recognized as a rare example of a strong, popular and resilient absolute monarchy. With a GDP per capita close to that of New Zealand and strong relationships with both the West and its Middle Eastern neighbors, it would appear that His Majesty Qaboos bin Said Al Said has struck upon, and delivered, a winning formula for Oman.

Nonetheless, Oman's economic progress has been derived primarily from its oil revenues, which, like its popular leader, are not eternal. Oman has long recognized the need to diversify its economy and has an ambitious aim to reduce the contribution of hydrocarbons from 45 percent to 9 percent of GDP by 2020.

This is to be achieved by, among other things, a number of transformational projects such as the Duqm Special Economic Zone, which has seen the fishing village of Duqm, 280 miles south of Muscat, transformed into a vast port and international business park, measuring 2,000km sq. It is expected that this development will create tens of thousands of new jobs and will thrive as a result of its strategic position on the Indian Ocean, as oil traders and shippers seek to avoid the Straits of Hormuz. Although welcome economic developments such as this are well under way, and the government has ring-fenced capital to support them, numerous economic hurdles require to be overcome. These include burgeoning welfare costs; demands to increase employment; sharing economic benefits with the growing population; and a mismatch of expectations and experience in the Oman workforce.

To address these issues, Oman has, on the back of the ninth five-year development plan (2016-2020), embarked on a national program – "Tanfeedh" (or "Execution") – to enhance the economy's diversification and put a number of plans into action. The program is based on Malaysia's tried and tested model known as the Economic Transformation Programme and the Omani government's existing diversification goals. The Tanfeedh program has the ambitious aim to increase Oman's GDP in the three focus sectors (logistics, manufacturing and tourism) from OMR 4.9 billion in 2015 to OMR 6.6 billion in 2020; to ensure that 80 percent of these initiatives are financed by the private sector, as opposed to dependence on the government; and to generate around 30,000 jobs for Omanis throughout the implementation phase. Based on an eight-step Malaysian methodology, the private and public sector participants who took part in the six-week consultation process (or "labs") were tasked to detail initiatives and to transform strategies from the 30,000-foot overview to a "3 feet" action plan, which in turn paves the way for establishing measurable outcomes and KPIs. The projects will be implemented by the appropriate ministries and related private sector parties. A dedicated

“Delivery Support and Follow-up Unit” has also been established by Royal Decree 50 of 2016, with the specific remit to focus on implementation.

Being one of the three sectors in focus in the ninth five-year plan, the manufacturing “lab” called for investment in renewable energy, with a target of 10 percent of energy generated to come from renewable sources by 2025. This would include generating at least 2,500 MW of solar power and 500 MW of wind power by this date. The proposed new energy policy also advocates alternative non-renewable resources, to include consumption of coal in the manufacturing sector, fully regulated by international environmental standards. The proposed energy policy would, if adopted, help to shift the focus of decision-makers in Oman towards renewable energy. This sector is expected to attract significant foreign investment (a key focus for the capital-constrained government) and to open up numerous opportunities for renewable energy players in what remains an untapped market.

In line with the anticipated shift to renewables, the Oman Power and Water Procurement Company SAOC (OPWP), the state-owned power and water procurer, has earmarked two locations for developing solar power plants. OPWP is appointing technical and economic advisors to carry out a feasibility study and economic benchmarking for the proposed 200 MW solar powered independent power plant. A tender process for selecting an IPP developer for the project is expected to start by the middle of 2017. It is envisaged that this project, if proven to be successful, will become the blueprint for future solar power projects in Oman. Solar industry players should be encouraged by the strong support displayed by the government to make this project successful, and to encourage the development of renewables and the diversification program.

With a view to preserving and continuing the growth the country has witnessed since 1970, the government of Oman has committed to planned, focused diversification of the economy. The Sultanate’s oil resources are dwindling; gas remains a complex, expensive unconventional play; and the future is trending towards renewables. While the “Tanfeedh” program has the potential to open a number of new opportunities in various sectors, opportunities in the renewable energy sector will largely depend on the success of the OPWP solar IPP. One thing is certain, though: Oman has put the wheels in motion to diversify its economy and to move away from oil dependency.



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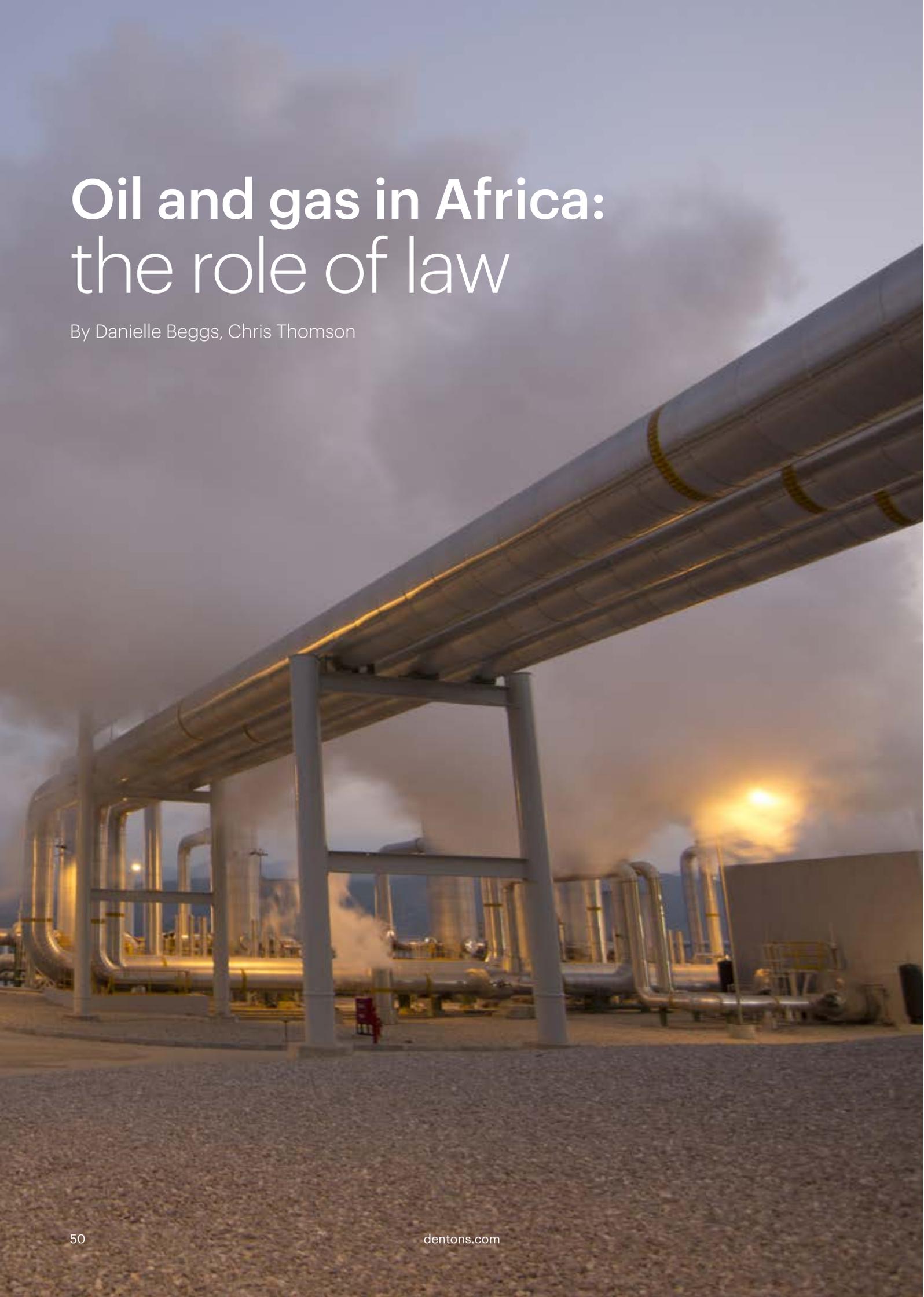
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Oil and gas in Africa: the role of law

By Danielle Beggs, Chris Thomson



Many African countries have the potential to develop thriving oil and gas industries, yet oil and gas projects in Africa suffer from many of the same problems as other African projects that are capital-intensive and/or particularly exposed to commodity price risks. In this context, the steps being taken by a number of governments to reform their oil and gas legislation are a welcome development.

Potential and problems

In its comparison of demand for oil and gas over different continents and major regions, ExxonMobil estimates that Africa will demonstrate the fastest rate of growth in demand for oil and gas over the next 25 years, fueled by proportionately the largest increases in population and GDP over the same period. How much of that growing demand will African countries be able to supply themselves?

A handful of these countries have globally important hydrocarbon reserves; a much larger number of others either produce or have the potential to produce quantities of oil and/or natural gas that are at least very significant in the context of their own economies. As they compete internationally for investment, their oil and gas sectors – some very mature, others not yet having reached the stage of commercial production – face the same challenges as their peers around the world, particularly as regards the current level of oil prices when compared to their typical costs of production. They also face a range of country-specific difficulties including everything from political and military conflict to a lack of refinery capacity.

In this context, the legislative and regulatory framework that governs the oil and gas sector is only one of a number of factors that can be critical in determining whether existing assets and new discoveries (of which Africa has recently seen a number, for example in Egypt and Senegal) are effectively exploited.

An indispensable starting point

Good laws and licensing arrangements or production sharing agreements are only one part of what African governments must get right. But, although they are not in themselves a sufficient condition for a flourishing hydrocarbons sector, they are certainly a necessary one. An effective legislative and regulatory framework can provide a counterweight to the potentially destabilising political cross-currents to which the industry is to some extent inevitably subject.

For example, it is arguable that the Buhari government in Nigeria cannot be judged to have materially improved the prospects of that country's oil and gas industry until it has resolved the ongoing uncertainty over the fate of the Petroleum Industry Governance Bill and the various other related pieces of legislation that it has been reported to be preparing.

Directions of reform

Each African country with an oil and gas industry has a different legal system and history of industry regulation. The changes that many of them have recently introduced or are about to introduce differ in many particulars, but a number of trends emerge.

National Oil Companies (NOCs) remain central to all aspects of the regimes in many countries, even after reform, for example requirements to include them in joint ventures or a right of first refusal in respect of proposed transfers of interests. But, in Angola, Sonangol is losing its quasi-regulatory functions, and in other jurisdictions too, such as Ghana, new legislation indicates at least the potential for greater clarity on the separate functions of different state bodies (NOCs, ministries and regulators).

In a number of countries, proposals for regulatory reform appear to have been prompted, or given fresh impetus, by discoveries of substantial new reserves. Egypt, where substantial new finds have gone hand in hand with the announcement of potentially very wide ranging liberalization of the downstream market, is an example of this. It also exemplifies the widespread trend towards changes that are designed to facilitate the exploitation of gas reserves in the country's own electricity generation industry.

A number of governments are seeing the benefits of developing a more competitive or nuanced fiscal regime to stimulate investment in new or marginal prospects. Examples include Morocco, Madagascar and Angola.

It is significant that Tanzania has recently adopted not only a new Act regulating petroleum exploration and production activities, but also two further Acts, one dealing with the establishment of what amounts to a sovereign wealth fund and another designed to ensure transparency and accountability in the management of its extractive industries. Tanzania is not alone in seeking legislative ways of ensuring an enduring national benefit from the oil and gas revenues gathered by the state, and of trying to reduce opportunities for graft and corruption.

Another country that has recently introduced obligations on international oil companies to contribute funds to community development schemes is Gabon, whose 2014 laws also exemplify a tendency to include provisions designed to strengthen environmental protection and administrative capacity building. Local content requirements – the obligation to employ local people or contractors where they are suitably qualified – are a continuing theme, and are becoming more sophisticated.

Conclusions

The immediate outcomes of the legislative and regulatory reform programs referred to here may not be perfect. Stakeholders have highlighted potential shortcomings in most, if not all, of the new draft or final form laws for the African oil and gas sector that have been produced in recent years. Insufficient detail on the criteria that will be applied when ministers or other government bodies are taking key decisions such as the award of licenses, and potential overlaps between different bodies in terms of their decision-making responsibilities, are typical examples.

Should the Tanzanian regulator hold a monopoly on the trading of gas? Does the new hydrocarbons regime in the Democratic Republic of Congo give the President too much power over the approval of petroleum contracts? The truth is that no system of hydrocarbons regulation is perfect and even those that are accepted as international benchmarks need periodic overhauls. Overall, African governments are moving in the right direction and the wider oil and gas development and investment communities should be prepared to recognize the progress that each jurisdiction has made in improving its legal framework.

For more detail on legal developments in the oil and gas sectors of a number of the countries mentioned above, see our publication *Africa Oil & Gas Highlights*.

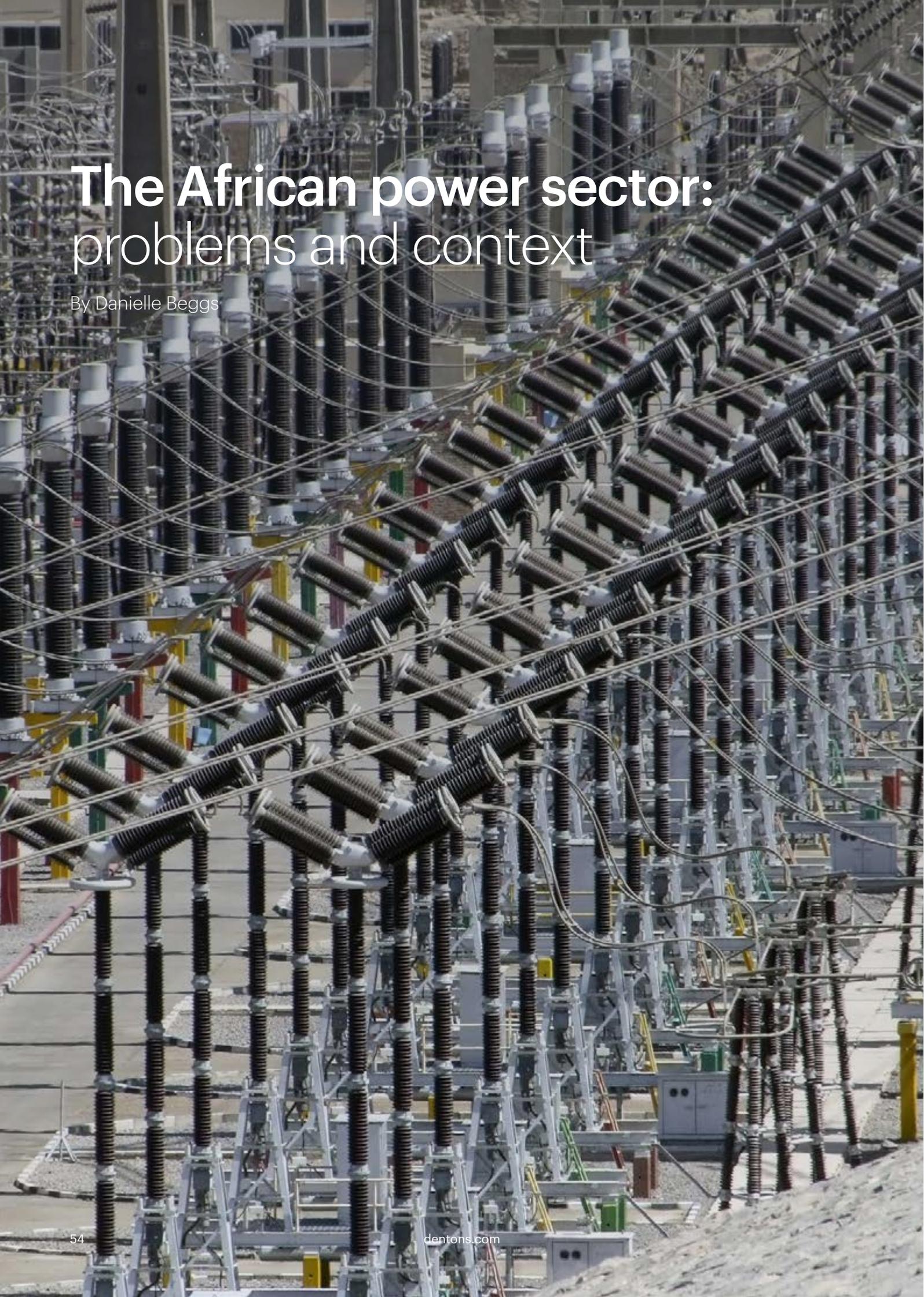


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A high-voltage electrical substation with numerous insulators and power lines. The image shows a dense array of vertical insulator strings and horizontal power lines, creating a complex, industrial scene. The background is slightly blurred, emphasizing the foreground equipment.

