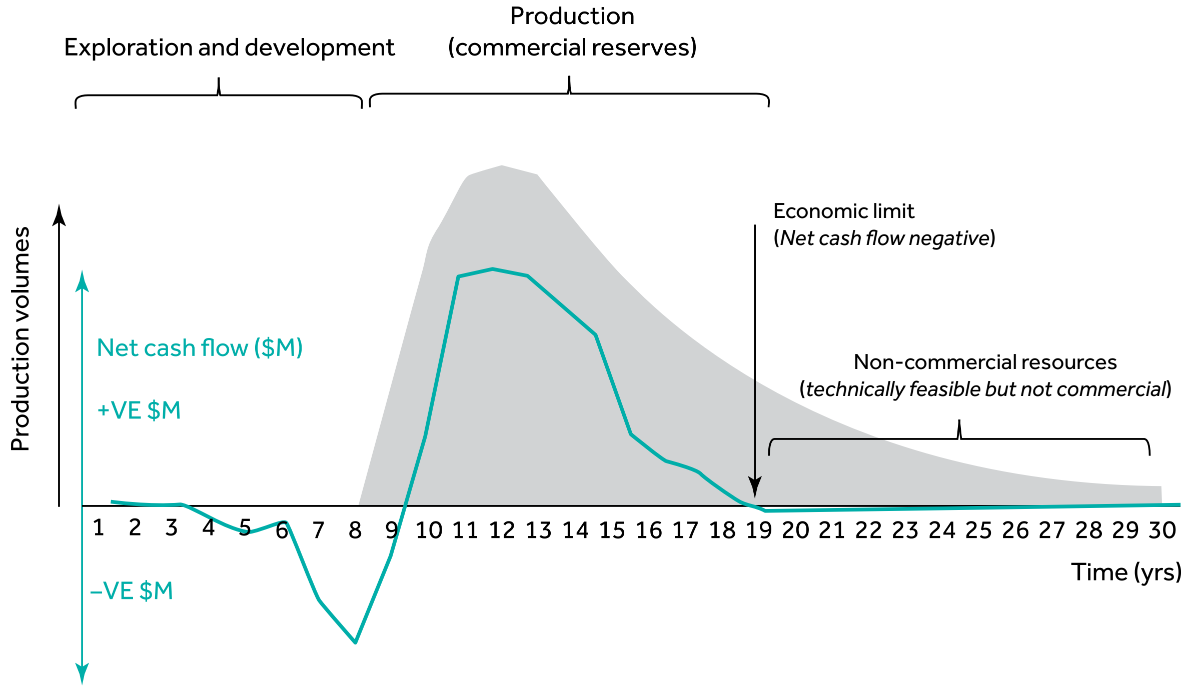
2. What is Decommissioning?

The life cycle of a petroleum project consists of four stages – exploration, development, production and decommissioning. As a field passes its peak production and begins to decline (commonly referred to as a 'mature field'), multiple options are explored to extend the productive life of the asset. When the costs of maintaining or extending production are greater than the associated revenues, the asset is no longer economically viable and has reached its 'economic limit'. While it may be possible to continue production, there is no commercial imperative to do so – as the project's ongoing net cash flows would be negative, as illustrated in Figure 2.1. It is at this point that the operator will cease operations (referred to as 'cessation of production' [CoP]) and take measures to decommission the field.

Figure 2.1 Production and net cash flow over the lifecycle of a petroleum project



Note: grey (as a square): production volumes teal line: net cash flow

2.1 Factors that influence the timing of decommissioning

When the owners of a discovery make a final investment decision (FID) to develop and produce the hydrocarbons in a field, it is underpinned by cash flow analysis based on assumptions on resource size, production rates, prices, costs etc. There is, therefore, a view of when a field will cease production before it is even developed. In countries with robust regulatory regimes, this information is required before approval to develop a project is granted.

