Introduction

In an earlier article (The OGA in Energy Transition: UK aims for upstream oil and gas regulation in line with "net zero" goals) we examined how the Oil and Gas Authority (OGA) has proposed (in a consultation of 6 May 2020) to revise its strategy of maximising economic recovery (MER) to be consistent with and to help meet the UK’s net zero target. With the goal of reaching net zero greenhouse gas emissions by 2050 and so avoiding unacceptably dangerous climate change, engaging positively with the "energy transition" appears set to become a mandatory requirement in the future for oil and gas companies active in the United Kingdom Continental Shelf (UKCS).

Oil and gas operations give rise to greenhouse gas emissions in three broad categories: (i) upstream emissions (flaring, venting etc.); (ii) midstream transport and process emissions (e.g. from refinery stacks, pipeline leaks, etc.); and (iii) end-use emissions (a broad category ranging from combustion in car or power stations to decomposition of plastics releasing methane). There are, therefore, a range of ways that oil and gas companies operating in the UKCS can satisfy the proposed new dual central obligation of MER and assisting the Secretary of State in meeting the net zero target.

The OGA’s consultation focuses mostly, but not exclusively, on the first two categories. It is interested not just in how the industry can contribute to net zero by reducing greenhouse gas emissions from its own activities (for example, from flaring, venting or power generation), but also in its ability, by participating in or facilitating carbon capture and storage (CCS) and hydrogen projects, to help the wider economy to decarbonise (and potentially to extend future demand for its products in a net zero world where they might have been converted into less emissions-intensive forms).

Oil and gas companies operating in the UKCS, together with other industry participants in the oil and gas value chain, will therefore soon need to consider, if they have not done so already (for example, in pursuit of their own sustainability goals), what they need to do to meet the new obligations proposed in the OGA’s consultation (indeed, in recent weeks we have seen the adoption by many international oil companies of voluntary decarbonisation goals).

Each decarbonising option will have differing intrinsic appeal to each individual industry participant, depending on its attitude to the energy transition and the stage of its petroleum operations (e.g. exploration, development, production or late life assets). Like most important decisions affecting upstream projects, decisions about pursuing such options will, in most cases, need to be taken not by a single company but collectively by the participants in unincorporated joint ventures. Moreover, there will often be an element of interface between the different technologies, and it may be that a different combination of the technologies described below could be relevant to different upstream participants based on a number of factors, such as location (i.e. proximity to infrastructure), stage of development and the nature of the operations. In this article, we give an overview of some of these options.
Electrification of platforms, gas-to-wire and offshore wind

Offshore oil and gas companies require large amounts of electricity to power all stages of their upstream petroleum operations, whether exploration, development or production activities. This is normally provided by gas turbines burning gas extracted from the reservoir or by heavy-fuel generators situated on the offshore platform. Whilst it may be economic to use gas from the reservoir itself, the use of gas turbines or heavy-fuel generators increases greenhouse gas emissions (as well as levels of SO\(_x\) and NO\(_x\) emissions that would not be permitted in an onshore installation).

On 16 June 2020, OGUK, the UK's oil and gas industry body, published The Pathway to Net Zero: Production Emissions Targets in which it has committed to halving operational emissions on a basin-wide basis in the next decade, confirming its pathway to becoming a net zero emissions basin by 2050. The report notes that upstream emissions account for 4% of UK greenhouse gas emissions; that the bulk of those emissions come from offshore power generation; and that the average carbon intensity of that generation is four to five times that of the generating mix of the onshore grid.

The report also highlights the correlation between higher power demand and the maturity of the basin (more late-life and deeper-water assets). Not surprisingly, it argues against earlier decommissioning or non-development of more energy-intensive assets on the basis that UK demand for oil and gas, even on a net zero trajectory to 2050, will consistently exceed UKCS output – meaning that early closure of UK production would simply result in exporting the UK economy's emissions.

The OGUK report is in line with the thrust of the OGA proposals. It highlights the potential for full or partial electrification of offshore assets, localised CCS on individual assets, integration of offshore hubs (much like onshore industrial clusters) and electrification of onshore terminals and processing plants. It also stresses the need for collective innovation and a coordinated effort between industry and government. Looking towards a Sector Deal for the industry with the UK government, it hints that rapid progress may depend on some form of assistance. OGUK emphasises what it considers to be the gap between what is technically feasible and what is currently commercially affordable, and the need for incremental operational improvements before any major step change in activities.

