

# **A review of offshore decommissioning regulations in five countries – strengths and weaknesses**

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## **Abstract**

The decommissioning of offshore structures around the world will be a persisting problem in the coming decades as many existing structures will exceed their shelf life, or when reservoirs are no longer productive. This paper examines an overview of the global offshore decommissioning legal regime, and a review of regulations in countries that are deemed to be more experienced in decommissioning such as the UK, Norway and USA. Two oil-producing countries in South East Asia, Malaysia and Thailand are also reviewed to identify potential gaps in decommissioning legislation for countries in its infancy in decommissioning. The differences were identified in terms of decommissioning preparation, decommissioning technical execution, additional environmental requirements and financial security framework. In conclusion, the majority of the regulations covering the technical section are similar. The major differences lie in two overarching philosophies of the framework, one that is more prescriptive with stricter requirements and another that is more flexible with a goal-setting regime. Non-technical decommissioning aspects appear to attract increasing attention from governments, such as a company's financial capability to withstand decommissioning costs, minimisation of costs while meeting regulations, transfer of liability if other decommissioning options are accepted, and the movement of wastes from offshore to onshore.

## **Keywords**

Decommissioning regulations; Offshore; Abandonment; Removal

## Acronym List

ALARP	As-Low-As-Reasonably-Practicable
ANIFPO	Anglo North Irish Fish Producers Organisation
ASCOPE	The council on petroleum of countries belonging to ASEAN
BOEM	Bureau of Ocean Energy Management (US)
BPEO	Best Practical Environmental Option
BSEE	Bureau of Safety and Environmental Enforcement (US)
CHARM	Chemical Hazard Assessment and Risk management
COBSEA	Coordinating Body on the Seas of East Asia
DEA	Decommissioning Environmental Assessment
DECC	Department of Energy and Climate Change (UK)
DEMP	Decommissioning Environmental Management Plan
DMF	Department of Mineral Fuels (Thailand)
DOI	Department of the Interior (US)
EA	Environment Agency (UK)
EMP	Environmental Management Plan
HSE	Health and Safety Executive (UK)
IOC	Independent Oil Company
JOA	Joint operating agreement
MCAA	Marine and Coastal Access Act 2009 (UK)
NDE	Non-destructive examination
NFFO	National Federation of Fishermen's Organisations
NIFPO	Northern Irish Fish Producers' Organisation
NOAA	National Oceanic and Atmospheric Administration (US)
NORSOK	Standards Norway
OBF	Oil based drilling fluids
OCNS	Offshore Chemical Notification Scheme
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
PEP	Post Environmental Assessment
PLEM	Pipeline end manifolds
PPGUA	PETRONAS procedures and guidelines for upstream activities
PSC	Production Sharing Contracts
PTT	Petroleum Authority of Thailand
RDEA	Regional Decommissioning Environmental Assessment
RSC	Risk Service Contract
SBF	Synthetic based drilling fluids
SFF	Scottish Fishermen's Federation
UKCS	UK Continental Shelf
USACE	U.S. Army Corps of Engineers
VisNed	Association of Dutch Demersal Fishers

## **1. Introduction**

The word ‘decommissioning’ is not well-defined in international and several national legislation, and can take on words like ‘abandonment’, ‘disposal’ and ‘removal’, which make up possible processes in decommissioning. It has been mentioned in the UK Petroleum Act (1998) and the 2011 Decommissioning Guidelines (Department for Business Energy and Industrial Strategy UK, 2011) that while ‘abandonment programme’ is referred to in the Petroleum Act, the generally accepted term is ‘decommissioning programme’.

Based on most legislation requirements investigated in this paper (Department for Business Energy and Industrial Strategy UK, 2011; Government of USA, 2014a; Petroleum Institute of Thailand, 2008; Petroleum Safety Authority (Norway), 2015a; PETRONAS, 2008) and current decommissioning practices (Techera and Chandler, 2015), it appears that decommissioning is the final stage of the life cycle of an industrial facility, and is the process of closing down an industrial facility via methods, which balances the sensitive boundaries of minimising financial costs, costs to human life and well-being and to the environment. In this paper, the industrial facility refers specifically to offshore production facilities. Offshore facilities are made up of the substructure that is secured to the seabed, a network of pipelines, and the topside structure existing above the seabed (Techera and Chandler, 2015). The decommissioning process thus entails the plugging and abandonment of wells, removal – partially or fully, of the platform and associated facilities on the platform, and clearing any “above mudline” structures or equipment from the seafloor.

Globally, there are many offshore installations which are getting older. In the North Sea, there are 1357 offshore installations, 726 sub-sea steel installations and fixed steel installations (OSPAR Commission, 2013), of which 20% are more than 30 years old (OSPAR Commission, 2013). In South East Asian waters, such as the Gulf of Thailand and the South China Sea, there are currently 444 offshore installations that have been in service between 20 and 30 years, and another 389 that have exceeded the typical 30-year service life of such installations and are still in operation (Lyons, 2012). Many of them are expected to be decommissioned within the next few years.

There are numerous decommissioning concepts to choose from such as complete or partial removal, structure severance options, leaving behind of shell mounds and drill cuttings. First and foremost, decommissioning procedures have to comply with local and international maritime legal requirements. Therefore, the viability of the options of decommissioning can only be studied if there is an understanding of the legal framework in the respective countries which includes, for example, waste management requirements and environmental monitoring requirements for rigs-to-reefs project.

### **1.1. Scope of paper**

This paper first identifies international regulations relevant to decommissioning. Next, in order to understand how decommissioning is carried out in countries experienced in such activities, the domestic regulations of Norway, the UK and USA are looked into. It is also expected that some elements of the international requirements could be found in these domestic regulations. There are also countries in which their offshore industry is gaining traction in developing its decommissioning guidelines and thus, Malaysia, and Thailand are part of the case-studies. In South East Asia, only Malaysia and Thailand had easily accessible resources to decommissioning legislation or guidelines, hence the focus on these two countries. Newly developed guidelines may showcase an interesting, or more thorough solution to any of the problems common to all decommissioning activities.

Section 1.2 of the report provides an overview of the general decommissioning procedures and methods. The next section, Section 2 identifies the international legal framework that is applicable to decommissioning. Section 3 presents the legal framework of countries with more experience in decommissioning activities such as the UK, Norway and USA. Section 7 focuses on the South East Asian countries which are beginning to establish regulatory guidelines for decommissioning procedures and where the offshore industry is in its infancy in terms of decommissioning. The discussion in Sections 3 and 7 take on the structure highlighted in **Figure 1**. The fifth section compares the regulations across the case-studies and highlights guidelines which are more thorough and strict in the requirements. The sixth section concludes the findings.

