

3. Key Issues and Implications for Governments

3.1 Limited country and company experience in decommissioning

While more than 95 countries have producing oil and gas fields, there is limited experience in decommissioning these fields. The notable exceptions often cited are the United States (Gulf of Mexico) and the North Sea (United Kingdom and Norway). With more than 70 per cent of the world's production⁹ coming from mature fields and flowing through ageing infrastructure, many fields will soon reach their economic limit. Decommissioning is therefore set to become a key issue for the industry.

It is estimated that more than 50,000 offshore wells and 10,000 offshore structures will be decommissioned worldwide, along with hundreds of thousands of onshore wells, facilities and sites.¹⁰ As an illustration of the increasing activity, the offshore decommissioning market alone is expected to grow from US\$2.4 billion in 2015 to US\$13 billion-per-year by 2040.¹¹

When the majority of these ageing fields were initially developed (some as early as the 1970s), decommissioning was not an area of focus and the governing legal instruments were not clear on its treatment, including reporting requirements. Governments therefore may not have a country-wide view of the costs, timing and level of decommissioning activity that is likely to occur. Depending on the regulatory framework in place, there may also be limited information about the inventory of wells, hazardous materials and various facilities.

Given the nascent stage of the decommissioning industry, there will be emerging best practices and learnings in dealing with these legacy issues, as well as in other areas such as technologies, cost estimating and project execution. As companies build experience and expertise, specialist firms are likely to arise with implications on how activities may be planned and executed. For example, outsourcing decommissioning to an independent company, instead of the current model of the oil and gas companies planning and executing activities. Government institutions will also build capacity in dealing with decommissioning as activity increases. Collaboration among regulators and other agencies could be useful in transferring learnings and best practices.

Implications for governments

1. It is important for government to have a national perspective on the timing and scale of decommissioning, to ensure that adequate plans are in place and a coherent approach to the issue is adopted. Depending on the context, a country-wide strategy may yield significant benefits to the companies and country.
2. A critical first step towards developing a national approach is understanding the timing and inventory of all wells, facilities, associated installations, materials etc. that will have to be dealt with during the decommissioning phase. These should ideally be available in FDPs, but this may not be applicable for many mature fields. In such cases, governments should engage with operators to understand CoP, the scope and timing of expected decommissioning activities, and the potential cost for those activities (the decommissioning liabilities).
3. Recognising the nascent stage that decommissioning is at, it is important for the national policy and strategy to promote collaboration among companies to transfer learnings and best practices.
4. Governments should explore opportunities to learn from peers in developing national strategies, strengthening regulatory oversight and effective engagements with operators.

⁹ Halliburton, available at: <https://www.halliburton.com/en-US/ps/solutions/mature-fields/about-mature-fields.html>

¹⁰ Boston Consulting Group (2019), *Oil and Gas Needs Decommissioning Models That Work at Scale*, available at: <https://www.bcg.com/publications/2019/oil-gas-decommissioning-models-work-at-scale>

¹¹ IHS Markit Offshore Decommissioning Study Report (2016).

3.2 Environmental and safety risks

There are large-scale environmental and safety risks associated with decommissioning, which may arise from the hazardous nature of hydrocarbons and decommissioning activities (pollution, oil spills, fires, accidents, explosions etc), as well as the remaining residual risk after decommissioning is completed.

The selected decommissioning option should minimise the impact on the environment, risks to public health and consider the safety of workers and the public. Some of the key areas that need to be addressed are:

- Ensuring that hydrocarbons from reservoirs that were produced through wellbores do not escape or migrate and contaminate freshwater aquifers, surface soils and surface waters.
- Ensuring the appropriate disposal and/or containment of hazardous substances and waste materials. Throughout the productive life of oil and gas assets, significant amounts of contaminants such as mercury, lead, iron sulphides, iron oxides and naturally occurring radioactive material (NORM) would have either been used or generated from the production process. These contaminants may be contained within the facilities (for example, within pipelines, at processing facilities) or stored as waste (for example, drill cuttings) and there will also be trace amounts of hydrocarbons in the system. These contaminants will have to be drained, purged and appropriately dealt with. If not, they will pose a risk to public health, the environment and the reusability of the area (for example, for agriculture, fishing).
- Ensuring the risks and potential effects on the ecosystem are carefully considered in selecting the decommissioning option. For example, loss of biodiversity, destruction of habitats and the release of hazardous materials. For offshore decommissioning, these will also include impacts on fishing, navigation, any marine protected areas the assets sit within, and long-term impacts of remaining structures. Structures left in situ will deteriorate over time and be susceptible to structural failure, which has implications for nearby activity and infrastructure. How these structures may be impacted from natural disasters, such as hurricanes, should also be considered. In addition, installations that have been in place for a very long time (easily 30 years or more) become part of the local ecosystem. Disturbance and/or removal can also have negative environmental and ecological impacts, and the best option will need careful consideration. The concept of 'net environmental benefit' is used to ensure that the overall environmental impact is minimised. For example, offshore drill cuttings generally are left in situ, as the impacts are relatively minor compared to the broader environmental, safety and health risks from returning the site to its pre-disturbed state (removing cuttings from the seabed, transporting ashore, handling and loading onto trucks for disposal in municipal landfill).
- Ensuring that significant environmental and safety risks in performing the actual operations (for example, P&A, dismantling, transporting, disposal) are effectively managed. For example, dismantling operations will generate noise, dust, odour and traffic, in and around the site over a significant period of time. The safety of the personnel conducting the decommissioning activity needs to be considered, as well as the total energy and raw material usage, including carbon emissions.
- Ensuring that there is adequate monitoring by an appropriate institution after decommissioning activities have been completed, to understand the residual risks.

'Residual risk' refers to the ongoing potential pollution and incidents that may arise after decommissioning is completed. For example, if only partial removal of an offshore platform occurs, this means that the remaining structure may take hundreds of years to degrade and therefore continues to pose some risk to the environment and other users of the marine space. In a recent UK decommissioning plan for Brent, it was suggested that the structures below sea level would take up between 500 and 1000 years to disintegrate. Residual risk also exists for wells that have been plugged and abandoned. The failure of barriers could occur at any time in the future and hence the risk of leaks, pollution and associated costs is a perpetual risk. Leaks from abandoned wells have long been recognised as an environmental problem, a health hazard and a public nuisance. They also pose a serious threat to the climate, which researchers and world governments are only now starting to understand. For example, according to the US Environmental Protection Agency, in 2018 more than 3 million abandoned wells emitted 281 kilotons of methane, at least as much environmental

damage as consuming about 16 million barrels of oil.¹² There are also the risks of explosion, soil and water contamination, and release of air pollutants, and fugitive emissions.

