

EnergySource

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BATTERY STORAGE:

A charged future

by David Wadham and Alex Bartho

**Oil and gas M&A in the Asia Pacific region:
Looking back at 2016, and moving forward**

BY DANIEL REINBOTT AND JESSICA HAM

**The changing mix of power generation in Asia:
Renewables make their mark but there is still a
role for coal**

BY ANDREW DIGGES AND ANNA HERMELIN

ALSO IN THIS ISSUE:

LNG pricing disputes: The lessons from Europe

BY MATTHEW SAUNDERS, RONNIE KING AND EMMA MARTIN

Blockchain: Beyond the Microgrid

BY DAVID FUTTER AND CHRISTOPHER BATES

Direct PPAs: Connecting with corporates

BY ANTONY SKINNER AND PETER GRAYSON

Written on the wind: Investment opportunities in French offshore wind projects

BY MICHEL LEQUIEN AND JACQUES DABRETEAU

Winds of opportunity: Investment opportunities in German offshore wind projects

BY MAXIMILIAN UIBELEISEN

Offshore wind: The UK perspective

BY ANTONY SKINNER AND JUSTYNA BREMEN

Waste projects: Waste-to-wealth initiatives

BY MICHAEL HARRISON, RICHARD GUIT AND NICK STALBOW



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We are delighted to introduce this eighteenth issue of EnergySource, our biannual publication in which we cover a range of legal and transactional issues relevant to the energy sector from our offices across the globe.

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Contents

In this issue we look at:

Battery storage: A charged future p4

Battery storage is the topic of the moment, set to revolutionise the energy industry. David Wadham and Alex Bartho take a close look at recent developments in this sector, as well as the legal issues raised.

Oil and gas M&A in the Asia Pacific region: Looking back at 2016, and moving forward p12

The oil and gas industry has been getting to grips with a period of sustained oil price volatility. Daniel Reinbott and Jessica Ham report on the impact that current conditions have had on oil and gas M&A in the Asia Pacific region.

The changing mix of power generation in Asia: Renewables make their mark but there is still a role for coal p16

Asian countries have been following the global drive towards renewable energy. However, at the same time, for many Asian countries coal is likely to remain an important element of their energy mix. Andrew Digges and Anna Hermelin discuss the policy drivers shaping this trend.

LNG pricing disputes: The lessons from Europe p22

It seems inevitable that current LNG market dynamics will lead to disputes under long-term LNG SPAs. While this may be uncharted territory, Matthew Saunders, Ronnie King and Emma Martin consider the lessons that can be learned from European natural gas sales price review arbitrations.

Blockchain: Beyond the Microgrid p26

Blockchain technology has the potential to transform the entire energy market. David Futter and Christopher Bates outline future opportunities for this technology, as well as the key legal and regulatory issues that it raises.

Direct PPAs: Connecting with corporates p30

As incentive regimes for renewable energy projects become less generous or are fully withdrawn, direct power purchase agreements with a non-utility offtaker will become a key means to making some renewable energy projects commercially viable. Antony Skinner and Peter Grayson discuss the different types of direct PPAs, and some of the legal issues that need to be considered if such an arrangement is contemplated.

Written on the wind: Investment opportunities in French offshore wind projects p36

Offshore wind projects offer huge potential to investors around the globe, although, as discussed in three articles looking at offshore wind opportunities in France, Germany and the UK, there is increasing pressure on developers to make their projects much cheaper than in the past. In this article, Michel Lequien and Jacques Dabreteau look at upcoming tenders for offshore wind farms in France.

Winds of opportunity: Investment opportunities in German offshore wind projects p40

Similarly to other jurisdictions, Germany has introduced reforms to drive down the cost of incentives for renewable energy, including offshore wind. Maximilian Uibeisen provides an overview of the key features of the new German regime for offshore wind farm projects.

Offshore wind: The UK perspective p46

In the UK, offshore wind is set to be one of the “winners” in future allocation rounds for support under the new Contracts for Difference regime. Antony Skinner and Justyna Bremen consider the second CfD allocation round in the context of offshore wind.

Waste projects: Waste-to-wealth initiatives p48

In the first of a three-part series of articles on the global waste sector, Michael Harrison, Richard Guit and Nick Stalbow explain why waste is now seen as a resource rather than as rubbish, and consider the legal issues surrounding the involvement of private sector capital in the growing waste sector. They also provide a detailed analysis of the various treatment options for waste, and the various uses to which the products obtained from these treatments can then be put.



BATTERY STORAGE:

A charged future

by David Wadham and Alex Bartho

After years of being “the next big thing”, battery storage has finally built up sufficient momentum through reduction in cost and improvements in technology to be commercially viable in grid-balancing, frequency response and demand-side management applications. The UK Government’s call for evidence on smart grids of November 2016 and changes to the Contracts for Difference standard terms in February 2017 are indicative of a rapidly improving regulatory landscape with many opportunities for potential investors. This article covers the core information energy professionals need to understand utility-scale and demand-side battery storage, with a specific focus on the issues facing the UK market and recent and upcoming regulatory changes.

What is grid-scale battery storage and why is it important?

In simple terms, battery storage is the storage of electrical energy as chemical energy for future re-conversion to electrical energy on demand. Historically, energy storage of any kind has been difficult, costly and subject to a number of limitations which have largely meant that, for most electrical grids, the rate at which electricity is consumed must more or less be matched by the rate at which it is generated at all times. This characteristic of electricity networks has defined the structure of the electricity industry and networks around the world. The rapid rise of large-scale

battery storage in recent years has the potential to dramatically alter this picture.

As battery technologies have improved, materials have reduced in cost and the benefits of scaled roll-out have begun to apply, grid-scale and demand-side battery storage has been gaining ground as a solution to a number of balancing issues increasingly facing modern electrical grids. As a result we are now beginning to see the first signs of commercial roll-out both in the UK and internationally. Battery storage is being touted as an economically feasible and more rapid provider of reactive power for grid frequency stabilisation, an effective localised approach to

smoothing out daily cyclical variations in demand and, in the future, the key to unlocking the full potential of large-scale intermittent generation.

For the purposes of this article, we focus primarily on large-scale, grid-connected battery storage, often referred to as “utility-scale” or “grid-scale” energy storage, though we also consider demand-side battery storage (used in conjunction with large consumers of electricity) as another important emerging trend. It is arguable that, in contrast to these large-scale energy storage applications which are just reaching maturity, the small or micro-scale battery energy

storage revolution has already happened over the last 15 years – in particular, the development of lithium-ion batteries has paved the way for all the portable electronic devices we take for granted, as well as electric cars. In contrast, large-scale energy storage has some catching up to do, but, as discussed below, we are now on the cusp of an industry transformation.

Historical context

The enormous potential value of grid-scale energy storage has long been recognised. As early as the 1930s the development of reversible hydroelectric turbines allowed for a form of pumped energy storage: filling reservoirs during times of low demand and generating electricity at times of peak demand. There is now approximately 120 GW of worldwide pumped storage capacity, but further roll-out is hampered by a need for very specific geography, high capex costs and significant efficiency losses inherent in the energy transitions involved (averaging no more than 70 to 80 per cent round-trip efficiency). Pumped storage is also generally only suited to predictable cyclical balancing roles, with only the newest variable speed turbines being capable of the rapid response times and controlled output needed for intermittent generation balancing and frequency response applications.

Other methods of grid-scale energy storage have been investigated (such as storage of energy through compressing air, creating hydrogen from hydrogen electrolysis, storing kinetic energy in flywheels and storing heat in various forms). However, cost, engineering challenges and round-trip efficiency remain major barriers to large-scale adoption.

Battery storage, benefiting from iterative technology development and decreasing cost in the consumer and transport spheres, as well as high round-trip efficiencies (newer batteries achieving in excess of 90 per cent), has rapidly emerged as a major grid-scale energy storage contender.

By the 1990s, lead-acid battery storage was already seeing widespread exploratory use in grid stabilisation and frequency response applications as a source of rapid reactive power. Early projects focused on isolated or remote grids where reliability

and frequency or voltage stabilisation might otherwise have been an issue, including a 20 MW, 5 MWh system in Puerto Rico and a 27 MW, 6.75 MWh bank in Fairbanks, Alaska. Bulk, cycle life and lead acid's toxic materials continued to be the primary drawbacks, though these are beginning to be addressed in modern iterations of the chemistry (see "Battery technology primer" overleaf).

The development in the 1990s of more energy-dense lithium-ion batteries, and their decrease in cost over subsequent decades, led to their explosive growth in the consumer electronics and electric vehicles markets. With lithium-ion battery costs plummeting between 11 and 24 per cent (depending on application) in 2016 alone, and production increasingly scaling up, grid-scale battery storage using lithium-ion batteries has now become viable. In the United States alone, as much as 1,800 MW of new battery storage, largely lithium-ion, is expected to come on line by 2021, with project sizes ranging from 2 to 30 MWs.

There is now near consensus from industry that battery storage will play an important role in the future development of the UK electricity grid. Tim Barrs, who heads energy storage sales for Centrica, said recently that past concerns about the bankability of battery storage projects are giving way to a flood of investor interest as understanding of (and confidence in) the technologies and related revenue streams grows.¹ In his view, a rush of investment decisions will likely be announced by summer 2017, with the market developing very rapidly thereafter.

How do you solve a problem like grid balancing?

The need for electricity supply and demand to be actively balanced across a grid creates some complex challenges. Battery storage has the potential to assist system operators in addressing system imbalance in a number of different scenarios: imbalance caused by changes in demand, imbalance caused by changes in supply, and managing stable electrical frequency levels across the grid.

¹ The Energyst – Centrica: Floodgates on battery storage investment to open in 2017 – 12 January 2017 (<http://theenergyst.com/centrica-floodgates-on-battery-storage-investment-to-open-in-2017/>)

Frequency response

Smooth grid operation relies upon the provision of rapid reactive power services (either by generators or dedicated facilities) to enable fine-scale frequency stabilisation of the grid on a second-by-second basis to smooth out deviations from the network's baseline 50 or 60 Hz frequency. Historically this need has been met by generators modifying their output on demand and dedicated reactive power services (largely provided by gas plants, flywheels and variable-speed hydropower). These traditional methods have a reaction time of under ten seconds. By contrast, battery storage can provide sub-second response times and has therefore, unsurprisingly, already begun to dominate this application in many jurisdictions.

In merchant electricity markets a fee is typically paid by the balancing authority for grid frequency stabilisation services, and it is this role and revenue stream which has led to the first non-demonstration, economically viable, grid-scale battery storage projects in various countries including the US, Japan, Korea and Germany. In the UK, as part of its Enhanced Frequency Response scheme, National Grid ran a technology-neutral auction for 200 MW of frequency response capacity in July 2016 in which battery storage was the biggest winner (see below).

Responding to fluctuations in demand

Electricity demand in a typical national grid varies dramatically over time, and balancing demand and supply in real time has proven an increasingly complex challenge as intermittent resources enlarge their role as a source of electricity. Some elements of electricity demand variation follow clear patterns, such as seasonal demand changes and daily peaks and troughs in usage. The difference between the lowest levels of daily electricity use (overnight) and peak electricity demand can equate to almost a doubling of demand, and a similar difference applies between the average summer and winter usage. Other variations are more difficult to predict – an advert break at half-time in a popular sporting event, for example, can see a significant spike in demand as millions of people switch on their kettles.

While base-load sources of electricity such as nuclear and coal power provide a reliable and consistent supply over long periods of time, they cannot quickly or cost-effectively be reactively brought on and off line, and intermittent sources such as wind and solar are, by their nature, completely incapable of reacting to demand. The need for cyclical and reactive “peaking” generation, therefore, has historically been met by generation sources able to stop and start to some degree on demand, such as gas turbines and hydropower plants. Battery storage has begun making inroads into this market as a flexible, modular and perhaps even cheaper alternative to traditional models, especially in urban areas.

As costs have fallen, battery storage has begun to be used in grids to provide a replacement for peaking generation required to meet peak daily demand, especially in more fragmented grids such as in the USA, where localised balancing is critical. Projects being developed by major utilities generally target the four hours of peak demand (typically between 4.00 p.m. and 8.00 p.m.) – aimed at bridging the peak electricity consumption hours without the need to build new gas peaking generation capacity in urban and sub-urban locations, where obtaining the necessary land and authorisations can be problematic.

Responding to fluctuations in supply

As well as swings in demand, the grid must be able to adapt to unexpected changes in supply. Generating plants suffer outages or reductions in output, and electricity output from intermittent renewable energy sources by their nature cannot be firmly relied upon. Reacting to unpredicted changes in supply in a matter of minutes requires electricity sources with very short start-up times, a role historically filled by gas turbine plants and more recently diesel generators. As modern grids increasingly rely on intermittent sources, building new large-scale gas turbine plants has long been a priority in many countries. However, in merchant grids where generators rely on the sale of electricity for revenue, making an economic case for investment in new large gas plants, which operate cost-effectively only at times when insufficient intermittent generation is available, has proved difficult. The UK Government has been attempting to address this issue through its Capacity Market (CM) incentive mechanism as part of its Electricity Market Reform measures, but has had limited success thus far in encouraging new large-scale gas-fired power plant construction due to significant capital costs, uncertain long-term political outlook for fossil-fuel-based generation and the

Battery technology primer

There are a number of competing battery technologies which have seen significant adoption for grid-scale storage (with many more at an earlier development stage), each having characteristics that make them suited for different applications in the grid-scale storage market.



1 Lead acid – a mature technology, lead-acid batteries account for as much as 50 per cent of all battery use worldwide, primarily in the form of car batteries. While lead-acid batteries benefit from their low cost and reasonable safety

characteristics, they contain toxic materials and have low energy densities. Lead-acid batteries were utilised in many of the early demonstration projects for grid-scale battery storage and account for around 25 GW of installed storage capacity in the US alone.

UltraBattery, a new iteration of the lead-acid battery which addresses some of the chemistry’s drawbacks, has seen considerable early uptake in both transportation and grid-storage applications. A number of US projects using UltraBatteries co-located with wind plants have been commissioned or are under development, including the completed PNM Prosperity test project in New Mexico (which co-locates 1 MW of batteries with a solar PV facility).

Though lead-acid batteries have been somewhat overshadowed by the more energy-dense lithium-ion batteries in the transportation and consumer spheres, they continue to shine in grid applications because of their low cost, safety profile and established (and highly effective) recycling and reuse infrastructure, all areas in which lithium-ion batteries are (currently at least) less able to compete.



2 Lithium-ion – the term lithium-ion refers to any one of a range of different lithium-anode-based rechargeable batteries, the first of which became widely commercially available in the early 1990s. Lithium-ion batteries have become

increasingly commonplace due to their high energy densities and falling costs, though they generally remain more expensive than the older lead-acid and nickel-cadmium battery technologies. Exact characteristics vary depending on the particular lithium-ion anode and cathode materials used, with some carrying explosion or overheating risks as a trade-off to increased performance, operating life or energy density.

Major electric vehicle industry figures including Tesla and Nissan have identified that the same lithium-ion battery technologies they use in their electric vehicles can be profitably utilised in consumer/commercial premises for demand-side and distributed-generation storage applications, as well as in grid-scale applications (when produced in a modular, scalable form). Nissan has taken this concept a step further, firstly by developing the xStorage device which uses recycled electric vehicle batteries in parallel to provide a storage solution, and secondly by developing plans to connect 100 vehicle-to-grid charging units across the UK to allow parked electric vehicles to be used overnight in a limited backup balancing capacity on the grid. Several other car manufacturers are also investigating these opportunities or actively developing projects.

domination of the CM mechanism by cheap (and dirty) diesel generators. Against this background, and the lack of sufficient investor interest in large-scale new gas projects, the potential opportunity for the use of grid-scale battery storage in this role is obvious.

In addition, as western countries invest in ever greater proportions of intermittent renewable generation, the need for standby peaking capacity has grown as a corollary to meet demand when intermittent sources are not generating, or to shift electricity which is generated at times of low demand to peak periods when demand is greater (generation from wind, for example, tends to be greater at night when electricity demand is at its lowest). Mitigation of intermittency costs becomes ever more valuable as the proportion of generation provided by intermittent sources increases. While frequency response has launched commercial grid-scale battery storage projects in earnest in the UK, it is likely that battery storage's potential role as a peaking provider of electricity deployed in tandem with intermittent sources will see it truly take off, including through future iterations of the CM mechanism, to complement the UK's increasing use of wind and solar power (discussed below).

As a corollary to bringing new sources of electricity on line to address drops in supply, system operators have increasingly been looking at ways in which demand in the system can instead be reduced when needed, a process described as demand-side management or load-shifting. Deliberately varying demand on the grid can allow big consumers of electricity to benefit from greater free generating capacity and in some cases cheaper electricity prices at off-peak times. Demand-side management can be greatly enhanced by the ability to take and store electricity, through charging batteries at off-peak times of day, allowing for the stored energy to be used during peak hours.

In future, smart grids, with time-dependent consumer electricity costs, will likely be increasingly relevant, and particularly important for those energy-intensive industries which cannot operate only during off-peak hours. Similarly, the last decade's explosive growth in rooftop solar panels and other distributed generation has seen mains-connected battery storage (most notably Tesla's "Powerwall") marketed to consumers to complement their home solar set-ups in a "behind the meter" configuration which allows for more careful control of the times at which the consumer draws electricity from the grid.



3 Nickel-metal hydride – developed in a similar time frame to lithium-ion batteries, nickel-metal hydride batteries built on the success of early nickel-cadmium rechargeable batteries. While lithium-ion batteries have much greater energy

density and lower cost, the higher safety profile and excellent cycle life of nickel-metal hydride batteries has allowed them to dominate the first generation of hybrid vehicle applications such as the Toyota Prius. However, as the market moves towards fully electric cars, it is likely that demand for nickel-metal hydride batteries will decrease as energy density becomes increasingly important. Nickel-metal hydride batteries have seen only limited use in grid-scale energy storage.



4 Flow batteries – flow batteries are batteries in which rechargeability is provided by two chemical components dissolved in liquids separated by a membrane through which ion exchange occurs, generating an electric

current. Key benefits of these systems are long cycle life, a fully scalable and flexibly laid-out design, and much higher power densities than lithium-ion batteries, with lower energy densities. This makes them suitable for applications where rapid charge and discharge over short time frames is needed, such as in frequency response services and demand-spike management. Vanadium redox flow batteries in particular are currently in use

at a number of sites around the world, including a 6 MWh battery co-located with Huxley Hill wind farm in Australia, a 6 MWh battery at Tomari Wind Hills in Hokkaido, Japan and a 12 MWh flow battery which is under development as part of Sorne Hill wind farm in Ireland. As well as lower energy density, cost-effectiveness remains a major concern, though research into new iterations continues.



5 Other contenders – other battery chemistries under development or already in use on a smaller scale include zinc-air and zinc-bromide (either of which could prove a cheap option in the long-term due to zinc's abundance) and

molten-salt sodium-sulfur, which, although in the early stages of development, has seen several hundred MWs of capacity deployed in Japan, including a 34 MW, 235 MWh project at a Japan Wind Development project in Aomori Prefecture.

UK context

Grid-scale battery storage deployment around the world has been led by the US, Japan, Korea and Germany, but the UK is now waking up to the significant investment opportunities afforded by the technology. More than 25 MW of capacity has already been deployed in the UK, including over 35 stand-alone projects and a huge number of domestic and small-scale commercial installations. The largest projects include:

- AES Kilroot Station in Northern Ireland, an announced 50 MW lithium-ion project, interconnected (of which more than 10 MW is already completed), focusing on augmenting intermittent renewable generation;
- an innovative £18.4m, 6 MW/10 MWh battery storage facility at Leighton Buzzard in Bedfordshire owned by UK Power Networks (UKPN) (through operator Smarter Network Storage), which has been operational since late 2014, and as of December 2016 has provided more than 7,500 hours of reactive power to National Grid;
- Orkney Storage Park Project, an operational 2 MW lithium-ion storage project aimed at reducing transmission network congestion;
- a battery storage system under construction at the headquarters of logistics and warehousing company JB Wheaton in Somerset being trialled by E.ON in conjunction with vanadium redox flow battery manufacturer RedT, as part of a bid to understand the potential for improved commercial returns on solar PV installations;
- a 1 MW Northern Isles New Energy Solution battery storage facility co-located with wind power in Lerwick, Shetlands, with a further 1 MW under construction;
- a 2.5 MW, 5 MWh single device project in Darlington as part of Northern Powergrid's storage trial programme;
- E.ON and Uniper's 2 MW lithium-titanate demonstrator facility at Willenhall; and
- Hazel Capital's Noriker Staunch storage project, currently under construction, which benefits from a two-year firm frequency response contract in Newcastle-under-Lyme.

In a report on smart power in March 2016, the National Infrastructure Commission (NIC) has said that, if costs continue to fall as anticipated, up to 15,000 MWh of battery storage could feasibly be deployed in the UK by 2030.² This figure could be even higher if the UK Government introduces additional incentivisation and regulatory support for the sector, particularly when used in co-location with renewable generation assets (discussed below). The NIC report further urged the UK Government to implement regulatory changes necessary to facilitate greater adoption of grid-scale battery storage as an essential building block of a smart grid for the UK.

While the UK's distribution network operators (DNOs) might seem an obvious fit to make use of battery storage in managing local network demand fluctuations, they are not permitted to own storage under current market rules. In its report in March 2016, the NIC called for the Department of Energy and Climate Change (a predecessor to the Department for Business, Energy and Industrial Strategy) and Ofgem (the gas and electricity markets regulator) to



expedite work to modernise regulation of DNOs, allowing them to own and operate storage assets and be subject to similar dynamic management and collaboration duties to those that already apply to National Grid. Changes to DNO regulation could ultimately allow DNOs to become distributed systems operators (DSOs): actively managing generation, storage and demand on their networks in response to macro-objectives requested by National Grid. It is evident that one of the key beneficiaries of such a move will be the battery storage market, given its versatility in meeting the demands the new DSOs will be required to address.

In response to these regulatory issues, the UK Government launched a call for evidence in November 2016 focusing on the future role of battery storage in smart energy grids, the results of which are expected in Q2 2017.³ The changes likely to result from this call for evidence have the potential to significantly improve the bankability of battery storage projects in the UK (as discussed below).

Bankability issues

Major bankability issues to consider when assessing UK battery storage projects include the key issues outlined below.

Securing a revenue stream

In the UK, bankable battery storage projects are likely to target one (or, in most cases, several) of the following revenue streams:

Enhanced Frequency Response contracts

In July 2016 National Grid put out a technology-neutral invitation-to-tender for its Enhanced Frequency Response (EFR) scheme. The purpose of the EFR scheme is to maintain the grid at a frequency as close to 50 Hz as possible at all times, as a replacement for National Grid's previous, slower, Firm Frequency Response scheme. The EFR scheme requires full active power output within one second in response to deviations in the grid from the standard

² National Infrastructure Commission Report, Smart Power, 4 March 2016 (<https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report>)

³ Department for Business, Energy, & Industrial Strategy, Call for evidence: A smart, flexible energy system, 10 November 2016 (<https://www.gov.uk/government/consultations/call-for-evidence-a-smart-flexible-energy-system>)



50 Hz frequency, to prevent faults. The previous scheme's fastest participants, generally gas plants, provide reactive power with a delay of around ten seconds. Of 37 providers bidding to become part of the scheme, 34 were from battery storage assets. Winners, including 200 MW of battery storage projects, were announced in July 2016, and included EDF Energy Renewables' 49 MW at its West Burton power station in Nottinghamshire, Vattenfall's 22 MW at Pen y Cymoedd wind farm in South Wales and E.ON's 10 MW at its Blackburn Meadow CHP plant in Sheffield. Winning bids are to enter into a four-year contract for provision of EFR services, which is double the length of those previously awarded under the Firm Frequency Response scheme.