The African power sector: problems and context

By Danielle Beggs

The opportunities and the challenges in the African power sector are unmatched in any other part of the world. But before looking in more detail at some of the potential game-changers in the sector it is important to get a sense of the scale and scope of the issues involved.

Africa's power deficit

There are over 50 countries in Africa: the precise number depends on which Indian Ocean and Atlantic islands you include. To attempt to generalize about any aspect of their societies, politics or economic life therefore risks gross over-simplification. But some high-level statistics are clear.

Africa has a total population of more than 1.1 billion, and it is growing fast. The population of sub-Saharan Africa has almost doubled in the last 20 years, and its GDP per capita has almost trebled over the same period. A majority of African countries (including many of the most populous ones) will double their population within 30 years. The continent's urban population is likely to treble by 2050.

More than half of Africa's current population has no access to electricity (rising to 75 percent or more of the populations of Central Africa and East Africa). The problem is not limited to the very poor, or to those living in rural areas. One study of 22 countries in sub-Saharan Africa found that, in 11 of those countries, more than half the households in the top 20 percent income bracket did not have access to the grid, and that, in 14 of those countries, less than half of poor households were connected to the grid.

Moreover, many of the other challenges that come with a growing population in African countries are linked to energy. In the words of Hany El-Nokrashy, a member of Egyptian President's advisory council of experts: "Water is directly connected to energy, whether in terms of energy required to extract it from wells, or to pump it into ... supply grids, or for desalination of seawater". In the case of Egypt, an anticipated 36 percent increase in Egypt's population by 2050, with a corresponding increase in demand for water, will outstrip the country's current reserves by 70 percent.

Even for those with access to electricity, the availability of supply is far from meeting the potential demand. In 2014, Africa's grid-connected power plants produced 765,039 GWh of electricity – less than is produced in just two European countries, France and Spain, for a combined population of less than 10 percent of that of Africa. Indeed, the installed generating capacity of the whole of sub-Saharan Africa (i.e. GW, rather than GWh) is said to be less than that of Spain. Per capita consumption of electricity in sub-Saharan Africa is reckoned by the World Bank to be 16 percent of the world average, the lowest of any region in the world and, on a scale of 0 to 8, overall supply reliability and tariff transparency in sub-Saharan Africa have been ranked at 0.9: outages are frequent and often prolonged.

Over 55 percent of the grid-connected power in Africa is produced in just two countries (South Africa and Egypt), which between them account for less than 15 percent of Africa's population. Some 78 percent of such power is generated in these and four other countries (Nigeria, Morocco, Libya and Algeria), which between them account for just over 30 percent of the Continent's people. But the most populous of these, Nigeria, with 188 million inhabitants, generates less grid-connected power than the least populous, Libya, which has only 6 million inhabitants. None of these countries is a net exporter of a significant proportion of its power output.

In one sense, these figures exaggerate the relative lack of power in many African countries. Unlike their counterparts in most of Europe and South America, many African businesses and households typically supplement the limited and often unreliable supply of grid-connected power with their own standalone generating plant. For example, by one estimate, 75 percent of power consumed in Nigeria is produced in this way – mostly by diesel-power generators.

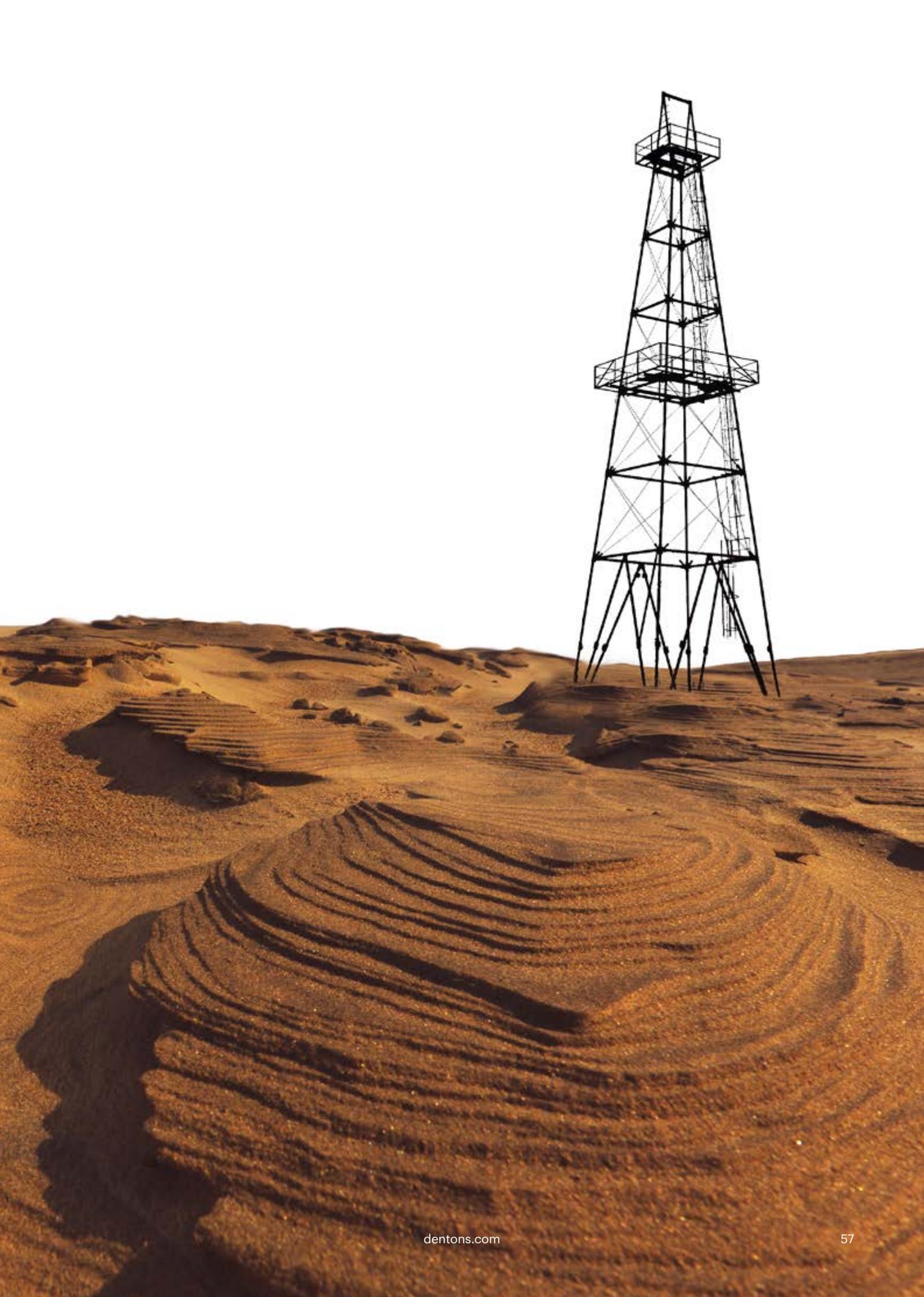
But such auto-generation is not cheap. It imposes a cost on African businesses that makes them less competitive in global markets and it is beyond the means of the half a billion or so Africans with no access to electricity. Moreover, the burning of diesel creates significant sulphur, nitrogen oxide and particulate emissions that are harmful to health, as well as contributing to climate change through increased CO2 emissions.

Power is not the only thing that African countries need more of in order to fulfil their economic potential and reduce significantly the proportion of the continent's population living in extreme poverty (currently about 40 percent). But there can be no doubt that making electricity more widely, cheaply and reliably available is a prerequisite to more widespread prosperity in virtually every African country.

Players and challenges

What would it take to make good Africa's current power deficit? One estimate is that it would take an additional 125 GW of generating capacity and perhaps US\$400 billion over 10 years to get sub-Saharan Africa up from its current per capita electricity consumption of 200kWh/year to the current level of lower middle income countries globally. Another estimate of infrastructure investment costs in the African power sector over the period 2015-2030 is US\$1 trillion, split roughly 2:1 between generation plant and networks. The International Renewable Energy Agency (IRENA) has broken this down regionally and by technology as follows (in US\$ billions):

Region	Large hydro	Other renewables	Other generation	Transmission and distribution
North Africa	2	218	122	186
West Africa	36	31	22	52
Central Africa	13	17	2	14
East Africa	36	21	15	49
South Africa	18	94	33	74
Total	106	381	194	375





In view of its mission, IRENA has naturally based its scenarios primarily around renewable solutions to making good the deficit on the power generation side, but there is no reason to suppose that other possible approaches would be materially cheaper in terms of both capital and operating costs.

For an example of what that could mean for one country, see the [summary produced by IRENA and the IEA](#) of Kenya's 20-year rolling Least Cost Power Development Plan: "It is estimated that 2011 peak load will grow 13 times by the year 2031. Forecasted peak demand for 2031 is 15,026 MW. The government ... identified that geothermal is the least-cost choice technology to meet Kenya's growing energy demand. The cumulative geothermal capacity target is 5.5 GW ... which is equivalent to 26 percent of the system peak demand by 2031. Wind and hydro power plants will provide 9 percent and 5 percent of total capacity respectively by 2031. The present value of the total system expansion cost over the period 2011-2031 for the reference case development plan amounts to US\$41.4 billion, expressed in constant prices as of the beginning of 2010. The transmission development plan indicates the need to develop approximately 10,345km of new lines at an estimated present cost of US\$4.48 billion."

In Kenya, as in most of the rest of Africa, most grid-connected power is generated and/or supplied and distributed to end-users by public sector utilities. These entities often have weak balance sheets, and few of the governments that stand behind them have significant budget surpluses, or strong credit ratings. As far as the utilities themselves are concerned there is an established pattern, elements of which are to be found in the electricity sectors of a large number of African countries, and the problems facing consumers in these markets are the mirror-image of those facing utilities:

- Formal and informal costs of obtaining a connection restrict the number of consumers gaining legitimate access to the grid.
- This limits the supply/distribution utility's revenues (but may at the same time increase its costs, as some consumers will gain illicit access to the grid, which they do not pay for).



- Cost recovery may be further restricted by a government policy of setting the tariffs for some or all end-users below the costs of production/ transmission and distribution.
- Staff are underpaid. This can lead to increases in “informal connection costs.”
- Anecdotal evidence also suggests that staff may sometimes offer to cancel all or part of a customer’s outstanding electricity bill in return for part payment of the outstanding sum to themselves. In any event, many customer bills go unpaid.
- Insufficient funds are available to invest in maintenance or replacement of network and generation assets. This in turn leads to deterioration in performance. Outages are one manifestation of this, but are generally not measured systematically enough. Another is the amount of power lost in the transmission and distribution networks: averaging 15 percent across Africa as a whole (better than in the non-OECD Americas (16 percent), but well above the all non-OECD average of 10 percent), and exceeding 20 percent, 30 percent or even 40 percent in some cases.
- Generation assets are incapable of operating at their design capacity and/or network assets are not able to transmit and distribute their output if they do operate at full capacity.
- Features of the market which ought to increase stability and confidence (multi-year sector planning, “independent” sector regulation) can be undermined by political interference.
- Banks are reluctant to lend money for new projects, unless there is a strong government guarantee of the utility company’s indebtedness.
- Lack of investment in infrastructure leads to deteriorating reliability of service, further discouraging potential customers from connecting (rather than pursuing auto-generation).

The challenges facing African governments in the power sector are not just financial – although the financial ones are formidable. Like governments elsewhere, they face the “energy trilemma”: how, when procuring new generating capacity, to balance the competing demands of security of supply, equity/affordability and sustainability.

The energy trilemma (standard version)

The phrase “the energy trilemma” has become a commonplace of policymakers. It is most often used as a shorthand way of stating that no one electricity generating technology combines the virtues of security of supply, equity/affordability and sustainability.

- The generating technologies that produce the most reliable and flexible ways of meeting demand, and thus the greatest security of supply, are: fossil fuels and biomass (both potentially controversial on sustainability grounds unless fitted with carbon capture and storage (CCS), which at present would appear to make them prohibitively expensive), nuclear (which is often



prohibitively expensive, and rejected by the public in any event), large hydro schemes (which are costly in themselves and often require very extensive additional network infrastructure to connect them to centers of demand), or supplementing the cheaper but intermittent renewable technologies of solar PV or wind with (currently relatively expensive) batteries or other storage devices to make the power they produce more responsive to the peaks and troughs of consumer demand.

- The technologies which are most obviously sustainable (renewables) tend to be more expensive per MW to construct than fossil-fuel plant, as well as being intermittent and therefore sub-optimal from a security of supply point of view (unless supplemented and made more costly by storage). Even hydro can be less available than anticipated because of shifts in rainfall patterns – although this appears to be less of a problem for many African projects than it has been recently in parts of South America – and, in addition to its relative costliness, building large-scale hydro projects takes a long time, so it is not ideal for meeting demand quickly.
- Fossil-fueled generation technologies, which are the cheapest to build per MW of generating capacity, are the least sustainable, because of their emissions, and do not provide complete security of supply in all cases since their performance is contingent on the constant availability of fuel. The case of Nigeria shows the difficulties that can arise even when there is an abundance of fossil fuel (specifically gas) in a country: its fleet of new gas-fired power stations so far seem unable to contribute as expected to meeting the country's demand for electricity because of problems with establishing and maintaining a secure gas supply to them.

The conclusion often drawn is that, since no one technology is without potential drawbacks, it is good to have a balanced portfolio of generating technologies in your national generation mix.

The trilemma: some African perspectives

A number of African countries at present are more dependent on fossil-fuelled generation than is desirable. Others already have a generating mix dominated by renewables in the form of hydro, but are not necessarily in a position to serve their current and future needs for additional generating capacity with this technology – or at least there are questions as to whether an expansion of large-scale hydro is the quickest or most cost-effective way to do so.

For some, an option might be to increase significantly the amount of power that they import from neighbors, if they are in a position to generate more power than they need, using cleaner and/or cheaper technology than the importing state could deploy. The classic example

is the Grand Inga scheme, where it is said that a series of dams in the DRC could eventually produce up to 40 MW – more than 25 times the amount of grid-connected electricity used in the DRC. However, as with all big interconnection schemes, there will be concerns about the security of supply consequences of relying on plant thousands of miles away in another country, as well as about the expense of building the transmission lines, not to mention the wisdom of relying on the construction, over a period of decades, of a project costing at least US\$80 billion in a country that ranked 147th in Transparency International's most recent survey of perceptions of corruption.

On the other hand, there are positive angles to the trilemma in an African context which do not figure in the calculations of developed country governments. It may be considerably easier to persuade African households to abandon kerosene lamps and inefficient "traditional biomass" as a cooking fuel – both of which produce significant negative environmental impacts – than it will be to devise and finance a way to wean consumers in the UK, for example, off using piped methane to cook their food and heat their homes with individual boilers. Many African countries are also in a better position than most developed countries to turn themselves into more effective "carbon sinks" without CCS, by planting large numbers of trees, simply because of the greater availability of suitable land.

A good sense of the range of considerations in play when African countries are making choices about their future generating mix comes across from the planning documents produced by the South African government – most recently in the 2016 updates on its [Integrated Energy Plan \(IEP\)](#) and [Integrated Resource Plan](#). It is a statutory requirement that the IEP "must deal with issues relating to the supply, transformation, transport, storage of and demand for energy in a way that accounts for security of supply; economically available energy resources; affordability; universal accessibility and free basic electricity; social equity; employment; the environment; international commitments; consumer protection; and contribution of energy supply to socio-economic development" as well as "developmental

requirements of the Southern African region"; and "optimal use of indigenous and regional energy resources." Around the world, it is not unusual for countries with significant coal mining industries to be reluctant to abandon coal-fired power: South Africa is relatively unusual, though, in having both large coal deposits and the potential to produce uranium for its own nuclear power stations. Although the IEP notes that solar has greater job-creation potential than some other generation technologies, looking at the whole value chain, the potential to create additional jobs in extractive industries could tilt the scales back in favor of coal and/or nuclear.