It should be obvious that the design, maintenance and monitoring of wells, and all associated facilities and materials, will heavily influence the environmental and safety risks and the selected decommissioning option. A particular challenge for many countries with mature producing fields is that there may not be comprehensive information about the assets, materials used and the integrity of associated infrastructure. Determining the optimal decommissioning solution is therefore very complicated in instances where there are many unknowns concerning the assets; this, in turn, increases the health, safety and the environment risks.

Implications for governments

1. Governments should undertake an industry-wide inventory assessment of all oil and gas assets, to understand the environmental and safety risks they pose and to have a preliminary view of decommissioning options being considered by operators.
2. Governments should ensure that the regulatory framework for the design of oil and gas projects and ongoing petroleum operations includes decommissioning and is based on international principles, such as the precautionary principle and polluter pays principle. The framework should also embed best practice to minimise environmental and safety risks during and after decommissioning. For legacy arrangements that did not contemplate or adequately address decommissioning, the government should seek specialist legal advice.
3. In approving new oil and gas projects (Field Development Plans or Plans of Development), governments should ensure that decommissioning is contemplated appropriately. Governments should consider adopting a policy of full removal as the default expectation for all projects, with any deviation from full removal requiring justification. This would incentivise operators and environmental regulators to proactively determine the data required over the whole life of the asset(s).
4. Government should ensure that appropriate and credible data are available to effectively evaluate the net environmental impact of decommissioning options. This underscores the importance of an environmental impact assessment and access to appropriate baseline, scientific research and ongoing environmental monitoring and reporting to inform selection of the appropriate decommissioning solution at the end of the asset's useful life.
5. Governments should understand what ongoing environmental monitoring is required post-decommissioning (for example, groundwater, presence of hydrocarbons including methane, species abundance and diversity) and how this will be implemented.

¹² Groom, N (2020), 'Special Report: Millions of abandoned oil wells are leaking methane, a climate menace', Reuters, available at: <https://www.reuters.com/article/us-usa-drilling-abandoned-specialreport-idUSKBN23N1NL>

3.3 Scale and uncertainty of decommissioning costs

Decommissioning costs, like development costs, can vary significantly from project to project and can easily amount to billions of US dollars. Estimating decommissioning costs for a particular project requires making assumptions on cessation of production (CoP), when decommissioning operations will occur, how each aspect of the operations will be performed (wells, pipelines, platforms etc.), and estimating how much those costs will be in the future (escalating current estimates for inflation). Credible estimates for decommissioning costs therefore require various technical experts' inputs; this is similar to estimating development costs, but with the added complexity of the uncertainty of timing (several decades into the future). It therefore follows that decommissioning costs will be of the magnitude of development costs (ranging from millions to billions of US dollars), complex and subject to a large uncertainty range.

Benchmarking is often used in the industry for estimating costs, but this depends on the availability and access to comparative data. On a global scale, this is fairly limited for decommissioning, given its relatively small scale (versus exploration or development). The United States (onshore and Gulf of Mexico) and the North Sea are noted areas with a history of decommissioning activity and, as such, tend to be used as benchmarks for estimating costs. While this may be a useful reference, it is important to understand the underlying assumptions that have been used to estimate the costs, as small changes in the assumptions can lead to very large changes in the total cost. Different regulatory requirements will also have cost implications. Regional differences in weather, sea states, water depths and distances from shoreline facilities can also affect decommissioning costs.

The two global frameworks for accounting and financial reporting¹³ require companies to recognise a decommissioning liability at the point of installation of an asset and, thereafter, subsequent material changes. These disclosures have been established for shareholders to understand the impact on a company's future cash flows, given the scale of decommissioning costs. Regulators should, therefore, be well-versed in understanding the different accounting treatments, to understand the implications of what is being reported in the financial statements for developments in their jurisdiction.

In addition to understanding the costs for a particular project, it is also important to understand the decommissioning picture at the country level. This will require clear definitions and a standardised approach to data collection from companies on an ongoing basis. For example, in the UK, each year operators are required to provide estimates for all fields according to standard cost classifications¹⁴ to the regulator – the UK Oil and Gas Authority (UKOGA). Based on data collected, the UK expects to spend over £15 billion on decommissioning activity in the next decade, with a total anticipated spend of around £50bn for all UK continental shelf (UKCS) liabilities¹⁵. The UKOGA has adopted a probabilistic approach in estimating these costs, recognising the uncertainties inherent in cost estimates. As an indication of the uncertainty range, the 2019 estimate ranges from £33bn to £81bn (as shown in Figure 3.1). The UKOGA, in collaboration with the industry, is actively pursuing a strategy to achieve more than 35 per cent cost reduction from the 2017 P50 estimate of £59.7bn – that is, targeting £39bn of costs.

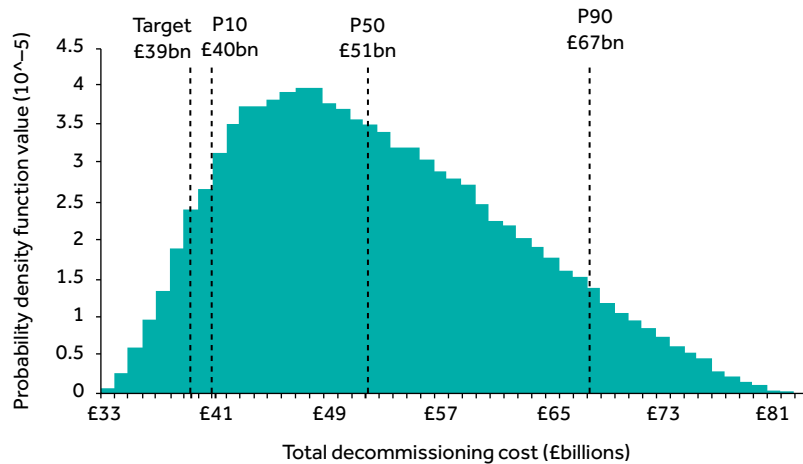
The scale of decommissioning costs has direct implications for the government, as there will be tax implications depending on the fiscal regime. For example, Wood Mackenzie forecasts that in future tax relief in the UK will be around £25 billion (45% of costs) and in Norway around US\$90 billion (78% of costs).