CM contracts

The most recent CM auction, the results of which were announced in December 2016, cleared at £22.50/kW, securing 52.4 GW of capacity from 2020 at a cost of around £1.2bn. Despite the UK Government's stated goal of incentivising the development of new, large-scale gas turbine plants, none won contracts in the auction (while two new smaller gas plants were awarded contracts, both were extensions/rebuilds of existing plants). As part of the auction around 500 MW of new-build battery storage projects were awarded contracts. The 28 winning battery storage projects included four that already benefit from EFR contracts – the 10 MW Cleator project in Cumbria and 40 MW Glassenbury project in Kent being developed by Low Carbon, as well as the 49 MW West Burton project and the 10 MW Blackburn Meadows projects mentioned above. Several projects that were unsuccessful in the EFR process were also awarded CM contracts, including Centrica's 48 MW Roosecote project. The latest round saw battery storage projects winning the longer 15-year contracts for CM services for the first time, having won only four year contracts in previous iterations. This new longer-term, secure income stream for battery storage projects is a paradigm shift in terms of bankability. Future iterations of the CM mechanism are likely

to see even greater interest from battery storage projects: Ofgem is currently consulting on splitting pumped storage from other storage technologies, which would mean battery storage would no longer be assumed to have pumped storage's (extremely high) availability and de-rating factor. Ofgem's recent decision to push forward with the removal of certain so-called "embedded benefits", which are seen to unfairly benefit distribution network connected diesel generators, may also inadvertently hurt the financial case for distribution network connected battery storage. Nevertheless, it is also likely that the UK Government will introduce measures to make it easier for battery storage embedded in demand-side response applications to participate in the CM (including the possibility of a minimum capacity in each auction which must be awarded to demand-side response providers) which may ameliorate in some instances the negative impact of the embedded benefits review.

Financial benefits of co-location with intermittent generation

Co-locating renewable generation assets with onsite battery storage offers a number of obvious benefits, allowing for maximisation of generation output, particularly where grid connection constraints prove a major bottleneck at times of peak generation. For solar, tidal and, to a degree, wind projects, where generation is limited to specific periods, battery storage can also offer access to price arbitrage opportunities. Battery storage may be developed as an integral component of the generating plant, as a retrospective addition, or as a stand-alone project utilising shared land or grid connection, each with its own metering approach and commercial arrangements between the operators. In some instances, the benefits of co-location can even be sufficient to economically justify a project without any other revenue stream – in September 2016, Camborine Energy Storage announced a commercial-scale battery storage project (estimated at around 0.5MWh), using Tesla's Powerpack batteries in Europe, co-located with a solar PV site in Somerset, which is unsupported by revenue from an EFR or CM contract. Against the obvious advantages of co-located storage, developers must also consider the risk of how changes to a project may impact its entitlement to renewable benefits (see below).

Aggregation with demand-side response

Demand-side response aggregators, who seek to respond to National Grid's balancing needs by securing commitments from large baskets of diverse businesses across the country to reduce their power usage on demand (for example, a supermarket chain could slightly turn down its freezers or air conditioners for half an hour without major impact on its operations), can be hampered by the slow response times these approaches often have. Adding a relatively small amount of battery storage to an aggregation set-up can bridge the gap in response time for a much larger portfolio. National Grid has expressed a goal of a greatly increased role for demand-side response measures in balancing (targeting as much as 30-50 per cent of balancing capacity coming from demand-side response by 2020), meaning this area will likely see considerable development going forward. Demand-side response is an area where the UK is leading the field internationally, with a robust regulatory framework already in place.

Impact on existing renewable benefits

A major risk with retrospectively added co-location arrangements is the possibility that the changes to the project may imperil existing renewable benefits accruing to the generation assets, such as Renewables Obligation Certificate (ROC) accreditation. To date no co-located ROC and battery storage projects have been commissioned, although a number are under consideration including both integrated storage and retrospective additions of storage to commissioned plants. The key concern is that the existing legislation and guidance is not sufficiently clear on how co-located storage will be treated. It is clear that a material “behind the meter” modification to an existing ROC-accredited project will require an amendment to the accreditation. While Ofgem is considering an amendment, no ROCs will be issued and, typically, Ofgem will not pre-approve amendments to accreditation before the relevant works are complete. This leaves operators of existing, operational ROC accredited projects with the problem of both a gap in income while the amendment is considered and, more worryingly, the possibility that the existing accreditation could be invalidated if the amendment is rejected. Obviously, for existing project-financed facilities these risks are likely to be difficult to manage in a way that will satisfy lenders. It is hoped that these concerns will be addressed by the UK Government through clarification of regulations and the introduction of a pre-approval process for amendments, though in the absence of such clarification lenders may take some comfort from a growing number of precedent transactions.

A further issue can arise if the storage facility is an embedded part of the generating station (i.e. “behind the meter”). Because ROCs are issued only on the basis of metered (i.e. net) export, if the storage facility operates pre-meter, storage losses (which can be between 5 and 20 per cent depending on the battery chemistry) will reduce ROC accrual (or FIT receipts). This drawback may also be addressed by the UK Government through new regulations in 2017 to ensure all generated output is counted.

Impact on connection arrangements

The fact that co-location of intermittent generation with storage allows for a proportion of electricity generated to be stored (to be fed into the grid at times of non-generation) means that an intermittent generator with sufficient storage capacity can release electricity onto the grid in a manner more akin to a base-load generator with a lower installed capacity but higher availability factor. This can have benefits in terms of connection arrangements, as it will potentially allow for a much smaller grid connection for the project (reflecting the generator’s average, rather than peak, output), and may even mean the generator can connect to a distribution network rather than the transmission network in some marginal cases.

Utilisation of battery storage in CfD projects

While the Contracts for Difference (CfD) standard terms in the 2015 CfD auction round do not expressly refer to battery storage, BEIS consulted in 2016 on proposals that, in the 2017 CfD auction round, co-located projects including storage should constitute separate Balancing Mechanism Units for the purposes of CfD metering. CfD payments would be calculated through metering at

generation, not subsequent export from the storage device, avoiding the problem highlighted above whereby storage efficiency losses could decrease renewable benefit allotment.

In the response to this consultation, published in February 2017, the UK Government noted strong opposition to this proposal – respondents generally preferring the flexibility afforded by robust import/export metering or registering separate MPANs under the same BM Unit, rather than being forced to separate the BM Units entirely.⁴ These approaches, which require de-linking CfD settlement from BM Unit Metered Volume, would allow generators a number of benefits, including the ability to internally balance output, take advantage of qualifications for supply licence exemptions, and allow co-location of batteries with each generating unit (e.g. per wind turbine).

Unfortunately, due to the complexity of the proposals and need for further consultation, the UK Government declined, in the consultation response, to commit to a course of action which would fully address the identified issues. Instead, as a stop-gap measure, storage will be permitted to be registered in the same BM Unit as a CfD-awarded generating facility provided the generator can demonstrate to the Low Carbon Contracts Company (the CfD counterparty) that such storage is only used to store electricity generated by the CfD-awarded generating facility. While this is helpful for many co-located projects, it effectively prevents import of electricity from the grid which is needed for many of the more complex battery storage applications (for example, it precludes frequency response applications). A more comprehensive solution will hopefully be pursued after the 2017 allocation round. The consultation response did, however, adopt the flexible definition for “Electricity Storage” put forward by industry body The Electricity Storage Network.⁵ This is encouraging as it likely heralds widespread adoption of this definition in the regulatory regime (something that will hopefully be borne out in the response to the recent call for evidence on smart grids (see above)).

Double-charging, consumption levies and lack of legal status

At present battery storage facilities are classified in certain circumstances for regulatory purposes as both electricity generators and consumers, and thus attract charges for use of the network and balancing system as well as consumption levies. Network charges for both import and export apply, some of which are designed to compensate the network for system stresses that battery storage may, perversely, be intended to mitigate. Finally as most grid-scale storage will purchase electricity from licensed suppliers, the effect of final consumption levies will be passed on to them through price although they are not strictly final consumers, including in respect of the Renewables Obligation, Contracts for Difference, CM and FIT regimes. The same applies

4 Department for Business, Energy & Industrial Strategy – Results: Consultation on amending the CfD contract and regulations – 8 February 2017 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/589996/FINAL_-_Government_Response_to_the_CfD_Contract_Changes_Consultation.pdf)

5 “Electricity Storage”, in the electricity system, is the conversion of electrical energy into a form of energy which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy.

“Electricity Storage Facility” means a facility where Electricity Storage occurs or can occur and includes all assets performing or contributing to any such Electricity Storage.”

in respect of the Climate Change Levy, though HMRC may waive CCL charges on a case by case basis. Clarifications of all of these regimes to remove double-charging and unfair levies are sorely needed, but are expected to be included in legislation changes to be introduced as part of the UK Government's response to the call for evidence on smart grids currently under way.

Generation licensing

The electricity licensing regime was designed at a time when pumped hydro, an iteration of existing hydropower generation stations, was the only material energy storage technology available. As a result, the regime classified pumped energy storage as a form of generation, and in the intervening years other forms of energy storage have automatically fallen within this classification (and resultant licensing requirements and obligations that follow from holding a generating licence), even though they may not be embedded in a generating plant. This will require developers to obtain a generating licence for non-embedded storage if the project capacity is over 100 MW, or a specific exemption if the project capacity is over 50 MW. Energy storage regulation, including its legal definition, clearly needs a rethink as well as separate regulatory provision, something the UK Government has acknowledged in its February 2017 response to its consultation on CfD contract changes. As with the charging methodology for use of the network, it is expected the UK Government will use the opportunity presented by its response to the 2016 call for evidence to provide some further clarity, though this may not amount to a commitment to pass primary legislation providing a comprehensive regulatory framework addressing battery storage's specific needs.

Planning consent

Because battery storage is not yet expressly provided for in electricity legislation there can be a lack of clarity when storage interacts with other areas of legislation and regulation, including the planning framework. For the time being, in the UK context, battery storage facilities are treated as a generating station for planning purposes, but this needs to be clarified in legislation (or ideally bespoke regulations for storage introduced) to avoid uncertainty.

Power purchase agreement considerations

New stand-alone battery storage projects or those to be co-located with a generation asset from its outset will need to ensure their power sales arrangements are sufficiently flexible to allow for any power shifting and attendant efficiency losses intended, as well as any alternative revenue streams they hope to realise from the storage. Where battery storage is retrospectively co-located with existing renewable generation, it is likely that the project's power purchase arrangements will need to be re-opened. In either case, areas likely to need significant attention will include arrangements for the import of electricity if this is envisaged for charging the batteries in some circumstances, reworking forecasting provisions to allow for a storage-augmented profile and removal of restrictions on (or a requirement to share revenue from) providing ancillary services or exporting additional power. Co-located projects may be willing to accept a greater share of imbalance

risks as they will be able to mitigate them through use of the storage. Some of the major power offtakers, including Smartest, are even beginning to prepare standard form "supply and offtake" agreements in preparation for use with battery storage projects.

Power hedging

Having on-site battery storage with both an import and export capability opens up the possibility for projects to utilise physical electricity price hedging/trading. While this may provide the potential for a significant upside to the project, careful thought will need to be given to appropriate restrictions, thresholds and tolerances if this is not to create un-bankable risks.

Other considerations

As with power offtake arrangements, for retrospective addition of battery storage to existing renewables projects, existing financing and grid connection arrangements, property rights, and necessary consents for the project must be reviewed for any necessary changes or permissions, in dialogue with the relevant counterparts.

Conclusion

We are in the midst of a period of great change in the energy market, with significant developments in battery storage technologies and a shifting regulatory and revenue-support landscape. There are multiple roles presenting opportunities for battery storage investors, developers and lenders, with projects targeting different available revenue streams each with their own associated regulatory and commercial issues.

While uncertainty remains for generators hoping to retrofit battery storage into existing ROC-accredited projects, clarity on the interaction of CfD-awarded generating facilities and battery storage provided in the BEIS February 2017 consultation response is very welcome and the new regulatory position offers opportunities to develop or retrofit battery storage as an integral part of a typical renewable generation CfD project going forward.

Against a background of a growing sophistication in the regulatory framework and maturing technology, Ashurst envisages an increasing number of bankable opportunities based on stable government revenue streams for third-party funding of new stand-alone battery storage facilities and battery storage embedded in CfD-awarded renewable generation projects to arise in the latter half of 2017.



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OIL AND GAS M&A IN THE ASIA PACIFIC REGION:

Looking back at 2016, and moving forward

by Daniel Reinbott and Jessica Ham



This article examines some of the key challenges which have created obstacles for successful upstream deals in the Asia Pacific region, and how these challenges will need to develop in order for the region to realise its M&A potential in the upstream sector in 2017.

Background

The oil and gas industry has been under pressure for a sustained period, with low and volatile oil prices creating an air of uncertainty across global markets for at least two years.

In previous oil price downturns, we have seen an increase in M&A activity across the oil and gas sector, as companies look to ride out the pressure to reduce costs and boost profitability by optimising asset portfolios.

The current downturn has been noticeably different. Although M&A activity has been up, in line with what we have seen in previous downturns, with the

exception of a handful of very significant deals (Shell's acquisition of the BG Group, for example, as well as interest in a takeover of InterOil Corporation, first by Oil Search and subsequently by Exxon Mobil), we have not seen the expected level of completed deals.

In 2016, Ashurst's global oil and gas practice undertook a research report, "**From Survival to Growth in a New Era**", which surveyed CEOs, CFOs and General

Counsel at over 50 oil and gas companies, together with funders working in the sector, private equity-backed investors and investment bankers.

The report revealed that over 80 per cent of companies expected a "substantial" increase in mergers and acquisitions in the next three to five years, with respondents identifying the Asia Pacific region as the likely location of their next investment.

As the report results had anticipated, we saw continued and increased interest in deals in the Asia Pacific region across 2016, particularly in key Southeast Asian markets such as Indonesia, Malaysia, Thailand, Vietnam and Papua New

¹ Please contact us for more information about this research or to receive a copy of the report. See also: <https://www.ashurst.com/en/news-and-insights/insights/energysource---issue-17---1---future-strategies-for-oil-and-gas-companies/>

Guinea, evidenced particularly by the sales/divestment processes initiated by a number of international oil companies (IOCs) in the region during this period. For example, Chevron and ConocoPhillips have both conducted divestment processes in the region in 2016, in particular, in relation to their respective interests in the South Natuna Sea Block B PSC in Indonesia. ConocoPhillips successfully completed the sale of its interest in the PSC (and associated gas transportation infrastructure) to Indonesia's Medco Energi in September 2016, with news surfacing on 28 March 2017 of the signing of a new deal between INPEX and Medco Energi in relation to the sale by INPEX of its interest in the same block. Repsol has also commenced divestments in the region, notably completing a sale of its interest in the Tangguh LNG project to the project Operator, BP, in December 2016. However, despite the availability of assets for sale; the anticipated levels of buyer interest; and the corresponding levels of deal activity, the level of signed and closed acquisitions fell short of expectations.

Transaction valuation

The "Value Gap" remains

A lack of consensus between buyers and sellers as to transaction valuation persists, resulting in a broader range of bid/ask spreads and, as a result, fewer completed transactions as buyers are unwilling to increase their offers, and sellers are unwilling to lower prices. This challenge is largely attributed to the significant uncertainty that remains around the oil price.

Although the oil price has risen slowly and steadily over 2016 (in line with what respondents to our report expected to see, \$53/bbl by the end of 2016), the recovery has been protracted (supporting the prevailing "lower for longer" attitude to oil prices). Glimmers of optimism as the price reached levels not seen since 2014 were short-lived, and the confidence generated was undermined by subsequent price falls.

Even the price rises seen in the first months of 2017, following OPEC's recent (and long-awaited) pact to curtail oil production, have been limited. Although there were hopes that the curtailment of production would result in price rises, the response from US oil producers to

OPEC's decision has moderated the level of recovery, with Brent prices currently hovering just over \$50/bbl.

Until buyers and sellers alike feel more comfortable as to where (and when) the oil price will reach a landing point, we expect that we will continue to see a range of valuations.

Few real "bargains"

Another potential explanation as to why transaction valuations remain challenging is that many buyers still appear to be looking for "bargains" in this market. This is intuitive in the current challenging market, and we had expected to see this activity from opportunists (such as private equity-backed investors).

We have not seen the level of distressed asset sales that would typically be expected in this climate. This has meant fewer opportunities for bargains, and increased competition from other buyers, particularly those looking to strategically consolidate their portfolios, who are more likely to pursue a transaction at a valuation that does not necessarily represent a "bargain", if the transaction serves their strategic focus.

Except where sellers are in distress, we have seen that the view of sellers is that quality assets should still attract prices which reflect that quality. This is particularly evident in the divestment programmes being conducted by the majors in Asia. Like many sellers, the majors are looking to optimise their portfolios and divest non-core assets, but they are not prepared to undervalue those assets in order to do so, resulting in some cases in lengthy transaction processes.

Valuation of mature assets

Compounding the issues associated with oil price volatility noted above, there is a significant degree of uncertainty regarding the future and longevity of some of the more mature assets currently held by IOCs in the region.

Where the relevant petroleum regimes do not grant a right of renewal to the current contract or concession holder, a lack of certainty regarding the potential for renewal (including details such as the term of renewal, the maximum participating interest held by the IOC, and potentially also the fiscal terms) can create challenges for valuation. Sellers often take a bullish view

of the potential for renewal of expiring concessions, and so look for some value to be attributed to future concession periods, but buyers are of course more conservative and can be unwilling to proceed without assurances that renewals will be granted.

While a seller will always prefer that a purchase price be paid as a lump sum at closing, applying an element of deferred consideration (triggered by a renewal or extension) can be considered as a way to balance interests of the sellers and buyers in these circumstances.

The rise in significance of national oil companies (NOCs) in the region, and the trend in the region towards a renewed focus on the development of domestic resources to satisfy domestic demand, has also presented challenges for successful transactions where an IOC (or other non-domestic company) is an interested buyer. This has been particularly evident in Indonesia, where new regulations introduced in 2016 give Indonesia's NOC, Pertamina, an effective right of first refusal in relation to the grant of new PSCs over expiring contract areas,² of which there are up to twenty-seven scheduled to expire within the next five years. Even where regulations do not give an advantage directly to NOCs, buyers can face heavy competition for the acquisition of those assets from NOCs or other regional/domestic oil companies, who often apply different investment criteria (sometimes focused on national interest considerations) and, unlike IOCs, may not consider the relative position of the relevant assets as part of a global portfolio (in terms of priority for capital).

Spotlight on decommissioning and abandonment

Mature assets available

Although Southeast Asia is widely thought to have significant potential for future exploration and production, as noted above, there are also a number of mature or aging assets in the region. Mature or aging assets are clear candidates for the "first round" of divestments by sellers looking to reshuffle or consolidate their portfolios, and sellers are often insistent on a "clean break" on the disposal of these assets.

² Minister of Energy Regulation 5/2015 concerning Management of Oil & Gas Work Areas Whose Cooperation Contract is to Expire

Buyer and seller interests in asset or share sale and purchase situations are never completely aligned. However, our experience in Southeast Asia in 2016 has indicated that this is the case now more so than ever, and particularly in terms of allocation of risk for decommissioning and abandonment liabilities.

Trends in decommissioning and abandonment regulations

Given the age of some of the assets in the region, decommissioning, abandonment and site restoration liabilities are a potential risk area for existing concession holders. The majority of mature assets in the region commenced operations before detailed regulations were in place, and the increasingly risk averse approach of sellers has largely been driven by a recent spotlight on the regulation of decommissioning obligations for concession holders.

There have been recent moves in a number of key Southeast Asian jurisdictions (notably Indonesia and Thailand) to tighten existing regulations and introduce clearer, and in some cases more stringent, obligations on concession holders, albeit with potentially different outcomes for contractors and concession holders.

In Indonesia, for example, the Government is currently preparing its first abandonment and site restoration regulation, which sets out procedures to propose abandonment and site restoration operations, provision of the relevant fund, and technical standards required. The draft circulated to the public in mid-2016 also provides that, in the case of transfers of operatorship or participating interest, obligations with respect to post-operation activities shall be transferred to the new operator or participating interest holder, as the case may be. This approach is, in essence, consistent with an earlier regulation concerning expiry of production sharing contracts issued in 2015, which provides for new contractors to be responsible for decommissioning and abandonment of facilities that are in place at the time of commencement of the new production sharing contract.

In Thailand, new regulations³ introduced in 2016 require a detailed decommissioning plan to be prepared by the concession holder, for the estimated costs of decommissioning activities to be audited and for the concession holder to provide security (in the form of cash or a cashier cheque payable by a bank, Thai government bonds, a letter of guarantee issued by a bank, an irrevocable standby letter of credit or other form prescribed by the Director General). Draft regulations have also proposed that a transferee of a concession interest may remain liable for a share of decommissioning liabilities, having reference to cumulative production and remaining recoverable reserves at the time of transfer. This proposal received considerable negative feedback from concessionaires in Thailand.

Risk allocation approaches

Understandably, sellers wish to avoid liability for costs associated with the decommissioning or abandonment of facilities or site restoration associated with petroleum operations, certainly where those liabilities crystallise after the completion of the sale. 2016 saw sellers more motivated than ever before by a desire to avoid the potential exposures associated with decommissioning and

³ Ministerial Regulation Prescribing Plan and Estimated Cost and Security for Decommissioning of Installations Used in the Petroleum Industry B.E. 2559 (2016).





abandonment liabilities, particularly where a sale process is being conducted as part of an IOC's country or region exit.

As part of the trend for sellers seeking a "clean break" (and particularly in the light of potential regulatory developments), an increasing trend that we observed in 2016 was for sellers to attempt to allocate pre-effective date risk and liability associated with decommissioning and abandonment costs to buyers (e.g., through the sale and purchase agreement's seller warranty (or the absence thereof) and indemnity mechanisms).

Buyers are naturally wary of assuming this liability. The buyer's risks associated with potential decommissioning liabilities can be mitigated to an extent, including by comprehensive due diligence on the relevant assets and a sound understanding of the operation of the relevant regulations. Buyers may also mitigate risks contractually (for example, we have seen buyers pushing back on sellers, including by requesting a greater range of asset-related warranties, particularly regarding compliance with environmental laws and maintenance of any decommissioning and abandonment funds).

However, our recent experience shows that buyers are keenly aware that the risks cannot be mitigated fully. Even if buyers are able to agree an acceptable risk allocation under sale and purchase agreement documentation, in the current climate, some uncertainty around the future approach of host governments to the regulation of decommissioning and abandonment remains, and buyers may be required by host governments to assume liabilities going forward which cannot be passed through to a seller, in some cases for years after completion of the relevant transaction.

This misalignment in seller and buyer expectations for the allocation of risk for decommissioning and abandonment liabilities and regulatory uncertainty has been a key factor contributing to the more protracted deal negotiations for many deals in the region and the lower than expected number of completed transactions.