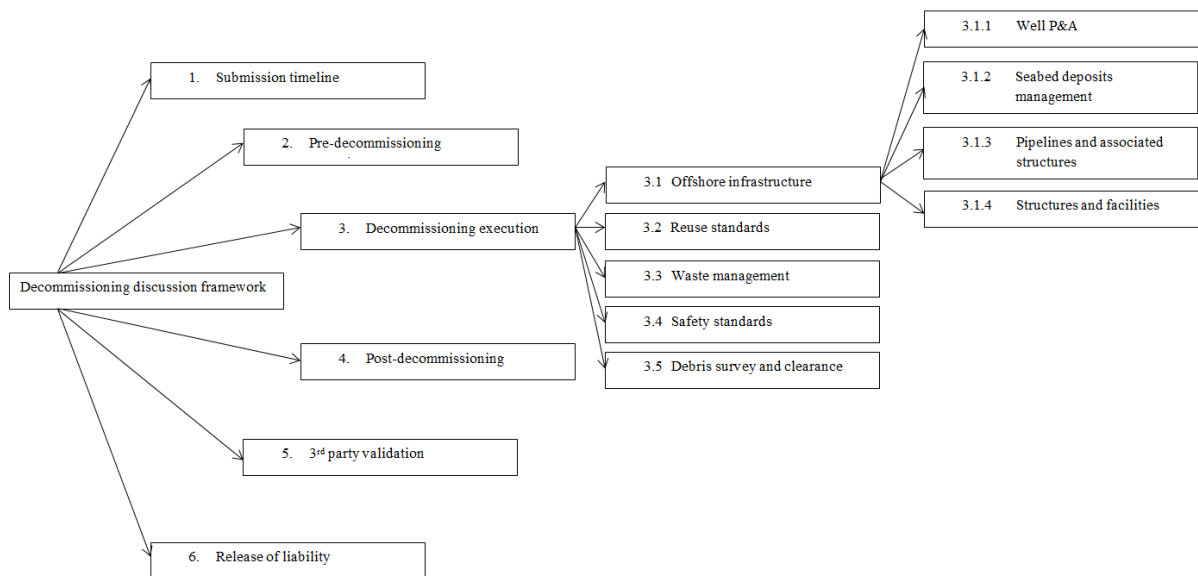


Figure 1 Mind map of the discussion framework of decommissioning items.

## 1.2. Decommissioning Procedures

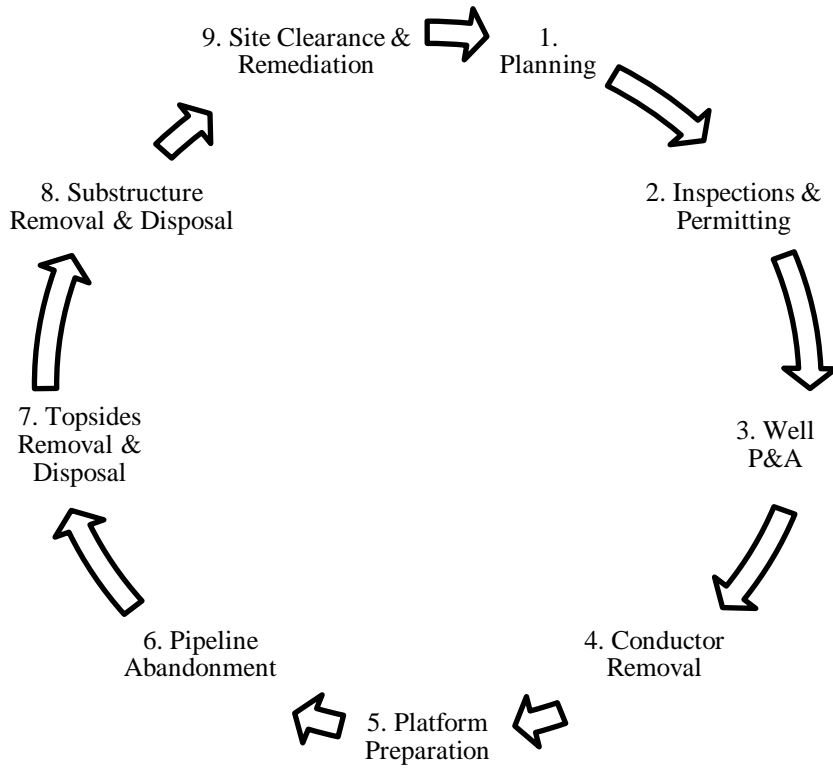
Based on international and national legislation, decommissioning generally takes on the process of shutting down operations, closing the wells, decontamination, making the platform safe and removing, disposing of or relocating facilities. A generic decommissioning procedure (See Figure 2) for one of the more common types of offshore structure (Osmudsen and Tveteras, 2003) such as a jacket structure is discussed.

The first step involves planning for decommissioning, which typically commences 2 to 3 years before production ceases. The planning process involves a review of all records including lease of equipment, production sales agreement, drilling records, maintenance and inspection records. Field inspection of the equipment such as well-heads and platform structural condition are carried out in order to prepare for detailed engineering analyses on how modules of the structure can be severed and removed in pieces. The second step is the preparation of the permits and submission of the decommissioning plan; in short a compilation of the work done in the first step as well as the proposed subsequent actions.

The third step is the commencement of the physical decommissioning work – the well plugging and abandonment. Wells will be plugged with cement or other materials, and the wellheads severed and

removed. The fourth step is the removal of the conductors. Typically, abrasive cutting methods will be used to sever the conductors, and the severed conductors are surfaced and cut into more manageable sizes so that they could be transported onshore. After the conductors are severed, they are dislodged or pulled from below the mud line using a casing jack. The fifth step is the preparation of the platform. This requires the topside (the production area) to be decontaminated, and subsequently the termination of piping electrical and instrumentation connections between production modules. Then, sections of the platform will be marked for the construction of new padeyes and lift supports for sectional removal. Below the waterline, inspection will be carried out by divers or ROVs to demarcate the sections of the jacket to be removed. The sixth step is pipeline decommissioning, which involves flushing and cleaning of the pipelines. The pipeline will be severed above the riser bend, and the remaining pipelines are sealed using plugs. Pipelines may be left in place or removed depending on the accepted proposal. Similar to the conductors, the pipelines will be cut into smaller sections for ease of transportation onshore.