The availability of zero carbon power for offshore upstream assets is not in doubt. UKCS is home to a large and growing number of offshore wind farms. There is the potential for offshore wind projects to provide power to upstream infrastructure located in proximity to the wind farm, no matter what stage of their petroleum operations, rather than using gas produced from the reservoir or generators, thereby reducing their carbon footprint. The scope for this kind of arrangement will increase as the offshore wind industry starts to make more use of floating, rather than fixed-bottom, structures for its turbines, opening up a significantly larger proportion of the UKCS to offshore wind development. The OGA has recently published analysis showing that the UKCS compares favourably with other basins in terms of the average carbon footprint of gas produced from it, although it clearly sees that as a record that can be improved. In addition to that, and any individual operators' sustainability goals, it is possible that, in a future world of systematic carbon-pricing, hydrocarbons produced with a lower carbon footprint could be at a competitive advantage in national or international markets.

In areas like the southern North Sea, upstream gas assets sit side by side with offshore wind farms. In this area, and other areas potentially too, there is therefore also considerable interest in the potential for power generated by the offshore combustion of gas to be exported to the onshore grid via spare offshore wind export cable capacity. Although it would not contribute to lower greenhouse gas emissions, gas-to-wire could help upstream assets that are coming
to the end of their period of production. It may be more cost-effective to monetise the remaining gas by turning it into power and exporting it to the grid via existing offshore wind transmission infrastructure. Equally, it could be a way to exploit otherwise stranded assets that it is not feasible to develop as sources of gas because of their size, location and, in some cases, chemical composition (which increases the processing costs required to meet onshore network specification).

The OGA has been looking carefully at gas-to-wire since at least 2018. In relation to gas-to-wire, an offshore generating station other than a wind farm, that generates power for the onshore grid, is also currently a regulatory anomaly and issues to be resolved in relation to gas-to-wire include licensing and integration into industry code structures, development consent (the offshore wind and upstream regimes are separate) and the application of industrial emissions rules. It will also be essential for shared use of the transmission cable not to result in the gas-fired generator’s output being metered, as if it were part of the output in respect of which the offshore wind farm is entitled to receive subsidies. However, Ofgem has already had to address similar metering issues in connection with onshore hybrid renewable projects, on which it has published guidance.

Some oil and gas companies have already taken their involvement with offshore wind beyond collaboration to participate directly in offshore wind projects. Ørsted, now arguably the market-leading offshore wind project developer, started life as oil and gas player DONG. A number of other upstream players, such as Total, Shell and Equinor, are also active in this space. Offshore wind, given its large scale, location, pre-construction costs and tendency towards joint venturing, is perhaps the most obvious renewable business fit for oil and gas companies operating in the UKCS. Technological progress means that offshore wind is now much less reliant on substantial state-organised financial support than was once the case and with the development of floating technology (whose superstructure and mooring systems reflect oil and gas experience), offshore wind is likely to become a viable source of significant amounts of low carbon power. As a technology, it will take the largest share of payments under the UK's Contracts for Difference (CfD) renewables support regime, and the UK government envisages that a further 15-25 GW (on top of the existing pipeline) of UKCS offshore wind projects should be financed under the CfD scheme by 2030.

Pursuing standalone offshore wind projects will only be relevant to certain upstream oil and gas companies willing to venture into an entirely new sector but, when considering offshore wind projects, upstream participants will need to be aware that output is exported through cables whose operation is more complex, and more vulnerable to outside impacts, than most pipelines and typically owned by a regulated third party offshore transmission owner (OFTO) (rather than other upstream players) and controlled by a separate, regulated system operator. Selling in the wholesale power market, where the supply/demand balance and prices regularly move further in a few hours than the oil price often does over a period of months or years, is also very different from supplying crude oil or even natural gas to the downstream sector.

It is also worth noting that the regulatory regimes for offshore upstream oil and gas operations and offshore wind are currently largely separate and a number of questions would need to be answered in order for the regimes to work more closely together and capture synergies between oil and gas operations and offshore wind. For example, given that OFTO licences anticipate a point-to-point connection of a single offshore windfarm, how much spare capacity is there likely to be? Would changes be required to an OFTO licence in order to manage the connection of more than one generating asset using different technology? How far could obligations on OFTOs to increase capacity be extended to include electricity from offshore gas projects? Would the regulator be prepared to allow recovery of funding from customers for construction of offshore infrastructure with spare capacity in contemplation of new upstream gas-to-wire projects? Would any changes or a requirement to connect offshore gas generating projects to OFTO infrastructure be a barrier to investment in existing project-financed OFTOs which may perceive risk in connecting a new party to its asset without a full, potentially uncapped, indemnity?
CCS

CCS is the process of capturing waste carbon dioxide (CO₂), normally from larger emitters such as power plants or industrial factories (e.g., cement), transporting it to a storage location and storing it, often in some sort of geological formation, such as a saline aquifer or oil and gas reservoir.