13 International Accounting Standards (IAS16 – Property, Plant and Equipment; IAS37 – Provisions, Contingent Liabilities and Contingent Assets) and the US Generally Accepted Accounting Principles (GAAP).

14 Costs are reported in the following Work Breakdown Structure (WBS) elements: project management, post-CoP running costs, well-decommissioning, facilities and pipelines permanent isolation and cleaning, topsides preparation, topsides removal, substructure removal, topsides and substructure onshore disposal, subsea infrastructure, site remediation, and post-decommissioning monitoring.

15 UK Oil and Gas Authority UKCS Decommissioning Cost Estimate 2021 (July 2021).

Figure 3.1 Decommissioning cost distribution for UKCS



Source: Oil and Gas Authority (2019), UKCS Decommissioning: 2019 Cost Estimate Report, available at: <https://www.ogauthority.co.uk/media/5906/decommissioning-estimate-cost-report-2019.pdf>

Implications for governments

1. Governments should have policies and regulations in place that require licensees to estimate decommissioning costs and update them regularly. Licensees should also be required to update decommissioning costs when changes to the operation of the field are likely to materially affect these costs.
2. Decommissioning cost estimates are uncertain and require regular reassessment during the production phase. Government should understand how decommissioning costs are calculated and what the underlying assumptions are. Assumptions about future events should be supported by sufficient objective evidence. Governments will also have to strike the right balance in the frequency and level of detail required in reforecasting decommissioning costs. Given its nature, detailed reforecasting in the first years of production is likely to yield very little benefit. Likewise, it would be foolhardy to wait until only a few years before cessation of production to look at detailed cost estimates.
3. Encouraging transparency and a collaborative industry approach would be important mechanisms to reduce costs through leveraging economies of scale and learnings. This is of crucial importance to countries where there are significant mature fields and ageing infrastructure.
4. Governments should understand how decommissioning is being treated in companies' financial statements, as this could prove a helpful basis for regulators to understand costs on an ongoing basis. This should only be used as an indicator, rather than the primary information source for regulatory oversight.
5. Regulators working together with the industry can develop a standardised approach and definitions for estimating decommissioning costs and to provide templates to operators. This could greatly aid in ensuring completeness in costs estimation, consistency and comparability among operators. This would enable a regulator to benchmark costs, understand performance of actual costs versus estimations (to inform other forecasts), and to build confidence in estimates as decommissioning activity increases.

3.4 Financial assurance

Decommissioning is a significant cost for a company when there is little or no revenue from a project. Given the magnitude of costs, it is critical that there are mechanisms in place to ensure that there are sufficient funds available to carry out the decommissioning activities. If this is not planned for appropriately, there is

a possibility that the company may not want to fund the activities or may not have the financial resources to complete decommissioning – either because costs are higher than anticipated or the company is in financial distress or bankrupt. If such a situation arises, governments will likely have to undertake and pay for decommissioning, because it is in the public interest and/or because it is required to meet the country's international obligations.

There are different types of financial assurance mechanisms, which range from letters of credit, insurance and bonds to cash being held as dedicated funds for decommissioning purposes. Each option will have associated advantages and disadvantages, which should be considered from both the country and investor perspectives. Please see Appendix A for a summary of key options. Regardless of the type of instrument used, the tax treatment of decommissioning costs should be clear and aligned with national tax policy and laws.

As discussed in Section 3.3, there is a high degree of uncertainty in estimating costs. If it is not reviewed appropriately during the production phase, it is possible for the actual amounts required for decommissioning activities to be significantly higher than anticipated. In addition, there is a wide range of factors that affect the timing of decommissioning (please see Section 2.2) The financial assurance mechanism should be predicated on ongoing review of decommissioning timing and costs to avoid shortfalls in funding. Please see Box 3.1 describing Canada's evolving financial security mechanism.

Box 3.1. Canada's evolving financial security mechanism to deal with its multibillion-dollar 'orphan wells' problem

Alberta, Canada, has a long history of oil and gas production, beginning from the 1900s, and a huge orphan inventory. An 'orphan' is a well, pipeline, facility or associated site that does not have a legally responsible and/or financially viable party to deal with its decommissioning and reclamation responsibilities. To deal with the issue, a not-for-profit organisation, the Orphan Well Association (OWA), was established in the 1990s and primarily funded by the industry (via an orphan fund levy) to decommission these wells and restore the land. In 2020, there were almost 3,000 orphan wells, with fears that many of the more than 95,000 inactive wells might also become orphaned.¹ There were also roughly 300 orphan facilities, 3,800 orphan pipelines and more than 3,000 orphan sites for reclamation. As of 31 March 2021, the total remaining closure cost to deal with the orphan inventory was estimated to range from \$650 million to \$700 million (*OWA 2020/21 Annual Report*).

The introduction of the orphan fund levy by the Alberta Energy Regulator (AER) was to 'prevent closure costs from being borne by Albertans'. The annual levy is set by the AER in consultation with the OWA and industry bodies. The AER also introduced the licensee liability rating (LLR), to reduce the risk of new orphans being created.

The LLR was designed such that as a company's financial situation deteriorates, it would be required to make deposits to cover its clean-up costs. The LLR is assessed monthly and expressed as a ratio of deemed assets (a company's production, multiplied by an industry average netback based on a three-year rolling average of prices) to deemed liabilities (established based on the average cost to abandon a well). If the company's ratio of assets to liabilities is less than one — if it has more liabilities than assets — it must pay a security deposit to the AER. As at March 2020, Alberta's associated liability was ~\$31 billion; however, only \$225 million was held in financial security by the regulator.

The Government of Alberta and the AER have for many years indicated that the LLR is an inadequate measure of licensees' financial health and is currently in the process of replacing it with a 'more comprehensive License Capability Assessment System' and the introduction of minimum annual spending requirements towards clean-up costs.