As the jacket is now no longer linked to the seabed (with the exception of the jacket piles), the following steps now concentrate on dismantling the topsides and jacket structure. The seventh step involves the topside removal. Previously in the fifth step, cutting and lifting points have been identified, and hence the corresponding sections will be removed by cutting these demarcated sections, and then transported on cargo barges. The eighth step is on jacket removal. The jackets will be sectioned in-situ, and then removed by a derrick barge. The piles, like the conductors and wells will be severed at a depth below the mud line. The sectioned jacket will then be loaded onto a cargo barge and taken on shore. The final step is site clearance and remediation, which involves conducting pre and post decommissioning surveys and close out reports to document the above activities and ensuring that requirements are met.



*Figure 2 Decommissioning procedures for one of the more common type of offshore structures, such as a jacket structure.*

## **2. International Regulations**

In order to protect the environment, navigation, fishing and other sea users, regulations and guidelines in that aspect have been developed by international organizations for decades. In this section, this report provides an overall summary of some international legal frameworks which are important to decommissioning procedures. In general, the international regulations listed below stemmed from a UN initiative, however, as conventions were developed, some of the conventions/commission were re-aligned with new specialised commissions or agencies, such as the IMO or the OSPAR Commission.

### *2.1. UN*

#### 2.1.1. United Nations Convention on the Continental Shelf / Geneva Convention (1958)

The United Nations Convention on the Continental Shelf 1958, or otherwise known as the Geneva Convention is the first international treaty addressing the abandonment or disused offshore oil & gas installations. The Geneva Convention in Article 5(1) addresses the issue that the exploration and exploitation of natural resources should not interfere with navigation, fishing and other users of the sea (ASEAN Council on Petroleum (ASCOPE), 2012). Article 5(3) also mentions the requirement of a safety zone extending 500m from the outer edge of the offshore facility that other users of the sea in this zone must also respect, while Article 5(7) establishes the requirement for the coastal state to undertake appropriate measures for the protection of living resources of the sea from harmful agents inside this safety zone (ASEAN Council on Petroleum (ASCOPE), 2012). The most important is that in Article 5 (5) which requires any installation that are abandoned or disused to be entirely removed (ASEAN Council on Petroleum (ASCOPE), 2012). It is interesting to note that the offshore oil and gas productions moved in to deeper and more hostile environments in the 1960s and 1970s, thus making a complete removal of any offshore facility a much trickier operation, in terms of technical feasibility and environmental concerns. This was later addressed in UNCLOS (1982), the International Maritime Organisation (IMO) Guidelines (1989) and the OSPAR Decision 98/3. Also, the Geneva Convention does not identify pipelines as part of the infrastructure to be removed.

#### 2.1.2. The Third United Nations Convention on the Law of the Sea / UNCLOS (1982)

The Third United Nations Convention on the Law of the Sea, also known as UNCLOS updates the previous two versions where some rules were considered inadequate. Under Article 60(3), UNCLOS modified the Geneva Convention and includes statements about specifically disused offshore installations. It also recognised that such requirements should also be governed by and with guidance from accepted international standards, that is by a competent international organisation (ASEAN Council on Petroleum (ASCOPE), 2012). The International Maritime Organisation (IMO) was then asked to develop guidelines and standards in accordance to latest developments (of that time, in 1989) in the offshore industry, called the “Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone” It is thus reiterated that any disused installations shall be removed, but it was recognised that due to new developments of bigger installations in deeper waters, all installations in deeper waters, may not be “entirely removed (ASEAN Council on Petroleum (ASCOPE), 2012).

There is also an emphasis on the protection and preservation of the marine environment by Article 210 (1) which requires states to prevent, reduce and control pollution of the marine environment by dumping (ASEAN Council on Petroleum (ASCOPE), 2012). The UNCLOS (1989) also makes no mention on the removal of pipelines (ASEAN Council on Petroleum (ASCOPE), 2012).

### 2.1.3. Basel Convention (1989)

The Basel Convention (1989) on the Control of Trans-boundary Movements of Hazardous Wastes and Disposal is the most comprehensive global environmental agreement on hazardous wastes and other wastes. This convention regulates trans-boundary movement of hazardous waste. Typically the nature of such wastes are toxic, poisonous, explosive, corrosive, flammable, eco-toxic, or infectious. The Basel convention governs two major areas (ASEAN Council on Petroleum (ASCOPE), 2012):

- (i) Regulation of the Trans-Boundary Movement of Hazardous Wastes
- (ii) Environmentally Sound Management of Hazardous Wastes

Under this convention, wastes can only be exported if both the state of import and export has given their consent in writing to the report, so that information about proposed trans-boundary movements can be communicated to the States concerned to enable the evaluation of effects on the proposed movement on health and the environment (ASEAN Council on Petroleum (ASCOPE), 2012).

## 2.2. *The International Maritime Organisation (IMO)*

The International Maritime Organisation (IMO) is the United Nations specialized agency with responsibility for the safety and security of shipping and the prevention of marine pollution by ships. The IMO covers all aspect of shipping, which includes operation and disposal at sea, thus drawing the relevance to decommissioning.

### 2.2.1. IMO Guidelines and standards (1989)

In 1989 the International Maritime Organisation set out the minimum global standards applicable to the removal of offshore installations and structures called “Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone” (International Maritime Organisation, 1989), while this guideline may be seen only as a recommendation, the UNCLOS (1982), an international regulation mentions that installations that are abandoned or are disused must be removed, while taking into consideration of generally accepted standards, by the competent international organisation, which in this case refers to the IMO. Thus, following the guidelines is a requirement if any state has ratified UNCLOS (1982).

The guidelines, compared to the earlier conventions, demonstrate more relevance to the offshore installations. The general removal requirement is that any abandoned or disused offshore installations are required to be removed, except if the non-removal or partial removal is consistent with the guidelines. The offshore facility can remain on the sea-bed, on a case-by-case basis by the state over the following areas of costs, technical feasibility, human health and safety risks, re-use of structure, potential effect on the marine environment etc (International Maritime Organisation, 1989). If structures are partially

removed, then the remaining structures must meet the guidelines, such as providing an unobstructed water column of not less than 55 metres at Lowest Astronomical Tide, and that it should be marked such that it does not interfere with navigation. There is also a requirement to provide a legal title for the remaining structures so that there is clear establishment for future maintenance or any liabilities. There is also forward thinking in that after 1 January 1998, no platforms shall be installed unless the structure's design and construction makes entire removal feasible (International Maritime Organisation, 1989).

It can be observed that the IMO guidelines cover removal, but mostly from a navigational safety point of view. In terms of pipelines, the guidelines has a provision that the state should give a specific official authorisation spelling the condition which any installation, parts thereof, will be allowed to remain on the seabed. As for leaving behind shell mounds or other waste disposal, the IMO guidelines have no coverage, but the London Dumping Convention (1972) would cover this.