Outlook for 2017

Despite the challenges noted above, we expect a moderate recovery in M&A activity in 2017 in Southeast Asia, and have seen signs of this in the first months of 2017 through the signing of a number of upstream deals. M&A activity should start to gather more momentum, as buyers and sellers alike become more accustomed to the lower oil price environment as the "new normal", with more certainty over future oil prices as the recent volatility reaches a plateau. Companies that have focused on maintaining relationships with other players in the region will be best placed to take advantage of the changing market dynamics and execute strategic or opportunistic transactions in 2017.



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THE CHANGING MIX OF POWER GENERATION IN ASIA:

Renewables make their mark but there is still a role for coal

by Andrew Digges and Anna Hermelin

There is an increasing anti-coal, anti-carbon sentiment in the global market for new electricity generating capacity. At the same time, there is acute demand for increased generating capacity in Asia, cheap thermal coal remains at its most available in some years and budgetary pressures on emerging Asian economies have been exacerbated by lower commodity prices and the slow growth in the Chinese and global economies. This creates a tension between the economic realities of Asia's need to develop affordable new generating capacity and the anti-coal sentiment building globally

A recent World Bank report finds that global investments in renewable energy were higher in 2015 than during the past five years.¹ EY also reported a record US\$329 billion of new investments in 2015, with 36 GW of solar and 31.5 GW of wind capacity added in Asia Pacific alone² (while the global figures for 2016 are expected to be lower due, in part, to a drop in offshore wind financing in Europe and lower electricity demand globally).

However, growth in renewable energy

¹ "World Bank finds cash moving to renewables", www.upi.com, 14 June 2016.

² "Renewable Energy Country Attractiveness Index 2016", EY, 23 February 2016.

is not necessarily at the expense of coal in the still power-hungry Asian market. Fossil fuels continue to account for a significant proportion of the fuel mix in much of Asia. A number of countries in Asia, both developed (such as Japan) and developing (such as Indonesia), have announced plans to construct greenfield coal-fired power plants in the coming years.

This article considers the key drivers for renewable energy growth in Asia and the reasons why such growth does not yet spell the imminent demise of coal-fired power generation in the region.

What are the key drivers for renewable energy growth in Asia?

Political pressure and global agreements

At the climate conference held in Paris in December 2015 (COP21), 195 countries adopted a legally binding climate deal that is due to come into force in 2020 (the Paris Agreement). Pursuant to the Paris Agreement, governments agreed a long-term goal of keeping the increase in global temperature to well below 2°C and to meet every five years to set more ambitious targets. Before and during COP21, individual governments submitted national climate

action plans setting out their plans for achieving the long-term goal. A rapid string of ratifications near the end of 2016 (including, in Asia Pacific, ratification by Malaysia, Pakistan and Australia) brought the Paris Agreement into force on 4 November 2016. This was followed by the next annual climate change talks, COP 22, on 17 to 18 November 2016, which made headway in setting out a plan to achieve the Paris Agreement goals, with the unveiling of the “Marrakesh Partnership for Global Climate Action” (MAP).

Aside from creating a new legal impetus for governments to take action to reduce emissions (governments will have to report to each other and the public on their progress), the Paris Agreement generated a huge amount of interest and a strengthened “moral” impetus for governments to take action to reduce emissions. It also created heightened media interest in the successes and failures of governments in their efforts to reduce emissions and saw renewed protests from environmentalists and the public against high emission projects such as coal-fired power plants. A key part of many countries’ pledges to reduce emissions, including those from Asia as discussed below, is to increase the proportion of electricity generated from low-emission plants, marking a policy shift towards increasing renewable energy generation.

The recent election in the US has clearly caused some to question the continued level of support that the Paris Agreement will enjoy but initial reaction indicates that, at least outside of the US, governments are still committed to fulfilling their pledges to reduce emissions.

Reducing cost of renewable energy development

In their 2015 joint report on the projected costs of generating electricity, the International Energy Agency (IEA) and the Nuclear Energy Agency highlight³ that while at the high-end of the spectrum, the projected levelised cost of electricity (LCOE) in 2020 for renewable energy remains significantly above that for base load (being coal-fired, gas-fired and nuclear) technologies, at the low-end of the spectrum of renewable technologies, the projected LCOE in 2020 is in line with (or in some cases below) base load technologies. The report also highlights that while onshore wind remains the lowest cost renewable technology, solar PV has seen significant reductions in cost since the IEA’s previous study was published in 2010. The year of 2016 saw record tariffs achieved, with solar PV bids as low as US\$0.0242/kWh in Abu Dhabi and US\$0.021/kWh in Chile,⁴ while onshore wind came in at just US\$0.028/kWh in Morocco.⁵ The long-accepted cost obstacle to the adoption of renewable technologies can therefore be seen to be on the wane, particularly in the case of solar PV and onshore wind, making renewable energy a more viable option for countries that previously would have disregarded it for cost reasons alone.

Funding

In November 2015, prior to COP21, the OECD member nations party to the Arrangement on Officially Supported Export Credits (the Arrangement), agreed to a new sector understanding

governing the export credit financing of coal-fired power plants (the New Rules). The New Rules aim to help achieve lower emissions targets by discouraging the financing of certain coal-fired power projects. The New Rules were scheduled to come into force in January 2017. Broadly speaking, the New Rules limit the ability of export credit agencies (ECAs) from nations that are party to the Arrangement to offer finance to support their country’s exporters investing in, or supplying parts for, certain less efficient coal-fired power plants. It will apply to ECAs from Australia, Canada, the European Union, South Korea, Japan, New Zealand, Norway, the United States and Switzerland. Under the New Rules, if a coal-fired power project utilises:

- ultra-supercritical technology, it will remain eligible for export credit support subject to a maximum 12-year repayment term;
- supercritical technology, it will be eligible for export credit support subject to a maximum ten-year repayment term, but only if:
 - i.) it qualifies as a medium (300 MW to 500 MW) or small-sized (<300 MW) project; and
 - ii.) is located in a country:
 - a.) that is eligible for International Development Association resources;
 - b.) where the national electrification rate is reported in the IEA World Energy Outlook Electricity Access database at 90 per cent or below; or
 - c.) that is otherwise located in a geographically isolated area where less carbon-intensive alternatives are not viable; and
- subcritical technology, it will be eligible for limited export credit support subject to a maximum ten-year repayment term only if:
 - i.) it qualifies as a small-sized project; and
 - ii.) the project is located in a country that is eligible for International Development Association resources or is otherwise located in a geographically isolated area where less carbon-intensive alternatives are not viable.

All projects that are eligible for official support may be afforded an additional two years on their repayment terms if they are considered to be “project finance transactions” based on criteria set out in the Arrangement.

Although it is difficult to determine exactly how many planned projects will be shelved, or will switch to a more efficient technology, as a result of the New Rules, the impact of implementing the New Rules on the global pipeline of coal-fired power projects will undoubtedly be substantial. While it is only partly useful to compare the technology of projects from a different time period, the OECD estimates that over two-thirds of the coal-fired power projects receiving official export credit support from participating countries between 2003 and 2013 would not have been eligible for such support under the New Rules.⁶

Notwithstanding that the New Rules only apply to ECAs from participating countries, it is not unreasonable to expect that the New Rules could form an “acceptable” basis or benchmark of criteria that will be applied by other institutions, including multilateral agencies such as the AIIB, ECAs from non-participating countries and also commercial banks, development financial institutions and other stakeholders.

3 “Projected Costs of Generating Electricity”, International Energy Agency and Nuclear Energy Agency, 2015 Edition.

4 https://www.pv-magazine.com/2016/08/17/renewables-sweep-chiles-electricity-market-and-set-historic-low-prices_100025801/

5 https://www.worldenergy.org/wp-content/uploads/2016/09/Variable-Renewables-Integration-in-Electricity-Systems-2016-How-to-get-it-right_-Full-Report-1.pdf

6 <http://www.oecd.org/newsroom/statement-from-participants-to-the-arrangement-on-officially-supported-export-credits.htm>



Indeed, a number of financial institutions have already announced that they will no longer be funding development of new coal projects with some exceptions for “clean” coal and/or new plants in developing countries, showing some parallels with the exceptions under the Arrangement. Multilateral agencies and development banks have also markedly reduced their support for coal-fired plants, with one report citing a reduction in multilateral and development bank financing for coal-fired power plants at US\$1.5 billion between 2011 and 2014 compared with US\$12.2 billion in the previous four-year period.⁷ The Asian Development Bank will now only support coal projects if they use high-efficiency and low-emissions technologies and the World Bank will now only support coal projects in “rare” circumstances (for example, where there is a lack of feasible alternatives to coal or a lack of financing for crucial coal power projects). In its Energy Sector Strategy discussion draft published in January 2017 as part of the second stage of a consultation exercise that began last year, AIIB has stated that it will focus on

⁷ “Coal or no coal: A balancing act for MDBs”, www.devex.com, 18 January 2016.

supporting and accelerating the region’s transition toward a low-carbon mix and as part of this only intends to support coal-fired plants that replace less efficient capacity or are essential to the reliability of the system or if no viable or affordable alternative exists, particularly in low income countries. This policy statement appears to be consistent with the OECD’s New Rules, although with perhaps more ground for subjective interpretation of the policy as currently stated.

As many financial institutions shift away from supporting the development of new coal-fired plants, they have also pledged to provide increased funding for new renewable energy plants, increasing the sources of funding for renewable energy developers and accelerating the growth of the industry.

Government targets and incentives under regulatory frameworks

Many governments in the Asian region have now adopted targets to increase the proportion of electricity generation produced from renewable energy sources. On a regional level, the 2016 ASEAN Plan of Action for Energy Cooperation included a target of 23 per cent renewable energy generation by 2025.

These targets are typically accompanied by a package of incentives to drive the necessary increase in renewable energy development, often including tax benefits and preferable tariffs. We consider the renewable energy aspirations of just a few countries in the region:

Thailand

Thailand is seeking to achieve a target of 22 GW of new renewable energy capacity by 2036 and its Alternative Energy Development Plan sets a target of 25 per cent energy consumption from renewable energy by 2021, including development of an additional 2 GW of solar, 363 MW of biomass and 1.2 GW of wind energy. Thailand initially incentivised renewable development with an “adder” tariff, introduced in 2006, that would add a premium to the wholesale electricity price. In 2015 this was replaced with a feed-in tariff (FiT) plus premium programme that focuses on supporting small projects up to 10 MW and, exceptionally for solar PV projects, up to 50 MW. In order to bring prices down for consumers, the government intends to introduce competitive bidding for all technologies other than solar PV. Thailand also encourages renewable energy investment through tax and other fiscal incentives as set out in its “Investment

Policy for Sustainable Development Campaign for Renewable Energy Projects". Thailand's renewable energy focus has led to a healthy solar market, with solar capacity increasing from less than 2 MW to 2800 MW in less than ten years.⁸ The solar market is expected to grow further to 6,000 MW by 2036 as the country begins to scale-up the size of its projects.

China

President Xi Jinping announced plans at COP21 to ensure China's carbon emissions would peak by 2030. Around the same time, in December 2015, official news agency Xinhua quoted the State Council as saying that it planned a major shutdown and upgrade of coal-fired power plants. In January 2017, the deputy head of the National Energy Administration, Li Yangzhe, announced that China intends to invest Rmb2.5 trillion (US\$359.8 billion) in the development of renewable energy resources as part of the 2016-2020 five-year plan for the energy sector.⁹ While China remains dependent on coal, the plan envisages the share of non-fossil fuels will rise to more than 15 per cent and the share of natural gas should reach ten per cent by 2020, covering 68 per cent of expected energy consumption growth to 2020. China has a FiT scheme in place for biomass, wind, solar and hydropower with particularly favourable tariffs for solar. China's Renewable Energy Law also offers various other fiscal incentives, including tax benefits and preferential loans. Following the successful operation of seven pilot schemes, China is also on track to launch its national unified carbon market in 2017, which will give fresh impetus to low-carbon generation in the country. Real progress has been seen in China as a result of these policies, with China taking over Germany's mantle in 2016 by having the world's largest solar generating capacity, totalling 43,000 MW. An additional 15,000 MW was installed in 2015. However, now that the solar market is established, the Chinese government is reportedly considering cuts of as much as 20-30 per cent to its current solar tariff which may slow down greenfield investment.

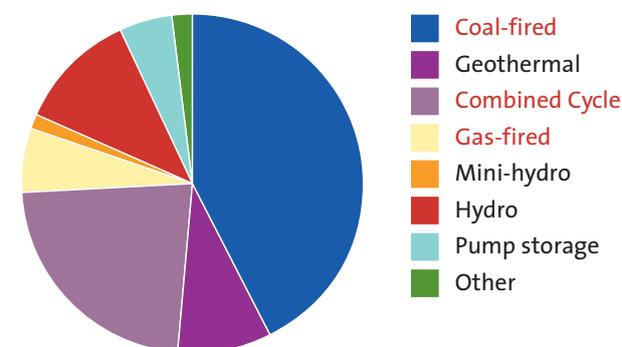
Indonesia

In June 2016 Indonesia released a new Electricity Supply Business Plan with a target to increase the proportion of electricity produced from renewable energy sources from six per cent in 2015 to 28 per cent by 2025. Of the 80.5 GW of planned new generating capacity, Indonesia's renewables focus will be on 14.5 GW of new hydro (large-scale, micro and pump storage) and 6.1 GW of geothermal. Less than 2 GW (2.4 per cent) is expected to come from solar, wind, biomass, tidal or any other forms of renewable energy. FiTs have been offered for electricity generated by biomass, municipal solid waste and landfill gas across different regions of Indonesia since 2012. A regulatory tariff (which varies depending on project size and geographic location) for solar projects was introduced in July 2016, and a similar tariff mechanism is expected for wind projects in early 2017. The Indonesian renewable energy programme has been slower to take off than other countries such as Thailand. Reports say that investment in new and renewable energy in Indonesia amounted to US\$870 million in the first half of

2016, 63.5 per cent of the total target of US\$1.37 billion. The biggest portion of that investment, US\$560 million, was invested into geothermal energy.¹⁰ At the same time, the Energy Supply Business Plan forecasts 34.8 GW of new coal-fired generation capacity, or 43.2 per cent of the total new capacity. Overall energy growth will continue in Indonesia. While supportive of renewable energy investment, the tariff regimes have left the state-owned electricity generation, transmission and distribution monopoly (which currently relies on government subsidies to survive a substantial gap between revenues achievable under regulated tariffs and the cost of generation) with the uncomfortable, if not unlikely, option of going further into the red to support offtake renewable energy projects. A new regulation issued by the Ministry of Energy and Mineral Resources in February 2017¹¹ seems aimed at reversing this outcome. Tariffs for the purchase of power from a number of renewable energy sources will now be capped at the lower of: (i) 85-100 per cent of the average cost of generation in the relevant local area where the power plant is located; and (ii) 100 per cent of the average national cost of generation.

On 5 January 2017, Cabinet Secretary Pramono Anung reaffirmed the Indonesian government's commitment to its ambitious 35,000 MW energy target for 2019 (despite some internal scepticism from the national power utility PLN and the Energy and Mineral Resources Ministry that this target may not be achievable).¹²

Chart: Not the end for coal in Indonesia: Indonesia's proposed energy mix in 2025 as set out in Indonesia's Energy Supply Business Plan 2016–2025 (issued June 2016)



Philippines

The Philippines' National Renewable Energy Program set a target to grow the country's renewable energy capacity from 26 per cent (including hydropower and geothermal) to 35 per cent of the total generating capacity by 2030, and achieve grid parity for wind power with the additional commissioning 2.3 GW.¹³ In order to achieve this target, the country adopted a feed-in tariff programme enabling renewable energy developers to sell electricity to the grid at a premium over 20 years as set by the Energy Regulatory Commission. In addition, as with Thailand, renewable energy

8 "Renewable energy and investment in ASEAN", ASEAN Briefing, Dezan Shira & Associates, 4 November 2015.

9 "China to invest billions into renewable energy by 2020", UJ Global, 6 January 2017.

10 <http://www.thejakartapost.com/news/2016/08/18/rp-14-quadrillion-investment-needed-clean-electricity.html>

11 Ministerial Decree of the Minister of Energy and Mineral Resources number 12/2017.

12 "Government maintains 35,000 megawatt electricity target", Antara News, 5 January 2017.

13 <https://www.doe.gov.ph/national-renewable-energy-program>

developers also benefit from a further package of financial incentives including tax benefits under the Renewable Energy Act of 2008. The Act also provides for priority connections to the grid for renewable energy and the right for consumers to source their electricity from renewable energy plants. The Philippines may need to take even more ambitious steps in the next decade, having signed on at COP 22 in 2016 as a climate vulnerable nation to aim for 100 per cent renewable energy between 2030 to 2050. However, messages from President Duterte's new government have been mixed, and the Philippines is yet to ratify the Paris Agreement.

Japan

In response to the Fukushima nuclear disaster, Japan adopted a renewable energy FIT regime in 2012 offering some of the most favourable tariffs in the world and that generated a significant level of interest in the market. The scheme is widely considered to be successful; Japan saw some US\$36.2 billion of investment in renewable energy in 2015, similar to the figure in 2016, and the total share of renewables in Japan's energy mix increased from 4 per cent to 6 per cent. However, the FIT for PV solar projects has been slowly wound back, and amendments to the scheme that are now coming into effect this year will see the FIT for large-scale PV solar projects replaced by a reverse auction system in order to address high costs and delays in the actual development of projects after initial certification. While this may drive prices down and dampen some interest, the FIT for other renewable resources including geothermal and offshore wind remains favourable.

Myanmar

Myanmar has set a target for renewable energy to make up nine per cent of its generated electricity by 2030. However, its renewable energy framework remains underdeveloped when compared with other countries in the region. There is no renewable energy law and there are no specific incentives. This is not necessarily surprising given that improving the transmission infrastructure is the key priority for the government. As a result, renewable energy projects have remained on a small, localised scale, with stand-alone PV solar used to bring electricity to remote rural areas and only small wind farms currently in operation.

Vietnam

Vietnam's renewable energy laws remain patchy and decentralised. There are relatively clear regulations for wind, hydro, biomass and waste to energy, but less clarity for solar, wave and geothermal. However, investment is expected to grow, and in May last year the government unveiled its new Renewable Energy Development Strategy, setting a target of increasing renewable power generation to seven per cent of total generation in 2020 and ten per cent in 2030 (from less than one per cent, excluding hydro, in 2014). The "Revised Master Plan – Development of National Power Sector VII" released by the government of Vietnam in March 2016 aims to meet those renewable energy goals. Nevertheless, it is worth noting that the Revised Master Plan still indicates an increasing reliance on fossil fuel generation, with 53 per cent of power generation in 2030 (equivalent to 55.3 GW) targeted to be coal-fired power (up from 34 per cent, or 13.1 GW in 2016) and another 17 per cent of power generation in 2030 to be gas-fired.



Energy security

A number of countries in Asia are reliant on imported fuel sources to operate their generating facilities. Governments are increasingly keen to consider alternative forms of power generation in order to mitigate the risk of over-reliance on such imports by accelerating the growth of renewable generating capacity. The concern is that over-reliance might create acute issues in the face of any sudden geo-political events or declining domestic fuel sources.

Why this is not the end of the story for coal

Asia is expected to become the largest energy-consuming region in the world. Even with the slowdown in growth in China, Asia remains an electricity-hungry region. Developing countries, in particular, need to add significant levels of capacity in order to deliver electricity to those in their populations who still lack access and to keep pace with the demands of rapid industrialisation and urbanisation. As a result, positive renewables targets and increases in investment in new renewable generation are only half the story. New coal plants continue to be planned in both developed markets, such as Japan and the developing markets of Southeast Asia. Even though China is the world leader in renewable energy in terms of generating capacity, coal remains its main source of power. There are a number of key drivers that keep coal-fired power generation as an essential part of the region's future energy mix:

Coal is cheap, abundant and efficient: the low price of coal, which seems likely to continue for some time, allows for low electricity prices to be passed onto the voting public. Coal is also



abundant and (especially if wider environmental costs are ignored) a very efficient means of producing energy.

Improving technology for coal-fired plants: while many coal-fired plants, particularly in developing countries, operate far below their design efficiencies, supercritical and ultra-supercritical technology can achieve higher efficiencies and significant emission reductions. Although capital costs are higher, these technologies remove some of the barriers to the continued use of coal, especially given that the use of ultra-supercritical technology might help avoid some of the funding restrictions placed on financial institutions, export credit agencies and multilaterals.

Consistency of supply: because renewable energy plants (particularly wind and solar) are generally intermittent output systems, coal is more attractive for base load electricity generation. Storage technology, which mitigates the disadvantages of intermittent power supply by storing excess power and releasing it when there is a production shortage, is developing at a fast rate but further advancement is required to allow cost-effective solutions. Some countries have managed, at least momentarily, to run their entire electricity network exclusively on renewable energy; in May 2016 Portugal covered its entire electricity consumption by solar, wind and hydro power in a 107-hour run and Germany announced that clean energy had powered almost all of its electricity needs on Sunday 15 May 2016.¹⁴ However, storage remains expensive and greater investment in this technology is needed. In the meantime, a

¹⁴ <http://www.bloomberg.com/news/articles/2016-05-16/germany-just-got-almost-all-of-its-power-from-renewable-energy>

heavy reliance on coal-fired (together with gas-fired) plants to meet base load requirement is likely to continue.

Grid connections and transmission infrastructure: in a number of jurisdictions in Asia, a lack of transmission infrastructure and grid connections is limiting renewable development. For example, it is estimated that only half of Thailand's renewable generation sites are connected to the grid. Putting transmission infrastructure in place can be a costly exercise for renewables where, except perhaps for biomass generation, the site of the generating facility is dictated by nature and not the location of consumer demand.

Scale: while the Middle East has seen large-scale solar PV projects in recent years, much of Asia (excluding China and India) has not yet seen large-scale renewable energy projects to match the generating capacity of coal or gas. Until renewable energy projects reach sufficient scale, fossil fuels are likely to remain the most viable energy source to meet the lion's share of the demands of industrialisation.

Conclusion

While Asia is, consistently with global trends, shifting towards renewable energy and policies to increase renewable energy's share of the energy mix, Asia is likely to continue to rely substantially on coal-fired plants for the near future.

The reason for this twin-track approach is primarily the need to utilise multiple generating sources in order to meet the vast energy needs of a region that includes a number of developing and industrialising countries, coupled with an abundance of efficient and cheap coal.

Gas has also attracted a lot of interest in Asia in recent years and should not be forgotten in the debate over finding the optimal fuel-mix for countries in the region. Gas prices are currently low and this is incentivising various countries to utilise more gas for power generation. Transportation of gas can be more challenging than coal, especially where there needs to be transport across the sea, but there is increasing development of medium to small-scale LNG transportation and regasification infrastructure in various parts of Asia. This infrastructure can be expensive, though, and the benefits in terms of emissions reductions when compared with coal may be marginal.

Overall, we expect coal to remain an important part of Asia's energy future in the region, even while renewable energy capacity continues to grow as a proportion of the whole. However, as the cost of renewable energy drops and storage technology improves, and global anti-coal sentiment and political pressure increases, the shift to renewable generating capacity will continue to ramp up in the longer term.



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LNG PRICING DISPUTES:

The lessons from Europe

by Matthew Saunders, Ronnie King and Emma Martin

Current market circumstances and forthcoming changes in the LNG industry will likely lead to an increase in the number of parties seeking to renegotiate the pricing provisions in their long-term LNG supply agreements. The European gas market has, for a number of years, been the main battleground for price reopener disputes. This article explores the lessons that can be taken from the European gas pricing experience and sets out some of the key considerations to be borne in mind by those likely to find themselves engaged in renegotiations of their long-term LNG commitments including, in particular, those relating to pricing and volume flexibility.