Originally used as a way to squeeze more revenue from depleted upstream assets through Enhanced Oil Recovery, in recent years CCS (or, as it is sometimes referred to, CCUS – carbon capture, use and storage) has gone from being seen as a transitional technology on the way to a net zero world to one likely to play an essential and necessary role in the long term. It can allow large-scale fossil-fuel power plants to provide secure, low-carbon power and grid stability; help to decarbonise heavy industry; produce hydrogen from methane (for clean transport and heating applications) without venting CO₂; support the production of carbon-neutral synthetic alternatives to fossil fuels for aviation, for example; and enable crucial “negative emissions” technologies that will be needed to offset residual emissions.

Upstream oil and gas companies have a significant role to play in all this. They own many of the prime assets that can be used for the transport and storage part of the CCUS value chain, and have valuable expertise in the relevant geology and in the transportation of fluids through pipes. Moreover, the oil and gas industry has an incentive to participate in CCUS because a flourishing CCUS sector could be one of the means by which it will continue to thrive in a significantly carbon-constrained future. The BEIS consultation paper on the re-use of oil and gas assets for CCUS projects (September 2019) contemplates relief from decommissioning liability for assets which undergo a change in use as the only regulatory incentive for oil companies to participate in CCS projects. It would therefore fit more naturally with the OGA’s proposed dual objective to allow companies to develop CCS capability as a way of enhancing oil recovery and extending field life for a period before an asset becomes solely dedicated to CCS.

The concept of storing natural gas in depleted gas fields or saline aquifers is well understood (for example, the Rough storage facility was used to store natural gas for a number of years). However, transporting CO₂ to offshore storage facilities will either need to be done by repurposed ships or via pipeline. It is unlikely that new pipelines will be built for this purpose, and it may be suboptimal or uneconomic to do so. There is a plethora of pipelines already in existence in the North Sea, an increasing number of which may no longer be required for their original purpose of transporting oil and gas to shore. It seems likely that some these could be used to transport CO₂, representing a considerable saving over the installation of new pipelines for CCS projects.

In relation to the offshore pipeline network and offshore storage facilities, there are still a number of questions as to how the regime for the transportation and storage of CO₂ would work. Will there be one entity responsible for a unified CO₂ transportation and storage network (for example, like National Grid Gas onshore) or would individual companies undertake this for themselves, developing pipelines to link individual onshore CCUS clusters of emitting plants to individual offshore storage sites (more in the "point to point" manner in which offshore wind farms have so far been connected to the onshore electricity transmission network)? What regulatory support would be put in place for the revenues of the transport and storage businesses (at present, the government appears to favour a regulated asset base model like that of onshore gas transporters)? How would the risks of emitting businesses not producing a steady stream of captured emissions and the transport or storage facilities not being available to receive them be allocated across the value chain and/or back-stopped by government support? Does it necessarily make sense for transport and storage to be in combined, rather than separate ownership/operation?

In relation to the storage of CO₂ it will also be necessary to establish a regime for dealing with the potential escape of any CO₂ from the storage infrastructure and potential consequences for the storage operator. The CCUS Advisory Group’s Investment Frameworks for Development of CCUS in the UK report (July 2019) recommends that, during the CO₂ store operating period, the company established to operate the transportation and storage infrastructure
contributes to a contingency reserve of Emissions Trading Scheme allowances at a rate agreed with the regulator. In the event of a leak, the transportation and storage infrastructure operator would draw on this fund and, if the fund is exhausted, the government would act as insurer of last resort. There may also need to be a mechanism in place for dealing with costs during the post-closure period of the store (for example, the costs of monitoring and clean up). Again, use of a fund built up during the operating period may be appropriate.

In a future article in our series on net zero and the OGA, we will also look at the legal EHS issues associated with offshore CCS operations.

**Hydrogen**

There has been a lot of discussion about using hydrogen as an alternative fuel (for example, in relation to transport). Hydrogen fuel, when used to produce electricity in a fuel cell, is a zero-emission energy carrier, whose only by-product is water. Using hydrogen as a fuel source has huge potential therefore for the UK meeting its net zero target. Hydrogen is currently mostly produced from natural gas through steam methane reformation (SMR) — so-called "grey" hydrogen. To be compatible with net zero objectives, hydrogen needs to be either "blue" or "green". "Blue" hydrogen involves fitting the SMR plant with CCS, so that when high pressure steam (H₂O) reacts with natural gas (CH₄) producing hydrogen (H₂) and CO₂, the CO₂ is then captured and stored. "Green" hydrogen is produced through the electrolysis of water by surplus renewable power and produces no CO₂ and so requires no CCS.