#### 2.2.2. London Dumping Convention and Protocol

##### **London Dumping Convention (1972)**

The “Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (1972), also known as the London Dumping Convention covers the deliberate disposal at sea of wastes or other matter from vessels, aircraft, and platforms(International Maritime Organisation, 2006). Dumping refers to the intentional disposal at sea of wastes of other materials from vessels, aircraft, platforms or other man-made structures at sea, or the intentional disposal at sea of vessels, aircraft, platforms or other manmade structures at sea. However, the convention provides that dumping does not include placement of matter for a purpose other than the disposal(International Maritime Organisation, 2006), and it is through this convention that there can be Reef to Rigs programmes in the Gulf of Mexico or in other parts of the world, as there is a provision in the convention that the state takes the final decision, after a reef-to-rigs assessment is performed. The convention also considers that the state has the authority to grant general permits of dumping of other wastes or matter, and platforms can be considered as “other wastes or matter” for sea disposal(International Maritime Organisation, 2006).

## **London Protocol (1996)**

In 1996, the parties to the London Dumping Convention adopted a Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter that entered into force in 2006 (International Maritime Organisation, 2006). The London Protocol was developed in order to update the London Dumping Convention and eventually replace it. There are several new concepts worth noting concerning sea disposal, one of which is the reverse list, which stems from the idea of prohibiting all dumping, except for the possibly acceptable waste on this list, that includes dredged materials, vessels, platforms or other man-made structures at sea (International Maritime Organisation, 2006). The London Protocol also emphasizes on the Polluter Pays Principle, so that the party responsible for producing the pollution is responsible for the damage done to the environment (International Maritime Organisation, 2006). The protocol also upholds the precautionary principle, where a lack of full scientific certainty will not be accepted as a good enough reason for postponing cost-effective measures.

### **2.3. The OSPAR Commission**

The OSPAR Commission mechanism between the EU and fifteen governments was established as a successor to the Oslo and Paris Conventions, where the Oslo Convention (1972) against dumping was broadened to cover land-based sources and the offshore industry by the Paris Convention (1974). In 1998, a new annex was created to cover biodiversity and ecosystems, which includes non-polluting human activities that can adversely affect the sea. The fifteen governments are Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom (OSPAR Commission, 2007). The OSPAR Commission protects and conserves the North-East Atlantic and its resources and now covers 5 main areas: - Hazardous Substances and Eutrophication, the Offshore Industry, Radioactive Substances, Biodiversity and Environmental Impact of Human Activities. The OSPAR Commission has a dedicated work area for the offshore industry and the most applicable instrument is the OSPAR Decision 98/3 that governs the disposal of disused offshore installation (OSPAR Commission, 2007).

#### **2.3.1. OSPAR Decision 98/3**

OSPAR Decision 98/3 is about disposal of disused offshore installation, and only applies to the fifteen countries that have ratified the OSPAR convention (OSPAR Commission, 2007). However many countries drilling in the North Sea has ratified to OSPAR, and hence decommissioning protocol will also include the stricter elements of the OSPAR Decision. Thus it will be noteworthy even for countries not part of the OSPAR Decision to understand the requirements and concessions of this decision.

In general, it is prohibited to dump and leave wholly or partly in place of offshore installations. The topsides of all installations must be returned to shore. All installations with a jacket weight less than 10,000 tonnes must be completely removed for re-use, recycling or final disposal on land (OSPAR Commission, 2007). The Decision recognises that there may be difficulty in removing the 'footings' of large steel jackets weighing more than 10,000 tonnes and in removing concrete installations. As a result there are exceptions from the general rule for these categories of installation. After 9 February 1999, the date on which the Decision entered into force, any steel emplaced must be completely removed for reuse or recycling or final disposal on land (OSPAR Commission, 2007). Only in very exceptional and unforeseen circumstances resulting from structural damage or deterioration or equivalent difficulties will there be a case for any offshore installation to be dumped or left wholly or partly in place (OSPAR Commission, 2007). The OSPAR Decision also does not mention on the fate of pipelines.

### **3. Decommissioning Framework in Areas with Established History of**

#### **Decommissioning**

There are several areas where there are offshore oil and gas activities, and the areas in which decommissioning is more established than other areas, are that in the North Sea and in the Gulf of Mexico. The dominant countries in the North Sea refer to Norway and the United Kingdom, while the United States manages the offshore facilities in the Gulf of Mexico.

In general, the technical requirements in both areas (North Sea and the Gulf of Mexico) are similar, such as the depth at which structures must be removed, in situ pipeline decommissioning (US and UK), waste management and responsibility tied to the waste shipment, as well as the use of the options analysis methodology to assess the best decommissioning method for a particular area.

In terms of legal and technical framework for re-use of offshore structures, the US is most advanced in this area. This could be due to the geographic location of the states whereby the rigs-to-reef activities could increase productivity in fisheries, such that the reef-to-rigs programme generates income in other ways beyond its role in the offshore industry. The US reef-to-rigs framework also considers the funding of the management of the reefs from the decommissioning costs offset (from relocating the structure to a rigs-to-reef location) by the facilities owner. In the North Sea, Norway and UK and thirteen other countries ratified the OSPAR convention and also need to uphold the OSPAR decision 98/3. Through the controversy surrounding the Brent Spar case, the OSPAR final guidelines thus excluded non-virgin materials as acceptable reef construction materials, effectively ruling out the use of rigs for reef construction in the North Sea (Jørgensen, 2012). In this area, there could be room for improving the legislation to include a case-by-case determination of the suitability of a structure for rigs-to-to-reef projects.

In terms of health and safety and general operational safety, Norway and UK takes on a goal setting approach, while the US undertakes a more prescriptive approach where the regulator sets out a series of 'one size fits all' requirements in which the operator must comply with. The goal setting approach

involves the operator developing their own objectives, and making a case to the regulator that they are managing safety effectively. Naturally, there are legal boundaries that shape the limits of the respective safety cases. There are also slight differences between the system in Norway and in the UK, where by in the former it is called Acknowledgement of Compliance, while in the latter, simply, a Safety Case. Such goal-setting systems only work where relevant statutory provisions are robust enough, both in terms of general management, and technical management. The flexibility in a goal-setting system allows exemptions to be granted, but with justification or identification of remedial measures that demonstrate compliance to overall safety goals. The “as low as reasonably practicable” (ALARP) concept is an important element of the goal-setting regime. It is designed to add value as a measure of how far major hazards can be controlled and risks reduced before costs are out of all proportion to the benefit gained. This is important as the onus now lies with the operator to ensure safety, rather than having a prescriptive system where a series of ticked safety items in a form could give false security on the robustness of a safety management system. Also, each platform is different and managed differently hence, the goal-setting regime may be more comprehensive. This resonates especially when transitioning from the day-to-day usual of hydrocarbon production activities to unfamiliar decommissioning activities such as well plugging, working without full access to all areas of the facility as each area is dismantled section by section.