According to the Oxford Institute for Energy Studies (OIES), one of the best informed observers of global gas markets, the LNG industry is on the verge of “radical” and “fundamental” change. In its September 2016 publication, “The Great Reconfiguration”, the OIES notes that dramatic changes are set to overturn more than five decades of industry practice, including – crucially – the model of LNG long-term sale and purchase agreements (SPAs) where pricing is linked to oil prices. The OIES cites two main potential causes of the pending changes: significant new LNG export capacity, which is due to come on stream in various parts of the world, and a slowing down of Asian demand.

Similarly, in autumn 2016, the LNG Journal noted (by reference to the latest analysis from the International Energy Agency) that: “The oversupply situation in liquefied natural gas markets that

emerged in 2015 is worsening in 2016 and will not substantially improve until 2019 at the earliest”.

The excess of LNG resulting from such supply-demand imbalance is expected to affect both the pricing and other contractual dynamics in long-term LNG SPAs (including, in particular, terms relating to flexibility).

The experience of the European natural gas markets over the past decade shows that any significant attempts to “reconfigure” existing contractual arrangements are likely to give rise to disputes. Two of the most likely subjects for dispute are those of pricing and related contractual flexibility, particularly as to volume, since those factors go to the core of whether a contract is profitable or not.

The experience of European natural gas markets since 2008 has been one of a dramatic upswing in the number of disputes,



many of which have ended up in international arbitration, arising from the invoking of “price reopener” clauses in gas SPAs. The effect of such widespread recourse to arbitration mechanisms has been the resetting of prices by arbitration tribunals and, on occasion, significant changes being made to other elements of pricing formulae which has provoked controversy as to whether such changes are properly within an arbitration tribunal’s jurisdiction.

The considerably adversarial nature of the arbitration process has also impacted upon the historically consensus-driven approach that has prevailed in the gas industry, which has a relatively small number of players and, until recently, has seen shared assumptions as to what is an acceptable “modus operandi” for commercial and contractual negotiation.

There are a number of lessons that can be drawn from the European natural gas experience and applied to LNG renegotiations and disputes in other regions. There are, of course, many significant differences between the contracting styles and commercial contexts that apply to natural gas sales arrangements in the European market and LNG sales arrangements in the global markets, but there are enough features in common and sufficient similarities of approach to the resolution of disputes for the study and analysis of the European gas market experience potentially to pay significant dividends – the lessons that can be drawn may maximise a party’s chances of success in both renegotiations and disputes.

Europe’s “perfect storm”

The European experience of an upswing in gas price arbitration came about by way of a “perfect storm” emerging from the global financial crisis of 2008. The key elements were:

- liberalisation of the European gas market pursuant to the EU’s Third Energy Package (combined with enforcement steps being taken by national regulators), which led to the development of gas trading hubs and the creation of both physical and administrative infrastructure capable of supporting spot trading of gas and thus an increase in gas-to-gas competition;
- a reduction in demand for gas arising from the slowdown of the European economy associated with the global financial crisis;
- a policy-driven increase in the role of renewables in the generating mix;
- technological developments supporting the availability of gas from non-conventional sources, leading to an increase in supply; and
- a resulting “decoupling” of spot market prices for gas from traditional oil-linked prices (where it had been historical practice to link the price of gas to that of alternative fuels, particularly oil products).

As a result, players sought to renegotiate the price at which they had committed – often for a lengthy period of time – to take gas. In many cases, negotiations gave way to arbitration.

Although there exists a significant diversity of approach (extending to gas SPAs without any price reopener provision



and some that contain only contractual hardship clauses), the European gas arbitration community has largely adopted a common approach to resolving these pricing disputes. It is this that enables wider lessons to be taken as to how parties dealing with LNG disputes may benefit.

Applicable legal principles

Although no single standard exists for European gas price reopener clauses, there are significant similarities in the approach to their drafting and interpretation. It is relevant that long-term gas sales agreements are predominantly continental European creatures, with few UK long-term contracts because of the much earlier liberalisation of UK gas markets. The effect of this is that the gas price arbitration world has been significantly influenced by civil law.

This is significant because it means that the civil law approach to issues such as document production, or the extent of a tribunal's jurisdiction to amend contractual provisions other than those relating simply to price, may prevail in LNG disputes, even where the governing law is not a civil law one.

Contracts are often vague as to how far a party is under an obligation to negotiate "in good faith" and what the implications may be if it can be shown not to have done so (it is relevant that civil law contract regimes may impose an obligation to negotiate in good faith even if one is not expressly provided for in the contract).

Revision of price (and other contract conditions) may also be available under certain civil law regimes where they have been chosen as the governing law of the contract. Certain civil law regimes grant a right to adjust the contractual bargain where changes unforeseeable at the time the contract was entered into have the effect of causing "unreasonable hardship". In extreme cases, the contract may be held to be ineffective as a whole. Such contractual rights are perhaps most clearly available in the Scandinavian context, applying section 36 of the relevant contracts act and the Scandinavian contractual doctrine of failed assumptions. Although such laws may be less commonly applicable in the LNG world, it pays to understand their implications.

Specific price reopener lessons to apply

Obligations to negotiate

One key lesson that can be taken from the European gas pricing experience is the significance of express obligations to negotiate. It will be particularly important that negotiation obligations are adhered to where the fact of negotiation having taken place may be a contractual precondition to commencing an arbitration. To run an arbitration and only at the end discover there was no jurisdiction, because a necessary precondition to the commencement of the arbitration process was not met, may prove to be an extremely expensive mistake.

Whether or not the governing contract law recognises the existence of an obligation to negotiate, or dismisses it as an unenforceable "agreement to agree", will commonly be a significant distinction between civil and common law governing laws.

Evidence of trigger

Another lesson is the fact that a party will commonly be expected to provide a measure of support for its assertion that a trigger for the resetting of a price has been met, including some degree of clarification as to the relevant market in which the inability to market gas economically has arisen. The contract itself may be vague on the level of substantiation to be given, but the applicable law may provide guidance.

Confidentiality

A further lesson is that close attention should be paid to requirements of confidentiality. Pricing formulae are contractual terms of the highest commercial sensitivity. Does the contract provide for material to be kept confidential? What degree of confidentiality will attach to documents that are provided to lawyers and experts or to the tribunal? What is the status of documents produced under compulsion through a document production exercise? How far can commercial secrecy be an effective objection if the counterparty makes an application for production of documents to the tribunal?

The key lesson is that these points should either be agreed with the counterparty or be the subject of an early procedural ruling from an arbitration tribunal. That way surprises can be avoided.

Economic evidence

Of prime importance is the need carefully to prepare the economic evidence that supports the claim (or which will be needed to respond to an anticipated claim), particularly expert economic evidence. There is a finite pool of experienced testifying economics experts and instructing the right team early on can bring significant advantages. It would be folly to commence a price review without understanding how far the economic analysis supports it.

Alongside economics experts, it may be necessary to adduce factual testimony or possibly expert testimony as to industry practice – experience suggests there is a particularly limited pool of industry experts with relevant recent experience. Tribunals may find evidence from an experienced commercial negotiator or contracts manager more compelling than that from a “hired gun” consultant.

Early input from legal counsel

From the outset, there should be input from counsel experienced in gas pricing disputes – their full involvement from an early stage will assist in establishing and maintaining legal privilege (thus protecting documents from compulsory production) and will ensure that the correct early – and key – decisions are taken.

The attitude of arbitrators

One result of the growth in gas price arbitrations has been the establishment of a “community” of legal and industry practitioners with shared experience of the interpretation of relevant clauses and the running of arbitrations. This “community” comprises not only specialist arbitration lawyers in leading arbitration practices, but also expert economists and a “cadre” of arbitrators who have experience in disputes often involving much more economic than legal controversy and which consequently require a degree of familiarity with economic principles.

It is quite likely that these same arbitrators – because of their gas sector experience – will be appointed and that – at least initially – they will adopt similar approaches to those developed in the European gas pricing context.

Alongside the choice of arbitration counsel, thought should be given from the outset as to the choice of arbitrator to be nominated and to preferred candidates for chairman. Points to consider include whether a common or civil law background is preferred and whether previous gas pricing experience, or experience of economics-based disputes, is necessary/desired. Careful research may provide useful intelligence as to an arbitrator’s likely attitude to issues such as document production – whether it will be restricted to those issues upon which a requesting party bears the burden of proof or whether it will be more widely available (for example, where a legitimate line of inquiry involving a defined and narrow class of documents is established).

Price review or rewriting the parties’ bargain?

A more fundamental issue worthy of research is the attitude an arbitrator is likely to take to his or her jurisdiction; does it

extend to merely adjusting the price or is there a risk that the arbitrator will go further and rewrite other elements of the price formula? Arbitration agreements are commonly imprecise as to the jurisdiction that is granted to an arbitration tribunal. This question is normally of little significance given their role is clearly to adjudicate the dispute, but the position is more complex (and controversial) in a pricing dispute.

It is important to consider how far the right to set a new price extends and whether it encompasses the arbitrator being able to change other elements of the pricing arrangements; for example, the point of reference from a basket of oil products to prices achieved on a particular gas trading hub. Critics contend that such actions amount to much more than price adjustment and represent impermissible rewriting of the parties’ contractual bargain. Proponents contend that only through such steps can tribunals properly take account of changed circumstances as fundamental as the decoupling of gas prices from oil pricing.

Parties are well advised to agree at the outset of an arbitration whether they actually wish to grant such wide-reaching powers to a tribunal comprised of arbitration lawyers who may have negligible commercial experience as to the implications of the changes they impose.

There is also sense in clarifying how far back a tribunal may look – must it restrict its analysis of evidence as to market changes to that available between the date of the last review and the invoking of the current process or may it also look at information available since? To what extent is the future relevant and is evidence required as to the likely impact of the changes relied upon in the future? Should the tribunal be aiming to set a price that renders the contract economically viable until the next point at which it can be reopened?

Looking forwards

It may very well be the case that in due course those responsible for adjudicating LNG disputes “steer their own course” and develop approaches unique to the LNG market. However, at least initially, it is likely that approaches similar to those experienced in European natural gas pricing disputes will prevail. It is because of the “proving ground” it has become for gas disputes that lessons from the European gas pricing experience can usefully be applied in order to maximise the chances of winning.



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BLOCKCHAIN:

Beyond the Microgrid

by David Futter and Christopher Bates

Blockchain technology has the potential to transform dramatically the entire energy market – from microgrids and beyond. In this article, we look at the future opportunities for the technology and explore some of the key legal and regulatory issues that will need to be considered before mainstream adoption can be realised.

In Spring 2016, a blockchain-powered project in Brooklyn, New York was piloted to enable the residents to buy and sell renewable energy directly to their neighbours. The project, run by a digital start-up called Transactive Grid, aims to disintermediate the central electricity suppliers and network providers through the use of blockchain technology. Participants in the project connect solar PV systems installed on their rooftops to a network of computers, which continuously record the energy generated and trade the excess within the community.

All buildings in the project are interconnected through the conventional power grid, with the energy transactions being managed and stored using a central blockchain. The project uses both smart meter technology and underlying blockchain software: the smart meters record the wattage of energy produced, while the blockchain

software executes and records the transactions. All energy is bought and sold without a central energy company being involved; the blockchain platform manages the market autonomously.

The Brooklyn Microgrid project is too nascent for us to assess properly its likely impact on the electricity market – whether the microgrid concept can evolve beyond merely an interesting local community initiative into something more fundamentally transformative remains to be seen. Nonetheless, there is little doubt that the underlying blockchain technology is capable of heralding serious transformation (or disruption, depending on your viewpoint) to the energy sector as a whole.

So, what is blockchain technology?

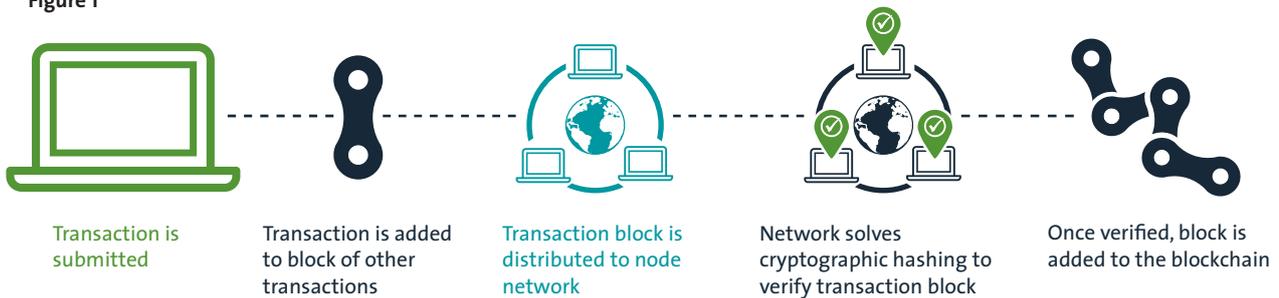
At a very high level, blockchain technology describes a collection of software programs

that enable identical copies of data to be recorded, maintained and verified across a community of users, enabling them all to agree on the data's authenticity and veracity. To achieve this, blockchains use decentralised storage platforms to record the data across a peer-to-peer network: each computer within the network can hold a complete copy of the data (i.e. in a ledger) and confirm blocks of new transaction messages that are submitted for entry onto the ledger by other members of the network.

In other words, it is basically a shared database: an enormous spreadsheet that runs simultaneously on thousands – in some cases millions – of computers (known as “nodes”), and which is open source, so that any one of those nodes can read, check and add to the database.

A blockchain can be permissioned (a private network where all participant nodes are known) or permission-less (a

Figure 1



public network where anybody can act as a node). In either case, the validation process typically involves nodes solving state-of-the-art cryptographic problems, using complex algorithmic functions (known as “hashes”). These hashes are used as evidence that each transaction has been authorised by its sender and used to link each block of transactions to each other. So, once a block has been validated by consensus on the network, it is then added indelibly onto the ledger – see figure 1. This is deliberate and serves to shield the blockchain against cyberattack – any hacker would have to control more than half the entire node network to alter any record in the blockchain.

The overall process creates a mutual consensus mechanism through which it

is practically impossible to alter any of the past, validated transactions on the ledger.

The first blockchain was developed as the basis of the crypto-currency “bitcoin”. Since then, various iterations of the core blockchain technology have evolved. These iterations deploy additional functionality, including blockchains which are beginning to integrate programmable logic to enable transactions to be effected automatically and consensually across the blockchain community (known as “smart contracts”).

Possible applications for blockchain in the energy sector

Apart from the prospect of decentrally generated energy being sold directly between participants in smart grids like that of the Brooklyn Microgrid, other future

applications for blockchain are being envisioned across the energy sector.

Many possible uses, like the ones outlined below, remain at early stage development. But because blockchain technology, particularly through the advance of Smart Contracts, enables transactions to be made directly between individual participants, it is beginning to change the way that energy firms think about their businesses. Much like the disruption experienced by financial services over the last few years, blockchain promises the energy industry opportunities to exploit lower operating costs, faster processing capacity and to create new innovative sell-side business models.

Simplified energy supply ecosystem

A major possible use being explored is to deploy blockchain technology via Smart Contracts to redesign the energy supply value chain. The concept is that, by creating decentralised common infrastructures, a future state can be created in which the current complex, multilateral energy value chain can be simplified dramatically. For example, Electron, a London-based energy start-up, is looking to apply blockchain technology to the industry’s asset registration services, to create a distributed shared platform for energy providers to obtain information about particular assets, and also to record any transactional changes to those assets.

Smart energy switching

Blockchain technologies could allow consumers to arbitrage energy rates in near real time, so that rather than paying for their energy needs at a fixed, set rate with a single supplier, they could switch



dynamically between multiple providers on an intra-day basis to optimise best price. Such a dynamic purchasing model is possible due to the potential speed and efficiency with which blockchain-based transactions can, in theory, be effected. In their latest Report on Innovation and Regulation, the British gas and electricity markets regulator, Ofgem, continues to identify a strong desire to overhaul the current processes for consumers to switch their energy suppliers, so this type of development is likely to be of keen interest to energy market regulators.

Global energy transfers

Blockchain technology could form the basis of software platforms for “sending” energy, such as electricity or gas, anywhere in the world. These energy transfers could be made via interconnected software applications that are developed on top of a blockchain. The developers of such energy transmission platforms see them competing with the money remittance market; for example, enabling migrant workers to send energy back home in place of cash, or by giving individuals the choice to donate energy to specific charities or even developing nations, with all donations being recorded and verified transparently.

Energy credits

Decentralised storage on a blockchain of all records of renewable energy generated by consumers, communities or businesses could be automatically converted into government-backed digital energy credits. These credits, being a new form of crypto-currency, could in turn be used to purchase commodities, effectively operating as a direct renewable energy incentive.

Key challenges to adoption

While industry’s recognition of the transformative potential of blockchain continues to grow, there remain considerable areas of risk, on which the market and global energy regulators will be keen to focus, as the technology and its applications mature.

One of the first hurdles is the lack of technical standardisation. It is unlikely that energy businesses that want to use a blockchain for a particular use will have all of the operational data needed to operate the service. Blockchain-based platforms will therefore need to integrate with both the energy businesses’ legacy systems and to exchange data with third party participants. To enable that data to be shared optimally, it needs to be standardised so that it is compatible and can interoperate efficiently across the distributed blockchain platform. Some helpful progress in this area is being made: in the Spring of 2016 the International Organisation for Standardisation (ISO) received official applications to establish a new field of technical activity on blockchain and other distributed ledger technologies. Although a useful step forward, it will take time to achieve truly international standards for blockchain.

A related concern is the current deficiency of acceptable governance models for blockchain-based technologies. Many prospective blockchain projects envision participation between various third parties within the energy supply market. Since control over the underlying blockchain ledger is (by definition) distributed,

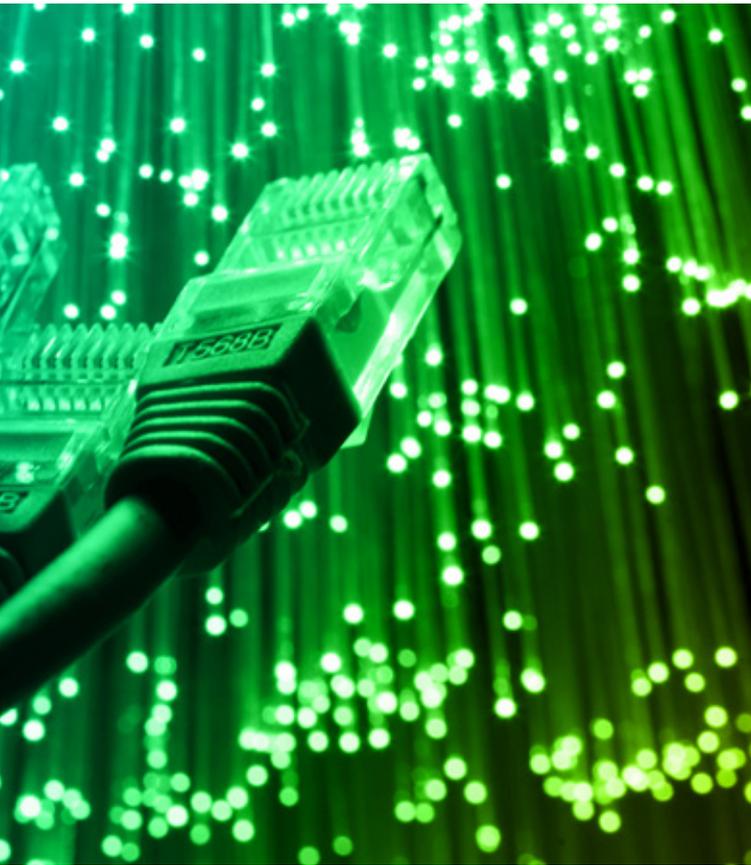


detailed participation agreements may be needed to govern access, set rules of conduct and to apportion accountability and liability. In the absence of a strong governance framework to define clearly the roles and responsibilities of the blockchain participants, blockchain platforms will continue to struggle to achieve widespread adoption, no matter how compelling the underlying business case.

While strong governance is crucial to ensuring the delivery of effective, predictable and sustainable blockchain services, different participants in a blockchain will have very different commercial drivers and expectations. Currently there is considerable debate in the blockchain community around what form governance over blockchain technologies should take. Getting it right will take time, effort and collaboration.

Regulatory uncertainty is also a major inhibitor to the adoption of blockchain. Regulators now recognise that innovation will play a vital part in shaping the future of the energy system and that advances in technology are already increasingly affecting how energy is produced, transported, managed and consumed. Importantly, they are beginning to appreciate that technological innovation alone is not the whole story – new business models and operating processes, empowered by innovations such as blockchain, can also drive greater market competition and realise benefits for energy consumers.

However, up to now authorities have shied away from engaging in discussions on how blockchain technologies might be regulated. Encouragingly, the regulators have started to show signs of



wanting to engage more proactively to create the right regulatory environment to foster innovation. For example, in early December 2016 Ofgem announced its launch of “Innovation Link”, a service to help technology-led businesses looking to operate in the energy markets obtain rapid feedback on the regulatory framework and what it might mean for their ideas. The regulator is also considering introducing a regulatory “sandbox” (something already successfully used in other industries such as financial services) to enable new products and services, including blockchain-based projects, to be trialled in a controlled environment within the existing regulatory framework. Part of the aim of these regulatory initiatives is to facilitate competition through innovation, but they also enable the regulators to become more familiar with blockchain technologies and to start to consider how the regulatory landscape may be adapted in the future to support them.

Aside from regulatory concerns, other legal issues need to be worked through too. The legal enforceability of transactions effected via blockchain technologies is yet to be fully tested. The contract law regimes in some jurisdictions (including the UK) present potential issues, particularly for permission-less ledgers. For instance, some question whether there is sufficient certainty as to the parties’ identities and/or all the contractual terms between the participants in a blockchain to stand up to legal challenge.

A primary benefit of blockchain technologies is that they are capable of generating considerable efficiencies for cross-border transactions, as the nodes on a blockchain can be located on servers anywhere in the world. In view of this, another significant

enforceability question remains unanswered: who should have jurisdiction to hear any disputes and in what forum?

How blockchains handle data also needs consideration from a legal perspective. Any type of data can be encoded into a block for entry onto a blockchain. Where this is personal data (such as energy consumers’ billing or meter details) it will be widely transferred to every other node in the network, some of which could be located across geographical boundaries. Careful consideration must therefore be given as to how personal data transfers across distributed blockchains can comply with international privacy law. For example, Principle 8 of the UK Data Protection Act 1998 restricts (and places certain protections on) transfers of UK residents’ personal data outside of the European Economic Area. While ensuring data compliance for blockchains is not impossible (and a number of blockchain innovators are developing proprietary applications aimed at achieving this) all issues must be considered from the outset as part of the design process to ensure the blockchain’s underlying coding and protocols are programmed appropriately.

Outlook

As is often the case with potentially transformative technological innovations, blockchain platforms are being developed faster than the existing regulatory and legal frameworks can be adapted. Nonetheless, and despite other challenges, real world applications of blockchain technologies have already achieved some surprising traction within other industries such as financial services, where both disruptive start-ups and incumbent legacy firms are investing seriously, either in competition or collaboration, in ways to leverage the technology and realise some of the enormous potential benefits it offers.