Reconciling all the statutory objectives of the IEP is a hard but necessary task, not least because the legislative requirements reflect the political reality of competing stakeholder expectations. But perhaps the key difficulty is that any kind of top-down planning for future energy infrastructure inevitably faces a chicken-and-egg problem. Estimates of how much new generating capacity (and, to some extent, what kinds of generating capacity) will be needed at any given point in the future are acutely sensitive to predictions of the anticipated rate of growth of the economy as a whole. But, at the same time, the availability of secure and reasonably priced power is itself a key enabler of many kinds of economic growth. Governments can take a "build it and they will come" approach, hoping that growth will follow the provision of new generating capacity, but the risks of doing so are not insignificant. Providing additional capacity on the assumption of future growth can involve incurring significantly higher levels of public sector debt and, if this approach fails to deliver the desired economic stimulus, a government may well find itself with a lower credit rating, a substantial underperforming asset and overcapacity in the power system that has negative, rather than positive, economic effects.

On the other hand, the trilemma may look different from the perspective of end-users of power who are not already provided with a secure electricity supply from the public grid (see next article).



Procuring private sector generating capacity

Within the current framework of organizing generating capacity that will be acquired by the major (invariably state-owned) distributors or retailers of power, having flowed over public transmission and distribution networks, the only way to secure significant new capacity in most African countries is either to manage a competitive tender for the provision of that capacity by the private sector or to oversee the procurement of new capacity by negotiation between the proposed provider and the national utility or another parastatal body. There are potential pitfalls in either approach.

A competitive process only works if: there is a sufficient pool of credible bidders; the underlying project documents, such as the model power purchase agreement (PPA) are commercially reasonable and robustly drafted; and there is nothing in the design of the auction that predisposes it to drive bids to a lower level than the winners are likely to be able to deliver at. Africa has seen some notable examples of success in this area, notably in the South African government's REIPPP program for tendering for new renewable generating capacity. The large number of bidders attracted by the terms of the program has been one reason for its success.

Where there are fewer competitors or the process begins on a negotiated basis, then, without a tightly managed and expert team on the government side, it can be hard to avoid the balance of bargaining power in a negotiated procurement slipping inexorably towards the contractor, leading to delays, cost overruns and ultimately even the possibility of non-delivery of some or all of the project.

From the point of view of a democratically elected government in particular, there are also inevitable tensions between idealism and pragmatism. Policies that may seem unquestionably right from a political or ideological standpoint may end up undermining the very objectives that they seek to promote if they turn out to have adverse practical consequences when put into effect.



Finally, those outside government and incumbent utilities who seek to develop commercial solutions to the problems of the sector often face a range of problems. Developers of new generation projects often experience a level of difficulty in establishing rights of ownership over land and authorization to build on it which has no parallel in legal or administrative systems in any other part of the world. On the face of it, most African countries have legislative provision for new entrants to most parts of the market to be granted licenses to carry out their proposed functions, but the process of obtaining such licenses can often be less than straightforward. And, even in jurisdictions which in many ways stand out as attractive places to invest, things can go wrong: for example, in South Africa Eskom has refused to sign off PPAs with some successful bidders in recent rounds of the REIPPP regime.

Reasons for (cautious) optimism

In the next three articles, we explore some of the technologies and strategies that could enable African countries to close their power deficits and significantly enhance their prospects for economic growth. Everything we say there needs to be read against the background of the negative, as well as the positive, features of African power markets that we have noted here. But on balance, and at the risk of both anticipating what follows and generalizing excessively about more than 50 diverse countries, we think that, although many individual markets and projects will remain problematic for a variety of reasons, there are, at present, grounds for optimism that overall conditions in the African power sector

may improve materially over the next few years. There are five main reasons for this.

- For most African countries confronting the challenges of energy and climate change policy in 2016, the starting point is very different from that of many developed countries. But there are ways in which “starting from scratch” can be an advantage. For example, given the potential to develop new business models for the power sector in an African context, it may be an advantage not to have a demand side that is dominated by a body of complacent consumers who have grown accustomed to being supplied with as much electricity as they want at relatively cheap rates, generated from a fleet of large centralized (and often fossil-fueled) generating stations whose capital costs are long since amortized, and who have to be heavily incentivized to think about their power consumption in different ways, or even at all.
- African power markets have an inherently very high potential to benefit from some of the same technological changes that have begun to be seen, or at least be talked about, in the electricity sector worldwide, such as renewables, storage, distributed generation, micro grids, prosumerism and smart technology. Partly because of the relative scarcity of existing power infrastructure in many African countries and partly because of the abundance of renewable energy sources in Africa, we can expect these trends both to transform and massively to expand the power sector in African countries.

- The delivery of all of these potentially transformative technologies is or could be linked in various ways to the use of mobile phones. Use of mobile phones is growing rapidly in many African countries, and there are many examples of mobile technology being used in Africa to develop new business models and overcome potential obstacles such as the relatively high proportion of the population that is not already integrated into the formal banking system.
- There are plenty of developers, contractors, equipment suppliers, investors and financiers who have been active in countries outside Africa where the market for many of these new technologies has been based on subsidies or other regulatory features which are no longer present. Many of these organizations are now looking to expand or move into markets where demand for e.g. solar power is driven by market fundamentals rather than being highly sensitive to political or regulatory policy changes, and they are doing this against a favorable international policy background based on such foundations as the Paris Agreement on climate change and the Obama administration's Power Africa initiative.
- There will in some cases be a need for regulatory or legislative action to facilitate some of the opportunities provided by new technologies and business models. But, on the whole, the changes required are not unprecedented or revolutionary ones. Indeed, overall, although in one sense the task facing many, if not most, African countries to equip their power sectors for the 21st century is huge, it is also capable of being broken down into a series of entirely manageable and well-understood steps. There will be many issues to resolve along the way, but an army of experts stands ready to help both the public and private sectors to navigate their way towards what should be shared goals in each case.



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African power generation: resources, technologies, opportunities

By John Woolley, Raj Kulasingam

No continent in the world is better endowed than Africa with the primary sources of energy that can be turned into electricity, even taking account of its overall size and present and likely future levels of population. Coal, oil, gas, wind, sun, rivers (for hydro), geothermal, biomass, uranium: it is all there in substantial quantities – albeit unevenly distributed between regions and individual states. Some of the diversity of African power resources can be seen from Tables 1 and 2 on page 78.

African countries are also fortunate to be looking to expand their power generating capacity at a time when technological progress and manufacturing economies of scale, stimulated by the deployment of subsidies and other incentives by governments elsewhere in the world, have made solar PV and onshore wind power competitive on price with traditional high carbon alternatives at a variety of levels. In this article we review the potential of a range of power technologies, both more and less established, to shape the development of the African power sector over the coming years.

Nationally determined contributions

At the time of writing, 52 African countries had signed the [Paris Agreement](#); 26 of these had ratified it; and 23 had submitted their nationally determined contributions (NDCs), as opposed to the intended NDCs (INDCs) submitted to the UN in advance of CoP21 during 2015). Those INDCS/NDCs provide a good level of insight into how each country's government sees its priorities in terms of taking action to mitigate and to adapt to climate change resulting from greenhouse gas (GHG) emissions.

Many of them make the point that their own contributions towards global GHG emissions are tiny (and typically much smaller than their share of world population, for example), and stress the need for international financial support to achieve their more ambitious (or "conditional") mitigation actions. Moreover, in many cases the prime focus of their mitigation actions is not on the power sector, because a much greater proportion of their current GHG emissions is produced by agriculture and/or the use of inefficient "traditional biomass" cooking techniques. Nevertheless, many of them do focus on power generation technologies and their key messages are summarized in Table 3 on page 79.

Solar

We begin with solar, and specifically solar photovoltaic (PV). It is true that concentrated solar power (CSP) has the potential to be deployed in more parts of Africa than at present. It is also true that CSP has the advantage of using solar energy in a way that does not limit generation to the hours of daylight, which is important. However, it lacks the key advantages of PV: the ability to be deployed almost anywhere in Africa, at almost any scale on a modular basis, on or off-grid, cost-effectively, and without particularly complex or technology-specific supporting infrastructure.

[IRENA calculates](#) that, in 2015, 47 GW of solar generating capacity was added worldwide, but less than 1 GW in Africa. And yet this comparatively small overall figure understates the amount of ongoing activity that could lead to significant expansion of African solar capacity in the next few years. Consider the following points:

- Outside Morocco and South Africa, African utility-scale solar is in its infancy. But Zambia recently announced a contract for solar PV at US\$0.06/kWh under the World Bank's scaling solar program.



This is extremely close to the level (US\$0.059/kWh) that was the lowest in the world when it was announced by Dubai only about 18 months earlier.

- The gap or lag between African pricing and what is seen elsewhere is no more than would be expected given the less mature state of the market. In terms of the average anticipated costs per Watt for projects aiming to commission in 2016 and beyond, the African range of between US\$1.4 and 3 is not inconsistent with the global average for 2015 of US\$1.8.
- In any case, what matters more than the relative costs of projects in Africa and elsewhere is that the current range of costs for African projects compares favorably with the alternative means of power supply available in Africa now. So, for example, in the context of one of its own 1 MW African projects, [SolarCentury estimates](#) that, in Kenya, the costs of a business generating its own solar power are in the range US\$0.10-0.15/kWh – appreciably less than the typical grid tariff of US\$0.20/kWh and significantly less than what it would cost them to self-generate using diesel (US\$0.30/kWh or more).
- [Danvest has calculated](#) that typical cost savings from adding solar to diesel generators are 25-30 percent, and up to 70 percent in “very remote locations with elevated diesel costs.” It has been estimated that sub-Saharan Africa has over 3,000 diesel gensets with an average size of 6.5 MW and more than 1 GW of such capacity being added each year – there is considerable potential for those generating their own power to save money by either replacing diesel capacity with solar (and a battery) or combining diesel and solar (with or without a battery): for the project mentioned above, SolarCentury calculates 25-year savings of US\$10 million.
- The average capacity factors of African solar PV projects are better than those of solar PV projects in Europe, China or the US, according to [REN21’s Global Status Report 2016](#).
- Although only about one in five African countries offers a feed-in tariff (FiT) subsidy for renewables, it is not clear that this kind of subsidy is as essential to the development of the industry in Africa as it has been in some other parts of the world. For example the higher quality of the solar resource in Africa often means that individual panels will be producing more power than would be the case in many parts of Europe much of the time.
- Even in Europe, where there are greater financial resources to support FiT policies, FiTs have been problematic in a number of ways, tending ultimately to become victims of their own success: the more capacity seeks to benefit from them, the greater the burden of paying

the tariffs. This leads to tariff reductions, which undermines investor confidence, and can result in individual schemes, whose development began on the expectation of a particular tariff level which is removed before they are completed, becoming uneconomic. This could prove particularly problematic in the African context, where project lifecycles are often longer.

- African governments or national utilities that want to encourage utility scale solar projects by offering stable income are therefore likely to get a better deal by adopting the kind of auction-based approach that has been used in South Africa and Morocco, where the REIPPP and the Moroccan National Energy Strategy continue to deliver significant amounts of new capacity and to attract keen interest for new bids at very competitive prices.
- An increasing number of utility scale projects are progressing down the pipeline of development, finance and construction in countries other than South Africa and Morocco. Notable recent examples include the PPAs for 14 solar IPPs (with a total of 1,125 MW of capacity) signed by the Nigerian Bulk Trading entity in July 2016, with help from Power Africa; two 10 MW plants reaching financial close in Uganda under the country's KfW-backed GET FiT subsidy scheme; agreement on construction financing, involving the UK and Norwegian governments, for a 20 MW solar development in Senegal being developed by GreenWish Partners, with backing from private equity investor Denham Capital; and agreement between the developers and the national power utility on a 25-year power purchase agreement for a 40 MW solar plant in Mozambique. It is also reported that construction of the first of six 50 MW tranches of a 300 MW project has begun in Djibouti.
- Although the large amounts of undeveloped land in many African countries make utility scale solar PV an attractive option, it is by no means the only area where there is room for significant expansion of solar capacity in Africa. One obvious area for potential development is rooftop solar in Africa's fast-growing cities, where a lot of the current demand for power is concentrated. In this context it is worth noting that average levels of solar irradiation in African capitals are between 52 percent and 117 percent higher than those in Germany, the home of the world's first great (and admittedly significantly subsidized) rooftop solar boom.
- Of course, a lot of those with suitable roofs for solar PV panels may currently be getting some or all of their power supply from a diesel generator but, as noted above, the two are not incompatible, with the use of solar enabling substantial savings on fuel costs.
- A number of countries, from South Africa to the Seychelles, are focusing on mass rollout of solar thermal technology for water heating.
- In the final article of this volume we consider the potential for the application of solar and other renewable technologies at a range of smaller scales, either in standalone domestic appliances supplied to consumers on a "pay as you go" basis, or in industrial or community mini- or micro-grids. Solar is ideally placed to be the gateway to electrification for many of those currently without access to electricity in Africa, and to challenge more than 100 years of accumulated assumptions about how electricity markets ought to operate in the process.

Wind

IRENA sees the potential for up to 100 GW of new wind power in Africa by 2030, representing about a third of the estimated total wind power capacity for Africa of 300 GW (based on areas which are likely to have suitable load factors of 30 percent or more). Even 100 MW would represent about 40 times the amount of wind power capacity on the continent at the end of 2014, but it is not necessarily unachievable: the sector in Africa grew by 37.6 percent in 2015.

Much of that growth, and of the even more dramatic increase in 2014 (almost 60 percent), was the result of tender processes in South Africa, Morocco, Egypt and Ethiopia. The most recent South African

tenders have produced bids with a levelized cost of electricity that is 40 percent cheaper than has been estimated for South Africa's new coal-fired plants. The South African Wind Energy Association has been encouraged by the prospect, raised in the [latest update to South Africa's Integrated Resource Plan \(IRP\)](#), of an additional 37 GW of wind capacity in the country by 2050, based on a "least cost and moderate emissions reduction trajectory," although at the same time it has been complaining to the regulator, NERSA, about Eskom's refusal to sign the PPAs for a number of REIPPP wind projects with a view to NERSA exercising its enforcement powers to persuade Eskom to comply.

Although – in contrast to solar resource – good wind resource is only found in certain parts of Africa, its quality is high in the areas where it is found. The average capacity factors of wind projects in Africa are better than those of wind projects in Europe, China or the rest of Asia. An increasing number of increasingly large-scale wind projects are progressing in a number of African countries.

- Notwithstanding the difficulties faced by a number of Egyptian solar projects in the wake of the recent "floating," and fall in value, of the Egyptian pound, there has been progress on some significant wind projects in the country, notably an agreement between KfW, EIB, AfD and the European Commission on the €340 million financing of a 250 MW wind park on the Gulf of Suez.
- In South Africa, several hundred MW of REIPPP capacity has recently been commissioned.
- In Ethiopia, five wind developments with a combined capacity of 550 MW and sponsors including Dongfang Electric, Hydrochina and the EIB responded to a government tender for PPAs earlier this year. It should not be long before Ethiopia has substantial IPP wind generating capacity in addition to its existing just over 300 MW of state-owned projects.
- In Ghana, Mainstream Renewables may be about to follow its successful South African projects by developing a 225 MW project for which it is reported to have secured a PPA.
- In Kenya, the largest of all African wind projects, which has taken many years to come to fruition, is finally under construction at Lake Turkana. On completion of the project, Google will acquire the 12.5 percent stake in it currently held by the turbine supplier Vestas. Elsewhere in Kenya, the 60 MW Kinangop project was abandoned due to local opposition, but there are indications that other projects of comparable or larger capacity are progressing more smoothly, and some are reported to have reached the stage of having completed both permitting and negotiation of a PPA.

Energy storage

As everybody knows, the problem with wind and solar PV power is that, although they are the cheapest forms of renewable electricity generation, they only generate when the wind is blowing or the sun is shining. But much of the usefulness of electricity to end-users depends on its being available on demand or, for example, after the sun has gone down. The obvious answer to this is to store power that has been generated when meteorological conditions are suitable, for use at other times when demand is higher. Developments in batteries and other storage technologies are beginning to make this a realistic prospect even at grid scale.