1 Alberta's looming multibillion-dollar orphan wells problem prompts auditor general probe | CBC News

The financial assurance mechanism adopted must also cater for possible ownership changes during the life of the asset. The typical evolution of operatorship in the industry is for late-life or marginal fields to shift from large companies to smaller companies, whose business models, expertise and lower costs enable them to operate the assets more profitably. As the industry matures, the government should expect increased activity on asset swaps, divestments, mergers, acquisitions and other arrangements that transfer working interests in assets. These transactions have in many cases extended the life of assets; however, if decommissioning is not adequately provided for, there is a risk that these transfers increase the risk that assets will not be properly decommissioned. Smaller companies do not have the same balance sheet strength nor diversified portfolio as larger players. This means that they may not have sufficient financial resources or are more vulnerable to financial distress with adverse changes, which may hamper their ability to effectively discharge their decommissioning obligations in the future. In 2017, the US Bureau of Safety and Environmental Enforcement (BSEE) indicated that more than 20 per cent of active facilities in the Gulf of Mexico were operated by financially at-risk companies (449 of 2,104 facilities).¹⁶ After a series of bankruptcies, the US is in the process of strengthening its financial assurance mechanisms.¹⁷ A number of other countries, after experiencing similar problems, are also reviewing the adequacy of existing financial assurance systems. For example, Australia, Canada and New Zealand.

In addition, with growing awareness of the issue, ambiguity of the decommissioning liabilities has translated to lower transactions in mature basins, as smaller companies seek clarity on the rules and requirements for financial assurance. This was notably the case in the UK's North Sea, where the treatment of decommissioning was cited as a barrier to mergers and acquisition (M&A) activity.¹⁸

The issue of ownership transfers also represents particular challenges in countries with production sharing contracts (PSCs), as the governing legal instruments commonly provide for assets to be assigned to the government, most commonly to a national oil company (NOC). It should be noted that such transfers to the state or an NOC is also done under other types of petroleum agreements (concessions, risk service contracts). The underlying assumption was that these oil and gas assets would remain productive after the PSCs expired and would continue to be a source of revenue. However, many petroleum agreements (PSCs etc.) did not contemplate the funding of decommissioning activities and the level of financial assurance is generally low. This could mean that governments are poised to accept multibillion liabilities (rather than assets) through these transfers, which will have to be funded in the future. This could represent a massive drain on public finances in the future, diverting money that could have been spent on other public services.

Additionally, where the government owns an interest in oil and gas assets (state participation via an NOC or other means), its share of decommissioning costs will need to be funded. Given the large scale of decommissioning costs, the state's share could be significant and may be a source of financial distress – either to the NOC or the government if not planned for appropriately.

Implications for governments

1. Governments should implement appropriate financial assurance mechanisms to avoid taxpayers having to foot the bill for decommissioning costs. It is important that the financial mechanisms are robust, to ensure that the full amount of funds is available when required and can accommodate changes in ownership and transfers of interests.
2. Governments should recognise the importance of tax policy and laws as a key enabler towards effective management of financial exposure from decommissioning.
3. Governments should undertake an industry-wide assessment to understand the scale of decommissioning activity, the associated timeframes, costs, what financial mechanisms are in place and the level of funding gap that may exist. This will be a critical starting point for engagement with

¹⁶ Offshore Technology Conference, data presented as at 21 April 2017.

¹⁷ Bloomberg (2020), 'US Seeks Stricter Funding for Abandoned Offshore Oil Wells', available at: <https://www.bloomberg.com/news/articles/2020-09-17/u-s-seeks-stricter-funding-for-abandoned-offshore-oil-wells>

¹⁸ Norton Rose Fulbright (2017), 'Decommissioning – the key to M&A in the North Sea?', available at: <https://www.nortonrosefulbright.com/en/knowledge/publications/46380d36/decommissioning---the-key-to-ma-in-the-north-sea>

operators and owners on the risks and feasible options to address funding gaps, and to identify opportunities for industry solutions.

4. The state's decommissioning obligations, where it owns interests in oil and gas assets, should be assessed and provided for.
5. The type of financial assurance adopted should provide effective protection in the event of companies experiencing financial distress or bankruptcy. There has been an increasing number of these cases and this trend is likely to continue, given recent price crashes (many firms are struggling financially) and the bleak long-term outlook.
6. Government due diligence prior to approving transfers of working interest should include assessment and verification that the existing owner's responsibility for decommissioning has been met. There should also be adequate assurance that the new owner is able to and has committed to meeting those obligations. In so far as possible, these requirements should be codified within the legal framework. This will help to reduce financial exposure to other owners and the government from unfunded decommissioning liabilities.
7. Given the wide variability of costs and volatility of the sector, the government institutions (for example, the regulator or NOCs) should be resourced to review decommissioning liabilities and companies' financial strength on an ongoing basis. Depending on the type of financial mechanism in place, without sufficient review and subsequent action, the intended protections could be rendered ineffective and result in huge cost to the taxpayer.
8. The financial risk to governments of unfairly bearing decommissioning costs is substantially higher for countries where the legal instruments provide for oil and gas assets being transferred to the state. This is especially so, but not limited to, PSCs and NOCs. Governments should undertake an assessment of the state's exposure to this risk and develop measures to mitigate.

3.5 Socio-economic impacts

Many local, regional and national stakeholders can become heavily dependent on the direct and indirect benefits from oil and gas projects. Over the course of decades, such projects can become the bedrock of a country or region's economy, through its significant contribution to government revenues (royalties, tax, production sharing), employment, corporate social responsibility programmes. It is well documented that petroleum-producing regions tend to be highly dependent on the sector, which results in a very narrow economic base – as there are limited alternative productive sectors of the economy. While employment from the oil and gas industry compared to other sectors is low nationally, at a regional level it can be disproportionately high in producing regions. These jobs are on average higher paying and often induce a high number of indirect jobs. As decommissioning activity begins, the winding down of production operations will inevitably cause significant disruption to livelihoods and regional economies.

Sources of distress may arise from areas such as economic stagnation, large fiscal deficits (from falling revenues), loss of services (transport, health clinics etc.), unemployment and shrinking population as locals migrate to other areas. On the other hand, depending on the scale of the industry and the national skills sets and capacity, entering the decommissioning phase may present new opportunities for employment and business opportunities. For example, analysis suggests that given Scotland's expertise and future decommissioning activity, the estimated gross value add (GVA) from activity over the next decade could be between £8.3 and £11.3 billion, while supporting peak employment of 16,925–22,775.¹⁹

There could also be significant potential to leverage existing oil and gas capabilities to develop expertise along the decommissioning supply chain. To do so effectively will require understanding of the complex nature of the tasks associated with decommissioning, which are illustrated below.