Whether blockchain will gain similar maturity in the energy sector remains to be seen; proponents of the technology see no reason why it should not. Looking past the hype, however, it is clear that considerable work remains to be done, with significant further collaboration required between industry and regulators to deliver workable, secure and compliant blockchain solutions. In our view, therefore, it feels unlikely that 2017 will be the year for widespread blockchain adoption in the sector. Nonetheless, it would be a daring C-suite which decided to dismiss its potential and not keep a close eye on where this technology is heading.



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DIRECT PPAS:

Connecting with corporates

by Antony Skinner and Peter Grayson

For onshore wind farm developers and solar PV developers in the UK, 2015 and 2016 have proved to be key years in their evolution. The UK Government has clearly come to the conclusion that onshore wind and solar PV projects in the UK are now advanced enough to stand on their own without the need (or justification) for a green subsidy. For energy from waste (EfW) plants, there continues to be a move away from local authority backed supply contracts to a merchant structure which relies upon waste supply and power offtake from corporates.

There are issues that arise regarding hurdles in the planning permission process, but the focus of this article is whether the development of an onshore wind farm, solar park or EfW/biomass facility can be commercially viable without a green subsidy by using a direct power purchase agreement (PPA) with a non-utility company offtaker who is willing to pay a higher price than the wholesale market price. We note that direct PPAs have already been used alongside green subsidies which further enhances their benefits.

The concept of direct PPAs has been in existence for many years but, in practice, their use has been relatively limited, primarily due to the availability of utility PPAs and the need for an investment grade utility offtaker in order to make a PPA “bankable” for the purposes of project financing. However, at a time when there is a material delta between the wholesale price for electricity that a generator will receive and the retail price for electricity that a large consumer can expect to pay, there is an incentive for generators and

consumers alike to be creative and devise bilateral solutions in order to cut out the middle man and arbitrage the difference.

Bankability of direct PPAs

From a bankability perspective, the identity and creditworthiness of the offtaker will be a key consideration. As a general rule, funders do not like to be exposed to corporate credit risk for longer than three to five years. Funders have accepted long-term credit risk on utilities companies on project finance transactions to date, but

taking the equivalent risk on a corporate whose business has nothing to do with electricity (other than a need to consume) is a very different proposition. It will be a challenge for funders to accept this risk without a form of credit support and funders are likely to review this on a case-by-case basis in the context of each transaction as a whole. If funders cannot accept the credit risk on the offtaker, they may disregard the price of power under the direct PPA and assume the price of power is based on the System Sell Price or another indexed price. This is unlikely to be attractive to sponsors as any upside under the direct PPA will only be taken into account in the equity financial model and not in the funders' base case.

Different types of direct PPAs

There are three main types of direct PPA, as follows:

- a contract for difference;
- a sleeving PPA; and
- a direct wire PPA.

We analyse each of these further below.

Contract for difference

A contract for difference (not to be confused with the specific contract for difference used by the Government to incentivise renewable energy development) is the simplest form of direct PPA. Under this form of contract, the generator and an offtaker enter into a contract for difference under which they both agree a market index price and an agreed strike price. If the market index price is above the strike price, the generator will have received a higher price than it was expecting to receive and conversely the offtaker will have had to pay a higher price than it was expecting to pay. Therefore, in this scenario, the generator will pay to the offtaker the difference between the strike price and market index price.

In the reverse scenario, where the market index price is below the strike price, the generator will have received a lower price than it was expecting to receive and, conversely, the offtaker will have had to pay a lower price than it was expecting to pay. The offtaker will therefore pay to the generator the difference between the strike price and market index price.

Under a contract for difference, there is no physical flow of electricity between the generator and the offtaker and therefore the contract for difference is closer to a financial instrument than a contract for the physical supply of power along direct wires.

This type of contract for difference has not been used as much as we would have expected given its simplicity and apparent effectiveness to fix power prices for both generators and offtakers. It is not entirely clear as to why this is the case. It may be due to the accounting treatment of the contract for difference. Although detailed consideration of the accounting treatment is beyond the scope of this article, we surmise that parties may be concerned that the contract for difference may have to be accounted for on a mark-to-market basis which would be very volatile for the profit and loss accounts of the relevant company. Parties would instead want to ensure that the arrangement is accounted for as a hedging instrument so that they achieve a fair value calculation.

Sleeving PPA

A sleeving PPA can be a bipartite or a tripartite agreement entered into between a generator and an offtaker and (in a tripartite situation) a licensed supplier. If the licensed supplier is not a party to the sleeving PPA itself, the sleeving PPA will have many references to the licensed supplier and the offtaker will need to enter into a separate agreement with the licensed supplier to pass on certain obligations under the sleeving PPA and ultimately to arrange for the physical export of power from the generating station to the grid and the delivery of power to the offtaker's premises.

Under a sleeving PPA, the generator agrees to sell its entire output of power (and potentially Renewables Obligation Certificates as well) to the offtaker for a price to be agreed between them. This may be a fixed price or an index-linked price (perhaps with a floor price), although a fixed price is more common. This is because the sleeving PPA is primarily used as a way for generators and non-utility offtakers to enter into long-term PPAs where the supply is not strictly coming from a third party licensed supplier and therefore the price can be determined bilaterally between the generator and the offtaker.

The offtaker is likely to be a corporate which is not a licensed supplier. Further, the generator is unlikely to be a licensed supplier. Therefore, the offtaker requires a contractual relationship with a licensed supplier so that the licensed supplier can take physical delivery of the power and act as the party responsible for the interface with the industry agreements such as the Distribution Connection Use of System Agreement. Only a licensed supplier is entitled to purchase power which is exported on to a local distribution network and it is the meter belonging to the licensed supplier which will be registered against the power exported by the generator. Furthermore, the licensed supplier and the offtaker will need to enter into a separate agreement under which the licensed supplier will physically supply the metered output from the sleeving PPA to the premises of the offtaker.

The licensed supplier will charge a fee to the offtaker for acting in its capacity as intermediary, but the sale and purchase of the power is still between the generator and the offtaker. The arrangements with the licensed supplier may also include payments to the generator for embedded benefits. Embedded benefits are any benefits that may now or in the future be realisable by any licensed supplier under industry agreements in the form of avoided transmission losses, transmission charges (including Triad benefits), distribution losses or distribution charges as a result of the generating facility being connected to a distribution system and not being connected to a transmission system, but excluding Generator Distribution Use of System Charges which will still need to be paid by the generator.

Direct wire PPA

A direct wire PPA requires proximity of the generating facility to the offtaker's premises so that a direct wire can be laid between the two premises. The advantage of this arrangement is that the contractual relationship for the sale and purchase of power can be bilateral between the generator and the offtaker. There is no need for a licensed supplier to be involved (in contrast to a sleeving PPA arrangement) and there is no need to connect to a distribution or transmission grid network, although, as discussed below, some



form of grid connection is likely. Furthermore, there may be no need for the generator to hold a supply licence and this creates significant savings. We note that under a sleeving PPA arrangement, the generator also doesn't hold a licence, but, as discussed above, a charge is payable to a licensed supplier intermediary.

Under the Electricity Act 1989, it is an offence to generate, transmit, distribute or supply electricity without a licence or an exemption from the requirement to hold a licence. The requirement to hold a supply licence carries various financial and administrative burdens, including the requirement to become a party to numerous industry codes, such as the Balancing and Settlement Code. In this context it is relevant to consider, in particular, the financial implications of being a licensed electricity supplier.

Licensed electricity suppliers are subject to the financial costs of complying with the Renewables Obligation, as well as their proportionate share (determined by market share) of costs arising under the small-scale Feed-in Tariff scheme, Contracts for Difference, the Capacity Market and various other miscellaneous schemes. These costs are passed down to the customers of those licensed electricity suppliers (other than certain energy-intensive industry customers, who benefit from some exemptions from those costs). It is these additional costs which contribute to the material delta between wholesale and retail electricity prices. Therefore, being able to benefit from an exemption from the

requirement to hold a supply licence offers a benefit to the supplier and its customers.

The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 sets out certain so-called class exemptions from the need to hold a supply, generation or distribution licence (as the case may be). Schedule 4 of the Order sets out the criteria that must be met by a supplier to benefit from an exemption under the Order. While a detailed discussion of all the criteria is outside of the scope of this article, the two main situations, relevant in this context, where an exemption may apply are as follows:

- a "class A" exemption, for small suppliers: this is where the person (other than a licensed supplier) is exempt from obtaining a supply licence if the person supplies electricity generated by themselves and does not at any time supply more than 5 MW in total and of which no more than 2.5 MW is supplied to domestic customers;
- a "class C" exemption, for on-site supply: this is where the electricity generated is used by only one customer, or group of customers on the same site as the electricity is generated, or the electricity is supplied to one or more off-site customers through a private wire arrangement.

While the Order is notoriously complex and unclear in its drafting (and in fact the Association for Decentralised Energy has recently renewed its efforts to push for reform in this area) it is always

worth checking if the project satisfies its requirements as doing so can realise significant savings. See figure 1 for a diagrammatical overview of the supply licence exemptions offered by the Order.

Direct wire PPAs – a more detailed analysis

The fact that direct wire PPAs create a physical interface between a generator’s plant and the offtaker’s plant, gives rise to a number of considerations which are exclusive to direct wire PPAs and are not applicable to utility PPAs, CfDs or sleeving PPAs.

The need for a grid connection

In all likelihood either the generator or the offtaker or both parties will require a physical connection to a distribution or transmission grid network. The reasons for this are:

- the intermittent nature of supply from a wind farm or solar PV park will not match the baseload demand of the offtaker;
- even with a baseload generator such as a biomass or EfW plant, it is almost inevitable that the offtaker will need a power supply at a time when the generating plant is offline or that its power consumption needs do not match the output of the generating plant and therefore requires an additional power supply;
- the generator will require certainty that it can sell its power at a time when the offtaker does not require power for whatever reason.

It may be that the offtaker will construct or may already have a direct connection to the local distribution network (LDN) so that it can import power from the grid and purchase its surplus requirements from a licensed supplier via the grid at times when the generation facility is either not generating or is not generating a sufficient volume of electricity to meet the offtaker’s demand. If this is the case, the generator will require that the offtaker’s connection to the LDN is two-way so that the offtaker can import from and export on to the LDN. Therefore, if ever the generation facility is generating more than the volume required to meet the offtaker’s demand, this surplus can be exported on to the LDN.

For the purposes of this article we will call this the “**Offtaker Grid Connection Option**”.

Alternatively, it may be that the generator has its own grid connection. If this is the case, the offtaker will require a “firm” power supply from the generator. This means that the generator is required to supply all of the offtaker’s power needs at all times regardless of whether the generator’s plant is generating (subject only to grid outages). The generator will therefore require access to an alternative form of back-up supply. For the purposes of this article we will call this the “**Generator Grid Connection Option**”.

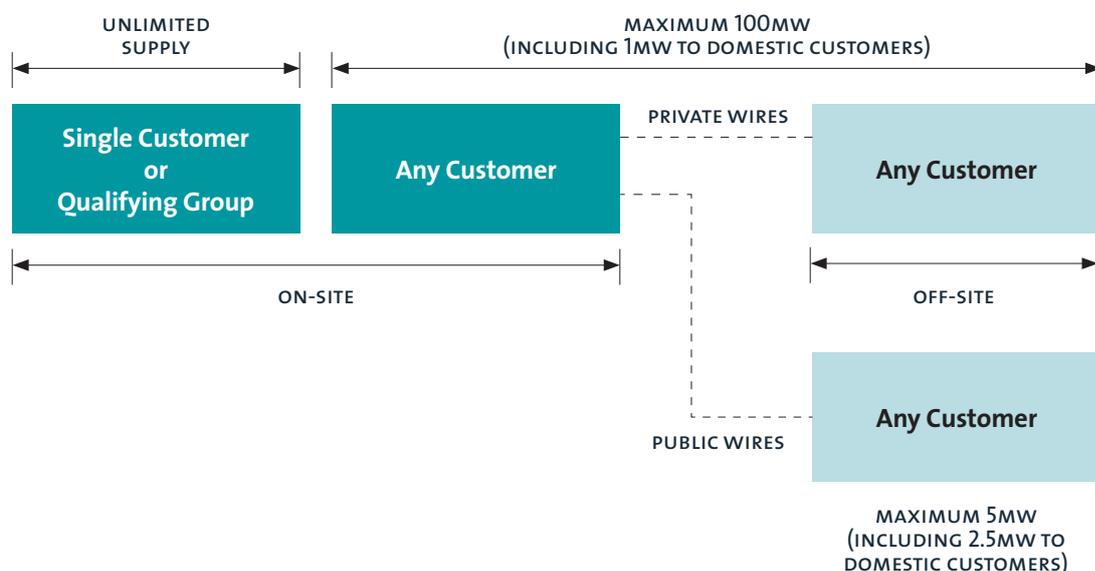
Finally, it may be that both the generator and the offtaker have their own grid connection. In this situation, the generator will be obliged to supply all of its power to the offtaker in the first instance and will only be permitted to export any surplus on to the grid. Similarly, the offtaker will be required to offtake all the power generated by the generator in the first instance and will only be entitled to import power over and above that supplied by the generator. In our experience, this third option is most unlikely, because the cost of constructing two grid connections usually outweighs the benefits.

For the purposes of this article, we will explore further some of the issues surrounding the Offtaker Grid Connection Option and the Generator Grid Connection Option.

Treatment of surplus electricity

With respect to the Offtaker Grid Connection Option, the parties will need to agree the price payable for any power that is exported on to the LDN and whether this is paid for at the contract price or at the System Sell Price (or another index price). Clearly, from a generator’s perspective, it will be argued that the contract price should be payable, in particular if the generator has assumed that the offtaker will always require the output from the generation facility. It may be that the generator will require a separate PPA with a licensed supplier who will offtake the surplus power not required by the direct wire offtaker. This requirement arises where the generator is not a licensed supplier or is not a party to the

Figure 1: The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001



Balancing and Settlement Code. In this case, it is likely that the licensed supplier who purchases the surplus power at the grid connection point will only be willing to pay a discounted System Sell Price for this surplus power because it has no control or visibility over the timing and volume of this power. This type of offtake arrangement is often referred to as a “spill PPA”.

With respect to the Generator Grid Connection Option, the parties will need to agree the price payable for any power that is delivered to the offtaker but which is not generated by the generator. The generator will need to enter into a power purchase and supply agreement with a licensed supplier pursuant to which this licensed supplier will agree to: (i) purchase any power generated but not consumed by the offtaker; and (ii) supply any power required by the generator or the offtaker. In our experience, it is likely that the generator and the offtaker will agree a pass through of costs from this power purchase and supply agreement so that the offtaker reimburses the generator for the cost of any power supplied to the offtaker from the licensed supplier.

The generator will need to consider if it requires any credit support from the offtaker: firstly, in general, but more particularly in respect of the generator’s exposure to the licensed supplier for power ultimately consumed by the offtaker.

Loss of offtaker

A key point to consider and mitigate against in order to make a direct wire PPA bankable is what happens in the event that the offtaker becomes insolvent or no longer requires the power. This is of particular concern under the Offtaker Grid Connection Option because the generator is connected to the offtaker’s plant and may not have its own connection agreement with the local distribution network operator (DNO). It is for this reason that the generator is likely to require that the offtaker’s plant is connected to the LDN for both import and export so that if the offtaker becomes insolvent or otherwise ceases to operate its facility, the generator has a means to export and sell its power. However, in this scenario, the generator would not have a direct connection agreement with the DNO.

The direct wire PPA may represent the generator’s only contractual right to connect to the LDN. The direct wire PPA therefore must include a provision whereby the offtaker expressly grants the generator the right to be (and remain) connected to the relevant substation and for such connection point to remain energised for the term of the direct wire PPA.

The generator needs to be aware that where the connection granted by the DNO to the offtaker under the offtaker’s connection agreement is de-energised, the generator will (through no fault of its own) lose its ability to export to the LDN. Such de-energisation may have occurred due to scheduled maintenance of the connection by the DNO, or another reason for which the offtaker is not responsible. In such a scenario, the generator is in no worse position than it would have been had it been the lead connecting party, with a direct contractual relationship with the DNO.

However, such de-energisation (or ultimately termination by the DNO) may arise as a result of a breach of the connection agreement by the offtaker. Therefore, the generator will wish to ensure that it has adequate protection/recourse against the offtaker under the direct wire PPA in the event it cannot export to the LDN due to the offtaker’s breach of the connection agreement.

What form this protection takes is a point for commercial negotiation. The optimum position for the generator would be for it to have an uncapped indemnity protection for any losses it suffers as a result of the offtaker’s breach of the connection agreement. Conversely, the offtaker may view such protection as draconian given the commercial benefits of the connection arrangement for the generator and the magnitude of the liability that could arise under such an indemnity. The offtaker may, therefore, consider damages at law or some form of capped liquidated damages regime to be more appropriate. The offtaker will also look for reciprocal protection against breaches or actions by the generator which cause a de-energisation or termination of the connection.

Another way in which the generator can mitigate its risk against offtaker insolvency is to procure land rights with respect to the route of the direct wire all the way to the substation and the connection to the LDN. This needs to be considered at an early stage of planning so the route can ideally be a standalone route and not rely too heavily on access to the offtaker’s physical premises. Land rights bind the land and not the individual and therefore survive the offtaker’s insolvency and will bind any insolvency official appointed.

In relation to the Generator Grid Connection Option, the offtaker will need to protect itself against breaches or de-energisation caused by the generator. The points made above will apply in reverse in relation to the Generator Grid Connection Option.

Further, under the Generator Grid Connection Option, if the offtaker becomes insolvent or ceases to require the power, the generator will have access to the grid to export its power, but the price it receives for its power might be lower than that paid by the direct wire offtaker. It is for this reason that funders might discount or even disregard the price of power to be paid for by the offtaker and instead assume a lower price of power in their financial model, perhaps based on wholesale power price forward curves.

DNO statutory duties

If the offtaker becomes insolvent under the Offtaker Grid Connection Option, it does not necessarily follow that the DNO will grant the generator a direct connection through the existing substation (notwithstanding that the generator may have secured relevant contractual protections with regard to access rights/ownership of the substation in the event of insolvency of the offtaker). This is because the DNO has a statutory duty to allocate unused grid capacity in an equitable manner. It may be that the insolvency of the offtaker means that the DNO can restructure connection arrangements to better suit the demands of that particular area. Technical advice can be sought through engagement with the DNO as to the materiality of this risk for the project in question (from the DNO itself, or a suitable technical consultant employed on the project).

Ideally, the generator and offtaker would procure a direct agreement with the DNO to enable the generator to step in and take over the offtaker’s grid connection. However, in our experience, DNO’s are reluctant to enter into direct agreements.

The ultimate protection for the generator in these circumstances is the DNO’s statutory obligation to provide a connection to any user who applies for one (subject to certain

PRIVATE WIRE CASE STUDIES

Queen Elizabeth II Floating Solar PV Project

The Queen Elizabeth II Floating Solar PV Project (QEII) is a floating solar array project located on the Queen Elizabeth II Reservoir, London, with a total PV capacity of 6.33 MWp (Megawatts peak). QEII has been commissioned by Thames Water as part of its bid to self-generate one-third of its energy by 2020.

The project developer is Lightsource Renewable Energy, which received financial backing from the Royal Bank of Scotland (senior) and AP capital (mezzanine). QEII is the first floating solar project to secure bank financing. The total cost of project is c.£6.5 million.

The project will be connected directly to the Thames Water private network via a submerged cable. Thames Water will off-take all the energy generated by the system and use it to power nearby water treatment plants.

Shotwick Solar Park

Shotwick Solar Park (SSP) received full accreditation from Ofgem in March 2016. SSP has been built on the Deeside Industrial Estate in North Wales and has a total PV capacity of c72 MWp. It is the UK's largest solar park with a private wire connection for commercial use.

The Shotton paper mill in Deeside, owned by UPM, a Finnish forest industry company, has entered into a 25 year direct wire power purchase agreement with the project

company under which UPM will purchase its energy directly from the project. While UPM is the principal offtaker, any surplus energy will be sold on to the grid to a licensed supplier.

Crookedstone Solar Farm

Crookedstone Solar Farm (CSF) is located in Antrim, Northern Ireland, and is connected directly to the private network of the nearby Belfast International Airport (BIA). CSF has a total PV capacity of 4.83 MWp and provides BIA with 27 per cent of its annual power demand.

The project was fully funded (costing c.£5 million) and installed by Lightsource Renewable Energy. Going forward, Lightsource will also operate and manage the project.

BIA has entered into a 25-year power purchase agreement and in the first six months of operation, CSF produced 2.79 million Kilowatt hours (kWh). BIA used 1.88 million kWh, leaving a balance of almost 910,000 kWh, which was exported to the Northern Ireland electricity grid. CSF is the first large-scale solar park in Northern Ireland, covers 14 hectares (35 acres) of land and consists of 18,630 solar panels. Lightsource won the Energy and Environment Innovation Prize at the Sustainable Ireland Awards in Belfast for its work on CSF.

The above case studies are based on publicly available information.

circumstances set out in the Electricity Act 1989). If this connection is not the original connection which was the subject of the direct wire PPA, the generator should be offered a new connection by the DNO, albeit potentially through a different route and at a cost (particularly if new infrastructure is required). The time that such a new connection would take to be constructed and energised will also need to be taken into account.

Therefore, insolvency of the offtaker is not without risk to the generator and ultimately, sponsors and lenders alike will need to be comfortable with the creditworthiness of the offtaker or with the back-up plan in the case of the insolvency of the offtaker.

Physical interface

Given the physical interface between the generator's facility and the offtaker's facility, the parties will need to agree who is responsible for the operation and maintenance of the private wire itself and where the "delivery point" is. Furthermore, both parties should take out market standard insurance, with obligations to provide evidence of such policies to the other. This will give the parties comfort that the other has relevant insurance protection in place, particularly with regard to physical damage. It may be that the parties agree that a "knock-for-knock" style insurance arrangement is most efficient so that each party is responsible for its own property and personnel regardless of how the damage is caused (subject to carve-outs for wilful default or recklessness).

Conclusion

In our view, direct PPAs are likely to become more prominent in the market and could be a key feature of subsidy-free wind, solar, biomass and EfW projects. Sponsors and funders will need to consider the risks associated with direct PPAs and it will not be a "one size fits all" solution.

From a corporate offtaker's perspective, locking in a long-term fixed or indexed price power supply at a discount to market price is likely to be attractive. This is further enhanced where that power supply is from a renewable source which enhances an offtaker's green credentials, which is increasingly important from a corporate and social responsibility perspective.