There are, however, so many variables that can change post-FID that the actual economic limit for the project may be very different than originally anticipated. Any variable which results in higher-than-expected revenue (resource size, higher prices) or lower costs (for example, drilling, operating) will extend the productive life of the asset. Conversely, variables that lead to lower revenues or higher costs will accelerate the asset's economic limit. Operators continually assess the future cash generating potential of a field and pursue opportunities to extend positive cash flows, such as enhanced recovery methods,[1] satellite

1 Or tertiary production: increasing the amount of hydrocarbon that can be recovered from a reservoir by injecting a substance into a well to increase pressure and reduce the viscosity. For example, steam, gas (natural gas, nitrogen or carbon dioxide) and chemicals.

developments, transportation and processing services to other fields. Other factors that can influence the economic limit are technological advancements (which ultimately result in improved production and/or lower costs), regulatory changes (for example, changes in fiscal terms, additional compliance measures), and the structural integrity of production facilities and associated infrastructure. The weather can also influence cessation of production (CoP), as storms and hurricanes can severely damage the integrity of facilities and/or the cost of repairing may be prohibitive. For example, in the Gulf of Mexico there was increased demand for decommissioning resources following Hurricanes Katrina, Rita and Ike, as several platforms were damaged and destroyed.

With operators pursuing various options to extend the productive life of assets and the advent of new technologies, it is very common for a field to remain operational well beyond its initial design lifespan. For example, the Brent Field in the North Sea had an expected lifespan of 25 years when discovered, but is being decommissioned 40 years after production first started.

2.2 Decommissioning phases

Cessation of production (CoP) occurs when all economically recoverable reserves have been produced. The CoP decision is important to both the investor and the state, and will be made after careful consideration of possibilities to extend the asset's productive life. Although the timing of CoP may be uncertain, decommissioning is the inevitable end of any oil and gas development and involves the following three stages:

1. **Planning and approval**. All projects should be designed with 'the end in mind', and a preliminary view of decommissioning should be submitted as part of project approval, that is, the field development plan (FDP) also referred to as the plan of development (POD). Naturally, this would be an initial view, which as CoP nears would require rigorous evaluation of the various potential decommissioning options. This would entail a wide range of detailed studies on the technical/engineering aspects, assessing alternative uses of the assets, comparison of environmental impact options, as well as consultations with stakeholders. The technical, economic, HSE (health, safety, environment) and social implications must be carefully considered, in order for the operator to arrive at a recommended decommissioning option.

   The government's approval of the preferred decommissioning option will need to be factored into timelines, as well as co-ordination for other regulatory approvals. Not surprisingly, it requires several years to develop a decommissioning plan that is approved by the regulator. As an example, in the North Sea, three to five years is considered a typical timeframe for this stage.[2] Procurement of various subcontractors and equipment etc. to execute the selected decommissioning option will also have to be included in the operators' planning.

   While decommissioning should be carried out as soon possible following CoP, it may be reasonable to defer some or all of the decommissioning operations to a future date in certain circumstances. For example, there may be benefits from conducting decommissioning in a phased manner or through a campaign approach (co-ordinating with other projects). When decommissioning is deferred, there should be arrangements for maintaining the un-decommissioned assets.

2. **Decommissioning operations**. The specific activities to decommission a field can be described as the reverse of the development phase. To develop a field, whether onshore or offshore, requires the drilling of wells and construction of several types of facilities to collect, process, store and export petroleum and its by-products – which will include platforms, pipelines, gathering stations, storage tanks and loading terminals. Decommissioning activities therefore consist of:
   - Plugging and abandonment (P&A) of wells to safely isolate and disconnect hydrocarbon reservoirs from the surface.