¹⁹ Government of Scotland (2018). Oil & Gas Decommissioning Action Plan, available at: <https://www.gov.scot/binaries/content/documents/govscot/publications/corporate-report/2018/11/oil-and-gas-decommissioning-action-plan/documents/oil-and-gas-decommissioning-action-plan/oil-and-gas-decommissioning-action-plan/govscot%3Adocument/Oil%2Band%2Bgas%2Bdecommissioning%2Baction%2Bplan.pdf>

As decommissioning is at a relatively early stage across the world, there is limited technical guidance and experience in managing these complex social and economic aspects. However, the experience of mine closures may prove instructive.

The characteristics of mining decommissioning and remediation are similar – for example, heavy regional economic dependence, multibillion decommissioning projects and large dislocation of a highly paid workforce. The socio-economic repercussions of mine closures can be severe because mining, like petroleum, often results in 'mono-industry' towns and communities. Experience with coal closures has shown that if not adequately planned for, many coal-dependent regions continue to lag socially and economically decades later after a mine has shut down. These downturns have proved to be particularly difficult for women due to several factors, for example, increased gender-based violence, higher burden of care as social services collapse, lower re-employment and limited access to capital or land.²⁰

The successful management of economic transition requires a package of measures under a broader structural policy approach. This includes economic diversification or stimulation to ensure long-term sustainability. See Box 3.2 for Germany's experience with the closure of coal mines.

Box 3.2 Germany's closure of coal mines

At the height of the coal industry, in 1957, Germany produced 150 million tonnes of black coal and employed 607,000 miners. Through the second half of the twentieth century, profitability and output declined dramatically, and increased commitments were made to international instruments looking towards limiting climate change. The Ruhr region underwent two phases of reorganisation, using long-term planning and the commitment to a 'Just Transition'. Pits were closed progressively across the region, with no forced job losses. The miners agreed to forgo a pay increase, while supportive policies, economic diversification and social support allowed workers to be either transferred within the industry, offered retraining into environmental technology and renewable energy positions or, if they were over 50, offered voluntary payouts. Large-scale investments were put into infrastructure development, education, technology and innovation. The miners had a significant role in shaping an agreement that guaranteed a socially responsible closure process.

The last mine was closed in 2018, and the area is now a world heritage site.

Implications for governments

- 1 Governments will need to have a strategic approach for the winding down of the sector. Dealing with the socio-economic aspects of COP and decommissioning requires long-term planning, to minimise disruptions and create other sources of revenue and employment. Governments should seek to understand best practices that can be applied to local contexts. Significant research and case studies have been done on coal mine closures, from which lessons and best practices have been identified and can prove helpful.
- 2 Decommissioning planning should include measures to mitigate the impacts on people and communities from CoP.
- 3 The involvement of stakeholders at the local community, towns and regional levels is important for identifying vulnerabilities from CoP and decommissioning activity, as well as developing and implementing strategies to mitigate associated effects. Meaningful and timely participation would enable locally adapted solutions and higher acceptance by affected stakeholders.

²⁰ Sesele, Kentse (2020), Women and Mining Decline in the Free State Goldfields.

3.6 Public acceptance of decommissioning options

Local communities and the public are important stakeholders that need to be considered as fields enter the decommissioning phase. There is likely to be very little awareness of the complexity and technical issues surrounding decommissioning, as well as the safety and environmental risks. In many countries, the image of the industry is low and the level of mistrust is high. This applies both to the relationship between the public and operating companies and the relationship between the public and government. It should not be a surprise if the prevailing public perception is the companies' preferred decommissioning solution and to leave structures in place, because it saves money but they do not consider the environmental consequences. Several non-governmental organisations (NGOs) have argued that this is the case with the concept of 'rigs-to-reef' in the United States and the United Kingdom. This, coupled with the narrative that companies are avoiding their responsibility after having made millions or billions from an asset, could prove politically damaging. This could also prove to be the case if costly tax relief plans or subsidies are provided for activities to be carried out.

Without early engagement, data-driven debate and timely communication, public resistance could be very possible. This may have significant implications, as was the case with the North Sea's Brent Spar decommissioning in the mid-1990s.

The disposal options for Brent Spar were the subject of negotiations between the operator, Shell, and the UK government for more than three years. The preferred solution, which was evaluated against criteria covering technical feasibility, safety, cost and environmental impacts, was determined to be deep-water disposal. However, there was very limited national consultation, and significant opposition and public outcry surrounded the perceived environmental risks. Both Shell and the government defended the plan as the environmentally safest option, based on scientific and technical analysis. Shell eventually changed the disposal option (with the structure reused to form the base of a new ferry quay) after inaccuracies in media reporting (particularly around the quantity of pollutants), Greenpeace occupying the facility for over a month, a boycott of Shell's products, the difficult political environment (opposition parties were not supportive of the proposal), international pressure and significant negative reputational and financial impacts.

Implications for governments

1. Governments and companies should anticipate a growing interest by stakeholders in decommissioning and ensure that consultation and effective communication is a key element of a decommissioning plan. Stakeholder mapping and an engagement plan should be developed as part of the planning phase.
2. Decommissioning planning must include measures to mitigate the impacts on people and communities. Effective and ongoing engagement and communication with stakeholders will be critical to successful measures.
3. Governments and companies should recognise the importance of transparency of data and reports to enable proactive fact-based dialogue with stakeholders, including NGOs, local communities and the general public.

3.7 Weak regulatory and liability frameworks

Decommissioning was not an area of focus when the majority of mature fields were initially developed, hence the governing legal framework is typically silent or unclear on the treatment of decommissioning. In addition to this legacy issue, regulation and guidance on decommissioning requirements have yet to be fully developed in many countries.²¹ For example, there are often simple provisions leaving the substantive elements to be negotiated at a later date; 'abandonment' and 'decommissioning' are used interchangeably and are poorly defined; financial assurance is weak (or non-existent); there is a lack of clarity on the

21 O&G Decommissioning Subsea Engineering Opportunity International Market Insights Report Series (2018), 25,26 Gilbert, S (2021), 'Decommissioning assets in the Middle East: the regulatory landscape', available at: <https://www.vysusgroup.com/articles/decommissioning-assets-in-the-middle-east-the-regulatory-landscape>

treatment of temporary closure; there are limited technical specifications; and the triggering event for addressing decommissioning in many contracts is five years prior to CoP. Given the issues described above (Sections 3.1 to 3.6), these measures are woefully inadequate and represent significant risk to the taxpayer, the environment and the public. This means that there is a weak regulatory framework for most of the world's existing oil and gas assets.