The combination of intermittent or variable generation renewables and storage potentially already has a competitive advantage in many African markets that it does not yet enjoy in the power markets of many more developed economies. In those markets, where power is supplied at competitive prices over a universally accessible grid system, there is debate over how long it will take for such a combination to be competitive with, for example, fossil-fuelled generation.

Some say it will take four to five years, others expect the price of batteries to fall rather more sharply. In any case, in the meantime, the talk is of having to stack a number of separate revenue streams in order to make a business case for combining, for example, a solar PV installation and a battery. The basic benefits of the combination are time-shifting demand (e.g. using electricity generated during the day at night) and/or arbitrage (exporting energy generated at periods of low demand at periods when demand – and therefore the wholesale power price – is higher). But it is generally thought that, at present, just as an unsubsidized investment in a solar installation is an insufficiently attractive prospect, so also investing in a battery will only be a compelling proposition if it can capture some elements of additional income (preferably underpinned by a contract awarded in advance of installation), for example by providing ancillary services to network operators.

Moreover, with a secure grid connection that enables a storage facility to import as well as export power at any time, and rules that may require subsidized renewable generation plant to be connected directly to the grid rather than running through storage (so that the metering of its entitlement to subsidies is not “contaminated” by non-renewable power that has been imported from the grid and stored in the battery), it may be more advantageous to run co-located battery and solar units separately (i.e. to charge the battery from the grid rather than the wind or solar generating plant).

However, for many users of power in Africa, these considerations will not apply. We have already seen above how the use of solar can bring cost savings as compared with diesel. Typically, in off-grid locations, the two are combined, with diesel providing power when the solar element does not. At least where conventional diesel engines are being used (which are designed to operate at a high load), this can lead to inefficient use of the diesel component, as it needs to be ready to supplement the solar component not only at night, but also at times when passing clouds reduce the output of the PV panels. Introducing an element of storage to provide this kind of back-up during daylight hours can ensure that the diesel gensets only run when necessary and in patterns that do not subject them to undue wear and tear, saving money in both fuel and maintenance costs.

Not just batteries

Batteries of one kind or another are not necessarily the only form of energy storage with significant potential to be deployed to make better use of electricity generated from renewable sources. Where large quantities of power are to be stored and released over longer periods of time than it typically takes to discharge a battery, compressed air energy storage (CAES) or pumped hydroelectric storage is likely to be a superior solution.

Of these two technologies, CAES is the more versatile and the cheaper. It works by the principle of using electricity to compress air into a suitable (usually underground) space and then releasing the air through a turbine to generate electricity again.



Most of the technology involved is very simple. The only difficult part is ensuring that too much energy is not lost in the form of heat during the compression and expansion of the air, but [Storelectric](#) and others have developed techniques for significantly improving the thermal management of CAES.

Although suitable geology is a prerequisite for CAES, this can be provided by caverns formed by the extraction of underground salt deposits or the depletion of oil and gas reservoirs, as well as underground aquifers. In the case of depleted oil and gas reservoirs, CAES has the additional benefit of being able to be used to enhance oil recovery. Some 20 African countries are already known to have some areas with suitable geology for CAES in the form of hydrocarbon reservoirs and/or salt deposits and many of those countries (such as Nigeria and Egypt) include the continent's larger populations and electricity markets.

CAES could be extremely useful as a means of storing the output from large-scale renewables plants that find themselves generating power that either is not required at the time of its generation or they cannot export at particular times when there is a market for it because of network infrastructure constraints (as long as the CAES facility is located behind the constraint). However, it is not only helpful in a renewables context. CAES can be deployed as part of a CCGT plant in such a way as to reduce its consumption of gas (and thus its principal operating cost) by at least a third.

Developers of large-scale African renewables or CCGT plants, and transmission grid operators, would therefore do well to consider the potential to incorporate CAES into their plans.

Coal

Coal is the highest carbon fossil fuel, but also the cheapest and easiest to transport over long distances, and its price tends not to fluctuate as much as the price of oil or gas. In some countries, the debate around



coal-fired power stations takes as its starting point the assumption that coal is an easy and cheap way of producing a lot of power quickly, but with highly undesirable environmental impacts. The rapid rate of coal-fired power plant construction during the massive expansion of Chinese manufacturing industry is cited, and the potential for large-scale new coal plant building programs in India is viewed with concern. Elsewhere, in parts of Europe, for example, coal has a position to defend as the dominant fuel of the existing power generation fleet, whose advocates still see it as having cost and security of fuel supply advantages over imported gas.

The position is somewhat different in Africa. Although coal dominates the mix in South Africa, the continent's largest power market, it only has a significant presence in a handful of other countries. In South Africa, the existing coal-fired plants are on average well over 30 years old. The two new coal-fired plants which have been planned (Medupi and Kusile) are considerably behind their originally planned construction schedule, but when completed they are expected to be among the largest coal-fired plants in the world (about 4.8 GW each). Even in South Africa, there are concerns about the sustainability of further coal-fired plant: quite apart from the environmental impact of emissions from coal-fired plant, there is the problem of the large distances between the coal mines, most of the demand for the power which they would produce, and suitable sources of the water for power plant cooling systems (although the lack of water can be compensated for to some extent by the use of less efficient dry cooling systems).

Of the other countries with substantial existing coal-fired generation, Morocco is focusing on renewables and combined cycle gas turbine (CCGT) capacity and, although plans exist for a number of possible new coal-fired plants in Zimbabwe, Botswana, Tanzania and Mozambique, it is clear that their going ahead depends to a large extent on their relationship to the South African market through the Southern Africa Power Pool (SAPP) and/or on the provision of investment by Chinese companies. For the moment, at least, a number of these projects appear to have been abandoned or are progressing very slowly. Elsewhere, in Ghana, the Minister responsible for power station permitting has said: "I will not be signing a permit for anyone to put up a coal plant when Ghana has just ratified the Climate Change Agreement". By contrast, in Kenya, which has signed but not yet ratified the Paris Agreement, and where – unlike in the countries of Southern Africa – there is not a substantial history of coal-fired generation, the government remains committed to the 1 GW Lamu project. An even larger example of a proposed coal-fired plant is the 6 GW facility at Hamrawein, for which the Egyptian government has invited tenders. More modest, and further advanced, is Morocco's new Safi coal-fired power station (1,386 MW, currently under construction).

Nuclear – only a long-term prospect for most of Africa

Currently, South Africa is the only country in Africa with commercial nuclear power generation capacity. It would like to add new nuclear generating capacity but, in view of the high costs of the technology and

other factors, these proposals have become a matter of considerable political controversy and the likely timing of any nuclear new build in South Africa remains unclear.

In Egypt, a site at El-Dabaa was first earmarked as the possible location for a nuclear power station over 30 years ago. Various proposals to develop it have come and gone in the intervening period. Most recently, the government announced the signing of agreements with Russia for the construction of 4.8 GW of nuclear generating capacity on the site and a US\$25 billion loan that would cover most of the construction costs. There have also been reports that the government is inviting bidders from China, France and South Korea to tender for a further 2.8 GW of new capacity.

Unless and until the deployment of small modular nuclear reactors becomes economically feasible on a wide scale, nuclear power is only feasible for those African countries with a sufficiently robust power grid to which a relatively large amount of demand and generation is connected. In practical terms, that means that nuclear power is a distant prospect for most until they have significantly expanded their existing power industries – unless, perhaps, they benefit from cross-border power trading, such as already exists in the SAPP. A number of West African nations with nuclear ambitions, for example, have plans to develop a regional nuclear program. Elsewhere, a number of countries whose industries are already at or are approaching the right scale (e.g. North African countries and Kenya) have begun to explore nuclear options with Russian or Chinese cooperation, but these discussions seem unlikely to result in concrete projects for commercial reactors in the short to medium term.

Gas

It is no accident that four out of the six African countries with the largest power industries are also among those that have systematically exploited their reserves of natural gas. Many other African countries either do not have such reserves or face significant challenges in developing them – for example Mozambique, where the reserves are offshore, remote from centers of power demand, and so large that financing the infrastructure necessary to exploit them is a major challenge. Meanwhile, among countries with an abundance of gas, Nigeria stands out for the difficulties it has experienced in providing a secure supply of gas by pipeline to its new gas-fired generating plants.

In Morocco, gas-fired generation is seen as one of the means by which to compensate for the intermittent output of wind and solar generation. This is probably the most realistic approach to dealing with the variability of wind and solar at a large scale and in markets where there is limited or no potential to deploy the forms of energy storage that are best

suited to large amounts of power and longer time periods (although there may be potential to exploit compressed air energy storage in Morocco given its salt deposits and oil reservoirs). Gas-fired plants currently account for 10 percent of Morocco's 8.3 GW of generating capacity. By 2030, the aim is that they should account for 23 percent of a total generating capacity of 25 GW. At present, most gas used in Morocco is imported from Algeria. The first step in diversifying supply will be to develop LNG import capacity, combined with 2.4 GW of new CCGT plant. A more distant prospect is opened up by the recent signing of an MoU with Nigeria to study the feasibility of a pipeline from Nigeria which could be extended as far as Europe.

We comment on the potential for LNG imports to South Africa elsewhere in this volume. It has also been noted that, with the LNG market oversupplied, there is more interest in developing smaller LNG import markets. There is potential to deploy floating storage regasification units (FSRUs) in a number of smaller African power markets with significant demand for power in coastal locations, such as Ghana and Senegal. Ghana has also gone one stage further in making use of floating energy infrastructure, by commissioning two 225 MW [powerships](#) from the Turkish group Karadeniz. The powerships are a good way of supplying additional flexible generating capacity at relatively short notice and without the need to commission capital intensive power station infrastructure, which may well prove attractive to other African countries, in conjunction with FSRUs.

Finally, there are two more factors which could significantly enhance the commercial potential for gas to play a larger part in the electricity generating mix in African countries:

- There is the possibility of a shale gas industry developing in South Africa. The extent of the unconventional gas resource in South Africa and its potential to be economically exploited remain to be investigated, but early estimates suggest that the country could hold the eighth largest reserves of shale gas in the world, principally in the Karoo basin. For all sorts of reasons (not least

the availability in the right places of the large quantities of water that are necessary for most forms of hydraulic fracturing), it is far too early to start envisaging a US-style shale revolution in which cheap gas displaces coal as the fuel for baseload power generation. But if a substantial South African shale gas industry were to develop, it could have a significant impact on the generating mix in South Africa and beyond.

- Gas can be considerably cheaper than diesel as a fuel for electricity generation. The only reasons for diesel's position as the default choice for smaller-scale and off-grid generation is that, historically, it was the fuel most small gensets were designed to run on and it was easier than gas for those who wanted their own source of power, but who were not connected to a secure gas distribution grid network, to transport and store. Both these historic advantages of diesel gensets are now being eroded and challenged by the improved performance of the latest small gas gensets, which are easy to transport and install, and by the development of techniques for supplying gas to generators that are not connected to a gas pipeline – using what GE, one of the leading exponents of both trends, calls a [“virtual pipeline”](#) to supply fuel in the form of either LNG or compressed natural gas (CNG).

Climate change synergies: biomass and energy from waste

We tend to think of renewables as a way of avoiding the emissions of carbon dioxide that result from the burning of fossil fuels. However, some renewable technologies can help to limit emissions of methane, which would otherwise naturally result from agricultural and other processes. Methane is itself a greenhouse gas. Although carbon dioxide may be emitted in the process of converting methane from biomass and other waste, methane is the more potent of the two greenhouse gases, so the net environmental effect of these technologies can be positive.

One of the striking things about the NDCs is how many of them mention as part of their plans to

mitigate greenhouse gas emissions the avoidance of methane emissions from waste, by capturing the methane and using it for power generation purposes. The use of landfill gas, and other techniques for generating electricity from biomass and other waste, can be a relatively low-cost way of combining the disposal of rubbish with the generation of dispatchable power from renewable sources.

At the smallest end of the scale, a particularly exciting recent development is the marketing by companies such as [SEAB](#) and [Qube Renewables](#) of containerized anaerobic digestion units that combine the functions of waste treatment, energy generation and the production of a digestate which can be used as fertilizer. Larger projects may also involve the production of liquid biofuels. In either case, there can be powerful synergies between filling the electricity generation gap in rural areas and improving the efficiency of agricultural processes.

The simpler techniques in this sector were once subsidized in countries such as the UK, but now new energy from waste projects are often only eligible for subsidy if they use more advanced techniques or incorporate combined heat and power (cogeneration). However, as with wind and solar, the simpler energy from waste technologies, whose further commercial potential without subsidies may be limited in developed countries, may be competitive against off-grid diesel even if they are not subsidized – although in fact some African governments, such as Egypt's, have proposed FiTs for energy from waste. Moreover, some industrial offtakers of power from biomass generation facilities may even be prepared to pay a premium for a reliable supply of renewable power for reasons of wider corporate policy – as is the case with the [BMW plant at Rosslyn, Pretoria](#), which takes power from Bio2Watt's 4.4 MW biogas fuelled generating plant at Bronkhorstspuit, some 52 miles away.

Hydro and geothermal

Hydro and geothermal are both well-established technologies. They also share the advantage of being “baseload,” having the ability to produce a continuous output round the clock that wind and solar lack (unless coupled with storage), although in the case of hydro this is contingent on water levels in lakes and rivers, which in some cases may be at risk from climate change. This makes them easier to integrate into transmission and distribution systems.

A lot of recent larger-scale African hydro projects have been carried out by Chinese contractors, perhaps facing a slow-down in their home market, and funded by loans from the Chinese Exim Bank, Industrial and Commerce Bank of China or China Development Bank. The EPC contractor begins work with its own funds prior to disbursement of the bank loan, most of which is paid to the government, with the remainder going direct to the contractor.

With the exception of Grand Inga, referred to elsewhere in this volume, the largest hydro project currently under development is the Grand Renaissance (formerly Millennium) Dam in Ethiopia, which aims to produce up to 6 GW. These very large schemes have a long gestation period, often involving as they do political controversy (e.g. with downstream states claiming that resources are being taken from them, or communities being displaced) as well as huge expense and engineering works, but they are the largest scale of renewable energy projects.

It is interesting that a number of the countries developing geothermal power see it as a way of deliberately diversifying from reliance on large hydro schemes – for example Kenya, which has the most developed geothermal sector in Africa, Eritrea and Ethiopia, which has an estimated 5 GW of geothermal potential. In areas without geothermal resource, small hydro is commonly seen as a good option, particularly, at the smallest scale, in the context of rural electrification.

Conclusions

This has been a brief survey of a large subject, but a number of points stand out:

- Africa as a whole and many of the countries (as well as wider regions) within it have an abundance and variety of resources for generating power, including many low carbon ones.
- The NDCs adopted by most African countries show a determination on the part of their governments to develop sustainable power solutions.
- Whilst many will need financial assistance to achieve their targets in this respect, in many cases developing new renewable generating capacity, for example, makes economic sense.
- There has been a lot of international attention paid to the big auction-based tender processes for new renewable generating capacity in South Africa and Morocco.
- These have indeed been considerable achievements, but their contribution to the total generating mix is still small, and they have focused on intermittent technologies which may need to be balanced with more despatchable generation, or storage.
- At the smaller level, it is relatively easy to see how to do this with hybrid mini-grids.
- At the bigger level, you are more likely to need pumped hydro (and if you have the geography for this it may be simpler to build large-scale hydro in the first place) or CAES – or to have to build some large-scale gas-fired plant.
- In terms of their ability to be deployed cost-effectively in a wide variety of locations and on a wide variety of scales, solar, small hydro and some biomass technologies appear to be among the best bets for broadening access to electricity with renewable sources.
- Diesel is likely to be an indispensable partner to solar for some time in many off-grid locations, but there is also the potential to switch to CNG or LNG.