According to the OGA's consultation, "the oil and gas industry is uniquely placed to deliver CCS projects, with significant potential for re-use of oil and gas infrastructure in the UKCS for carbon transport and storage". In relation to "blue" hydrogen, this could mean using offshore storage facilities (as described in the CCS section above) to store CO₂ produced onshore as part of the "blue" hydrogen production process. In addition, upstream infrastructure owners (e.g. pipeline owners) could look to take "green" hydrogen produced offshore by an offshore renewables project and transport it onshore using their existing pipeline network, or transport CO₂ produced onshore from "blue" hydrogen projects to storage facilities. Upstream oil and gas companies could even look to undertake an offshore renewables project (e.g. offshore wind) to generate "green" hydrogen offshore and again transport it onshore using the existing pipeline network or store it in depleted oil and gas reservoirs offshore.

However, developing a hydrogen industry poses a number of challenges, not least maximising the scale advantages of "blue" hydrogen before "green" hydrogen achieves better efficiency and gains traction, but also because, potentially, for many years the pipeline network may need to transport a mixture of hydrogen and methane which have very different physical properties, raising significant commercial and technical challenges. In addition, no regulatory regime currently exists in the UK for the development of hydrogen projects and will obviously therefore need to be created.

**Repurposing assets: is this a magic bullet to avoid decommissioning costs?**

According to the OGA's UKCS Decommissioning 2019 Cost Estimate Report, decommissioning remaining UK offshore oil and gas production, transportation and processing infrastructure will cost £49 billion (based on 2016 prices). Decommissioning existing and future upstream assets in the UKCS therefore obviously poses a significant financial hurdle for UKCS participants and also poses a challenge for companies wishing to farm-down their interests or exit the basin, due to ongoing liability for decommissioning costs.

In a recent article in the *Financial Times*, a study co-authored by Alex Kemp of the University of Aberdeen warned
that more than a third of all estimated available hydrocarbons in the North Sea were likely to remain undeveloped between now and 2050 at oil prices of US$35 a barrel. It is not yet clear whether the likely acceleration of decommissioning liabilities as a result of it being uneconomic to recover a greater proportion of reserves will therefore mean a push for repurposing of assets.

As described above, the BEIS consultation paper on the re-use of oil and gas assets for CCUS projects focuses on a proposal to relieve parties currently liable for decommissioning upstream assets in respect of assets which have been transferred to a CO₂ storage project. This policy should help to achieve the stated aim of mitigating the disincentive on current asset owners to transfer these assets. However, we think that the regulatory framework for commercial CO₂ storage projects will need to cater for a period of overlap between late-life upstream operations and early-stage CO₂ or hydrogen storage operations. The provisions in the Energy Act 2008 and its subsidiary regulations for CO₂ storage projects do not, in our view, adequately allow for such an overlap.

The value of existing industry assets which may be near zero, or negative in view of decommissioning/clean-up obligations, may be considerably enhanced by the opportunity of CCS or the other opportunities discussed above (e.g. gas-to-wire or "green" hydrogen). At the very least, decommissioning costs can be expected to be deferred. In addition, some parties currently facing contingent liabilities may be relieved of them. The OGA's consultation recognises that, where infrastructure is or can be repurposed, the asset stewardship principles that apply in upstream scenarios should also apply (i.e. collaboration, timely and good faith negotiations relating to access, and granting access to infrastructure on fair, reasonable and non-discriminatory terms). For potential projects offshore (whether CCS or other), this may be seen as breaking down a barrier to ensure access to infrastructure is granted in a manner to foster investment. However, it should be noted that, even where an asset is repurposed, there may be a requirement to decommission part of the infrastructure before additions are made in order to repurpose the asset.

One of the next articles in our series on net zero and the OGA will focus on how the repurposing of assets may be impacted by the varying decommissioning regimes and regulations in the offshore oil and gas space, and the potential for decommissioning liabilities and other issues.

**Conclusion**

Currently the regulatory regimes for the options set out above either do not exist (e.g. hydrogen), are separate from the upstream regime and not adapted to interact with it (e.g. gas-to-wire and offshore wind) or require a lot of further development (e.g. CCS). In addition, there are a multiplicity of regulators in the overlapping sectors (e.g. OGA, OPRED and OFGEM) potentially making it harder to implement these options. There will therefore need to be the creation of new regimes, as well as a convergence of the existing regimes and regulators in order to allow these options to be implemented and to interface with each other. In a series of follow-on articles relating to each opportunity set out above, we will cover the existing regulatory regime and what changes may be required to it – and existing industry commercial models – in respect of that opportunity.

Currently, it has often been the case that where UKCS regulation leads (for example, in relation to EHS), other jurisdictions tend to follow, so the OGA's consultation may begin a trend we see in other jurisdictions around the world, in particular with lenders tightening their policies on investing in fossil fuels often prompted by growing regulatory reporting obligations. Watch this space.