2 DECC Document Template – Standard Numbering (publishing.service.gov.uk). See: Department for Business, Energy & Industrial Strategy (2018), Guidance Notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines, available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760560/Decom_Guidance_Notes_November_2018.pdf

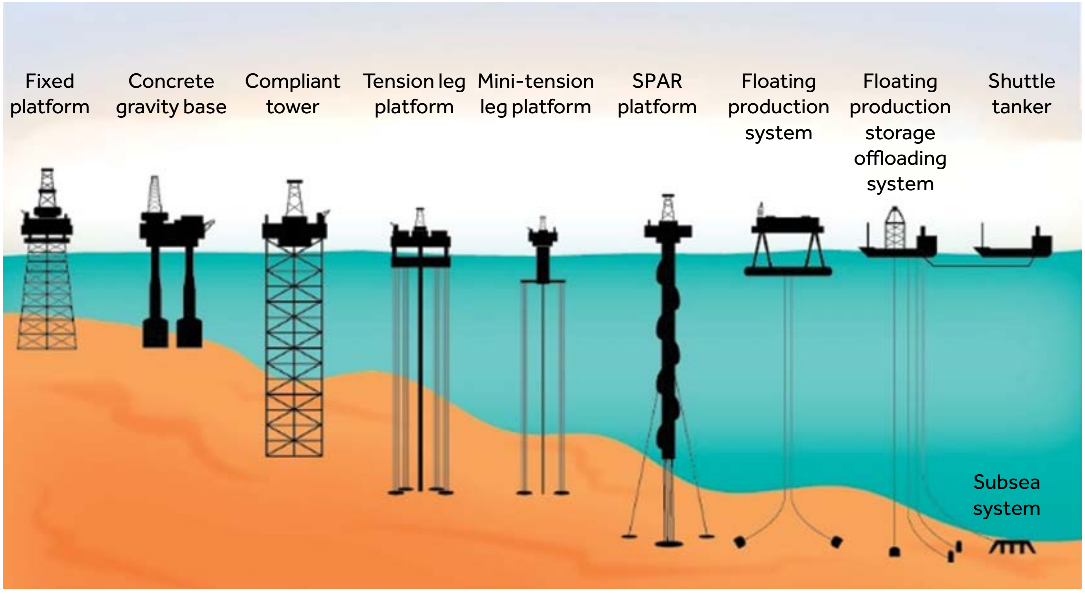
- Cleaning of facilities to remove hydrocarbons and hazardous materials.
- Removal, disposal or otherwise handling of installations. The decommissioning options for dealing with physical structures are either to leave in place (in situ) or to remove (either partial or total) and thereafter either dispose of or recycle, on land or in the sea. The specific decommissioning option chosen will depend on several factors, including the installation's location (onshore, offshore), the type of facilities, alternative uses for the infrastructure, environmental impacts, safety, costs and regulatory requirements. Decommissioning options for offshore developments must factor in additional considerations, which are described in Section 2.3.
- Site restoration for areas disturbed by production operations. This will enable the potential productive use of the area by individuals and the community in the future, such as for agriculture, fishing etc.

3. **Post decommissioning**. After decommissioning operations have been concluded, ongoing monitoring of structures not removed will be required to detect if there are any leaks or residual toxicity (by monitoring levels of hydrocarbons or other contaminants in wells, pipelines, in situ structures, drill cuttings), the state of the structures left in place and ongoing environmental impacts. The strategy for monitoring and reporting should be covered in the decommissioning plan.

2.3 Offshore decommissioning options

Offshore developments can vary greatly in size, configuration and function. As illustrated in Figure 2.2, these are determined by factors such as water depth, proximity to existing infrastructure, environmental impacts and economics. Options to decommission must therefore consider the structures above water (topsides) and those underwater (substructures), including pipelines, as well as the treatment of waste, in particular drill cuttings.