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Table 1: Grid connected power production in Africa

Total and six largest power producing countries (2014)

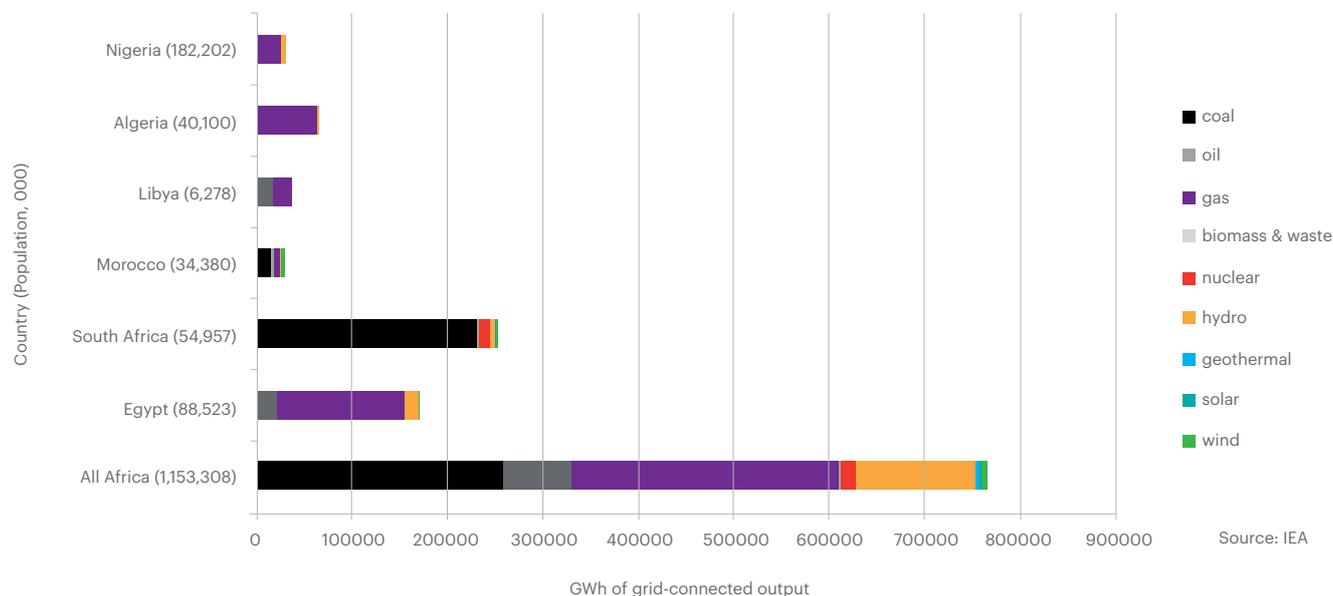


Table 2: Grid-connected power production in Africa

Selected mid-ranking and smaller power producing countries (2014)

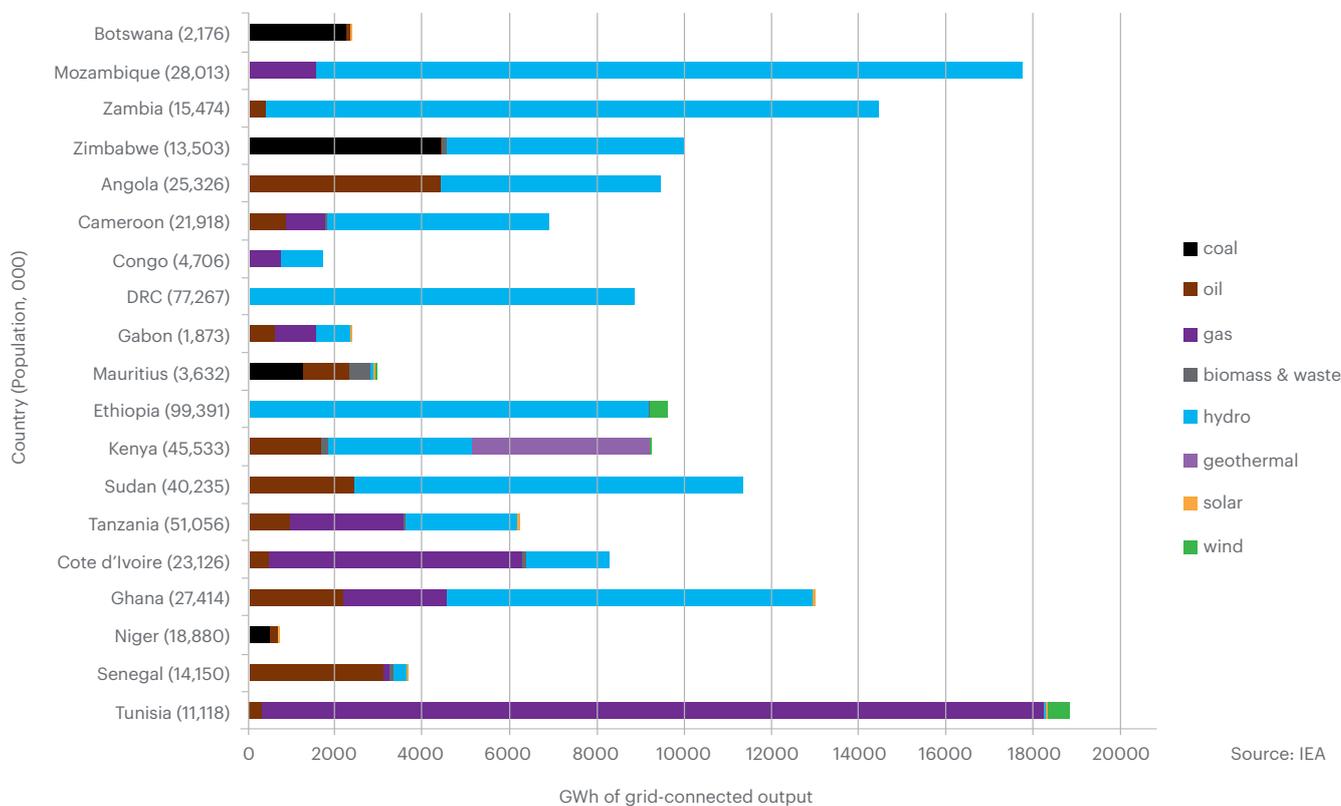


Table 3: Principal energy-related commitments in African countries' INDCs / NDCs¹

Country	Electricity access (2013, percentage of population)	Points to note from (I)NDC
Algeria*	99	Reduce energy consumption by 9 percent by 2030. Convert 1 million LDVs and 20,000 buses to LPG. RES make up to 27 percent of power generation. Reduce gas flaring below 1 percent. Massive solar and significant geothermal potential. Separately targeting 7-22 percent GHG emissions reduction by 2030 against business as usual scenario (BAU) and 22GW RES power by 2030.
Angola	30	Lists 8,491 MW of RES projects under evaluation (over 60 individual projects): from 2 MW solar to 2,172 MW hydro. Current installed capacity 2,388 MW.
Benin	31	400 MW gas-fired, 396.6 MW hydro, 54.2 MW solar.
Botswana*	66	Very short and unspecific NDC. Estimates US\$ 18.4 billion required to meet GHG emissions target. Separately targeting 15 percent GHG emissions reduction by 2030 against 2010 base.
Burkina Faso*	18.5	Small hydro, solar, recovery of methane from waste, bioenergy (including biodiesel), efficiency in electric lighting (total cost US\$756 million).
Burundi	5	3 new hydro plants. Separately targeting 40 MW of solar and 10MW of wind power in addition to 212 MW of hydro.
Cabo Verde	93.6	Rising RES power targets 2016 (35 percent), 2020 (50 percent), 2025 (100 percent). Smart grids, energy storage, renewable micro-grids, solar home systems and solar water heaters.
Cameroon*	55	Agricultural emissions dominate GHG emissions profile. Use of agricultural waste to produce bio energy. Connect three transmission grids within the country (currently not interconnected); more cross-border trading of power; cogeneration. Large towns to have target of 70 percent methane recovery from waste. Small hydro, solar, biomass. RES to make up 25 percent by 2030. Reduce GHG emissions by 33 percent against reference scenario by 2035.
Central African Republic	3	Solar PV; rehabilitation of hydro plants; rural electrification.
Chad	4	50 GWh/year of wind power; national 225kV line to all cities; cross country power grid; increase solar to 200 GWh/year; interconnect to Cameroon to access 500 GWh of hydro. Targeting unconditional / conditional GHG emissions reductions of 18.2 percent/71 percent by 2030.
Comoros*	69	Mitigation actions in energy sector: 64 percent of impact in emissions reductions to 2020 to be achieved through reducing distribution losses (as opposed to rehabilitating existing power stations or increasing solar / hydro use). Increase in RES generating capacity from 3 percent in 2010 to 43 percent in 2030.
DRC	9	Agriculture dominates. Hydro main renewable identified.
Congo	42	Eliminate flaring. Targeting 85 percent hydro, 15 percent gas power by 2025, with solar electrification of villages.
Cote d'Ivoire*	26	42 percent power from RES by 2030, 32 percent from gas.
Djibouti*	50	Interconnections with Ethiopia; 60 MW wind turbines in 2025; 250 MW solar in 2025; exploit geothermal by 2030; improve energy efficiency of public buildings (and fit rooftop solar).
Egypt	99.6	Possible national / regional emissions trading market. Improve efficiency of fossil fuel plant (replace, co-fire biomass, CHP). More renewables. New nuclear. Reform fossil fuel subsidies. Separately targeting by 2020 2.2GW hydro, 220 MW solar PV (700 MW by 2027), and 7.2 GW wind.
Equatorial Guinea	66	One big hydro scheme to electrify all the mainland. Rehabilitation of existing hydro / wind / solar / marine energy to power islands.
Eritrea	32	Cogeneration, waste heat recovery at cement plant; efficient wood stoves (single biggest reduction in GHG); biodiesel from municipal solid waste; LPG stoves replacing wood; geothermal; onshore wind; solar; energy efficiency. Unconditional GHG emissions reduction of 39.6 percent on 2010 levels by 2030. Conditional 80.6 percent by 2030.

Country	Electricity access (2013, percentage of population)	Points to note from (I)NDC
Ethiopia	24	More wind, solar and geothermal so as to decrease reliance on drought-vulnerable hydro.
Gabon*	89	More than double hydro capacity by 2025.
Gambia*	36	Upgrade grid from 33 to 132kV to reduce losses; more solar, wind and hydro power; capture and flare landfill methane.
Ghana*	72	Several hundred MW of new utility scale wind, solar and hydro capacity. 55 solar mini-grids. LPG up from 5 percent to 50 percent of peri-urban and rural households. Replace light crude oil with gas in power plants.
Guinea*	26	Over 1 GW of new hydro; additional 47 MW wind and solar capacity over 3 MW 2011 baseline; modern biofuels to replace traditional. Boost energy efficiency and RES consumption of mining sector.
Guinea-Bissau	21	Targeting 80% renewable energy and electricity access by 2030.
Kenya	20	Expansion in geothermal, solar and wind. Reduce GHG emissions by 30 percent by 2030 against BAU.
Lesotho	28	20 percent improved energy efficiency by 2020. Electricity coverage to 35 percent households in 2015, 50 percent 2020, 80 percent 2030; additional 40 MW solar, 35 MW from wind and 125 MW from hydro by 2025.
Liberia	10	Promote private investment in renewables; rehabilitate / expand hydro facilities; 30 MW biomass by 2030; capture and use methane from landfill.
Libya	99.8	No NDC.
Madagascar*	15	Hydro and solar from 35 percent to 79 percent by 2030. Overhaul existing plant and networks, rural electrification, improve energy efficiency.
Malawi*	9	20,000 solar PV systems. Additional 800 MW hydro, increase mass transport passengers by 30 percent. Increase biodiesel and bioethanol production.
Mali*	26	"will remain a carbon sink until 2030". Scaling up Renewable Energy plan (with AfDB funding) includes mini/micro hydro and hybrid mini grids for villages. Two larger hydro projects (Manantali and Kénié).
Mauritania	28	Rural electrification.
Mauritius*	100	Expand solar, wind and biomass; modernise and smarten grid; gradual shift towards LNG and other clean technologies. 30 percent GHG emissions reduction by 2030 against BAU.
Morocco*	99	52 percent of power from RES by 2030; reduce energy consumption by 15 percent by 2030. Increase use of gas (LNG) – additional 3900 MW of CCGT using imported gas.
Mozambique	39	Policies, plans and strategies for RES, biofuels, natural gas. Recovery of methane from landfill.
Namibia*	32	Increase RES share of power from 33 percent in 2010 to 70 percent in 2030 (hydro, wind, solar, biomass); reduce energy consumption by 10 percent in 2030; mass transport system in Windhoek to reduce cars / taxis by 40 percent. GHG emissions reduction of 89 percent by 2030 against BAU.
Niger*	14	Consumption to triple to 2030. Energy efficiency, reduction of network losses. Increase RES from 4 to 250 MW by 2030 (130 MW of which is one large hydro plant, 20 MW of which would be wind; also solar PV and CSP). Nuclear and gas.
Nigeria	64	End gas flaring by 2030. 13 GW of off-grid solar PV. Efficient gas generators and power grid. Car to bus shift. GHG emissions reduction of 25 percent unconditional, 40 percent conditional by 2030 as against 2010-2014.
Rwanda*	21	More hydro. Up to 100 solar PV rural mini-grids. Zero-carbon green industrial parks. Landfill gas utilisation. Sustainable charcoal. Energy efficiency in e.g. agro-processing. Vehicle efficiency

Country	Electricity access (2013, percentage of population)	Points to note from (I)NDC
Sao Tome and Principe*	59	26 MW of solar and hydro would introduce 47 percent of RES into power mix.
Senegal	55	Conditional options by 2025 include 200 MW each of wind and solar PV; 50 MW each of biomass and CSP; an extra 200 GWh of hydro; replacing a 320 MW coal-fired plant with two 200 MW CCGT plants running on LNG; 5,000 villages electrified; 49,000 domestic AD units; substitute 40 percent of coal used in industrial combustion units with gas.
Seychelles*	99	Increase wind and solar power. Target of 80 percent solar water heating by 2035; target of 50 percent energy savings on fans and AC in households by 2035.
Sierra Leone*	5	Focus on biofuel, solar, mini-hydro, LPG.
Somalia*	15	Rehabilitate Fanoole dam. Sustainable charcoal production. Upscaling solar.
South Africa*	85	Fairly brief and unspecific NDC. Carbon tax among the policy instruments mentioned. Targeting 17.8 GW RES by 2030. GHG emissions in range 398-614 Mt CO ₂ eq by 2025-2030.
South Sudan	1	Increase efficiency of biomass & power use. Exploit high wind & solar potential. New / improved hydro.
Sudan	35	1000 MW wind, 1000 MW solar PV, 100 MW solar CSP, 80 MW energy from waste, 80 MW biomass, 300 MW geothermal, 50 MW small hydro, 1.1 million solar home systems (total cost US\$4.3 billion)
Swaziland*	27	Double RES share in the energy mix by 2030 as against 2010 levels. Small-scale decentralised renewables in rural areas. Grid-connected energy from waste, solar, bagasse and wood chips.
Tanzania	24	Expand use of natural gas and renewables; reduce GHG emissions by 10-20% by 2030 against BAU.
Togo	27	Mostly not focused on electricity, but more use of solar envisaged.
Tunisia	100	RES share of power to increase from 4 percent (2015) to 14 percent in 2020 and 30 percent in 2030. Aiming to reduce carbon intensity by 40 percent from 2010 by 2030.
Uganda*	15	Generally promoting renewables and improving efficiency. RES from 729 MW in 2013 to 3200 MW in 2030.
Zambia	26	Biodiesel to replace diesel; biomass instead of coal; off-grid electrification (wind and solar). Grid extension.
Zimbabwe	37	Increased hydro; coal-bed methane power; solar powered off-grids.

1 *Denotes a country which has submitted an NDC.

Unlocking financing for independent power projects in Nigeria

By Dominic Spacie, Omosuyi Fred-Omojole

Nigeria exemplifies some of the challenges and opportunities of the African power sector in their starkest form. This makes it, at least from one point of view, a good case study for the application of traditional project finance techniques to African power projects. Although the focus of this article is on only one jurisdiction, and specifically on gas-fired plant, the underlying principles identified will be relevant to other markets and technologies as well.

There is nothing particularly novel about these principles from an international perspective, but it would make a significant difference to the power sector in Nigeria and elsewhere in Africa if they could be applied more consistently.