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WRITTEN ON THE WIND:

Investment opportunities in French offshore wind projects

by Michel Lequien and Jacques Dabreteau

On 16 December 2016, the Ministry of the Environment, Energy and the Sea (Ministère de l'Environnement, de l'Énergie et de la Mer) (the Ministry) launched a tender for the construction and operation of 250-700 MW of offshore wind capacity off the coast of Dunkirk¹ in northern France (the “Dunkirk Tender”). The Dunkirk Tender had already been announced in April 2016². A tender for a further offshore wind farm off the coast of Oleron island (near La Rochelle) was announced by the Ministry in November 2016 (the Oleron Tender)³ and is forecast for the first quarter of 2017.⁴

The decree setting out the competitive dialogue procedure that will apply to the implementation of the Dunkirk and Oleron Tenders (the New Offshore Tenders) was passed in August 2016 (the New Tender Decree).⁵

Drawing on lessons learned from the first two offshore wind tenders of 2011 and 2013, the Government has decided to

- 1 <http://www.cre.fr/documents/appels-d-offres/dialogue-concurrentiel-n-1-2016-portant-sur-des-installations-eoliennes-de-production-d-electricite-en-mer-dans-une-zone-au-large-de-dunkerque>
- 2 Press release issued by the Ministry of the environment, energy and the sea (Ministère de l'Environnement, de l'Énergie et de la Mer) on 3 April 2016
- 3 Press release issued by the Ministry of the environment, energy and the sea (Ministère de l'Environnement, de l'Énergie et de la Mer) on 23 November 2016
- 4 Source: Les Echos 28 November 2016, “La France veut abaisser les coûts de l'éolien en mer” <http://www.lesechos.fr/industrie-services/energie-environnement/0211539579336-la-france-veut-abaisser-les-couts-de-leolien-en-mer-2046266.php>
- 5 Décret n°2016-1129 du 17 août 2016 relatif à la procédure de dialogue concurrentiel pour les installations de production d'électricité, amending and completing the Energy Code (Code de l'énergie). We note that while the tender procedure is not applicable only to offshore wind farm tenders, it was designed specifically with the Dunkirk Tender in mind.

structure the third offshore wind tender differently from the earlier offshore wind tenders and has also designed a more flexible and co-operative tender procedure through the New Tender Decree.

It is not intended that the New Offshore Tenders trigger an immediate wave of new offshore projects in France; the Government will first want to test the new procedure and also evaluate the projects awarded in the first tenders, which are expected to come on stream between 2020 and 2022. However, 6,000 MW of additional offshore wind capacity is already planned for development by 2023 – the New Offshore Tenders therefore create an excellent opportunity for international developers and operators to enter and position themselves in the French offshore wind market, which is still largely underdeveloped and presents a significant pipeline of future projects.

The offshore wind tenders of 2011 and 2013

When the installed generation capacity of a given source of energy is insufficient to achieve the country's set objectives in terms of the energy mix, the Energy Code (Code de l'énergie) allows the Government to organise tenders for the development

of the missing capacity. The Government has made use of that mechanism for offshore wind energy capacity on three occasions. A first tender was organised in 2005 but the winning project was never completed. A second and a third tender were launched in 2011 (see figure 1) and 2013 (see figure 2) respectively, resulting in the award in 2012 and 2014 of six fixed offshore wind farm projects, with an aggregate capacity of 2,900 MW, geographically spread across six sites on the Atlantic coast, to three separate consortia.

As illustrated in figures 1 and 2, and as had been made clear from the outset by the Government, a key objective of the tenders was to foster the development of a national offshore wind industry on French territory. This is evident from the weighting of the selection criteria used in the tender procedures (which were substantially similar in both rounds):

- Price – 40 per cent
- Quality/robustness of the project (qualité du projet industriel), i.e. the industrial and economic framework of the project, including the project company's links with local industry and its technical expertise – 40 per cent
- Environmental characteristics and compatibility with existing usage of the sea at the site (e.g. fishery industry, yachting) – 20 per cent

The Government was seeking a strong long-term commitment from the winning bidders to establish dedicated manufacturing

and maintenance facilities close to the offshore wind farms, to use local port facilities and to create local jobs. In that context, national energy champions EDF and Engie, each in its respective consortium with solid and experienced developers, were in a position to win five out of the six projects awarded in 2012 and 2014.

The commitments of the winning bidders in the first two rounds of tenders included significant levels of investment – approximately EUR 11 billion for the six projects – and the creation of 10,000 jobs in aggregate, a significant part of which are located in the coastal regions concerned (Pays-de-la-Loire, Bretagne, Basse-Normandie et Haute-Normandie).

The price payable under the power purchase agreements awarded to the winning bidders in the tenders ranges from EUR 180 per MWh to EUR 200 per MWh. This is significantly higher than the price of offshore wind electricity produced in countries with more mature offshore wind industries, such as Denmark, with prices in the EUR 130-145 per MWh range (not even taking into account the outcome of the most recent tenders, which have achieved significantly lower prices); the United Kingdom, with an average price of EUR 168 for offshore wind farm projects developed in recent years;⁶ or Germany, where the two rounds of tenders planned for 2017/2018 will set a price ceiling of EUR 120 per MWh. The Ministry now expects prices in the Offshore Tenders to be below EUR 150.

6 Source: Financial Times, 5 June 2016 - <https://www.ft.com/content/cob56810-29b9-11e6-8b18-91555f2f4fde>

Figure 1: July 2011 tender - awarded 6 April 2012

Site	Saint Nazaire	Fécamp	Courseulles-sur-Mer	Saint-Brieuc
Winning bidders	EDF EN DONG Energy (since replaced by WPD Offshore)	EDF EN DONG Energy (since replaced by WPD Offshore)	EDF EN DONG Energy (since replaced by WPD Offshore)	Iberdrola Eole RES
Turbines/ capacity	80 6 MW Alstom turbines (now GE turbines) Aggregate capacity: 480 MW	83 6 MW Alstom turbines (now GE turbines) Aggregate capacity: 498 MW	75 6 MW Alstom turbines (now GE turbines) Aggregate capacity: 450 MW	100 5 MW Areva turbines Aggregate capacity: 500 MW
Cost	EUR 2 billion	EUR 2 billion	EUR 1.8 billion	EUR 2 billion
Commercial Operation Date	Start of construction 2018/COD 2020	Start of construction 2018/COD 2020	Start of construction 2018/COD 2020	COD 2020

Figure 2: March 2013 tender - awarded 6 April 2014

Site	Dieppe et le Tréport	Ile d'Yeu et Noirmoutier
Winning bidders	ENGIE EDP Renewables; Neoen Marine	ENGIE EDP Renewables; Neoen Marine
Turbines/capacity	62 8 MW Areva turbines Aggregate capacity: 496 MW	62 8 MW Areva turbines Aggregate capacity: 496 MW
Cost	EUR 2 billion	EUR 2 billion
Commercial Operation Date	2021	2021

The New Offshore Tenders

For the New Offshore Tenders, the Government has changed its approach substantially.

With the creation of a national offshore wind industry base having already been secured in the earlier rounds, the Government has changed its priorities.⁷ The central theme of the New Offshore Tenders will be to achieve a substantially lower tariff for offshore electricity by:

- limiting technical uncertainties;
- providing more flexibility for bidders to determine their technical solutions; and
- optimising the risk allocation.

Contrary to what had originally been announced by the Government, the pre-qualification document (document de consultation) does not provide that the right to occupy the public maritime domain (concession d'occupation du domaine public maritime) will be issued upon award. This would have been a significant step forward towards the acceleration and streamlining of the permitting process.

The tender will no longer be based on the feed-in tariff (FIT) system (obligation d'achat) that applied to the first tenders but on the new contract for difference system (complement de rémunération), which is now replacing the former FIT system.

The new rules applicable to the tendering of offshore wind projects are now aimed at fostering competition by attracting a wider range of bidders, with bidding and pricing strategies that will be very different from those imposed by the rigid tender terms applied in the first two rounds.

Competitive dialogue

In the first two offshore tenders, bidders were required to submit a proposal based on the terms of reference issued by the energy regulator (Commission de régulation de l'énergie (CRE)), with only very limited information on the sites of the maritime zones in which the wind farms were intended to be constructed and operated. While certain bidders had already carried out maritime surveys and feasibility studies, those who had not done so, whether for time or cost reasons, were at a disadvantage and some even dissuaded from participating in the tender. In any event, the timing of the tenders did not allow bidders to carry out sufficient studies to fully assess all of the risks of the relevant zones. This resulted in bidders factoring a substantial risk premium into the price offered in their bids.

The new competitive dialogue procedure (dialogue concurrentiel) introduced by the New Tender Decree will allow for detailed discussions between the Ministry and the bidders on project risks and risk allocation before bidders submit their binding bids. The "dialogue" will be based on on-site maritime surveys and other technical, meteorological and environmental feasibility studies commissioned by the Ministry and disclosed

⁷ This mirrors the approach taken in the UK, where the Government has taken steps to implement its policy that it will only support offshore wind if its cost is reduced. Under the new UK Contracts for Difference regime, in the first competitive allocation round, the two offshore wind farm projects that were successful received support at £114.39 and £119.89 per MWh (so-called strike prices). For the second allocation round, announced recently, the strike price has been capped at between £100 and £105 and it is expected that the actual prices awarded as a result of the auction may be lower. The UK Government has said that the expected price reductions will continue to be accelerated, with projects needing to aim to be viable at a strike price support rate of £85/MWh by 2026.

to all bidders. Bidders will also have the option to carry out their own studies.

The aim of the procedure is to allow bidders to gain a better understanding of the actual environmental and technical risks of the project in the preparation of their bids, while allowing the Government to progressively develop final terms of reference (cahier des charges) tailored to the particulars of the project on the basis of the outcomes of the dialogue. Unlike in the earlier rounds, bidders will now be in a position to submit better informed bids on the basis of detailed and specific terms of reference.

It is therefore expected that the competitive dialogue procedure will allow bidders to reduce their tender and pre-development costs, attract more bidders as a result, and, ultimately, lead to competitive pricing, thereby pushing down the price of offshore wind electricity.

Procedure

In summary, the competitive dialogue procedure has three stages⁸:

- A pre-qualification stage, based on the terms of a pre-qualification document (document de consultation) setting out the key terms of the tender: the purpose of the competitive dialogue; the provisional timetable for the tender; the technical and financial qualifications required for candidates to be eligible as bidders; and the criteria for the selection of the best final offer.
- A competitive dialogue stage organised by the Ministry, in which the Ministry and pre-qualified bidders exchange information and views about the request for proposals, including the timetable and the draft terms of reference (cahier des charges). The purpose of the dialogue is to adjust and refine the terms of reference on the basis of which bidders will formulate their binding offers.
- The offer stage in which bidders submit their offers. The bids are examined by the CRE, which makes a recommendation to the Ministry. The winning bidder is declared by the Ministry (after consultation with the CRE if it decides to deviate from the recommendation of the CRE).

The winning bidder will then sign a contract for difference (contrat de complément de rémunération) with EDF in accordance with the terms and conditions of the tender and the terms of its bid.

Selection criteria

Pursuant to the Energy Code, the key criterion for the evaluation of bids is price.⁹

This criterion may, however, be complemented by other criteria (critères complémentaires), such as the "quality" of the bid (i.e. its technical and/or financial robustness), the project return, or the security of supply guaranteed by the project.

The pre-qualification document for the Dunkirk Tender sets out the following criteria, in order of importance:

- price;
- "zone optimisation" (optimisation de l'occupation de la zone), taking into account specific constraints in the area (Dunkerque

⁸ Article R.311-25-1 et seq of the Energy Code

⁹ Article L311-10-1 of the Energy Code



semaphore, Gravelines nuclear site) and compatibility with other usage (fishery industry, commercial shipping traffic, leisure activities); and

- management of environmental issues, taking into account the biodiversity of the two Natura 2000 protected sites within the area, as well as the impact of the project on the landscape.

It has not yet been determined precisely how these three criteria will be weighted. In any event, the price criterion will remain paramount. No “offshore wind industrial base development” criterion is explicitly mentioned in the Energy Code, nor in any announcement of the Government. This is confirmed by the terms of the pre-qualification document for the Dunkirk Tender, which no longer makes any explicit reference to the “quality and robustness of the industrial project” (*qualité du projet industriel*), which was a key selection criterion in previous tenders. While that criterion is no longer present in the New Offshore Tenders, the manner in which bidders will potentially use the industrial base developed for the construction and operation of the projects awarded in the first two rounds, and thereby contribute to their long term viability, is likely to play a role in the evaluation of bids.

Current status and prospects

The pre-qualification document for the Dunkirk Tender required candidates to submit three documents in order to apply for the pre-qualification stage:

- a letter of application (*lettre de candidature*) describing the basic features of the candidate (e.g. legal form, ownership structure, capitalisation, etc.);
- a 15-page note (*note détaillée*) allowing the assessment of the candidate’s financial standing and creditworthiness. The note is to contain the candidate’s references in relation to energy projects requiring investments in excess of EUR 500 million. The note is also required to contain information on the borrowing ability of the candidate; and
- a detailed 20-page note describing the candidate’s technical capacity and abilities in order to assess its ability to build, operate and maintain a project similar to the project being tendered. This note is required to specifically describe the

candidate’s offshore wind farm experience and track record.

The closing date for pre-qualification applications was 28 February 2017. An Engie/EDPR consortium and ED FEN have submitted bids, and Vattenfall has also been reported to be a bidder.

The names of the candidates selected to participate in the competitive dialogue are to be announced at the end of a one-month review process by CRE so that the competitive dialogue stage can begin in April 2017. The pre-qualification document indicates that the duration of the competitive dialogue is expected to be four to six months.

Representatives of the wind industry have voiced disappointment at the limited capacity to be awarded in the third round (Dunkirk Tender). However, the rapid launch of the Oleron Tender must be seen as a positive sign of the Government’s commitment to comply in the short to medium-term with its multi-annual plan for energy,¹⁰ which expressly contemplates the development of up to 6,000 MW of offshore wind capacity by 2023. The launch of further projects will, however, very much depend on the ability of energy companies to substantially cut the cost of offshore wind farm projects and deliver lower, more competitive tariffs. The Government has also confirmed that in the meantime it will continue the process of identifying appropriate maritime zones for the development of further offshore wind farms.

¹⁰ As approved by Decree no. 2016-1442 of 27 October 2016 on the multi-annual plan for energy.



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WINDS OF OPPORTUNITY:

Investment opportunities in German offshore wind farms

by Maximilian Uibeisen

On 8 July 2016, the German parliament passed legislation making significant changes to the existing funding scheme for renewable energy projects. The new Renewable Energy Act 2017 (EEG 2017), together with a new Offshore Wind Act, entered into force on 1 January 2017 and introduced public tender procedures for the most important renewable energy technologies, including offshore and onshore wind, solar and biomass.

Under the new regime, project developers will in general no longer receive statutory tariffs as under the current Renewable Energy Act (EEG 2014) regime, but will have to bid for tariffs. Successful bidders will then receive remuneration at the level of their bid (“pay-as-bid”) for a fixed period of 20 years. To take account of varying costs, technologies and permitting requirements, specific rules for tender procedures were introduced for each renewable energy source.

The Offshore Wind Act

For offshore wind farms, these rules are, in addition to the EEG 2017, set out in a new Offshore Wind Act (Windenergie-auf-See-Gesetz). The Offshore Wind Act introduces a new planning regime for offshore wind farms. Roughly speaking, under this so-called “central model”, areas for offshore wind farms will be pre-developed by the state and project developers can bid for projects in these pre-developed areas only.

However, in order to allow for sufficient time for the new planning regime to be implemented and to take reasonable account of offshore wind farm projects which have already reached an advanced stage under the existing planning regime, the central model only applies to projects which will be commissioned from 2026, with tender procedures starting in 2021.

Before the new regime kicks in, all projects which have already been permitted and hold grid connection capacities and which will be commissioned by the end of 2020 are still eligible for the statutory tariffs under the EEG 2014 regime. In addition, there will be two early tender rounds in 2017 and 2018 for “existing projects”, as further defined in the law.

The expansion of offshore wind farms is limited to 15,000 MW until 2030 under the EEG 2017. While this target has not been reduced compared to the former regime, the target capacity has been allocated to certain time periods in order to ensure a continuous, planned expansion of offshore wind farms in line with the necessary building of grid connections.



Investment opportunities

For investors seeking to identify upcoming investment opportunities, it will be important to know which projects qualify for the existing statutory tariffs (first group) and which projects are eligible as so-called “existing projects” to participate in the first two early tender rounds in 2017 and 2018 (second group), as these projects have a chance to be realised in the near future until 2025.

The projects belonging in these two groups are identified in tables 1 and 2 below,¹ setting out for each of the projects their current owners and status as well as their location and capacity. All other offshore wind farm projects are referred to as the “third group”, as discussed below.

¹ The tables have been prepared on the basis of publicly available information and may therefore not be fully accurate.

First group: projects eligible for statutory tariffs (7,700 MW)

Offshore wind farms which:

- have either received grid connection capacities from the German regulator, the Federal Network Agency (Bundesnetzagentur), or which have received grid connection commitments from the responsible grid operators before 1 January 2017; and
- which will be commissioned by the end of 2020,

do not have to participate in tender procedures. These projects remain eligible for statutory tariffs and the tariffs under the EEG 2017 largely reflect the situation under the former EEG 2014.

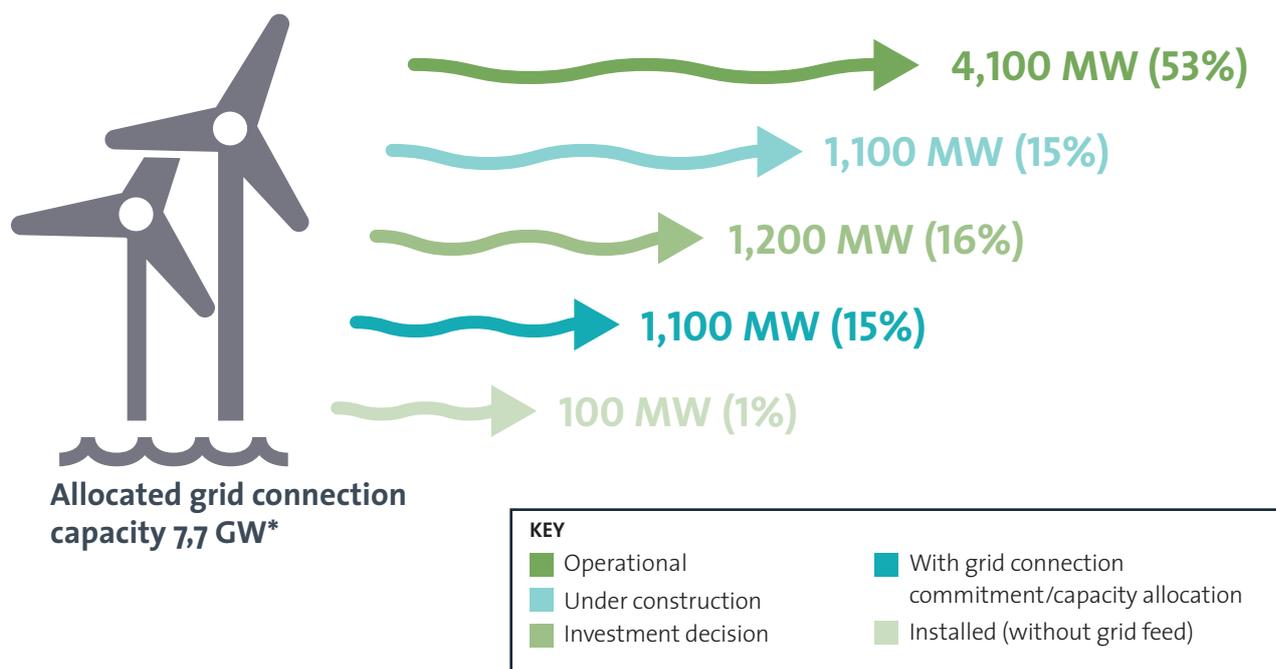
The projects in this group add up to a total capacity of almost 7,700 MW. This figure includes 947 wind turbines with a total capacity of about 4,100 MW which were already operational as of 31 December 2016. In addition, wind turbines with a capacity of 1,486 MW are currently being built. A final investment decision has been taken

Three groups of offshore wind projects

In summary, the following three groups of offshore wind projects result from the changes introduced by the EEG 2017 and the Offshore Wind Act:

- a first group comprises all existing offshore wind farms and all projects commissioned by the end of 2020 with a total volume of around 7,700 MW. All of these projects will still be eligible for statutory tariffs as under the former EEG 2014 regime;
- a second group of advanced stage projects (so-called “existing projects”) will be competing in two early tender rounds in 2017 and 2018 for additional 3,100 MW to be realised between 2021 and 2025;
- a third group comprises all remaining projects which will have to compete in a “central model” for the remaining 4,200 MW adding up to the total volume of 15,000 MW by 2030.

German offshore wind performance as of 31 December 2016



*Figures rounded. Source: Deutsche WindGuard, "Status des Offshore-Windenergieausbaus in Deutschland", Gesamtjahr 2016.

for further wind turbines with a capacity of 1,200 MW. For wind turbines with a capacity of around 1,100 MW, a final investment decision has not yet been taken.²

In table 1, we list those projects which are either in the construction or the pre-construction stage (excluding those projects which have already been commissioned or which are already installed).

Second group: two tenders in 2017/2018 for "existing projects" (3,100 MW)

Two early tender rounds will take place on 3 April 2017 and 1 April 2018 for projects to be commissioned in the period between 2021-2025. These projects are not eligible for statutory tariffs any more, and instead have to bid for tariffs in public tenders.

The aim of the two early tender rounds is, amongst other things, to give developers of projects which have already reached an advanced stage of development before the changes were introduced the possibility to still realise their projects outside of the new central model.

Therefore, only so-called "existing projects" are eligible to participate in these tenders. These are defined as projects which:

- have been permitted or which have undergone a public hearing (Erörterungstermin) before 1 August 2016;
- for which the permitting authority confirms that the permit is valid or that a permit is likely to be granted; and
- are located in clusters 1-8 of the offshore grid development plan for the German North Sea or in clusters 1-3 of the offshore grid development plan for the German Baltic Sea.

² Deutsche Windguard, Status Offshore Wind Expansion in Germany, December 2016.

The volume of the two early tenders is limited to 1,550 MW per tender round (3,100 MW in total). With regard to the commissioning dates of the projects, the volumes are mainly allocated to the single years between 2021 and 2025 on the basis of the timelines for grid connections to be built as set out in the German offshore grid development plan³ as follows:

- 2021/2022: 500 MW per year; in 2021, the 500 MW capacity is reserved to projects in the Baltic Sea only.⁴
- 2023-2025: 700 MW per year.

As can be seen in table 2 below, projects which qualify as "existing projects" have a volume of around 6,400 MW and more than double the limit of 3,100 MW. Investors must therefore consider that there will likely be significant competition already in these two tenders leading to a pressure on prices. This situation should be taken into account when choosing investment targets as well as when considering to team up with a current owner or developer. Furthermore, the offshore grid development plan and the projected grid lines and connection capacities on these lines (as well as potential scarcities on single lines) need to be taken into consideration.

"Entry right" for later tenders

To address the issue of insufficient capacity for all "existing projects" as well as legal concerns relating to the withdrawal of rights of other existing projects, existing projects which have been unsuccessful in both tender rounds in 2017/2018 are granted

³ The offshore grid development plan 2025 (Offshore-Netzentwicklungsplan/O-NEP) has been confirmed by the Federal Network Agency on 25 November 2016 and is available on the homepage of the Agency.

⁴ The background for this rule is an existing delay of grid connections in the North Sea.