The experience in onshore United States and Canada serves as an illustration of the problems that can arise from poor regulatory oversight. In both countries, the industry has been in existence for more than 50 years; onshore activity is regulated at the local level and decommissioning was not a priority during the production phase. This has led to a huge inventory of orphan wells, a situation where the original owners are no longer around, and the liability for abandoning the wells and remediating the land is unclear. In Alberta, Canada, there are more than 95,000 inactive wells, with many not officially abandoned and none yet decommissioned. This represents significant safety and environmental risks and the land has been rendered unsuitable for alternative uses. A similar situation exists in many states in the USA, with thousands of wells left without decommissioning or removal. This situation is, however, not limited to the onshore industry, as there is also a significant number of suspended wells offshore in the Gulf of Mexico. The regulators in each country are adopting various measures to remedy the situation, which serves as a cautionary tale.

In many regimes, it is also not clear who the responsible party is for decommissioning liabilities. This is a glaring lacuna in the legal framework and means that the potential for disputes is high. Box 3.3 highlights the exposure surrounding one such area, transfers of ownership to the state. Furthermore, the regime is often silent on the treatment of residual risks and, given that most companies are unlikely to exist after decommissioning activities have been completed, it is important that the regulatory framework specifically addresses this gap. This weakness stems from the common practice of structuring ownership of assets through limited liability subsidiary companies and joint ventures, which means that once the governing petroleum agreement or licence has been relinquished, these entities would in effect cease to exist.

In contrast, modern legal frameworks for decommissioning adopt a lifecycle approach – with decommissioning being considered as part of the approval process for new projects (with a preliminary view included in the FDP submission to government). This is complemented by ongoing review of timing and costs over the production phase, to ensure that the gamut of environmental, financial and social issues can be adequately addressed at the end of the asset's productive life. Without such a robust regulatory framework, the taxpayer and the public face substantial risks (financial, environmental, health etc.) that decommissioning will not be appropriately dealt with. Recent experience in Australia and New Zealand has prompted reforms to address gaps in the regulatory framework. See Box 3.4.

Effective regimes are also coherent across national regulations and approvals. For example, there are multiple intersection points with the waste management industry and naturally occurring radioactive material (NORM) is a known challenge. Co-ordination across various government regulators is important to safeguard the country's interests and provide clarity to operators on what is required.

Additionally, robust regulations would ensure that countries' obligations under international conventions and treaties flow through to the operators. Without such measures, the country bears the risk for non-compliance. This is of particular concern with offshore developments, where there are several international and regional obligations. See Section 4 for a summary of key international and regional frameworks and Appendix B for further details on Commonwealth countries.

A particular issue for developing countries to bear in mind is 'regulatory capture'. This refers to a situation where the positions taken, and decisions made, by regulatory authorities are unduly influenced by the industry they are charged with regulating. The result is that an agency, charged with acting in the public interest, instead acts in ways that benefit incumbent firms in the industry it is supposed to be regulating. This could be due to several factors, including corruption, lack of information or expertise, and the inability of government institutions to carry out tasks effectively (for example, due to insufficient resources – in terms of funds or staff). As described earlier, decommissioning is a fairly new area and the highly technical nature of the operations means that asymmetries between the government and companies will be very pronounced. This represents a high risk of regulatory capture.

Box 3.3 Dispute on footing decommissioning bill for transfer of field to Thailand's NOC

The offshore Erawan gas field accounts for around 25 per cent of Thailand's gas supply and has been operated by Chevron for nearly 50 years. When Chevron's concessions expire in April 2022, it is due to cede control to the national oil company, PTT Exploration & Production (PTTEP). There is an ongoing dispute about who should pay decommissioning costs, estimated to be around US\$2.5 billion, once the field eventually stops producing in the early 2030s – Chevron or Thailand's Department of Mineral Fuels (DMF).

The disagreement stems from the retroactive enforcement of a law passed in 2016, which requires operators to pay the cost of decommissioning assets they have installed, including those transferred to the next operator, including to PTTEP. Chevron says the law should not affect a contract it made earlier with the state, which did not require it to pay for the costs. The company argues that, under the terms of its initial contracts from 1971, it is only liable for infrastructure that is no longer deemed usable, and the transferred assets are the responsibility of the new operator.

Source: Reuters (2019), 'Chevron says no arbitration for now over Thai energy dispute', available at: <https://www.reuters.com/article/us-thailand-chevron-idUSKBN1WA2NR>

Box 3.4 Hundreds of millions cost to taxpayers triggers reforms in Australia and New Zealand

In 2019, the Australian government was forced to assume responsibility for the Laminaria-Corallina oil fields, and the associated Northern Endeavor floating production, storage and offloading (FPSO) infrastructure, when its owner, Northern Oil & Gas Australia (NOGA) went into liquidation. NOGA was incorporated in August 2015 and acquired full ownership of the oil fields and FPSO in 2016 from Woodside Energy and Talisman. Production began in 1999 and the prior owners envisioned that the economic limit would be reached by the end of 2016.

The event prompted an independent review, which found that 'none of the regulatory controls anticipates the circumstances of a titleholder liquidation. This is a serious concern, as such events could be repeated as Australia's offshore industry matures and late-life assets are likely to be passed from established major oil companies to smaller, less-substantial titleholders'. A number of recommendations were made, and reforms are currently underway to strengthen the regulatory framework. This includes the controversial imposition of a levy from July 2021, to cover the costs to decommission NOGA's assets, which appears to be over US\$200 million.

New Zealand is also facing a similar problem with the Tui oil field and Umuroa FPSO after the operator, Tamarind Taranaki (which assumed control in 2017) went into liquidation in November 2019. The initial estimated cost to taxpayers was US\$155 million; however, this has more than doubled to US\$394 million, as the initial estimate was based on a 2015 study which proved to be inaccurate. This is the country's first offshore decommissioning project and has prompted review and revision of the laws governing decommissioning (the Crown Minerals Decommissioning and Other Matters Bill, introduced on 23 June 2021).