Recent trends, opportunities and challenges

As noted elsewhere, the deficiencies of Nigeria's power generation sector are significant. It is hoped that the current drive by the federal government of Nigeria (the Nigerian Government) to increase Nigeria's power generation capacity will have a significant impact on its economic and sociopolitical development. The Nigerian Government has taken some significant steps to liberalize, increase liquidity and attract investment into the power sector (such as implementing the Power Privatization Program,¹ direct funding² and entry into the Power Africa memorandum of understanding with the Government of the United States of America³). However, there is still a huge amount of work to be done by the Nigerian Government, the domestic private sector and international partners to develop Nigeria's power sector.

In addition to developing renewable power projects to diversify Nigeria's power generation mix, the development of greenfield gas-fired power generation projects by private developers, commonly referred to as independent power projects (IPPs), will significantly increase Nigeria's power generation capacity. However, developers of IPPs (IPP Developers) face a raft of challenges in developing successful IPPs. These challenges include:

- the high cost and extensive timeline involved in achieving an acceptable allocation of risks and rewards among stakeholders;
- the difficulty in raising commercial debt funding for project development activities, particularly following the recent tightening of credit to emerging market borrowers;
- obtaining uninterrupted access to feedstock gas for power generation and achieving a bankable offtake arrangement with Nigerian Bulk Electricity PLC (NBET);

1 The Power Privatization Program comprised: (a) the unbundling of the National Electric Power Authority, the vertically integrated state-owned entity, into: (i) six generation companies, (ii) 11 distribution companies and (iii) a transmission company; (b) the sale by the Nigerian Government (through the Bureau of Public Enterprise) of its majority interests in the power generation and distribution companies to private sector participants, primarily comprised of Nigerian investors and their international technical partners; and (c) the Nigerian Government subcontracting the management of the national grid operator, the Transmission Company of Nigeria, to Manitoba Hydro International.

2 For example, the CBN's disbursement of the Nigerian Electricity Market Stabilization Facility.

3 Power Africa has played a key role in increasing access to liquidity and credit enhancement products from US government agencies (such as OPIC and USAID) and increasing the levels of technical capacity in the domestic power sector.



- low regulated domestic electricity prices which do not reflect the costs of power generation; and
- navigating a labyrinth of political, legal and regulatory frameworks in order to successfully develop and operate IPPs.

In this article we focus on IPPs and highlight:

- some of the milestones that IPP Developers will need to achieve and associated challenges to be overcome in order to successfully develop IPPs; and
- some of the key risks which lenders who finance IPPs (the Lenders) will expect to see managed to a satisfactory level in order to develop a bankable IPP that can be financed on a project finance basis.

Developing power projects: avoiding the common pitfalls

Lenders will typically expect IPP Developers to have completed a number of project development milestones prior to the debt financing phase of the IPP, which include:

Formalizing relationships between project development partners

Developing an IPP in Nigeria, as in many emerging markets, is time-consuming,⁴ capital-intensive and sensitive to in-country political, economic, social and regulatory risks. Consequently, IPPs are usually undertaken by a number of co-venturing developers who agree to pool resources (including funding, assets, know-how and expertise) and share the risks and rewards associated with the development and operation of the IPP.

The development partners will usually enter into commercial agreements (e.g., a joint development agreement, a shareholders agreement and/or a development and cooperation agreement) in order to formalize their relationship and document their respective rights and obligations during the development and/or operation phases of the IPP.

4

It is reported that the lead time on the Azura-Edo IPP, the first fully-privately-financed greenfield IPP in Nigeria, was six years from the start of the project to financial close – Azura Report titled: “High Voltage – A Development Guide to the 459MW Azura-Edo IPP”.



Engagement with stakeholders

IPP Developers' engagement with a project's other key stakeholders – the local community, regulators and any adjoining landowners (together, the Stakeholders) – is crucial for disseminating project-related information, identifying and addressing concerns and obtaining Stakeholders' support for the IPP. Engagement with Stakeholders may help to address legal and other challenges to the IPP which might otherwise arise at a later stage. Development of a well-considered action plan early in the project development phase – one which identifies the Stakeholders and their representatives and which sets out formal procedures for engaging with these Stakeholders – can be an effective tool for engaging with Stakeholders.

Land procurement and perfecting proprietary rights

IPP Developers will need to ensure that the company incorporated to own the project assets and enter into project documents on their behalf (the Project Company) has obtained a proprietary interest in the project site land as evidenced through a certificate of ownership.

Alternatively, the Project Company may obtain a long-term lease of the project site land under a lease agreement with satisfactory terms, particularly robust termination provisions. Lenders will typically expect the Project Company to (i) exercise its proprietary rights to the project site land free of adverse rights and (ii) create security over its proprietary rights to the project site land in favor of the Lenders.

Satisfying social and environmental requirements

The majority of international financial institutions have adopted the Equator Principles, a risk management framework for determining, assessing and managing environmental and social risk of projects, which is based on the International Finance Corporation's standards on social and environmental sustainability.

As a precondition to obtaining project financing for an IPP, the Project Company will be required to satisfy the Lenders of social and environmental requirements. These requirements typically include:

- completion of feasibility studies to ascertain the impact of the project on the community and environment; and
- the Lenders' technical consultants' approval of the remedial action plans, which may include compensation, resettlement and decommissioning arrangements.

Obtaining regulatory permits

The IPP Developers and/or the Project Company will be required to obtain certain permits, authorizations, approvals and/or waivers from the relevant Nigerian regulators in order to validly construct and/or operate the IPP (together, Permits). The scope of applicable Permits for an IPP is wide ranging and will typically include Permits relating to the following activities: construction of the power plant, power generation, environmental, health and safety procedures, equipment importation, obtaining insurance, reinsurance and foreign exchange.

Experience has demonstrated the need for an IPP Developer/Project Company to:

- engage its transactional advisors to conduct extensive due diligence on the IPP in order to ascertain the exact scope of requisite Permits;
- develop an action plan with stipulated procedure, timelines and allocation of responsibility for obtaining the Permits;
- anticipate that the Lenders will insist that all relevant Permits are obtained as conditions precedent to drawdown of their loans;
- consider the additional risks associated with obtaining the Permits, such as (i) delays to the transaction timetable where there is no deadline by which processing of a Permit must be completed and (ii) increased transaction costs resulting from the payment of applicable fees for obtaining or extending a Permit;
- make conservative assumptions on the requirements, process and timeline for obtaining the Permits when developing the transaction timetable;
- engage with the relevant regulatory authorities at an early stage in the project development phase;
- pre-agree the process, scope and consequence of extensions to any applicable “longstop dates” for the completion of the transaction due to delays in obtaining the Permits; or
- mitigate the risks related to cancellation of Permits, and arbitrary delays in granting or extending Permits through obtaining political risk insurance and/or by including such events within the scope of “political force majeure” provisions in the project and finance documents.

Sourcing funding

During the Power Privatisation Program, Nigerian banks provided more than 80 percent of the acquisition debt provided to the purchasers of power generation and distribution assets. These acquisition facilities, the majority of which are still outstanding and have needed further restructuring, have resulted in liquidity constraints in the domestic debt market. The Central Bank of Nigeria (the CBN) has imposed restrictions on Nigerian banks’ level of exposure to this industry sector by reference to a percentage of their loan portfolio. This CBN regulation and the recent unavailability of foreign exchange in the Nigerian financial market (linked in part to low global oil prices and Nigeria’s recent monetary policies in response to reduced oil export revenue) have further exacerbated illiquidity in the domestic debt market.

Consequently, IPP Developers will need to source funding for IPPs from both the domestic debt market and international Lenders – not only commercial banks, but also export credit agencies and development finance institutions. Funding from international Lenders will typically be structured on a limited-recourse or non-recourse basis and, therefore, involve a rigorous bankability assessment and risk allocation process, a summary of which is set out below.

Lenders' bankability assessment and risk allocation

The majority of an IPP's capital costs will be financed by the Lenders (alongside a smaller portion funded by the IPP Developers' equity investment).⁵ Consequently, satisfaction of the Lenders' bankability requirements will be a critical precondition to funding the IPP on a limited-recourse or non-recourse basis and therefore a key consideration for the IPP Developers. Reference to "Lenders' bankability requirement" means the Lenders' expectation that material project risks relating to the IPP have been assessed and allocated satisfactorily to a project counterparty that is able to bear such a risk or, if retained by the IPP, is mitigated to the satisfaction of the Lenders.

The bankability assessment will be largely project-specific and will take into account a number of additional factors, such as the prevailing market practice in the relevant debt market, the nature and location of the IPP, the host country and the identity of the project participants. It is, however, typical for Lenders to expect the IPP Developer to have mitigated the following risks through the project documents and other ancillary commercial arrangements:

Mitigating fuel supply and/or transportation risk

The IPP's ability to generate sufficient revenue from the sale of power to cover its costs and repay its debt will depend upon its access to a secure source of feedstock gas delivered to the IPP. Accordingly, the Lenders (and their transactional advisors) will need to be satisfied that:

- the Project Company will enter into a long-term gas supply agreement (a Gas Supply Agreement) with a creditworthy gas supplier (the Gas Supplier), which is typically an upstream producer, or indirectly through the Gas Aggregation Company of Nigeria;
- the Gas Supply Agreement includes a firm feedstock gas throughput obligation to underpin the Project Company's ability to generate sufficient power to discharge its power generation delivery obligation to NBET under the power purchase agreement entered into between the Project Company and NBET (the PPA); and
- the Project Company has entered into a satisfactory gas transportation arrangement that provides sufficient pipeline capacity and/or adequate contractual protection (e.g., through business interruption insurance) against the heightened risk of disruption to gas supply, for example resulting from frequent sabotage of onshore oil and gas pipelines and associated infrastructure in the Niger Delta region.⁶

In return, the Gas Supplier is likely to expect the Project Company to provide credit support to back-stop its payment obligations under the Gas Supply Agreement. This credit support may be provided in different forms, including a parent company guarantee from an IPP Developer or through a letter of credit (an LC), which may be structured as part of the financing to be provided by the Lenders (e.g., through an LC facility).

Mitigating the EPC Contractor's payment and/or performance risk

The IPP will not become operational or capable of generating revenue until it has been constructed and successfully commissioned for power generation. Consequently, the Lenders (and their transactional advisors) will expect:

- the Project Company to enter into a turnkey engineering, procurement and construction contract (the EPC Contract) with a creditworthy,

⁵ We have seen debt-to-equity ratios around the range of 70:30.

⁶ Additional fuel supply risk mitigants include: (i) for the Project company to secure alternative fuel supply arrangements on a contingency basis; or (ii) for the IPP to be developed to have dual fuel capabilities – for example, a power plant that is capable of using biofuel, diesel or heavy fuel oil for power generation in the event that gas feedstock is temporarily unavailable.



experienced and technically capable contractor (the EPC Contractor);

- the EPC Contract to include incentives and penalties (as applicable) to ensure that the construction of the IPP is completed on schedule, within budget and in line with a pre-agreed set of specifications;⁷
- the EPC Contractor to be under an obligation to pay liquidated damages for delays to the construction timetable or under-performance and provisions in the EPC Contract to ensure that any overall cap on the EPC Contractor's liabilities is at a satisfactory level;
- the EPC Contract to include explicit controls over assignment, transfer and/or subcontracting of the EPC Contractor's obligations, e.g. by making the completion of any of these processes subject to (i) the Project Company's prior approval or (ii) the assignee, transferee or subcontractor satisfying minimum financial, reputational and technical requirements; and
- the EPC Contractor to provide an acceptable form of credit enhancement in favor of the Project Company to back-stop its payment or performance obligations (including a parent company guarantee, a performance bond or an LC), particularly where the EPC Contractor does not have a credit rating.

Mitigating the Operator's payment and/or performance risk

Effective and uninterrupted operation of the IPP is clearly an essential precondition to the Project Company producing the power required to be sold to NBET under the PPA and for generating the revenues required to fund operating costs and debt service.

Accordingly, the Lenders (and their transactional advisors) will expect:

- the Project Company to have entered into a long-term operation and maintenance contract (the O&M Contract) with a creditworthy, experienced and technically capable operator (the Operator), which might be an affiliate of the Project Company or a third party;
- the Operator to be under an obligation to run the IPP based on pre-agreed key performance indicators that are in line with industry standards of performance for maximizing the processing capability of the IPP;
- an approved strategy and budget for procurement of spare parts and effecting scheduled maintenance, which is reflected in the financial model, the project accounts structure and finance documents;

- the scope of operation and maintenance services, fees and any applicable limitation of the Operator's liability to be in line with current market standards; and
- there to be explicit controls over assignment, transfer and/or subcontracting of the Operator's obligations, for example by making the completion of any of these processes subject to (i) the Project Company's prior approval or (ii) the assignee, transferee or subcontractor satisfying minimum financial, reputational and technical requirements.

Mitigating NBET's payment and/or performance risk

The PPA is the main source of revenue from which the Project Company will discharge its debt service obligations to the Lenders and payment obligations to the Gas Supplier under the Gas Supply Agreement. The scope of NBET's credit risk as offtaker under PPAs is exacerbated given that (i) it is a special purpose vehicle with limited trading history and (ii) it is directly exposed to the credit and performance risk of power distribution companies (in their capacity as power purchasers under vesting contracts). Lenders will therefore view the stability and predictability of the revenue stream under the PPA and credit enhancement of NBET as critical to the project's bankability assessment.

In particular, the Lenders (and their transactional advisors) will expect the PPA to satisfy the following requirements:

- the tenor of the PPA must exceed the term of the debt facility provided by the Lenders;
- the PPA should provide a robust tariff structure

that includes payment of capacity charges for dependable capacity and energy charges for electrical energy delivered, with the capacity component being sized to cover scheduled debt service;

- NBET must be sufficiently capitalized and its payment obligations⁸ back-stopped by the Nigerian Government through acceptable forms of credit enhancement products, such as: (i) the provision of letters of credit from acceptable financial institutions or back-stopped by a partial risk guarantee;⁹ (ii) letters of support from the Nigerian Government;¹⁰ (iii) guarantees from the Nigerian Government in order to maximise the credit rating of any debt instruments issued by NBET; (iv) cash escrow accounts;¹¹ and/or (v) a put and call option agreement which enables the IPP Developer to sell the IPP (or its shares in the Project Company) to the Nigerian Government at a predetermined price, which will be sufficient to cover the outstanding debt;¹²
- given the transitional nature of NBET,¹³ there is a need for PPAs to address the process, risk exposure and protection related to NBET's transfer of its rights and obligations under PPAs to a distribution company, particularly where such a transfer results in a termination of any credit enhancement provided by the Nigerian Government in relation to NBET's obligations under the PPA; and
- the scope of the "force majeure" provisions in the PPA will need to be consistent with the scope of the "force majeure" provisions across the suite of project documents, particularly the Gas Supply Agreement, EPC Contract and O&M Contract.

7 This will enable the IPP to satisfactorily complete the commissioning testing with minimal snagging requirements.

8 For example, in the event that NBET exercises its early termination rights under the PPA, which is likely to trigger NBET's compensation obligations in favor of the Project Company.

9 For example, provided by a multilateral financial institution, such as The World Bank or its affiliated entities.

10 Depending on the precise drafting, the letter of support might be construed as giving soft comfort to the Project Company in respect of the IPP, which may be insufficient to give rise to binding obligations on the Nigerian Government.

11 The use of cash as a credit enhancement tool is likely to be a more expensive option from NBET's perspective given the prevailing liquidity constraint in the Nigerian power sector and the negative cost of carry associated with depositing cash in an escrow account.

12 We understand that, on the Azura-Edo IPP financing, the project company mitigated the risk of NBET's termination of the PPA by obtaining a "put and call option" from NBET and the Nigerian Ministry of Finance. Azura Report titled: "High Voltage – A Development Guide to the 459MW Azura-Edo IPP".

13 The Electric Power Sector Reform Act 2005 anticipates that NBET will fulfil its intermediary bulk trading role (comprising (i) purchase of power from power producers under PPAs and (ii) resale of power to distribution companies under vesting contracts) until the power distribution companies have demonstrated their commercial viability to purchase power directly from the power producers.

Mitigating project interface risk

Risks related to the transition of the project from the construction phase to the operation phase can be exacerbated if (as is often the case) the EPC Contractor is a separate entity from the Operator. It will be important to ensure that the works completed under the EPC Contract are acceptable to the Operator through its participation in the commissioning tests, thereby avoiding claims by the Operator that the IPP is incapable of proper performance or requires remedial works.