#### **4. The United Kingdom**

##### *4.1. An overview of the UK Upstream Oil and Gas Industry*

In the United Kingdom, the Department for Business, Energy and Industrial Strategy (BEIS), formally known as the Department of Energy and Climate Change (DECC) is the competent authority for decommissioning and regulates offshore oil and gas decommissioning under the Petroleum Act 1998/ Energy Act 2008. The Oil & Gas Authority works with the BEIS to assess decommissioning programmes on the basis of cost, future alternative use and collaboration, and does so based on the

direction of the Maximise Economic Recovery (MER UK) strategy of the UK continental shelf as a result of the Wood Review in 2014 (Oil & Gas Authority UK, 2016a).

In 2000, the first version of the “Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998 Guidance Notes” was published by the Offshore Decommissioning Unit, of the former DECC. The most updated version is as of 2011 (Department for Business Energy and Industrial Strategy UK, 2011) and is still available on the Oil & Gas Authority website as part of decommissioning guidance materials (Oil & Gas Authority UK, 2016b). However, based on OGA’s Decommissioning Delivery Guidance document, a draft guidance notes, or decommissioning planning road map has been targeted to be published by the fourth quarter of 2016 (Oil & Gas Authority UK, 2016c). The Decommissioning Delivery Guidance is slated to take into consideration the requirements of the MER UK Strategy, the updated Energy Act and the OGA Corporate Plan 2016 – 2021. The three focal areas are (i) cost certainty and reduction, (ii) decommissioning delivery capability and (iii) decommissioning scope, guidance and stakeholder engagement (Oil & Gas Authority UK, 2016c). One of the biggest cost items of the decommissioning process is that of the well plugging and abandonment event, and there will be an optimisation programme (Oil & Gas Authority UK, 2016c) in the upcoming guidance. It is expected that the other segments of decommissioning guidance of 2011 will still be relevant, as OGA maintains the said document in the decommissioning guidance information page.

As of May 2016, the total number of operational installations is 303, and the total number of operational installations is 273, with 30 platforms in the process of being decommissioned. These 30 platforms had its first oil/gas date ranging from 1971 to 2009 (Government of the United Kingdom, 2016a). Of the remaining 273 operational installations, 107 installations (i.e. 40% of remaining installations) are at least 30 years old, with the oldest commissioning since 1967 (Government of the United Kingdom, 2016a).

There are currently two decommissioning yards for offshore structures that in the UK. One is Able on Teesside, which in 2009 took delivery of structures from North West Hutton for decommissioning. The other is the Greenhead Base on Shetland, which has decommissioned structures from Frigg. In addition,

the Norwegian company, AF Decom, plans to build a base at Dales Voe north of Lerwick in Shetland (Norwegian Climate and Pollution Agency, 2011).

#### 4.2. *The legal framework*

The decommissioning of offshore oil and gas infrastructure in the UK continental Shelf (UKCS) is principally governed by the Petroleum Act 1998, as amended by the Energy Act 2008, and recently the Energy Act 2016 on 12 May 2016. These two regulations are based on the OSPAR Convention guidelines, especially with reference to the OSPAR Decision 98/3.

In 2014, an independent review by of the UKCS oil and gas recovery, also known as the Wood Review, resulted in the creation of a new independent body (the Oil & Gas Authority) from the BEIS that is responsible for the operational regulation of the UKCS, and also empowered to take actions, such as sanctions to remove operatorship to facilitate the strategy of maximising economic recovery from the UKCS (Oil & Gas Authority UK, 2016c). The Wood Review also paid attention to decommissioning as one of the six Sector Strategies (Oil & Gas Authority UK, 2016c).

The Wood Review thus resulted in the updated Energy Act 2016 that established the Oil & Gas Authority (OGA) as an independent regulator and with additional powers such as having access to company meetings, data acquisition and imposing sanctions. The Act also enables more comprehensive charging of the offshore oil and gas industry for permits and licences for environmental and decommissioning activity (Government of the United Kingdom, 2016b). This allows the UK Government to continue to recover the costs of its environmental and decommissioning activity in line with the ‘polluter pays’ principle of environmental law and addressed this gap in legislation (Government of the United Kingdom, 2016b). In terms of decommissioning, there is now a particular clause (Part 3, Item 73, subsection (4) (7)) that includes the consideration of alternative measures to abandonment or decommissioning such as re-use or preservation (Government of the United Kingdom, 2016b), highlighting that the options for reducing the cost of decommissioning or re-using facilities for some other purpose are to be considered. Licensees will now also have to consult the OGA before

submitting the decommissioning programme to the Secretary of State (BEIS), whereby the OGA will opine on two areas – whether alternative uses of the facilities exists or whether the decommissioning programme is carried out at the lowest costs possible.

Apart from the international obligations and the above new requirements, the decommissioning plan also needs to meet other UK Regulations which have been categorised under the environmental, technical and financial framework.

#### *4.3. The environmental framework*

An Environment Impact Assessment (EIA) will be required for all license applications relating to decommissioning operations, under the Marine and Coastal Access Act 2009 (MCAA) and the Marine (Scotland) Act 2010). A public participation directive is also required under the Offshore Production and Pipelines (Assessment of Environmental Effects) Regulation 1999. The EIA should include potential impacts on the marine environment including exposure of biota to contaminants associated with the decommissioning of the installation; other biological impacts arising from physical effects; conflicts with the conservation of species with the protection of their habitats, or with mariculture; and, interference with other legitimate uses of the sea.

The other relevant organisations that are to be consulted in the EIA are the Environment Agency (EA), Scottish Fishermen's Federation (SFF), Northern Irish Fish Producers' Organisation (NIFPO), Anglo North Irish Fish Producers Organisation (ANIFPO), National Federation of Fishermen's Organisations (NFFO) and VisNed (Association of Dutch Demersal Fishers). The framework also considers a guideline by the UK Joint Nature Conservation Committee on the use on explosives and minimising the injury to marine mammals (Joint Nature Conservation Committee (JNCC) UK, 2010).