Implications for governments

1. Lacunas in the decommissioning regulatory regime represent a significant risk to the country. It is critical that the government takes a detailed diagnostic review to understand weaknesses and work collaboratively with the industry to remedy issues as soon as practically possible. If this isn't done, the 'polluter pays principle' is likely to be violated, with the costs being borne by taxpayers and the public, rather than the oil and gas companies.

2. Governments should pay particular attention to their financial exposure across both the NOC, as well as other forms of state participation. Decommissioning liability may arise either from ownership interests or the transfer of assets at the end of petroleum agreements (PSCs, licensees etc.).
3. To reduce the exposure of the public and taxpayer, the legal framework should clearly establish who bears the responsibility for decommissioning liability, including residual risks. A government would need to consider the advantages and disadvantages of the different approaches available, to determine which is most appropriate. For example, liability in perpetuity is common for all infrastructure in all North Sea regulatory regimes, except for plugged wells in the Netherlands – where the operator’s liability ends once a well is plugged and abandoned. The Norwegian Petroleum Act 1996 allows for the licensees and the field owners to make alternative liability agreements with the state. This can allow for future maintenance, responsibility and liability to be taken over by the state, based on an agreed financial compensation. New Zealand is currently in the process of designing an industry-wide funding mechanism as part of reform efforts.²²
4. Numerous situations lead companies to temporarily shut down activities and these should be considered in the provisions made for decommissioning and closure. For example, regulations should clearly establish processes and timelines for companies to deal with suspended or inactive wells.
5. Given the relatively nascent stage of decommissioning, the legislative requirements need to provide flexibility to accommodate changes in context, technological developments or stakeholder priorities, which may require adjustments in the final decommissioning plan.
6. Governments needs to build capacity in decommissioning, in order to formulate effective strategies and laws etc. and to enforce compliance with those requirements.

3.8 Energy transition and bankruptcy risks

As the global momentum towards decarbonisation builds, the long-term outlook for oil and gas assets has changed considerably. This has significantly increased governments’ exposure to decommissioning risks, due to the anticipated higher incidence of accelerated decommissioning, mothballed assets (temporary suspension of production) and bankruptcies.

A bearish pricing outlook, lower anticipated sector returns and the higher cost of capital for companies mean the economic limit for old, marginal and carbon-intensive assets could be significantly earlier than expected. As discussed earlier, in the absence of adequate financial security, there is the potential risk that governments may be saddled with dealing with decommissioning such assets. Given the immense sums needed to decommission and the fact that many companies will be cash constrained after the recent precipitous price crash, operators are likely to temporarily suspend activity rather than permanently cease operations. For example, some operators will try to defer plugging and abandonment for as long as possible in a low pricing environment, as this accounts for nearly 50 per cent of decommissioning costs. If adequate regulatory controls are not in place, the growing inventory of suspended and temporarily shut-in assets could morph into an orphan problem. For example, the UKOGA has forecast that the number of suspended wells in the UK North Sea will almost double within five years to more than 1,550²³ (compared to 758 suspended wells in 2021).

The number of bankruptcies is also likely to increase in the face of challenging operating environments. For example, the number of oil and gas bankruptcies in the United States and Canada rose 50 per cent to 42 in 2019 and increased by another 62 per cent in 2020.²⁴ In 2020, the bankruptcy debt across the North American industry passed US\$100bn for the first time. According to the Boston Consulting Group, the

22 Government of New Zealand, Ministry of Business, Innovation & Employment (2021), ‘Residual liability for petroleum wells and infrastructure following decommissioning’, available at: <https://www.mbie.govt.nz/dmsdocument/14681-residual-liability-for-petroleum-wells-and-infrastructure-following-decommissioning>

23 Thomas, A (2021a), ‘OGA crackdown as number of suspended North Sea wells to double to 1,500, News for the Energy Sector, Energy Voice, available at: <https://www.energyvoice.com/oilandgas/north-sea/decom/321556/north-sea-suspended-wells/>

24 Bloomberg (2020), ‘US Seeks Stricter Funding for Abandoned Offshore Oil Wells’.

decommissioning costs of oil and gas firms that have recently gone bankrupt or are in financial distress is near US\$15 billion.²⁵ Analysts expect this trend to continue, given the implications of the pandemic-related slide in energy prices.²⁶

The industry trend of smaller less experienced companies acquiring mature assets further increases bankruptcy risk. As discussed in Section 3.4, it is common for ownership of late-life or marginal fields to transfer from large companies to smaller companies, whose business models, expertise and lower costs enable them to operate the assets more profitably. The energy transition is likely to result in an increase in these types of transactions, as international oil companies (IOCs) divest mature high-carbon assets to lower the carbon intensity of their portfolio. In comparison to IOCs, the smaller companies tend to have a small asset base, less cash flow and weaker balance sheets, and consequently are not as resilient to downturns and shocks. For example, given the scale of decommissioning costs, significant increases could conceivably trigger insolvency in a smaller company, whereas an IOC would likely be able to survive.

With an increasing number of asset transfers and insolvencies expected, this increases the risk associated with funding decommissioning. This risk materialised in 2019 in New Zealand's first decommissioning project, Tui oil field, where the government had limited ability to regulate an asset transfer and the company subsequently went into liquidation. See Box 3.5 for more details.

Box 3.5 Government's exposure to decommissioning via asset transfers

In 2017, Tamarind Taranaki assumed control of Tui by acquiring all the shares of the participants holding the petroleum permit. The transaction, which represented a 'change of control', did not require prior ministerial approval, only notification after the event.

At the time of the sale, the base case for decommissioning was 2019; however, Tamarind intended to extend the life of the field by drilling three new development wells to access 6–8 million barrels. This was expected to push decommissioning out to late 2025, in effect adding five years to the life of the field. However, the drilling campaign was not successful. Failure of the drilling campaign coupled with cost overruns, reduced production, withdrawal of financial support and the low price of crude oil resulted in Tamarind's liquidation. Neither Tamarind nor any of the other owners were able to meet any part of the decommissioning costs. To protect the environment, the government stepped in as the provider of last resort to decommission the assets.

The 2017 Tui transaction highlighted a 'loophole' in the Crown Minerals Act, whereby a company could sidestep the tests that would normally be in place for a new operator of a petroleum permit (by acquiring the shares of existing petroleum permit operators). This did not allow for any assessment of the operator's technical, health and safety, and financial capabilities under new ownership and enabled the tests for transfer and change of operator to be avoided. This loophole closed on 19 February 2019 via the Crown Minerals Amendment Act 2019 (2019 No 2).