Figure 2.2 Types of offshore developments

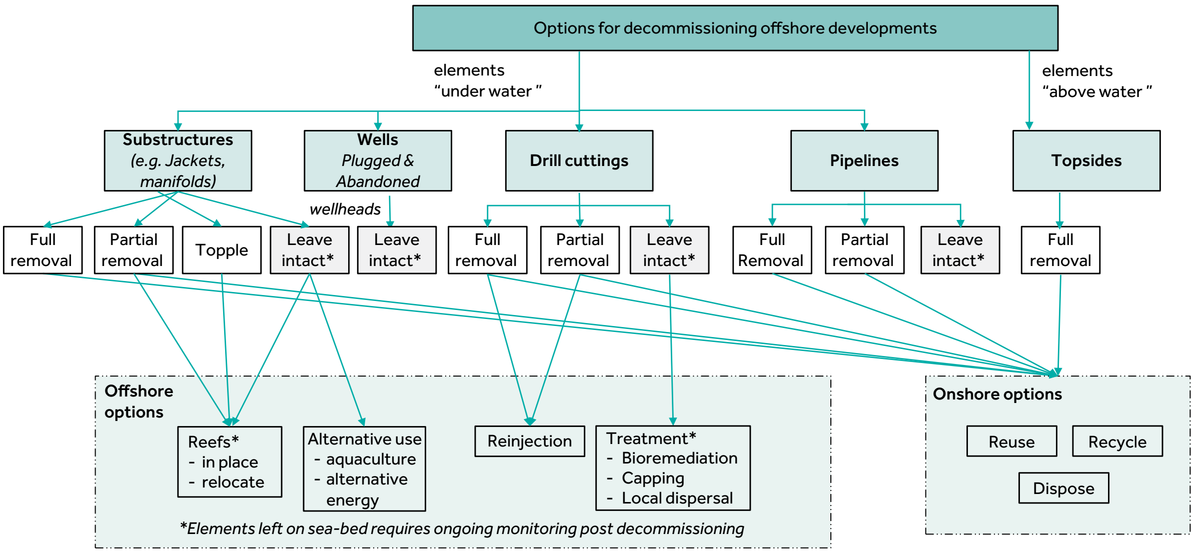


The topsides are typically taken onshore for disposal and/or recycling and reuse. The size of the topsides will determine the complexity of removal operations. Smaller topsides can be removed in a single lift and towed to shore. However, larger installations will require dismantling on-site prior to multiple lifts. Substructures can be left in place, toppled on-site or removed. Removed substructures can either be recycled, reused, disposed of onshore, disposed elsewhere offshore for alternative uses (for example, as an artificial reef to be promoted in diving tourism or as a fish aggregation device for use in fisheries or aquaculture), or left in situ for reuse by other energy industries, such as renewables.[3] The options for

3 Recharge (2021), 'World's first offshore green hydrogen project on an oil platform gets go-ahead', available at: https://www.rechargenews.com/energy-transition/worlds-first-offshore-green-hydrogen-project-on-an-oil-platform-gets-go-ahead/2-1-1043998

dealing with any drill cuttings pile are to leave in situ or removal (lifted to the surface for treatment, taken onshore for treatment and disposal, or re-injected down new or water injection wells). These options are illustrated in Figure 2.3.

Figure 2.3 Offshore decommissioning scenarios



Rigs-to-reefs (RtR)

Rigs-to-reefs programmes are present in a number of countries, but are most advanced in the US's Gulf of Mexico states, where 11 per cent of decommissioned platforms have been adopted into state artificial reef programmes.[4] While the Gulf of Mexico contains the majority of current rigs-to-reefs activity and legislation, several Commonwealth countries also have considerable experience of the creation of artificial reefs. Please see Box 2.1.

Whether a decommissioned rig is suitable for use as an artificial reef depends on several criteria, especially the materials used in the rig, the levels of maintenance and monitoring undertaken on the rig during its life, siting of the rig, and the possibility of liability transfers.[5] Criteria for disposal sites are also numerous, including water depth, oceanographic conditions, water quality, proximity to other users of the sea, marine planning criteria and access to sources of larvae for reef recruitment.[4].

Drill cuttings

'Drill cuttings' are ground up rock fragments recovered during the drilling of wells into oil and gas reservoirs. 'Drilling mud' is the fluid circulated around the well to lubricate the drill bit, transport the cuttings to the surface and keep the hole from collapsing, and to balance the reservoir pressure to prevent uncontrolled release of hydrocarbons. When the drilling mud comes to the surface, the fluid is recovered on the drilling rig and the cuttings are discharged as waste product. The size of the drill cuttings piles on the seabed can be large. In a survey of cuttings piles on the UK continental shelf, Henry et al.[6] (2017) noted that cuttings piles were sized from 500m to 1200m (radius), while the Brent field cuttings piles were characterised as between 20,047 and 22,444m^3 in volume.[7]

4 Bull, A and MS Love (2019), 'Worldwide oil and gas platform decommissioning: A review of practices and reefing options', *Ocean & Coastal Management*, Vol 168, 274–306, available at: https://doi.org/10.1016/j.ocecoaman.2018.10.024.