Separately, the commissioning process under the EPC Contract will need to be harmonized with the provisions of the PPA and O&M Agreement in order to ensure that there is a back-to-back position across the suite of project documents. Similarly, a delay to the commissioning of the IPP that results in payment of delay-related liquidated damages under the PPA should give rise to a corresponding payment of delay-related liquidated damages under the EPC Contract.

Lastly, the IPP Developers will need to identify whether any of the Project Company's counterparties (a Project Party) is responsible for delivering any associated infrastructure for the construction or operation of the IPP (such as connecting the power plant to gas supply infrastructure and/or the grid network) and include this additional timeline in the project timetable. In any event, the associated infrastructure will need to have been put in place before the IPP is commissioned to ensure that there are no delays to the commencement of the IPP's operational (revenue-generating) phase.

Mitigating currency risk

It is typical for the majority of loan facilities for IPPs to be denominated in a foreign currency (typically, US dollars) to reflect the currency of material project costs (particularly under the EPC Contract) and given the short tenor available and high cost of obtaining Naira denominated facilities. The majority of PPAs are structured on the basis that payments due from NBET to the power producer are denominated in Nigerian Naira. The use of Nigerian Naira denominated revenues to service a foreign currency denominated loan facility clearly gives rise to a currency mismatch and several associated risks. These risks include (i) restrictions on convertibility of Nigerian Naira to a foreign currency, (ii) limitations on transfer of foreign currency out of Nigeria and (iii) devaluation of the Nigerian Naira against a foreign currency.

In order to mitigate repatriation risk, the Project Company will need to obtain a certificate of importation, which serves as documentary evidence that the Project Company has brought foreign currency into Nigeria (through debt, equity or otherwise) for the purpose of developing, financing or operating the IPP and permits the Project Company to repatriate revenues from the IPP towards debt service in favor of the Lenders and/or distributions to the IPP Developers.



In addition, the Project Company may mitigate currency risk by obtaining currency hedging products or political risk insurance or utilizing offshore collection accounts.

Mitigating Project Party's performance risk

In addition to Lenders receiving assurance of the financial standing, experience and technical capability of a Project Party, the Lenders will typically expect to be granted a direct contractual relationship with the Project Party through their entry into a direct agreement with the Project Company and the relevant Project Party (a Direct Agreement).

During negotiations of a project document between the Project Company and a Project Party (even where financing is not yet contemplated), it is recommended that the project document (i) includes a form of the Direct Agreement to be entered into between the Project Company, the Relevant Project Party and the Lenders or (ii) recognizes that the Project Company, the Relevant Project Party and the Lenders will enter into a Direct Agreement.

Marshaling project revenue

Given the limited recourse nature of project financing structures, the Lenders will seek to regulate the collection and use of the IPP's revenues as follows:

- through the use of several designated accounts (which may include (i) revenue accounts, (ii)

operating accounts, (iii) debt service accounts, (iv) debt service and maintenance reserve accounts and (v) distribution accounts, together the Project Accounts) that are secured in favor of the Lenders;

- by including a cashflow waterfall in a finance document (for example, account provisions in the facility agreement or a stand-alone accounts agreement) that stipulates a synchronized order of priority for permitted withdrawals from the Project Accounts (typically, allowing payment of operating expenses, followed by debt service, topping up maintenance and reserve accounts before permitting distributions to the IPP Developers, subject to the satisfaction of any required distribution controls); and
- imposing covenants on the Project Company only to make withdrawals from the Project Accounts in line with the cashflow waterfall.

Conclusion—where there's political will, there's a way

The successful closing of the financing for the Azura-Edo IPP demonstrates that, under the right circumstances, well-structured IPPs in Nigeria will be able to source a combination of international and domestic financing and achieve financial close. In order to achieve these objectives, it is imperative that (i) IPP Developers and Lenders remain committed to finding innovative solutions to the commercial, fiscal

and legal challenges that may arise on the path to developing and financing IPPs and (ii) the Nigerian Government continues to demonstrate the political will to provide a suitable political, fiscal and regulatory environment that attracts and increases the level of private sector participation and investment in Nigeria's power sector.

In particular, to achieve the Nigerian Government's increased conventional power generation targets, there is a general consensus that the Nigerian Government will need to:

- ensure fiscal stability, cost reflectivity and transparency of the electricity pricing structure that supports a level of economic returns to IPP Developers without compromising affordability of power supply to final consumers;
- secure a reliable supply of gas from upstream and midstream activities and facilitate investment in power transmission and distribution infrastructure to avoid a scenario where generated power becomes a stranded asset;

- improve liquidity and continued provision of credit enhancement of NBET to preserve the bankability of PPAs;
- support distribution companies in developing a robust system of metering, billing and collection;
- implement investment-friendly market reforms in order to attract private investment; and
- reduce system inefficiencies across the power value chain whilst reducing bureaucracy within the relevant governmental agencies.

Finally, it has been reported that the Nigerian Government is currently in consultation with stakeholders¹⁴ in respect of the proposed issuance of green bonds in Nigeria in 2017. These green bonds¹⁵ will be used to fund a pipeline of eligible renewable energy projects in Nigeria, which will (i) facilitate the Nigerian Government's implementation of the Paris Agreement on climate change and (ii) provide additional liquidity into the Nigerian power sector by expanding the funding sources for power projects to attract investment from pension funds, asset managers and other institutional investors.



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¹⁴ Stakeholders include: the Ministry of Environment; the Ministry of Finance; the Ministry of Budget and National Planning; the Ministry of Trade and Investment; the Nigerian Stock Exchange; the Debt Management Office; the CBN; the Securities and Exchange Commission; several financial institutions and other private sector representatives.

¹⁵ Green bonds are a specific sub-set of bond instruments, the proceeds of which are used to finance the construction and operation of renewable energy projects that satisfy energy efficiency and environmental benefit parameters.



Reform from the bottom up: making African power markets work better

By Adam Brown



In this final article, we look at two recent trends: off-grid solar and micro-grids. Alongside a more rigorous approach to project finance of larger generation projects (as discussed in the previous article) these could make a big difference to the African power sector. They could allow the continent's ample energy resources to be harnessed more effectively to address the significant power gaps that exist in so many African countries, and improve the environmental performance of African power generation.

Grass roots solar

Over the last few years, a number of companies in Africa have developed a new business model for access to electricity. They supply customers with standalone solar-powered devices which the customer pays for by instalments. If a payment is missed, the device is automatically disabled until the customer makes up the shortfall in payments. The factors that make this kind of arrangement possible are:

- the availability of cheap and reliable standalone solar appliances which can fulfil the functions for which customers currently use other forms of energy that are either more expensive (e.g. kerosene for lighting) or time-consuming to acquire (e.g. wood for cooking, or electricity provided by a third party, located some distance away, for phone charging);
- widespread subscription to mobile phone networks and the user-friendly forms of remote payment service that they can provide or facilitate for customers who may find it difficult to access conventional banking or credit services; and
- the development of business models that can combine these two technologies into a package that can be successfully sold to consumers and that can be administered efficiently in a way that is financially sustainable.

A number of companies have managed successfully to combine these elements:

- **M-KOPA** is based in Kenya. It sells its customers a system consisting of a solar panel, two LED bulbs, an LED flashlight, a rechargeable radio, a battery (with a four-year warranty), adaptors for charging a mobile phone, and a control box. The price is US\$200, with US\$35 payable up front and then 45 cents a day for a year – after which the customer owns the system. There is a SIM card in the control box that will only activate the battery if outstanding payments have been made. 93 percent of customers make all their payments, yet 80 percent of them live on less than US\$2 a day. Over a four-year period, typical Kenyan M-KOPA customers could save US\$750 on what it would otherwise cost them to buy kerosene for lighting and pay to charge their mobile phone (estimated at 75 cents a day).
- **Off Grid Electric** in Tanzania and Rwanda has a similar approach. In the words of its CEO, Xavier Helgesen: "We simply redirect funds that were already paying for kerosene and batteries to a solar lease payment."

Customers are provided with a 50 W solar panel and a lithium-ion battery. The initial set-up charge is US\$6, with a further US\$6 payable monthly, again based on mobile phone payments: this is a lease, rather than a rent-to-own model. Upgrades include appliances that can enable rural households to supplement their incomes, such as phone charging strips or hair clippers. The company recently announced a joint venture with EDF to deliver power to 2 million people in rural and peri-urban areas of Ivory Coast by 2020.

Of course, there are also other projects and initiatives that aim to deliver power to those currently without access to electricity. Some of these are government sponsored or financed, or help to facilitate government procurement of solar power for communities, such as [Akon Lighting Africa](#). There are also other companies providing a similar service to M-KOPA and Off Grid Electric but for larger systems (for a fuller survey and much useful analysis, see Bloomberg's [Off-grid solar market trends report 2016](#)). What is notable about these two companies and some of those selling larger systems is that they are private enterprises, selling a consumer product directly to the end consumers.

This is the world of solar home systems and of the mobile phone based payment services that have the potential to act as surrogate banks for millions of Africans. African mobile phone companies have added 316 million subscribers since 2000 and are expected to grow their customer base by another 79 percent by 2020. Already, over 180 million customers have "mobile wallets" as part of their service (three times as many as in the US).

The mobile payment app [M-Pesa](#) accounts for 6.59 percent of the clearing value in the Kenyan banking system, but 66.56 percent of the volume of transactions passing through it. For whatever reason, many customers appear to trust mobile operators more than they do banks. Their mobile phone bill payment records become a form of credit history which can be useful in seeking other forms of finance. It is clear that enabling those without access to electricity to use electrical appliances for the first time can have a transformative effect on their economic opportunities.

Bloomberg estimates that 89 million people in the developing world have at least one solar lighting product; that unit sales will see a compound annual growth rate of 34 percent over the next five years; that consumers of the smallest-scale solar products in Africa save on average US\$3.15 for every US\$1 that they spend on them; and that the market for off-grid phone charging alone runs to several billion US dollars.

Solar home systems are currently about providing power for an individual household. It is one of the features of the extremely scalable nature of solar that it is almost uniquely well adapted to providing power in this way. All you need is a roof – and typically the areas that are not served well by existing power distribution networks are not ones where one finds large apartment



blocks or other patterns of occupation where the lack of sufficient roof space would be a problem.

Companies like M-KOPA and Off Grid Electric are using technology to make electricity both accessible and affordable to those who would be unlikely to access or to afford it. Their approach is revolutionary, particularly in the African context. They are selling access to electricity without many of the problems faced by most African electric utilities: without having to invest in ageing fixed network infrastructure; without having to worry about power being stolen by people illegally tapping in to that infrastructure; without having to read a meter or issue a bill; without having to worry about whether that bill will be paid (having supplied the electricity on credit, and having no way to reclaim it); and without having to deal with customer complaints about power paid for but not supplied (a common problem with the prepayment arrangements of some African networks).

At the same time, the nature of the product being sold has changed: it is no longer about access to a networked service with a physical connection to centralized generation. A parallel has been drawn with the evolution of mobile telephony in Africa, where much of the continent seems to have “skipped” the phase of fixed line communications and gone “straight to mobile”.

How far can one push this parallel? Some would take the view that mobile phones are superior to fixed

lines, so that missing out on the fixed line stage is no disadvantage. There is also a view that we can and/or should aspire to a state where a large proportion at least of domestic demand for electricity is capable of being satisfied by what individual households can generate from e.g. their own rooftop solar PV. But is a future in which each household is an energy island necessarily progress? Are there no benefits in being connected to a network of other consumers and producers of power?

In countries with universal grid access, we tend to ask whether the rise of “prosumerism”, where households generate and consume their own power, will lead consumers – perhaps, typically, more affluent consumers – to disconnect from the grid, leaving the costs of funding the public distribution and transmission networks to fall on those consumers who are not in a position to, or have not chosen to, equip themselves to produce their own (often generously subsidized renewable) power. In many African countries, the question is perhaps whether widespread take-up of solar home systems will erode the potential customer base for grid-distributed power, thereby entrenching the division between those parts of the country that are and those that are not, in conventional terms, “electrified.”

If a government has set itself a target of electrifying a certain proportion of homes or settlements currently unserved by the grid, how does it count a household that has a solar home system but



no grid connection? In this kind of context, what is better: a village where 70 percent of households have solar home systems but no grid connection, or extending the grid to serve a village where only 30 percent of households can afford the connection fee? (A [study by the World Bank](#) has found that the average cost of connecting to the grid as an individual household in many African countries is several times the monthly income of many households.) Then again, in many versions of the prosumerist future, even if households are no longer relying primarily on the grid to provide centrally generated power from some distance away, the local grid network would still provide neighbors with the possibility of trading their surplus power amongst themselves (automatically, using software such as [Blockchain](#)).

In short, the fixed line/mobile analogy breaks down at a certain point if one regards solar home systems as analogous to the mobile phone. Both fixed line and mobile subscribers are part of a network. If you only have a solar home system, you do not have the benefits of being physically connected to other consumers and generators in the electricity market in terms of additional resilience, the ability to use larger amounts of power than you can generate, or to monetize any power which you have generated that you cannot either use or store.

But the power sector equivalent of the mobile phone is not the solar home system. Arguably, the truly novel feature of the solar home system is to offer a completely different model for future energy suppliers: instead of selling kWh of energy, selling the goods that energy enables, such as light, heat (cost-effective solar cookers are already available) and cooling (see e.g. the freestanding systems being developed by [Solar Polar](#)).

The opportunity for Africa to go “straight to mobile” in the power sector perhaps lies elsewhere, in its ability to avoid the difficulties of a transition that many countries with universal grid access are struggling with: reversing a trend that began over a hundred years ago, as power stations began to be built on a large scale and to be located some way outside the centers of demand for electricity.

Starting in the early twentieth century, the pursuit of economies of scale in thermal (originally coal-fired, later also nuclear) or hydroelectric generation and/or the nationalization or national planning of the electricity industry led to a network with fewer and larger generating stations. Distribution networks, which had first been built to serve the customers of small generating plants in towns and cities, were designed around flows of power going “outwards” from large central generation stations connected to the transmission networks that fed into the distribution networks, not “inwards” from the customer end of the distribution network. In many parts of Europe, the current move towards patterns of generation which are inherently more “distributed”

or “decentralized”, so that their output is being fed in from the “wrong end” of the distribution networks, has been problematic in a variety of ways.

Yet the trend towards decentralized generation seems inexorable. The “mobile phone” opportunity for African countries is to shape the development of their often still relatively underdeveloped power networks around this trend. It is important to bear solar home systems in mind when thinking about network development, because this sector could start to grow very rapidly if, for example, large corporates seeking to leverage existing brands and/or distribution networks (such as drinks or telecoms companies) were to move into it. And with an inverter (to convert their DC output to AC) and a slightly more sophisticated form of meter (both of which could be provided by the supplier of their solar home system on similar terms to other equipment it supplies), those with solar home systems should be able to feed their surplus into these local networks.

Small can be beautiful: right-sizing the grid

Mini-grids, micro-grids, pico-grids: there are different names for and ways of classifying, at various different scales, the new kind of distribution networks that the IEA assumes will account for 40 percent of new electrification globally to 2030. We generally use the term micro-grids below for convenience.

As noted above, a traditional distribution network was usually conceived of purely as a means of distributing power that has been fed to it from the transmission network and generated by a power station that is connected to it. A large power station, connected to the transmission network, will not necessarily supply any of its power to customers located in the territory of the same distribution network operator where it is situated, because the transmission network is a national system. All micro-grids, on the other hand, by definition have some element of generating capacity integrated into them, primarily with a view to satisfying local demand.

The big division within the family of micro-grids is between interconnected micro-grids – those that are connected to another grid (micro- or traditional) – and isolated micro-grids: those that are not.