Table 1: Projects eligible for feed-in tariffs in construction/pre-construction phase as of 1 September 2016

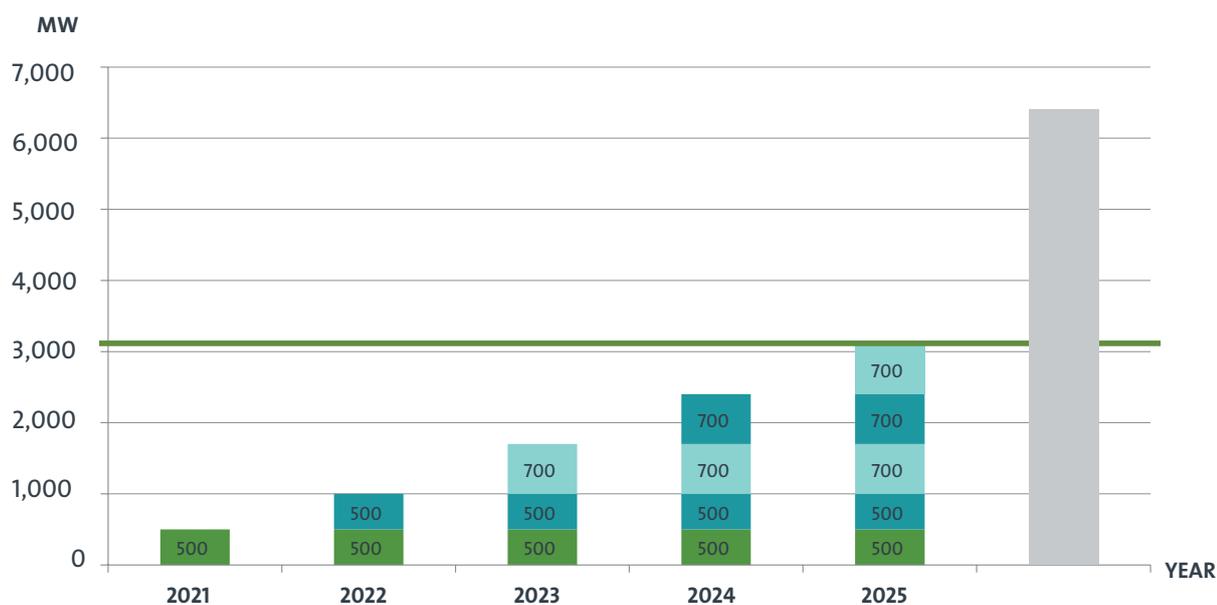
PROJECT	OWNER/DEVELOPER	STATUS	LOCATION	CAPACITY
Albatros Phase I	EnBW	Pre-construction	North Sea	116 MW
Borkum Riffgrund 2	DONG Energy	Final investment decision; commissioning planned for 2019	North Sea	450 MW
Deutsche Bucht	Highland Group	Pre-construction	North Sea	252 MW
EnBW Hohe See	EnBW	Pre-construction	North Sea	500 MW
Merkur Offshore	Deme Concessions Wind GE Financial Services Partners Group InfraRed Capital Partners Ademe	Pre-construction	North Sea	400 MW
Nordergründe	Gothaer Leben Renewables WPD Offshore John Laing	Under construction	North Sea	111 MW
Nordsee One	RWE Innogy Northland Power	Under construction	North Sea	332 MW
Sandbank	Vattenfall Stadtwerke München	Under construction; partly commissioned	North Sea	288 MW
Trianel Borkum II	EWE AG Trianel	Pre-construction	North Sea	200 MW
Veja Mate	Highland Group Siemens Financial Services Copenhagen Infra-structure Partners	Under construction	North Sea	400 MW
Arkona Becken Südost	E.ON Statoil	Final investment decision; commissioning planned for 2019	Baltic Sea	385 MW
Wikinger	Iberdrola Renovables	Under construction	Baltic Sea	350 MW
GICON SOF (Pilot)	GICON	Final investment decision; commissioning planned for 2019	Baltic Sea	2 MW
Total:				3,786 MW⁵

⁵ Note: Figure includes about 270 MW already commissioned in wind farms Gode Wind 1 and 2.

Table 2: Projects eligible for participation in two early rounds of tender in 2017/2018

PROJECT	OWNER/DEVELOPER	STATUS	LOCATION	CAPACITY
Borkum Riffgrund West 1	DONG Energy	Permit	North Sea; cluster 1	270 MW
Borkum Riffgrund West 2	DONG Energy	Public hearing	North Sea, cluster 1	285 MW
OWP West	DONG Energy	Permit	North Sea; cluster 1	205-328 MW
OWP Delta Nordsee 1	E.ON	Permit	North Sea, cluster 3	210 MW
OWP Delta Nordsee 2	E.ON	Permit	North Sea; cluster 3	192 MW
Innogy Nordsee 2	RWE Innogy	Permit	North Sea; cluster 3	295 MW
Innogy Nordsee 3	RWE Innogy	Permit	North Sea; cluster 3	369 MW
Gode Wind 3	DONG Energy	Public hearing	North Sea, cluster 3	90 MW
Gode Wind 4	DONG Energy	Permit	North Sea; cluster 3	252 MW
Kaskasi II	RWE Innogy	Public hearing	North Sea, cluster 4	272 MW
Nördlicher Grund	Blackstone	Permit	North Sea; cluster 5	384 MW
Nördlicher Grund/Area Sandbank	Vattenfall Stadtwerke München	Permit	North Sea, cluster 5	96 MW
Atlantis I	Vattenfall	Public hearing	North Sea, cluster 6	400 MW
EnBW He Dreiht	EnBW	Permit	North Sea, cluster 7	732 MW
Global Tech II	Vattenfall	Public hearing	North Sea, cluster 7	395-553 MW
Arcadis Ost 1	WV Energie Innsbrucker Kom-munalbetriebe KNK Ocean Breeze Stadtwerke Bad Vilbel	Permit	Baltic Sea, 12 nm zone	348 MW
Adlergrund 500	BEC Energie Consult	Public hearing	Baltic Sea, cluster 1	72 MW
Adlergrund GAP	BEC Energie Consult	Public hearing	Baltic Sea, cluster 1	155 MW
Windanker	Iberdrola Renovables	Public hearing	Baltic Sea, cluster 1	252 MW
Wikinger Nord	Iberdrola Renovables	Public hearing	Baltic Sea, cluster 1	40 MW
Wikinger Süd	Iberdrola Renovables	Public hearing	Baltic Sea, cluster 1	90 MW
Baltic Eagle	Sea Wind	Public hearing	Baltic Sea, cluster 2	500 MW
Ostseeschatz	Financial Insurance	Public hearing	Baltic Sea, cluster 2	225 MW
Total:				6,129-6,410 MW

Capacity in early tenders vs. eligible “existing projects”



a so-called “entry right” (i.e. a step-in right) for the later tenders under the central model. This means that the unsuccessful projects can “enter” or “step” into successful bids of other bidders (in the same location as the earlier unsuccessful bid) under the central model for the period after 2026 if certain further conditions are met.

Rules for the tender procedures

The EEG 2017 and the Offshore Wind Act set forth a number of rules for the tender procedures which investors need to be aware of when deciding to purchase a project or to team up with a current project owner or developer. These rules include the following:

- the two early tender rounds in 2017/2018 must be published at least eight weeks before their respective dates on the homepage of the Federal Network Agency;
- the publications will, among other things, contain information on the tender deadlines, the tender volumes, the grid connection capacities, the year in which the grid connections are planned to be in place as well as the formal requirements for bids;
- a statutory price ceiling of 12 ct./kWh will apply for the projects participating in the two early tender rounds. Bid prices are expected to be significantly below this ceiling;
- bids can be structured by using bands for which a certain price applies (Mindestgebotsmenge) as well as secondary offers at a higher price for a lower amount of installed production capacity (Hilfsgebot) in order to avoid an unsuccessful bid due to a scarcity situation;
- cash deposits or bank guarantees at an amount of 100 EUR/kW of the capacity to be installed must be provided to the Federal Network Agency before the tender deadlines. These deposits serve the aim to secure a timely realisation of projects in case a project wins a bid and certain penalties become due if statutory

milestones are not met. There are no specific rating requirements for the guarantees;

- tenders will be awarded on the basis of price up to the maximum volumes in each round of tender year (1,550 MW) and the available grid connection capacities.

Third group: Tender procedures under the central model (4,200 MW)

For projects commissioned between 2026 and 2030, tender procedures will take place under the “central model” with a first tender round on 1 September 2021. Under this new regime, the authorities will pre-develop areas for offshore wind farms. Tenders will then be run with regard to pre-developed sites only. After a successful bid for a tariff, the developers have the right to apply for a permit for the building and operation of the wind farm.

The tender volume for the period 2026-2030 totals 4,200 MW with 840 MW per year on average. There will be a price ceiling for these tenders determined on the basis of the lowest successful bid in the second early tender round in 2018.



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THE UK:

Offshore wind all the way

by Antony Skinner and Justyna Bremen

In the UK, as in other European jurisdictions, the Government has sought to limit the cost of renewables to consumers. As a result, the incentives previously available for onshore wind projects have now been withdrawn for new projects. In contrast, the Government has indicated that it will continue to offer incentives for offshore wind although, as discussed below, it expects the offshore wind industry to make significant savings so that projects can go ahead with much lower rates of support.

The CfD regime

It is relevant to note that in the UK, the Contracts for Difference (CfD) regime was implemented in 2014 to replace the Renewables Obligation (RO) green certificate scheme (which is closing on 31 March 2017, subject to some grace periods) as the main form of support for low-carbon electricity generation projects in the UK. Under a CfD, the developer is paid a top-up payment above the wholesale price (the reference price), up to the strike price, for a term of 15 years. The CfD regime contemplates that for most renewable energy technologies, if the number of projects applying for support exceeds the allocated budget, CfD allocation will involve a reverse auction, to achieve the lowest price for electricity consumers.

Even before the new CfD regime was fully implemented, the Government awarded a number of so-called investment contracts – an early form of the CfD contract – to various projects, five of which were offshore wind farm projects. The award of these investment

contracts did not involve an auction, and therefore these projects were awarded support at a strike price set using an administrative process (the “administrative” strike price). The administrative strike price for delivery years up to 2018/19 was set at a range starting at £155/MWh, reducing to £140/MWh for the latter years. The first CfD allocation round took place in October 2014 and resulted in two offshore wind farm projects being awarded CfDs at a strike price of £119.89/MWh and £114.39/MWh respectively (which is approximately 20 per cent lower than the “administrative” strike price set for offshore wind in that allocation round).

The CfD allocation rounds were originally intended to take place annually, but until now, no further allocation rounds have been held. However, in the March 2016 Budget, the Government announced that it would make available up to £730m of CfD funding this Parliament (i.e. before 2020) for up to 4GW of offshore wind and other “less established” renewables technologies, across three separate allocation rounds.



The second CfD allocation round

Overview

In November 2016 the Government indicated in a draft budget for the second allocation round that £290m of CfD funding will be available for projects which are planning to commission in the delivery years 2021/22 and 2022/23. This was confirmed in March 2017, with the publication of the final budget. The £290m figure does not represent a lump sum covering the cost of the projects over their total CfD term, but rather how much is available to cover payments to the successful projects on an annual basis. It does not matter whether a project will be commissioned in 2021/22 or 2022/23 – the Government has said that CfDs will be allocated to the cheapest projects first, regardless of their start date, as long as they fit within the budget profile provided.

The established technologies that are eligible to participate in the second allocation round are offshore wind, advanced conversion technologies (ACT) (with or without CHP), anaerobic digestion (with or without CHP), dedicated biomass with CHP, wave, tidal stream and geothermal technologies. Because of the way the allocation round is being structured – including a proposed “maxima” of 150MW in relation to fuelled technology projects – a large proportion of the budget is expected to be available for offshore wind farm projects. However, offshore wind farm developers are expected to make significant cost savings.

Figure 1 sets out the administrative strike prices for offshore wind announced in the Government’s budget

notice. For comparison, we have also set out the strike price that was originally set for the 2018/2019 delivery year. These administratively set strike prices represent the maximum strike prices that can be awarded to eligible projects participating in the second allocation round. If the CfD funding that would be required for all such eligible projects (paid at the administrative strike prices) exceeds the budget available, then a constrained allocation auction will take place, whereby these projects will bid lower strike prices to compete for the available budget. This is what happened in the first allocation round.

As can be seen from the table, offshore wind projects are expected to be economically viable with the benefit of much lower strike prices, with the support offered being at a much lower level compared to the first allocation round. Indeed, the Department for Business, Energy and Industrial Strategy previously said that offshore wind farm projects would need to aim to be viable at a strike price support rate of £85/MWh by 2026. With offshore wind farm projects in various European jurisdictions being awarded ever-lower rates of support, the pressure will be on for UK-based projects to achieve similar savings.

Phased offshore wind farm projects

The Allocation Framework, which sets out the rules for the second CfD allocation round, sets out some restrictions on offshore wind projects which are to be carried out in phases. In particular, after all phases are completed, the whole offshore wind farm project must have a capacity not greater than 1500 MW, and the first phase must represent at least 25 per cent of the total capacity of the project after all phases are completed.

The application “window”

The application window for projects participating in the second allocation round is 3 April to 21 April 2017, and the whole allocation process is to be completed by 11 September 2017.

Figure 1

Technology	CfD Strike Prices (£/MWh, 2012 prices)		
	2018/19 (Included here for comparison purposes only)	2021/22	2022/23
Offshore wind	140	105	100



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WASTE PROJECTS:

Waste-to-wealth initiatives

by Michael Harrison, Richard Guit and Nick Stalbow

As populations grow and urbanise, the quantity of “municipal solid waste” (MSW) arising also grows. With this growth, the environment is subject to greater environmental pressure from both contamination and emissions: a fair proportion of waste is not collected and is subject to open dumping (and possibly open burning). In addition, contaminants leach into water (both groundwater and coastal waters) giving rise to associated on-going health risks.

In an urban environment, waste¹ provides a resource that can be “mined” and otherwise used to avoid or reduce contamination and emissions – effectively an “urban ore body”.² In a rural environment, organic waste produced through agriculture and forestry (including bagasse and biomass) provides a resource – a “rural ore body”. Borrowing the terminology used in the Eleventh Malaysian Plan (2016 to 2020), these urban and rural ore bodies can be mined for “waste-to-wealth initiatives”. In recent times there has been a shift in the

global language surrounding waste: it is now seen as a resource, rather than being considered as “garbage” or “rubbish”.

The World Bank has estimated that, by 2025, between 2.2 billion and 2.4 billion tonnes of municipal solid waste³ (MSW) will be generated annually by the world’s urban population.⁴ This figure may be conservative, given that some countries have already outpaced the 2025 projections.⁵ If the right mix of waste projects and diversion from landfill is achieved, this will reduce greenhouse gas emissions by well over a billion tonnes

per year on current waste and MSW volumes, and considerably more as waste volumes increase.

MSW can be: (i) used to produce energy (as fuel or feedstock for waste-to-energy (WtE)⁶ facilities); (ii) processed by mechanical and biological treatment plants (MBTs) to create organic compost material and to sort re-usable⁷ and recyclable⁸ “fractions” of MSW; or,

1 “Waste arising” is a term of art within the waste management industry. For the remainder of this article we refer to waste volume.

2 Reflecting the fact that early projects in Australia made use of processing technologies used in, and were engineered by contractors to, the mining industry.

3 As distinct from sewage or waste water.

4 Daniel Hoornweg, Perinaz Bhada-Tata & Charles Peterson, ‘What a Waste: A Global Review of Solid Waste Management’ (Report, World Bank, 2012).

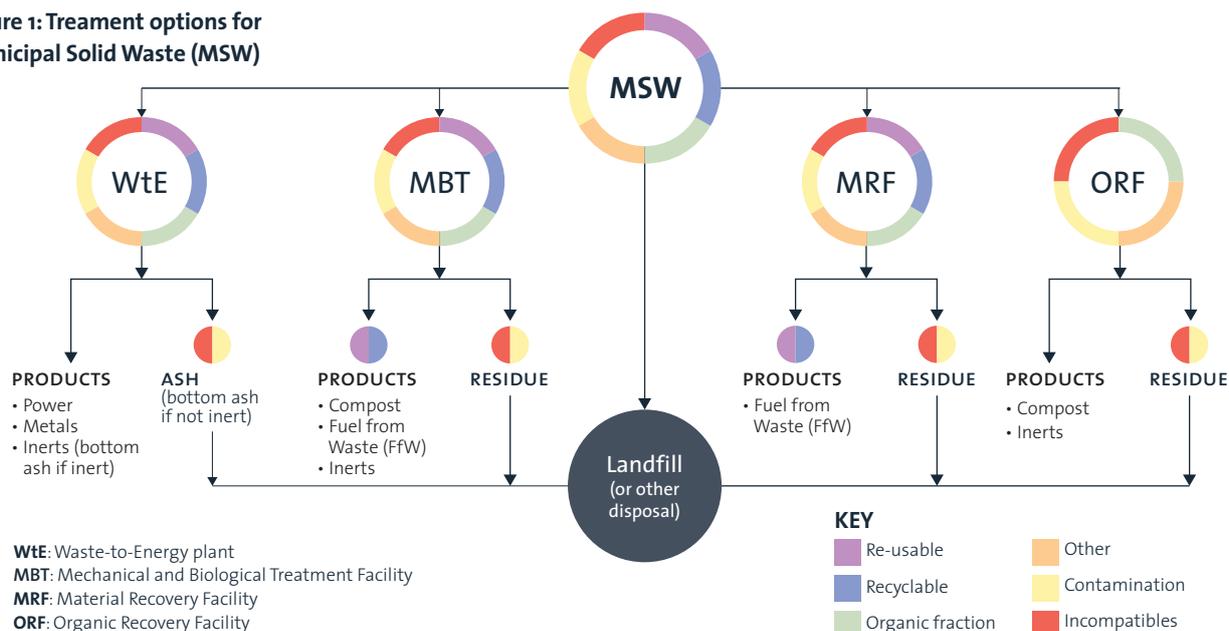
5 Indonesia has outpaced the 2025 projection of 150,000 tonnes a day. Currently, over 175,000 tonnes a day is generated.

6 The terminology differs between hemispheres: “Energy from Waste” (EfW) and “Waste-to-Energy” (WtE) are the same thing.

7 Materials that may be recovered from the waste stream and re-used: in the context of waste projects, re-usables are not typical.

8 Materials that may be recovered from the waste stream and recycled, for example, cardboard, paper (including newspapers and magazines), glass bottles, plastic bottles and containers, drink cans (aluminium) and food cans (ferrous metals), the recycling of which will require the use of energy.

Figure 1: Treatment options for Municipal Solid Waste (MSW)



(iii) sorted into re-usable, recyclable and organic fractions and processed using material recovery facilities (MRFs) or organic recovery facilities (ORFs) to derive and produce saleable materials. Ideally, WtE project technologies will sort and remove re-usable and recyclable materials from the MSW first, in a process known as pre-sorting; see figure 1 for further details. In some parts of the world, the higher calorific value fractions of MSW (having low or no organic content) are first processed into a solid fuel⁹ (FfW) for use by power or manufacturing facilities. There is no single process for creating energy from waste, creating compost or sorting and processing the re-usable, recyclable and organic fractions, although certain methods are preferred globally.

In this, the first of three articles, Michael Harrison, Richard Guit and Nick Stalbow provide an outline of waste projects in general. In subsequent articles, we will consider in greater detail WtE, FfW and MBTs first, and MRFs and ORFs second, in the context of key markets, including Asia Pacific, Africa, and South America (in each case by country).

9 Depending on the jurisdiction, “Fuel from Waste” (FfW) may be referred to as PEF (process engineered fuel), RDF (refuse derived fuel) or SRF (solid/specified recovered fuel). These are solid fuels as opposed to gaseous fuels, such as methane (derived from landfill capture in some circumstances) or syngas (derived from gasification of MSW using some forms of WtE technologies).

Waste volumes

The World Bank estimates that more than 40 per cent of the MSW produced by the world’s urban populations by 2025 will be produced in the Asia and Pacific region (which includes East Asia).

Within the Asia Pacific region, China has the largest quantity of waste volumes and some of the most developed waste management systems. It is estimated that between 180 and 200 million tonnes per year of MSW is collected from the urban population in China. This equates to sufficient MSW to provide feedstock for nearly 900 average sized MBTs (with capacity for 225,000 tonnes a year) or up to 345¹⁰ average sized (i.e. 50 MW) WtE facilities or, stated another way, 17,250 MW of electricity generation capacity. China’s current intention is that WtE facilities will treat 40 per cent of MSW volumes by 2020. According to the World Bank, by 2025, 1.4 million tonnes of MSW will arise each day in China, equivalent to over 510 million tonnes per year. If these volumes of MSW are collected, the scope for the WtE industry in China is vast.

It is estimated that Indonesia produces between 175,000 to 180,000 tonnes of

10 Assumes 0.75 MW per tonne of MSW, or 584,000 tonnes of MSW for a 50 MW (438,000 MW/h per year) WtE facility. We have seen 0.55 (wetter MSW) to 0.8 (drier MSW) MW per tonne of MSW depending on the mix and origin of waste stream, which impacts the calorific value of the MSW and as such the MJ/kg derived.

MSW per day, or 64 to 66 million tonnes of MSW per year.¹¹ The composition of this MSW is ideal for some waste projects.¹² If all of the MSW arising in Indonesia were collected this would equate to 290 average sized MBTs or up to 115 average sized (i.e. 50 MW) WtE facilities or, stated another way, 5,750 MW of electricity generation capacity, equivalent to one sixth of Indonesia’s planned 35 GW expansion of installed capacity by 2019.

The USA continues to be the world’s biggest producer of MSW (producing at least 260 million tonnes per year).¹³ While the USA has a considerable number of established waste businesses, it offers great potential for waste projects.¹⁴ For example, the US Energy Information Administration reported over 70 operating WtE facilities in the US at the end of 2015, using approximately 29 million tonnes

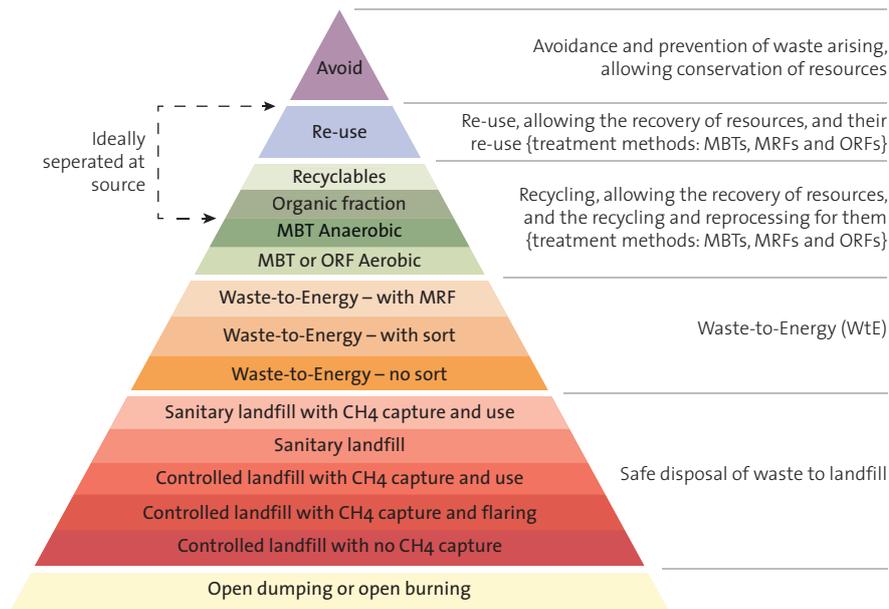
11 These figures were reported in The Jakarta Post in October 2015: While reported in tons (short tons), we have assumed metric tonnes.

12 Approximately 60 per cent is organic, 15 per cent plastic (and as such re-usable or recyclable), 9 per cent paper (and as such capable of being used for PEF/RDF/SRF), and 4 per cent metal (and as such re-usable).

13 Estimates of MSW arising vary by source of information, with this being the most conservative estimate.

14 In the USA, as published by the United States Environmental Protection Agency in 2014, 54 per cent of MSW is landfilled, 26 per cent is recycled, 8 per cent is composted, and 12 per cent is used in WtE (tending to indicate MSW arising of 270 million). A Bicycle/Columbia University State of Garbage Survey indicates that up to 69 per cent of MSW is being landfilled.