In terms of minimising pollution to the environment, some relevant legislation are the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations as amended, and the Offshore Chemicals (Amendment) Regulations 2011. The decommissioning plan also needs to meet biodiversity

and marine nature conservation requirements under the Offshore Marine Conservation (Natural Habitats, &c.) (Amendment) Regulations 2010. For waste handling, there is a duty of care under Environmental Protection Act 1990, Licence under Waste Management Licensing Regulations 1994/Environmental Permit issued under Environmental Permitting (England and Wales) Regulations 2007, Notification under Special Waste Regulations 1996 and Special Waste Amendment (Scotland) Regulations 2004 / Hazardous Waste (England and Wales) Regulations 2005, Authorisation under Radioactive Substances Act 1993, Authorisation under the Transfrontier Shipment of Waste Regulations 2007.

*4.4. The financial framework*

In the Energy Act 2008, Section 73 on Financial resources, it enables the Secretary of State to require action (including the provision of financial security, such as a letter of credit) to be taken by a person who has been served with a notice under section 29 or who has a duty to carry out a programme, where the Secretary of State is not satisfied that the person is capable of carrying out the programme (Department for Business Energy and Industrial Strategy UK, 2011). In a thorough manner, the subsequent section 74 on Protection of abandonment funds from creditors, states that in the event of insolvency of a person responsible for a decommissioning programme or a person with obligations under that programme, the funds set aside for meeting those liabilities remain available for decommissioning and are not available to the general body of creditors.

The system has 4 company risk classification based on a percentage of the respective decommissioning costs to their net worth:

*Table 1 Risk classification company risk classification based on a percentage of the respective decommissioning costs to their net worth.*

<b>Class 1</b>	<b>Class 2</b>	<b>Class 3</b>	<b>Class 4</b>
0 – 30 %	31 – 50%	51 – 70%	71% +
Company can easily afford costs	Funds are adequate to meet costs	Company should be able to meet costs but may have some difficulty	Company would have considerable difficulty meeting costs.

The risk classification is based on 4 steps (Department for Business Energy and Industrial Strategy UK, 2011). The first step is to make a note of project decommissioning costs. The second step is to compare the company share of project decommissioning costs against its net worth. The third step is to compare company share of UKCS decommissioning costs against its net worth. The fourth test is to compare the corporate group's share of UKCS decommissioning costs against the group net worth.

The risk classification that concerns the authorities most are medium or high risk. For companies in that category, the BEIS will consider whether the company has a parent or other associate which is UK registered and has sufficient assets to cover decommissioning costs at the appropriate time. If the risks are assessed such that it is unacceptable, the Energy Act enables the Secretary of State to require a company to provide security to ensure they fulfil their duty of an approved decommissioning programme (Department for Business Energy and Industrial Strategy UK, 2011).

The Energy Act (2016) Chapter 20 also provides the Oil & Gas Authority with powers to issue sanctions notices that can take on an enforcement notice, a financial penalty notice, revocation notice or an operator removal notice (Government of the United Kingdom, 2016b).

#### *4.5. The technical framework*

##### *4.5.1. Submission timeline*

The requirement is for timely action to be taken, and the onus rests on the Operator to initiate the discussions. In the case of a large field with multiple facilities, this may be 3 years or more in advance. In the case of a potential derogation case it may be up to 5 years in advance (Department for Business Energy and Industrial Strategy UK, 2011).

At a mutually agreed time, following preliminary discussions, the Operator should submit to consultation draft of the decommissioning programme to the OGA and the BEIS (Department for Business Energy and Industrial Strategy UK, 2011).

#### 4.5.2. Pre-Decommissioning

Under the 1998 Act a decommissioning programme should contain an estimate of the cost of the measures proposed; specify the times at or within which those measures are to be taken or make provision for determining those times; and, where an installation or pipeline is to remain in position or be only partly removed, include provision for maintenance where necessary. It is recognised that where appropriate a decommissioning programme will deal with both removal and disposal of an installation or pipeline (Department for Business Energy and Industrial Strategy UK, 2011).

Alternative removal and disposal options must be described, and a comparative assessment be laid out, in which the assessment should examine and compare each option on the basis of: complexity and associated technical risk; risks to personnel; environmental impact; effect on safety of navigation and other uses of the sea; and economics (Department for Business Energy and Industrial Strategy UK, 2011).

#### 4.5.3. Decommissioning Execution

The decommissioning execution is a broad section covering five areas: offshore infrastructure, reuse standards, waste management, safety standards and debris survey and clearance. Each topic within the decommissioning execution section will be discussed as a sub-section of its own (such as Section 4.5.3.

Decommissioning execution – offshore infrastructure, Section 4.5.34 decommissioning execution – reuse standards, etc)

Offshore infrastructure consists of the following four areas: (i) well plugging and abandonment, (ii) seabed deposits management, (iii) pipelines and associated structures and (iv) structures and facilities.

##### *Well Plugging & Abandonment*

The Decommissioning Strategy Delivery (Oil & Gas Authority UK, 2016c) has a focus on optimising the costs of Well P&A activities, whereby the Energy Act 2016 now requires the submission of an

abandonment cost estimate, in consultation with OGA before submission, while the OGA Corporate plan also aims to reduce decommissioning costs by 35%.

The UK refers to the industry body Oil & Gas UK Well Abandonment Guidelines, which specifies the well abandonment option to the well complexity, and the mitigation measures for potential well barrier failure modes, such as chemical degradation, creep, thermal expansion difference. The methodology should also meet the Offshore installation and Wells (Design and Construction etc) Regulations 1996.

As example is the criteria for classifying Phase 1 Well Abandonment Complexity based on 4 types of complexity (Simple rig-less, complex rig-less, simple rig or complex rig), and the well characteristics, such as sustained casing pressure due to hydrocarbons or overpressures, presence of annulus safety valve, multiple reservoirs to be isolated, inclination > 60 deg above packer etc, in the case of high inclination, wireline access may not be possible for settling wireline plugs and punching casing (Oil & Gas UK, 2015).

While the above technical criteria will likely remain to ensure well sealing integrity, operators perhaps need to show cooperation or contracting collaboration in order to optimise well identification sequencing and timing as part of the overall plugging programme (Oil & Gas Authority UK, 2016c).

### *Seabed Deposits Management*

The UK refers to the OSPAR Recommendation 2006/5 on Management Regime for Offshore Cuttings Piles (Department for Business Energy and Industrial Strategy UK, 2011).

The Cuttings Pile Management Regime is divided into two stages. Stage 1 involves initial screening of all cuttings piles. This should be completed within 2 years of the Recommendation taking effect. Stage 2 involves a BAT and/or BEP assessment and should, where applicable, be carried out in the timeframe determined in Stage 1.