What is good about micro-grids? Sometimes, a micro-grid is the only economically sensible option. In the words of a 2011 Rwandan “Law Governing Electricity” (with emphasis added):

“The electricity market of Rwanda shall be a market based on free and equal access to the activities of electricity production, transmission and distribution. The electricity transmission and distribution activities shall be non-discriminatory. They are based on the tariffs approved and published by the regulatory agency. **However, transmission or distribution through the grid may be denied where such grid is of a low capacity or where granting it would cause prejudice to the existing grid users.**”

The classic example is a mining project at a location which is too remote or insecure to be connected to the traditional grid, and where the availability of renewable electricity generating resources is easily exploited. In an industry where energy can represent 20-40 percent of costs, anything that can reduce fuel costs is welcome. As noted elsewhere in this volume, the traditional generating source for such micro-grids, diesel, is now increasingly being augmented, or even potentially replaced, by a combination of renewable power (such as solar or wind) and battery storage. An example from Mauritania, where the Société Nationale Industrielle et Minière is the second-largest power producer in the country, is the 4.4 MW wind farm installed at Nouadhibou. This helps to power iron ore conveyors and crushers and run alongside 16 MW diesel generators: the use of the two generating plants is optimized through the application of Vergnet’s proprietary Hybrid Wizard® control system.

Another example of infrastructure that is often located far away from reliable sources of grid-connected power supply is telecom towers. In Africa, more than 200,000 of these are in places with either no grid connection or an unreliable connection. Yet many of these towers are not entirely isolated from towns or villages, and they have the potential to serve as “anchor customers” for a micro-grid. They may already be relying on a small diesel genset: African telecoms companies spend millions of US dollars each year on diesel to provide power for this kind of infrastructure.

These gensets could be enlarged and/or supplemented with, for example, some solar panels and a battery, and the surplus power used by other consumers – indeed (jumping ahead), given this and the link between mobile technology and payment, telecoms companies might be well placed to move into the electricity sector as micro-grid operators. Some other types of remote social infrastructure, such as schools, could also be used in a similar way to act as an anchor for a micro-grid.

As noted in an earlier article, it is not just remote rural locations that are often poorly served by existing distribution networks. When we talk about the phenomenally rapid growth in the population of African cities, a lot of that growth involves people moving from the countryside to the slums on the outskirts of existing cities, where some 65 percent of city-dwelling Africans live: places which often do not benefit much, if at all, from the traditional infrastructure-related advantages of living in a city. Legitimate access to grid-connected power is just one of the benefits of city-dwelling that tends to be in short supply here – although, as we have seen, in some African countries the lack of such power is by no means limited to the lowest urban socioeconomic groups.

Moreover, micro-grids don't just make sense when they are more or less the only option. Where traditional networks are not always reliable and lose more power than they should in the process of transmission and distribution, micro-grids can deliver improved security of supply and go naturally with renewables. They are by no means limited to remote locations. To take a rather different example, at the Clearwater Mall in the suburban setting of Roodeport near Johannesburg, the developer of the property installed 1.5 MW of solar panels on the roof and these now supply power to the retail units in the mall, whose consumption patterns closely match the panels' output.

So perhaps the true lesson from solar home systems is this:

- If you are an isolated household, it is more cost-effective to buy a solar kit (even to do so in instalments on what looks like a fairly high rate of interest, such as 20 percent) than to supply your energy needs without electricity. Whilst the per kWh price of power supplied over the public grid might in theory be cheaper, the connection costs make that, in practice, a prohibitively expensive option overall.
- For example, the obvious way to mitigate the high cost of securing a connection to the grid is to share a connection with neighbors, thereby reducing the connection charge paid by individual users. However, in many cases, those multiple users will then only be served by one meter, and receive one bill from the electricity utility between them. Because this bill records the usage of multiple households, the monthly consumption will tend to exceed the number of kWh below which any specially calculated "subsistence" tariff is payable. So

while sharing a connection makes the connection cheaper, it makes the power itself more costly.

- Something similar can be true at the level of a community. If it is remote from existing network infrastructure, by having its own network and source of generation it avoids the cost of building a link to the public grid (or, depending on the grid charging regime, it avoids that cost being imposed on the relevant utility company, which is probably already under-funded). Even if it is not so remote from existing network infrastructure, it may be able to provide itself with a more reliable source of power, and enable individual homes and businesses to save on their overall energy bills, by using a micro-grid.

There is no doubt that the equipment manufacturers see the opportunity, and are preparing to supply the market for micro-grids. Companies such as Caterpillar, ABB, Hitachi, Schneider Electric and Siemens are all active in this space. Some of those involved also have substantial captive finance arms which could help customers who are not able to pay the full costs of installation up front.

Look at it from another perspective: of course there are advantages in having all generators and consumers of power interconnected in a single grid structure, but, if a country's grid currently reaches less than half of the population (as is not uncommon in Africa), what is the best way to achieve 100 percent coverage? To wait for under-resourced distribution companies to install connections across quite large distances to customers who may not be able to pay for the electricity they distribute – and of which there is also a shortage of supply to the public grid? Or to encourage those in areas unserved or poorly served by the current grid to develop micro-grids?

Under the latter approach, not only is the immediate pressure taken off the distribution company, but, if it connects to the micro-grids at a later stage, it will be gaining a mature group of customers who already have connections to the micro-grid, as well as an extra source of power supply in the form of the micro-grid generating plant. (Indeed, under the Rwandan legislation cited earlier, for example, the existence of a source of generation in an off-grid location may

compel the network operator to extend its network in a way that the mere presence of a group of potential consumers of power would not.) There are parallels with how grids developed in many countries in the early twentieth century – linking together local networks that had been developed by the pioneering power utilities in each area.

Time for some (more) regulation?

But wait a minute. As we pointed out above, the essence of a micro-grid is that it combines the generation and the distribution of power within a relatively small area. And, indeed, if it is built to supply other residential or business end-users of power, the micro-grid will also be supplying retail power to them. In other words, it combines three of the four primary functions of the electricity industry: generation, supply and distribution – having removed the need for the fourth (transmission).

Now, many African countries, following the model developed by the UK and others, have a system of separate regulation and licensing for each of the different primary functions. In some cases, they have taken the further step of “unbundling” the primary functions and requiring that they be carried out by separate corporate entities. Such an approach has long since mandated in the UK and elsewhere in the EU. Varying levels of accounting or ownership separation are required to be maintained between any parts of a group that is involved in both transmission or distribution operations, that are seen as natural monopolies, and generation or supply, that are seen as naturally competitive areas.

This model is dictated by economic orthodoxy. From this perspective, are micro-grids a backward step? From one point of view, it could be said that the doctrine of “unbundling” does not always make sense in the African context. The idea behind separating network operation from generation and supply is that one wants to avoid a situation where the network operator favors a generation or supply business that is linked to it over one that is not. But, if there is little or no competition in the retail sector anyway, and even independent generators are still selling to a single offtaker, the objections to vertical integration of two or more of the primary functions may not be so strong.



On the other hand, there is, potentially, a real problem with micro-grids. Customers in a remote community may save money to start with in comparison with the alternatives that are available now. But what if, once they have become used to grid-connected power and perhaps feel that they cannot do without it, the micro-grid decides to double its tariffs overnight, and the public distribution network operator has no plans/budget to build a connection to that community for another two years?

In countries where the price of grid-connected power is subject to tariff regulation, the natural response to this problem might be to regulate micro-grids in the same way as distribution companies or other power suppliers. But this is not necessarily the right answer, not least because they are likely to have a very different cost base.

In any event, it is a further indicator of the potential for micro-grids to fill some of Africa's power gaps that African energy regulators are starting to get to grips with the regulatory challenge they pose. We look at two recent examples of this below.

In Tanzania, [new rules for small power producers have been promulgated](#), in which the exploitation of micro-grid opportunities feature prominently:

- The rules provide for a category of Small Power Producers (SPPs) generating between 100 kW and 10 MW, and selling to a distribution network operator (DNO) or directly to end-users. Those generating below 100 kW are Very Small Power Producers (VSPPs).
- The rules also provide for Small Power Distributors (SPDs), who may purchase power from a third party and also have their own SPP or VSPP "and use this generator to sell power to a DNO ... or to provide a backup supply of power to its own customers."
- The rules envisage that DNOs could be publicly or privately owned.
- Depending on the technology and size of generating plant, there is either a regulated tariff regime or competitive bidding – with the latter being mandatory for all DNOs dealing with prospective solar or wind SPPs above 1 MW. Standardized PPA terms are prescribed.
- It is envisaged that developers of small power plants "may, for solar and wind small power projects connected to isolated Mini-Grids, bid to substitute up to 75 percent of the DNO's existing generating capacity, where the DNO has identified unmet existing or future demand".
- DNOs may invite such developers to submit tenders to supply power to the grid of their own volition, as well as when instructed by the government or regulator.
- The rules also provide for the integration of plant that has been supplying a micro-grid into the public network. The SPP can either

become a supplier to a DNO via the public grid, become an SPD, or become some combination of the two. It may also remove or sell its generating assets.

- Except in the case of “eligible customers” (approved by the regulator as such), an SPP or SPD must seek regulatory approval of its retail tariff structure. Nevertheless, whilst setting the broad parameters of costs that can be recovered through tariffs, the rules envisage a range of possibilities. These include differentiation by ability to pay; “conventional kWh tariffs, flat tariffs, power tariffs or any combination of the above”; “on-bill financing, such as financing of connection charges ... internal wiring, upgrades ... or electrical end-use equipment for productive uses;” and separate backup power tariffs.

In Nigeria, the Nigerian Electricity Regulation Commission (NERC) is consulting on [proposed Regulations for Mini-Grids](#) which cover some of the same ground as the Tanzanian rules but also go further in a number of respects:

- The Regulations distinguish between “isolated mini-grids” and those that are interconnected. However, they only apply to mini-grids with a generating capacity of up to 1 MW. They also distinguish between “underserved areas” (those with a “poorly supplied or non-functional distribution system”) and “unserved areas” (without an existing distribution system).
- Another key concept is that of a community of customers or potential customers, who must be “organized under a local leadership structure or a legally recognized corporate entity and in both cases capable of entering into contracts and being capable of suing and being sued.” A community can, amongst other things, grant the prospective operator of an isolated mini-grid an exclusive right to develop it for up to 12 months (or longer with NERC approval).
- The prospective operator of a mini-grid must enter into a contract with the existing distribution licensee and the “connected community” that has been approved by the regulator. Mini-grid

developers also require permits (but not licenses) to construct and operate their infrastructure.

- An application for a permit for an isolated mini-grid requires the support of the incumbent distribution licensee if it is within its current five-year expansion.
- However, isolated mini-grids of up to 100 kW may bypass the permitting process and opt for the simpler process of registration.
- Permit-holding mini-grid operators must base their tariffs on the national multi-year tariff order (MYTO) methodology that applies to distribution licensees. Registered mini-grid operators have the alternative of agreeing tariffs with customers representing 60 percent of the “electricity output” of the community, subject to NERC’s right to intervene if the operator’s rate of return would exceed a specified threshold.
- When a distribution licensee extends its network to an isolated mini-grid operated under a permit, the operator has the option of transferring its assets to the licensee in return for compensation calculated on specified principles or of becoming an interconnected mini-grid. Rather less generous treatment is proposed for registered operators, who must remove their assets on the request of the distribution licensee and are not eligible for compensation.

Some [stakeholders have been quite critical of the NERC proposals](#), which they feel are too

favorable to incumbent distribution licensees.

Getting the framework right is important, because otherwise developers will not invest – just as the UK government’s first well-meaning attempts to regulate the nascent electricity supply industry, in 1882, had a significant chilling effect in practice because it made insufficient allowance for the risks faced by the developers of the first power networks and made it too easy for their assets to be acquired by local authorities after only a short amount of time.

Of course, there is a case to be made for the incumbent distribution licensees as well. If micro-grid operations are allowed to proliferate wherever the

operators choose, with no rights for public grid operators to acquire their assets when they extend their networks, there is a risk that the public grid will always be less efficient than it could be. Micro-grid operators may also “cherry pick” the best locations for new grid operations, leaving the public grid to serve the areas nobody else wants – or at any rate reducing the distribution network operators’ ability to recruit new customers, increase their revenues and therefore be in a position to reduce the amount of electricity lost in transit.

A number of balances need to be struck: between the interests of micro-grid operators, customers and distribution licensees; between the benefits of free enterprise and the potential detriments of private monopoly service providers; between planned and market-led network development; between over-regulation of small enterprises and allowing poor quality networks to be installed, locking in future inefficiency; and between simplicity of regulation (on tariffs, for example) and ensuring the most accurate reflection of micro-grid developers’ costs. And should any micro-grid customers with solar home systems be entitled to feed in their surplus to the micro-grid, and if so on what terms?

But regulators should take up the challenge of grappling with these issues, and be prepared to experiment, because a really healthy micro-grid sector could potentially solve two big problems. It could dramatically increase electrification rates and at the same time help existing network operators to improve their performance. The ultimate test, perhaps, of any new micro-grid regime will be if it encourages companies with the right skill sets and sufficient financial strength to move into the sector on a large scale, so that micro-grid customers do not lose the chance to benefit from potential economies of scale in the sector, including access to international financial markets.

What else? Conclusions

Solar home systems and micro-grids are not the only answers to Africa’s power problems. There is still plenty of scope for the traditional prescriptions which the World Bank and others have been issuing to African governments for some years. Make consumer tariffs cost-reflective wherever possible. Make sure consumers pay what they owe. Ensure that regulation of the sector is truly independent from national utilities and other vested interests. Make generation and retail supply markets competitive wherever possible. Put in place the fundamentals that will facilitate larger-scale independent power projects. There is progress in a number of places on a number of these areas, but it is inevitably mostly incremental, and complicated by politics.

Others have noted the potential for increased interconnection between the grids in African countries, but that is a long-term project. Even in the European Union, which has a supranational system of electricity market regulation and a much more dynamic cross-border power trading market than Africa, getting new interconnector projects agreed and built takes time.

Perhaps a more immediately promising or scalable development is the involvement of city authorities in the electricity market. For example, in South Africa, over 60 percent of cities play a formal role in electricity supply (where they act as wholesale purchasers and re-sellers) and grid connections. Some generate up to 30 percent or more of their revenues from reselling power. Cape Town has gone further and commissioned 4.5 MW of grid-connected small solar PV projects. Both Cape Town and Stellenbosch have issued guidelines to help potential consumers who are considering the installation of small-scale renewables. The Nelson Mandela Bay Metropolitan Municipality was the first to allow small-scale (sub-100 kW) generation without a license and has entered into innovative trading arrangements with Amatola Green Energy, which trades under the name POWERX, as [South Africa's first licensed energy exchange](#), actively seeking to develop business with municipalities trading renewable power.

The need for more electricity to be generated to meet Africa's ever-growing power requirements, and for ways to be found of giving potential end-users access to power, is so great that there is plenty of room for a range of possible solutions – top-down, bottom-up and sideways – to be pursued and to add value. Many African countries will still need to procure additional large-scale, transmission-connected generating capacity. But, at this moment, if one puts aside any prejudice in favor of centralized power systems, it is the solar home system sellers and the micro-grid operators that – given the right regulatory environment – seem to have the most widespread game-changing potential. They offer the prospect of allowing the private sector to connect directly with end-users of electricity, without (to a large extent) having to go through problematic interactions with incumbent utilities in order to do so. They are a natural and economic fit with renewables such as solar, biomass and small hydro – and increasingly with battery storage as well as diesel or CNG/LNG. They offer communities a degree of empowerment in gaining access to electricity.

They are individually small-scale, but capable, with the right structure and backing, of being rolled out rapidly on a very large scale.

We cannot know how much of a difference closing Africa's power deficit would make economically and otherwise. But we do know that most African economies are predicted to grow by at least 3 percent in 2017 (many by between 4 and 8 percent), notwithstanding the fall in the price of oil and other commodities on which many African countries depend for a significant part of their export earnings. We also know that about half have literacy rates of more than 80 percent among 15-24 year olds; and that most show markedly higher literacy rates in that age group than previous generations – another indicator of growth potential. More specifically, the government of Kenya, which in many respects has one of the better performing power sectors in sub-Saharan Africa, has estimated that power outages currently cost that country between 1.5 and 2 percent of GDP. Above all, these are inherently dynamic economies with a lot of highly entrepreneurial people in them – removing any factor that currently constrains their growth as much as an inadequate power supply is likely to make a significant difference. Much wider access to a much more reliable supply of cleaner electricity cannot fail to be a game changer for Africa, and there is reason to believe that over the next decade it is attainable.



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