Figure 2: The “Waste Management Hierarchy”



of MSW in that year and providing approximately 2,320 MW of generation capacity (sufficient for a little under 2,000,000 homes): for the time being at least, the USA has the potential to be the largest user of MSW feedstock for WtE projects in the world.

Europe¹⁵ produces approximately 240 million tonnes of MSW a year¹⁶ and has some of the most developed and diverse waste management systems in the world, including approximately 490 MBTs¹⁷ and 510 WtE facilities.¹⁸

The “Waste Management Hierarchy”

The development of waste projects directly achieves the re-use, recycling, MBT and WtE outcomes set out in the “Waste Management Hierarchy” (see figure 2) and, through diversion from landfill, reduces the quantity of waste disposal to landfill.

The Waste Management Hierarchy is the touchstone for environmental legislative initiatives around the world: it provides an overarching statement of policy outcomes that are widely recognised. Further, this statement of policy outcomes has been applied in many legislative initiatives worldwide.

Some legislative initiatives have underpinned the development of the MBT and WtE industries and, thereby, the achievement of and progression towards the Waste Management Hierarchy outcomes. Most notably in this regard, within the European Union, EC Council Directive 26 April 1999¹⁹ was the catalyst for

government sponsored initiatives and regulatory policy settings aimed at diverting waste from landfill and facilitating investment in waste sorting, processing and treatment alternatives.²⁰

Waste projects

Waste facilities are typically developed as “projects” aimed at delivering a solution in line with the Waste Management Hierarchy.

Waste projects which achieve the policy outcomes of the Waste Management Hierarchy are as follows:

- Organic Recovery Facilities (ORFs) which recover and process the organic fraction from green waste²¹ and other organic waste (including food waste and garden waste),²² but not from MSW. ORFs derive and produce organic products for agricultural use (effectively re-use), thereby diverting organics from landfill;²³
- Materials Recovery Facilities (MRFs) which recover re-usable and recyclable materials²⁴ from the waste stream, including as part of a pre-sort to a MBT or WtE facility, thereby allowing re-use, recycling and reprocessing of resources, the production of FfW and diverting waste from landfill;
- Mechanical Biological Treatment facilities (MBTs)²⁵ which recover re-usable and recyclable materials from the waste processed (invariably MSW, often C&I Waste,²⁶ and in some instances C&D

15 For these purposes Europe includes Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Lithuania, Luxembourg, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Switzerland and the United Kingdom.

16 2014 figures, source: OECD, Municipal Waste, <<https://data.oecd.org/waste/municipal-waste.htm>>.

17 With a disposal capacity of around 47 million tonnes per annum, source: Mark Doing, “The Market for Mechanical Biological Waste Treatment Plants in Europe”, (September 2016) 6 Waste Management.

18 2014 figures, source: Confederation of European Waste-to-Energy Plants, <www.cewep.eu>.

19 Directive 1999/31/EC.

20 In jurisdictions such as the UK, local planning laws have also influenced outcomes, such as investment in MBT solutions over WtE solutions (as councils adopted anti-“incineration” policies based on bad experiences in the 1980s and early 1990s in the time prior to technological advancement and cleaner WtE technologies).

21 Organic material from domestic “green” bins and activities of municipalities (typically, parks and gardens and lopping and topping of trees).

22 Note: ORFs usually require organic waste to be segregated at source, with a low tolerance for contamination from non-organic waste materials.

23 Depending on the profile of the organics delivered to an ORF, diversion of 95 percent by mass can be achieved.

24 In our second article we will consider in detail materials regarded as re-usable and recyclable by reference to various markets.

25 In our second article we will consider in detail the range of MBT technologies used.

26 Commercial and industrial waste from commercial and industrial premises.



Waste²⁷) typically as part of a front-end pre-sort MRF, and process and treat waste in an aerobic or anaerobic environment, in order to separate, process and treat the organic fraction of the waste stream, thereby allowing re-use, recycling and reprocessing of resources, the production of PEF,²⁸ RDF²⁹ or SRF,³⁰ the use of organic products, as well as diverting waste from landfill;³¹ and

- WtE facilities (also known as EfW facilities) which use thermal technologies to burn waste or use gasification technologies to burn the gas produced by the waste (typically MSW, often C&I Waste, and in some instances C&D Waste and bio-solids)³²

thereby generating electricity (or producing power and heat on co-generation³³), diverting waste from landfill,³⁴ and reducing emissions. WtE facilities may or may not recover re-usable and recyclable materials from waste as part of a front-end pre-sort MRF.

Secondary waste projects

As noted above, MRFs (including as front-end pre-sort to MBTs and WtE facilities) may produce FfW. The FfW may be subject to further processing to allow for its use in industrial processes, most typically as feedstock to fire cement kilns.

Policy settings are key for the development of waste projects

Background

Unless municipalities choose to develop waste projects simply because it is the right thing to do, broader policy settings are required to facilitate investment in the delivery of waste projects.

In practice, these policy settings

are most effective when they place a cost on landfill and place a value on the environmental benefit resulting from the waste project. It is critical for municipalities, and any central or provincial government, to consider the direct and indirect impact of a move away from landfill, including in some jurisdictions the impact on disposal scavengers.

As we will note in our two subsequent articles, because waste projects need the right policy settings to be developed and to maintain viability, one of the key risks for waste projects – if not the key risk – is the risk of a change in the law (including a “timing out” of any law) which places a cost on landfill and/or attributes value to environmental benefits.

Landfill

If one ignores the cost of environmental contamination, and the health consequences, of open dumping (and, in some jurisdictions, open burning and burying waste) open dumping³⁵ is the cheapest way to dispose of waste. For waste projects to be developed in jurisdictions that currently allow open dumping, municipalities, as well as central and provincial governments, must make policy decisions prohibiting open dumping

27 Construction and demolition waste from construction and demolition sites.
 28 Process engineered fuel (PEF), being fuel (with limited or no organic content) derived from waste used to fire industrial facilities, including cement kilns, being a FfW.
 29 Refuse derived fuel, being solid fuel (with limited or no organic content) derived from waste used to fire industrial facilities, including cement kilns, being a FfW.
 30 Solid/specified recovered fuel, being solid fuel (with limited or no organic content) derived from waste used to fire industrial facilities, including cement kilns, being a FfW.
 31 In terms of mass, MBT can divert up to 90 per cent by mass from landfill, although diversion of 70 per cent by mass is more usual.
 32 Animal and human waste matter derived from waste water processing, that may be used in agriculture or as supplementary feedstock for WtE facilities.

33 The generation of electricity and the production of heat (typically steam).
 34 The use of land to dispose of waste arising in urban and rural areas. In terms of volume, typically WtE diverts 90 per cent by volume from landfill: fly ash and bottom ash are residual by-products of WtE, with fly ash requiring safe disposal but bottom ash may be usable as alternative daily cover or re-used as a constituent for road covering.

35 Dumping of waste other than at a controlled or sanitary landfill, including at any unlicensed landfill.

(and open burning) and move to a policy of controlled landfill³⁶ and sanitary landfill³⁷ (and in so doing place a cost on landfill), or impose limits on the use of landfill (and thereby stimulate a programme of new non-landfill waste infrastructure).

As a general statement, for waste projects to be developed the cost of landfill needs to be such that waste projects are able to provide waste sorting, processing and treatment services at a price that is comparable with the cost of landfill,³⁸ i.e. the levelling of the playing field. This may not be achieved by prohibiting open dumping and placing a cost on controlled or sanitary landfill. It may be necessary to place limits (caps) on the quantity of waste that can be landfilled at controlled or sanitary landfills, thereby making landfill capacity (airspace or void space) more scarce and, as a consequence, more expensive. A decision of this kind is unlikely to be taken at the municipal level and, as such, may have to be a central or provincial government level decision. If this is not sufficient to level the playing field, the imposition of levies or taxes on waste which is disposed of to landfill may assist³⁹ but, again, this is likely to be a central or provincial government decision.

It is likely that scarcity of airspace (or void space⁴⁰) at landfill, in combination with a levy or tax on waste disposed of to landfill, will level the playing field. In some jurisdictions, ultimately landfill will be phased out completely, thereby forcing the development of waste projects: landfill can be phased out completely by either price signals (including levies and taxes) or through not consenting to new landfill sites. In other jurisdictions, the cost of developing new controlled or sanitary landfill may be regarded as prohibitive, as increasingly stringent licence conditions are imposed to ensure emission, environmental and health outcomes which are broadly consistent with an equivalent waste project.

Renewable energy

In many countries in Asia, WtE (or EfW) projects (and renewable energy projects generally) are supported by feed-in-tariff (FiT) regimes.⁴¹ Typically, the government obliges a generator or transmission or distribution company to source renewable energy from renewable energy generators for a fixed price (which may escalate over time). This provides developers of WtE projects with revenue certainty for the electricity that they generate.

In other countries, governments require retailers of electricity and large users of electricity to source from renewable energy sources a percentage of the electricity they sell. To underpin this requirement, the government issues renewable energy certificates

36 Landfill that is licensed, including compliance with requirements as to control and operation.

37 Licensed landfill isolated from the environment such that disposal to it is safe because isolation continues until waste has degraded biologically and physically.

38 For project finance funded WtE projects, the WtE project must be able to earn sufficient revenue from payments for diversion of waste from landfill and from sale of electricity, or electricity and steam, to service debt, repay principal and earn a rate of return for equity investors.

39 Examples of jurisdictions in which landfill levies and taxes have been imposed include the United Kingdom, where a per tonne tax on landfill was imposed ten years ago and has risen incrementally to £82.60 per tonne for non-inert waste, and Australia, with the landfill levy rate in each state for MSW is set out below: New South Wales, Metro: AU\$135.70 per tonne; Regional: AU\$78.20 per tonne. Victoria, Metro: AU\$62.03 per tonne, and Rural: AU\$31.09 per tonne. South Australia, Metro: AU\$76 per tonne; Regional: AU\$35 per tonne. Western Australia, Putrescible (including MSW): AU\$60 per tonne; and Inert: AU\$50 per tonne.

40 The capacity at a landfill capable of being used to dispose of waste.

41 In our second article we will include details of FiT regimes.





to renewable energy generators and requires retailers to pay a penalty if they do not source the required percentage of electricity from these generators. The penalty may be avoided or reduced if the retailer surrenders renewable energy certificates. The cost of the renewable energy certificates is prescribed by legislation.

In the context of a co-generation WtE facility (being a facility that produces heat and power), revenue may also be earned by the sale of heat (in the form of steam) to an industrial user.⁴²

Other policy settings

While placing a cost on landfill and placing a value on the benefits of renewable waste projects are key, they are not the only policy settings used to encourage the development of waste projects, or other environmentally-beneficial projects for that matter.

Another option is to make a contribution to the cost of development of waste projects, for example in the form of grants or financing on concessionary terms, subsidies or concessionary treatment. In addition, international agencies (including the Asian Development Bank) may provide assistance.⁴³

In addition to this, local planning and development schemes can influence the type of waste project that is to be developed. For instance, local planning laws in many parts of the UK expressly rejected developing “incineration” or “mass burn” style WtE facilities. This was largely a legacy policy position from the 1980s when those plants were notoriously bad polluters. Consequently, many waste projects developed in the UK in the mid-2000s took the form of MBT plants – producing an SRF (which was then used as a fuel by WtE facilities in other locations). The policy objectives of diverting waste from landfill were still achieved by this type of project.

Finally, in some jurisdictions companies undertaking waste projects are eligible for concessionary tax treatment.

Importance of collection and segregation at source

Collection and delivery

Waste projects are facilitated by effective waste collection systems which enable the delivery of appropriate waste to individual waste facilities. This may comprise direct delivery to the waste facility or a network of transport routes and sites (transfer stations) used to consolidate certain wastes for onward transport to the waste facility.

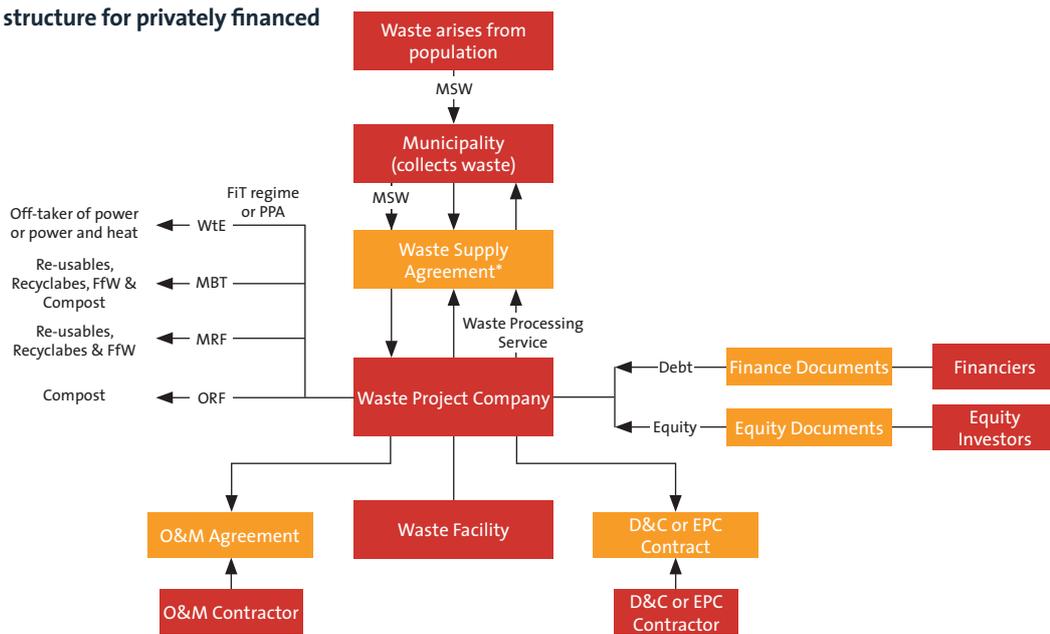
In many jurisdictions, the collection of waste is the responsibility of municipalities. In many other jurisdictions, the collection of waste is not an established practice and is regarded as expensive.

With increasing urbanisation in many jurisdictions, the collection of waste by municipalities is a new activity for them, and the cost of doing so is a new cost, and a relatively expensive one. This new cost may be regarded as being outweighed by the environmental benefits of coordinated collection and management.

⁴² In addition, for some waste projects the policy settings confer value in terms of certificates that may be sold by project and therefore provide another source of revenue. We will consider these in later articles.

⁴³ In the two subsequent articles, we will consider the form of assistance given.

Figure 3: Typical structure for privately financed waste project



Separation at source

At its simplest, “source separation” is giving households the ability to put their waste into different bins: organics (food, kitchen and garden), recycling (plastic and paper) and residual (everything else). For some types of waste processing facility, segregation of the waste stream at source is very helpful. The strong preference of operators of MRFs and ORFs is for source separation, so that the re-usable and recyclable fraction of the waste stream is delivered to the MRF (dry MRF) and the organic fraction (food, kitchen and garden waste) is delivered to the ORF. In contrast, MBTs can sort and process deliveries of separated-at-source materials (e.g. plastics, metals, glass and cardboard) and unseparated-at-source materials. There is also a class of MRF (“dirty” or “wet” MRFs) which processes the re-usable, recyclable and organic fraction, although the compostable output has more limited application due to potential cross-contamination.⁴⁴ Separation at source requires a multiple bin system and multiple collections and deliveries. These systems have higher running costs, which are ultimately borne by households. Consequently, they tend to feature in jurisdictions where developed waste collection and management system are well established.

⁴⁴ There are different economics to dry and wet MRFs (including in the context of the source of the waste containing the recycle fraction). We will consider these in the later articles.

Re-usable and recyclable waste may be of value, and one-bin systems (which contain re-usable and recyclable waste) can be perceived as beneficial by some waste project operators, particularly if there is a front-end MRF which will allow separation of the re-usable and recyclable fraction for an MBT. At the end of the day, different processing technologies have different limitations in terms of what they can receive and process, and a tailored solution will be required in each case.

Power of municipality to collect and quantity collected

One of the key risks on any waste project is the volume and type and, therefore, the composition of waste within the municipality’s catchment area. Will there be sufficient waste from the catchment area (typically, the geographic area for which a municipality is responsible) to justify the investment in the particular waste project? Sufficient volume is needed to reduce the cost per tonne of waste processed or treated, and to deliver the efficient operation of the waste project, particularly for WtE facilities.

There are a number of dimensions to waste volume and supply risk, the first of which is whether or not the municipality with which the private sector developer is to contract actually has the power to collect waste and to deliver that waste to the facility. This is not always a straightforward matter.

In those cases where the cost and risk of financing a waste project rests with the private sector, the waste project company (and its financiers) will be concerned to understand the waste volume risk of the municipality and, therefore, the waste supply risk to the project. This is relevant if the municipality chooses to procure the delivery of the waste project under a Build Own Operate (BOO), Build Own Operate Transfer (BOOT), Design, Finance, Build, Own, Maintain (DFBOM) or Public Private Partnership (PPP) delivery model: see figure 3 for a typical project structure for such an arrangement. If the municipality develops and pays for the project itself under a Design and Construction (D&C) or Engineering Procurement Construction (EPC) delivery model, the risk of insufficient waste volume within the municipality and, therefore, the number of tonnes supplied to the waste project, usually remains with the municipality.

Other dimensions of waste volume and supply risk include the actual type and quantity (and, therefore, the composition) of waste generated within the area (and how this may change over time) and assumptions made as to the growth in that waste volume and, therefore, the waste supply over time (as it would be unusual for a waste plant to be sized without contemplating growth

in waste volumes),⁴⁵ and whether or not the private sector is being given exclusive rights to that waste. Each of these issues will be addressed in more detail in articles 2 and 3 of this series.

Project Participants

Waste projects are developed using a variety of project delivery models and, as such, can have different project participants.

Municipalities may develop a waste project themselves, contracting with a D&C contractor or EPC contractor to deliver the project, and then either operate the project themselves or contract with an Operations & Maintenance (O&M) contractor to operate and maintain (and repair) the project. This tends to be the more prevalent model in China.

Alternatively, municipalities may choose to contract with a private sector developer under a BOO, BOOT, DFBOM or PPP delivery model, as described above. These delivery models are the most complex contractually. (We will describe these models in greater detail in articles 2 and 3 of this series.)

Industrial companies may develop waste projects themselves, most typically a WtE facility (possibly using bagasse, biomass or another by-product of a primary industry and, in some instances, waste from a secondary industry). As with municipalities, industrial companies may develop a WtE facility by contracting with a D&C or EPC contractor to deliver the project, and then operating the facility themselves or contracting with an O&M contractor to do so. Or, alternatively, an industrial company may choose to contract with a private sector developer under a BOO, BOOT or DFBOM model.

Some electricity generators or transmission/distribution companies may develop WtE facilities. Electricity companies are more likely to develop and to operate such facilities themselves, rather than contracting with the private sector, other than with a D&C or EPC contractor to construct the facility.

Some projects are developed as merchant facilities (i.e. the feedstock is non-municipal waste, or feedstock is supplied by a municipality but the developer is taking risk on the volume and composition of waste supplied) with the waste project company (and its debt providers and equity investors) satisfying itself that sufficient waste is committed contractually or is otherwise obtainable within the facility's catchment area⁴⁶ to meet the tonnage capacity, and a route to market for the power (either to a captive off-taker or through access to the electricity grid under a FIT regime) to allow for export of all electricity generated.



Combined heat and power projects will require a heat offtake commitment. In order to be commercially viable, such demand for waste capacity, electricity and heat must be at pricing levels which enable the facility to generate sufficient revenue to service debt, repay principal and provide a rate of return for the equity invested in the facility. Merchant facilities may be delivered by a D&C or EPC contractor (depending on the required level of transfer of technology risk) and may be operated and maintained (and repaired) by the waste project company (as the owner of the facility), by an equity investor in the project with experience as an O&M contractor, or a separate O&M contractor.

In conclusion

As noted at the start of this article, the demand for waste projects is driven by the growth in waste volume as the world's population grows and becomes increasingly urbanised. This means that there will continue to be a growing demand for new waste treatment infrastructure.

In articles 2 and 3 we will explore the different types of waste projects in more detail.

⁴⁵ In the context of WtE projects delivered as PPPs, it is more likely than not that the waste project will be over-sized in order to accommodate growth in municipal waste arising over the life of the project facilities. In order to optimise the cost of finance, it is often important to bank the gate fee and electricity revenue from the spare capacity. This puts pressure on sponsors to guarantee their ability to secure merchant waste in the quantities needed to operate the facility at full capacity.

⁴⁶ Unlike a municipality, the catchment area of a merchant facility is not defined by an area within which the municipality has power, or the obligation and power, to collect and to dispose of waste. The catchment area of a merchant facility is defined by the substitutability of the service provided by the merchant facility by another means of waste processing or treatment, which is a function of the cost to the customer for the service provided by the merchant facility (compared to any substitutable service), which includes the charges/fees of the merchant facility, the cost of transportation to the merchant facility, and the cost of disposal of any residue, and whether sufficient waste can be derived from that catchment area will enable the merchant facility to generate sufficient electricity (in the context of WtE), re-usables/recyclables, FfW and compost (in the context of an MBT), re-usables/recyclables or FfW (in the context of a MRF) or compost (in the context of an ORF).



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Iran and The New Silk Road: Opportunities & Legal Considerations

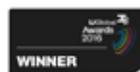
On 7 March 2017 Ashurst jointly hosted a seminar with the New Silk Road Forum, based in our London office. The event focused on the business environment and opportunities in post-sanctions Iran and was attended by clients across the spectrum of the energy and finance sectors.

The Q&A panel session was co-chaired by partners Abradat Kamalpour and Hassan Javanshir featuring a series of key external and internal speakers including Mr Richard Bacon MP (Conservative), Chair of the All-Party Parliamentary Group on Iran, one of the drivers of the UK and Iran relationship in parliament; Lord Waverley, Deputy-Chair of the All-Party Parliamentary Group on Iran and Chairman of the New Silk Road Forum; Amir Seyedi, Advisor to the CEO of Arman Investment Bank, Iran; Karim El Assir, Corporate Intelligence, Risk Consulting, KPMG; William Jenkins, Senior Consultant, Ernst & Young and Tom Cummins, who leads our Sanctions Group.

The Ashurst Iran desk is unrivalled. We have a bench of Persian speaking partners and senior lawyers who are well placed to advise companies seeking to invest in Iran. As a global law firm we have the expertise in key sectors of interest in Iran, including oil and gas, resources, transport, infrastructure and finance.

Recent awards

In the past six months Ashurst has been recognised for its outstanding work in the energy sector by the following awards:



IJ Global Awards

Africa M&A Deal of the Year – advising Iluka Resources Limited on its A\$375m acquisition of Sierra Rutile

Middle Eastern Renewables Deal of the Year – Al Fujeij Wind Farm



Legal Business Awards

Ashurst has been named **Restructuring Team of the Year** at the Legal Business Awards 2017, held in London on 23 March. The firm received the award in recognition of its work advising the largest independent UK oil producer in the UK North Sea, EnQuest, on its financial restructuring.



Global Derivatives Awards 2016

Ashurst has been named **Asia Pacific Law Firm of the Year** for regulatory work at the Global Derivatives Awards 2016, which were announced in London on Tuesday, 20 September. These awards recognise firms which have made a significant impact on the global derivatives market during the last 12 months.

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