Depending on the type of drilling fluids used, some further investigation is required, such as the rate of oil loss and persistence over the area of seabed contamination. Some considerations are that the rate of oil loss to water column should be 10 tonnes/yr and the persistence over the area of seabed contaminated: 1 500 km<sup>2</sup>/yr.

When assessing BAT and/or BEP, consideration should include, but not be limited to, the following options:

- Onshore treatment and reuse
- Onshore treatment and disposal
- Offshore injection
- Bioremediation in situ
- Covering in situ
- Natural degradation in situ

#### *Pipelines and Associated Structures*

The provisions of OSPAR Decision 98/3 do not apply to pipelines. There are no international guidelines on the decommissioning of disused pipelines.

The Petroleum Act 1998 provides a framework for the orderly decommissioning of both offshore installations and offshore pipelines. The Pipeline Safety Regulations 1996, administered by the HSE, provide requirements for the safe decommissioning of pipelines (Department for Business Energy and Industrial Strategy UK, 2011).

The following approach will be taken in considering the decommissioning of pipelines on the UKCS:

**Removal:** Small diameter pipelines, including flexible flowlines and umbilicals which are neither trenched nor buried should normally be entirely removed.

**Monitoring:** Pipelines decommissioned in place will be subject to a suitable monitoring programme

agreed with BEIS in consultation with other government departments.

**Deferral:** In those cases where a pipeline reaches the end of its operational life before other facilities in the field, the Operator should notify BEIS's Offshore Decommissioning Unit that the pipeline is no longer in use.

The potential for reuse of the pipeline in connection with further hydrocarbon developments should be considered before decommissioning together with other existing projects (such as hydrocarbon storage and carbon capture and storage). If reuse is considered viable, suitable and sufficient maintenance of the pipeline must be detailed. All feasible decommissioning options should be considered and a comparative assessment made.

Sub-sea installations include drilling templates, production manifolds, well heads, protective structures, anchor blocks and anchor points, anchor chains, risers and riser bases. Such installations must be completely removed for re-use or recycling or final disposal on land. Any piles should be cut below natural seabed level at such a depth to ensure that any remains are unlikely to become uncovered. The depth will in the main depend upon the prevailing seabed conditions and currents. However, there is room to appeal to for exceptions to leave in place a sub-sea installation because of the difficulty of removing (Department for Business Energy and Industrial Strategy UK, 2011).

### *Structure and Facilities*

The structure and facilities refer to topsides, steel installations; gravity based concrete installations, hybrid installations and floating installations (Department for Business Energy and Industrial Strategy UK, 2011).

### **Topsides**

The topsides of all installations must be returned to shore for re-use or recycling or final disposal on land.

### **Steel installations**

Steel installations that weigh less than 10,000 tonnes must be completely removed for re-use or recycling or final disposal on land. Piles are required to be severed below the natural seabed at a depth to ensure that any remains are unlikely to become uncovered. The depth will depend upon the prevailing seabed conditions and currents.

There is a presumption that steel installations weighing more than 10,000 tonnes should be totally removed and this is the starting point for the consideration of any decommissioning proposals. However, it is possible to consider that the 'footings' or part of the 'footings' of the installation to be left in place. The upper section of the jacket above the 'footings' or any removed part of the 'footings' must either be reused, recycled or disposed of on land. Any removed parts may not be disposed of at sea.

There is room to appeal for derogation from the general rule of total removal, it will be necessary for the Operator of the installation to demonstrate that there are significant reasons why leaving the 'footings' or part of the 'footings' in place is preferable to returning them to shore for reuse or recycling or final disposal on land.

### **Gravity based concrete installations**

Similar to steel installations that weigh more than 10,000 tonnes, the assessment must show that there are significant reasons why sea disposal or leaving the installation in place is preferable to re-use or recycling or final disposal on land

### **Hybrid installations**

Since the introduction of Decision 98/3 a number of new development proposals have considered the use of hybrid installations, combining both concrete and steel in their construction. A typical hybrid installation may have a concrete gravity base storage tank with a fixed steel structure located above. Therefore, the respective parts will be considered as per concrete or steel installations.

## **Floating Installations**

At the end of field life floating installations will be floated off location and re-use elsewhere as a production or storage facility is likely to be a high priority. In those cases where re-use does not prove possible it will be necessary to return the facility to shore for storage or dismantling in line with the hierarchy of waste disposal options.

### **4.5.4. Decommissioning Execution - Reuse standards**

The UK government refers to the OSPAR Guidelines on Artificial Reefs in relation to Living Marine Resources of June 1999 for the placement of materials on the seabed for a purpose other than that for which it is originally intended for (Department for Business Energy and Industrial Strategy UK, 2011). In the UK, there has been 5 Reef-to-Rigs project with only 1 project at Whitsand Bay, Cornwall where the decommissioning frigate HMS Scylla was sunken. The other projects were made up gravel and sand, rock (OSPAR Commission, 2009).

The national laws applicable to Reef-to-Rigs projects are Food and Environment Protection Act, 1985 (as Amended); Coast Protection Act, 1949 (as Amended) and Marine Works Regulations 2007 (OSPAR Commission, 2009).

### **4.5.5. Decommissioning Execution - Waste Management**

The guiding regulations are The Offshore Chemical Regulations 2002 & OSPAR & MARPOL & Environmental Protection Act 1990 & The Merchant Shipping Regulations 2008 (Department for Business Energy and Industrial Strategy UK, 2011).

Chemicals used offshore must be notified through the Offshore Chemical Notification Scheme (OCNS) and chemicals are ranked by hazard quotient, using the Chemical Hazard Assessment and Risk

management (CHARM) model. Applications for permits are made via the submission of the relevant PET system permit application.

The use of Oil based drilling fluids (OBF) is still allowed provided total containment is operated. The use of diesel-oil-based drilling fluids is prohibited. The discharge of whole OBF to the sea is prohibited. The mixing of OBF with cuttings for the purpose of disposal is not acceptable. The discharge of cuttings contaminated with OBF (including SBF) greater than 1% by weight on dry cuttings is prohibited. The use of OPF in the upper part of the well is prohibited. Exemptions may be granted by the national competent authority for geological or safety reasons.

Waste producers are required to ensure that wastes are identified, described and labelled accurately, kept securely and safely during storage, transferred only to authorised persons and that records of transfers (waste transfer notes) are maintained for a minimum of two years.

Vessels including fixed or floating platforms which operate in the marine environment require sewage system surveys & certification and sewage systems with an exception for fixed installations at a distance of more than 12 nautical miles from the nearest land.