Source: Government of New Zealand, MBIE (2020).

In cases such as New Zealand's, the government unfortunately must fund the decommissioning activity; however, there should be recourse to recovering these costs in the bankruptcy process. When a company goes into liquidation, its assets are sold and the proceeds used to pay creditors (the companies and individuals who are owed money). Which creditors get paid and how much is based on the amount of funds available and the 'priority' of claims. Priority debts typically must be paid in full, while those creditors with weaker claims may have to accept partial or no payment. This raises a critical question of where the government's claim for decommissioning costs sits in the prioritisation of claims.

25 Thomas, A (2021b), 'BCG: Distressed or bankrupt oil firms face \$15 billion decommissioning costs', Energy Voice, available at: <https://www.energyvoice.com/oilandgas/north-sea/decom/333865/bcg-decommissioning-costs-oil-firms/>

26 Groom, N (2020), 'Special Report: Millions of abandoned oil wells are leaking methane, a climate menace'.

If it is treated as a priority, the government should be able to recover money. If, however, it is treated as an unsecured claim, it is possible for the government to make zero recovery and the full burden will be borne by taxpayers. Ideally this situation would be addressed within national legislation (for example, in bankruptcy, environmental and petroleum laws), but in instances where the legal position is not clear, this is likely to result in lengthy litigation. This occurred in Alberta, Canada, where there was protracted litigation over the prioritisation of the government's claim in a bankruptcy. This was resolved by the Supreme Court ruling that the companies' decommissioning obligations were outside the bankruptcy priority scheme and must first be met before any creditor claims could be applied (see Box 3.6 for further details).

Furthermore, if there is no proper planning around decommissioning of shared infrastructure (for example, pipelines, processing facilities), this could have a 'domino effect', resulting in accelerated decommissioning of other assets. For example, if two fields share a pipeline export route, the operating costs are not likely to fall significantly if one field is decommissioned. The remaining field would have to bear all the costs, which could lead to it also reaching its economic limit. It is thus important to consider decommissioning on a systems basis across multiple operators. This domino-type event could also be an unintended consequence when companies become insolvent.

Implications for governments

- The energy transition and higher incidence of bankruptcies in the sector are increasing the decommissioning risks to governments.
- The time for decommissioning may be sooner than expected. This underscores the urgent need for governments to understand the environmental, financial and socio-economic risks and put appropriate measures in place to address, manage and mitigate these.
- Governments should ensure there is a process to monitor the financial health of companies operating in the sector.
- Governments should ensure that transfers of ownership interests require prior government approval, which should be granted after rigorous assessment of the company's financial strength and ability to cover decommissioning costs. Lacunas or gaps around change of control should be remedied in the legislation, to ensure prior approval is required; that is, change of control should require the same treatment as change of operator.
- Governments should ensure that the legal framework adequately addresses the risks from inactive wells and mothballed facilities. For example, by specifying the maximum number of years that a well or facility can be temporarily suspended, putting in place maintenance requirements for mothballed facilities, and via ongoing monitoring and inspection of such assets.
- Depending on the portfolio of companies operating within the sector, the government should carefully assess the most appropriate financial assurance mechanism and pace of change to avoid creating unintended consequences. Large changes in extremely short timeframes could lead to companies voluntarily liquidating, and in effect could create the situation the government is trying to avoid. Rigorous assessment of the situation, technical expertise and industry consultation would be required to craft country-appropriate solutions.
- Governments should ensure that decommissioning obligations are legally established as a 'super-priority' over bankruptcy priority schemes, to protect the nation's interests and avoid lengthy litigation.

Box 3.6 Canada's Supreme Court ruling on superiority of decommissioning obligations in bankruptcy

In Alberta, Canada, a company cannot be granted an oil and gas licence unless it assumes what are called 'end-of-life responsibilities' (or reclamation and abandonment obligations) to plug and cap oil wells to prevent leaks, dismantle surface structures and restore the surface to its previous condition to the extent possible. In *Orphan Wells Association v Grant Thornton Ltd*, [2019] 1 S.C.R. 150, the Supreme Court of Canada was asked to decide what happens to these obligations when a licensee (in this case, Redwater Energy Corporation [REC]) becomes bankrupt and its trustee in bankruptcy is tasked to distribute its assets among its creditors in line with the priority scheme established under Canadian bankruptcy legislation (the Bankruptcy and Insolvency Act). There was no law directly addressing the point.

In 2009, REC was granted an oil and gas licence by the Alberta Energy Regulator. In 2013, ATB Financial advanced funds to REC and was granted a security interest in REC's present and future assets. When REC began to have financial difficulties, ATB successfully applied to the court to appoint Grant Thornton Ltd as REC's receiver (2015). The abandonment costs were greater than the expected sale proceeds from the productive wells in REC's portfolio and Grant Thornton informed the regulator that it did not intend to comply with statutory orders to abandon the renounced assets. While the regulator and the receiver were battling to resolve the issue, REC went bankrupt and the receiver was appointed its trustee in bankruptcy. The regulator immediately commenced legal action against the receiver to enforce the abandonment order.

The question before the courts was whether payment of the abandonment costs was subject to the priority scheme established under Canadian bankruptcy law, which specifies the types of creditors that should be paid first. Generally, secured creditors are paid before unsecured creditors. Thus, was the receiver bound to pay other creditors of REC before paying the regulator the abandonment costs and pay the regulator only if there was any money left? The resolution of the question turned in part on whether the abandonment costs were treated as a debt owed by REC to the regulator. If they were treated as a debt, they were then a 'claim provable in bankruptcy' and therefore could be paid only if there was any money left after other creditors had been paid.

Both the trial court and the Alberta Court of Appeal ruled against the regulator. The trial court gave its ruling in May 2016, while the Court of Appeal gave its ruling in April 2017. The regulator appealed to the Supreme Court, which gave its ruling in February 2019.

In resolving the appeal, the Supreme Court drew a distinction between abandonment costs, which Alberta sought to obtain from the receiver, and the debt owed to a creditor. The Court ruled that the abandonment costs were not debts requiring payment and therefore not a 'claim provable in bankruptcy', but were duties owed by REC to the Alberta public (and nearby landowners). As such, the regulator was not a creditor of REC but was merely enforcing a public duty and therefore was not subject to the priority scheme established under Canadian bankruptcy legislation.