5 Jagerroos, S and PR Krause (2016), 'Rigs-To-Reef; Impact or Enhancement on Marine Biodiversity', *Journal of Ecosys Ecograph* 6, 187. doi:10.4172/2157-7625.1000187

6 Henry, LA, D Harries, P Kingston, JM Roberts (2017), 'Historic scale and persistence of drill cuttings impacts on North Sea benthos', *Marine Environmental Research* Vol 129, 219–228.

7 Brent Alpha 20047m^3, Brent Bravo 21761m^3, Brent Charlie 22,444m^3, Brent Delta 21,616m^3, estimated volume of OPF-contaminated drill cuttings (Shell 2016 supporting document BDE-F-SUB-BA-5801-00001 to the Brent Field Decommissioning Programme).

The toxicity of these drill cuttings piles depends on the type of mud that was used during drilling operations. Two main types of drilling mud have been used – oil-based (diesel and synthetic) and water-based muds. Oil-based muds and the discharge of oil-based mud contaminated cuttings are now broadly prohibited from use in a number of countries and regions, including the USA, Nigeria, Saudi Arabia and the OSPAR (Oslo and Paris Convention on the Protection of the Marine Environment in the Northeast Atlantic). From a decommissioning perspective, what is important is what fluids were used during drilling activity. As oil-based mud was frequently used in the past, the legacy issue of contaminated cuttings piles persists.

In many cases, the preferred option is to leave the drill cuttings in place and most decommissioning plans are based on minimising disturbance. For example, the use of internal (rather than external) cutting methods used to release jacket legs from their foundations results in smaller volumes of cuttings being displaced. If cuttings are disturbed, there may be consequences to the environment and other users of the sea.[8]

Box 2.1. Commonwealth experience of rigs-to-reefs (RtR)

Malaysia: Of the 300 fixed offshore platforms located in shallow waters, 60 per cent are nearing the end of their production life (Jagerroos and Krause 2016). Three major RtR initiatives have been undertaken in Malaysia to date, with a history back to the 1970s of smaller local reefing initiatives to aid the fisheries industry. Baram-8 was a single well three-legged wellhead and jacket, located 8 nautical miles (nm) off the coast of Miri, Sarawak, that was damaged in a storm in 1975. Decommissioning started in 2001, and the local fisheries department requested that reefing occur; it was placed in 2004 at around 60 feet (ft) offshore from Miri. A 2012 monitoring survey showed that the structure had grown into a functional reef structure, with high abundances of soft corals, sponges and fish.

In 2017, the Dana and D30 platforms were also laid out as artificial reefs in Sarawak.

Brunei Darussalam: Close to 150 installations located within 200 nautical miles of the Brunei coastline are 20 years old or older (Lyons et al. 2013). The Brunei RtR policy was introduced in 1988, and decommissioning policies include the 2009 Guidelines for Decommissioning, Abandonment and Restoration of the Oil and Gas Industry Assets. Two sets of structures were disposed of as artificial reefs near Two Fathom Rocks. The first set of structures (1988) consisted of two platforms, and the second (1994) of five jackets. The oil and gas installations used were based in 16–60m and the jackets weighed between 85 and 165 tonnes.

Australia: Currently, the National Offshore Petroleum Safety and Environmental Management Authority is exploring the possibility of supporting an in situ decommissioning policy. Woodside is currently proposing that an artificial reef is created from the disused Nganhurra long riser turret mooring. This would be placed close to the Ningaloo Coast Reef World Heritage Area.

8 See OSPAR, Implementation report on Recommendation 2006/5 on a management regime for offshore cuttings piles https://www.ospar.org/documents?v=7170