#### 4.5.6. Decommissioning Execution - Safety standards

A safety case is required under the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) which came into force on 19 July 2015. They apply to oil and gas operations in external waters (the UK's territorial sea or designated areas within the UKCS) which replaced the Offshore Installations (Safety Case) Regulations 2005 (Petroleum Safety Authority (Norway), 2015b).

A range of other statutory health and safety provisions will apply during decommissioning, including regulation 10 of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996

which requires the decommissioning and dismantlement of an installation to be done safely so as to maintain its integrity during work activities.

The Pipelines Safety Regulations 1996 contain requirements that pipelines are decommissioned safely either by dismantlement and removal or by being left in a safe condition, and for notification of decommissioning works at least 3 months prior to commencement.

#### 4.5.7. Decommissioning Execution - Debris Survey and Clearance

Upon completion of each decommissioning operation, appropriate surveys should be undertaken to identify and recover any debris located on the seabed which has arisen from the decommissioning operation or from past development and production activity. The area to be covered will depend on the circumstances of each case. However, the minimum required will be a radius of 500 metres from the location of an installation.

Following the removal of any debris, independent verification of seabed clearance will be required. The advisability of post decommissioning over trawling to confirm that the area is clear of debris will be considered on a case by case basis and will be dependent upon the extent of any cuttings piles and any other relevant circumstances (Department for Business Energy and Industrial Strategy UK, 2011).

#### 4.5.8. Post- Decommissioning

In addition to debris surveys, a post decommissioning environmental seabed sampling survey should be undertaken, in particular to monitor levels of hydrocarbons, heavy metals and other contaminants in sediment and biota.

This will involve the submission of a Close-out Report within four months of the completion of offshore work, including debris clearance and post decommissioning surveys (Department for Business Energy and Industrial Strategy UK, 2011). The report should explain major variations from the decommissioning

programme and should summarise the decommissioning programme as a whole based on milestones, major variances from the programme such as sludge amounts, and costs, any independent verification reports and future schedule for monitoring.

#### 4.5.9. Third-Party Validation

3rd party validation is required for the estimation of decommissioning costs. Estimates of decommissioning costs and of the net value of remaining recoverable reserves used to calculate the required levels of security must be carried out at least every 3 years and may be required annually depending on the project timescales. An independent third party expert approved by BEIS must verify this audit process (Department for Business Energy and Industrial Strategy UK, 2011).

#### 4.5.10. Release of Liability

The persons who own an installation or pipeline at the time of its decommissioning will remain the owners of any residues. Any residual liability remains with the owners in perpetuity (Department for Business Energy and Industrial Strategy UK, 2011).

Any remains of installations or pipelines will be subject to monitoring at suitable intervals as specified in each decommissioning programme and may require maintenance or remedial action in the longer term.

## 5. Norway

### 5.1. *An overview of the Norwegian Upstream Oil and Gas Industry*

In Norway, the dismantling of offshore installations is considered as part of petroleum production related activities, and hence is regulated by the Ministry of Petroleum and Energy. Demolition, recycling, and transporting of the components are regulated by other Ministries. In 2011, the Climate and Pollution Agency, with input from Norwegian Petroleum Directorate, the Directorate of Health, the Directorate of Fisheries and the Norwegian Radiation Protection Authority developed a report on the Decommissioning of Offshore Installations (Norwegian Climate and Pollution Agency, 2011). At present, the Norwegian state covers about 80% of the costs through tax deduction arrangements and its ownership interests in oil and gas fields.

The decommissioning process of the North Sea oil and gas installations in Norway is broadly similar to that in operation within UK territorial waters. Like the UK, Norway is a contracting party to the OSPAR Convention and, thus, subject to the constraints imposed by OSPAR Decision 98/3 (Norwegian Climate and Pollution Agency, 2011). However, as Norway has a wide range of fields that differs significantly in terms of water depths and types of resource extraction facility (concrete gravity based structures to jacket structures), a number of large installations greater than 10,000 tonnes on the Norwegian Continent Shelf (NCS) is not directly regulated by the convention. In Norway, it is not considered a good option by the Norwegian government to leave steel installations with the topside intact or to topple it on site (Osmudsen and Tveteras, 2003). The experience from decommissioning of the Odin field in the NCS is that it was cheaper to take the topside on shore than to dump it on site, as in deep-water scenarios, the transportation costs of taking an installation on shore is similar to deep-water disposal, and that deep-water disposal is much more costly at sea (Osmudsen and Tveteras, 2003). This measure also removes future liability to the Norwegian government for dumped installations.

Norway is prepared for decommissioning activities in the near future, and already has four decommissioning yards ready for when the installations are retired. The decommissioning yards are also prepared for the North Sea decommissioning “boom” from the UK (Norwegian Climate and Pollution Agency, 2011). There are four decommissioning facilities in Norway (AF Miljøbase Vats, Aker Stord, Scanmet AS, Lyngdal Recycling). One of the decommissioning facilities is also capable of handling and storing radioactive waste from decommissioned offshore platforms. The Norwegian facilities have the

advantage of deep fjords and deep-water quays, and can therefore be used by deep-draught installations (Norwegian Climate and Pollution Agency, 2011).

There are a total of 12 concrete installations, 88 fixed steel installations, 19 non-concrete floating installations and 348 subsea systems (Norwegian Climate and Pollution Agency, 2011). It has been estimated that 18 installations (with 12 steel jacket platforms and 4 concrete gravity based platforms forming the majority) will be closed down from the year 2015 – 2020 (Norwegian Climate and Pollution Agency, 2011).

## 5.2. *The legal framework*

There are several acts and regulations that apply to decommissioning of offshore installations, with the main one as the Petroleum Activities Act, where the Ministry of Petroleum and Energy is the regulatory body, and through which the Norwegian Petroleum Directorate acts as a specialist directorate and administrative body. There is also the Petroleum Safety Authority of Norway that is acting as the independent government regulator pertaining to safety, emergency preparedness and the working environment in the Norwegian oil and gas industry (Petroleum Safety Authority (Norway), 2016a). The regulations support an mutually trusting environment in which the Ministry of Labour and Social Affairs provides guidance, but the companies bear responsibility for operating acceptably through a risk-based system of audits and verification (Petroleum Safety Authority (Norway), 2016b).

The international regimes that Norway is obligated to follow are the OSPAR convention, IMO International Convention for the Safe and Environmentally Sound Recycling of Ships, and the EU Marine Strategy Directive (Norwegian Climate and Pollution Agency, 2011).

The other national legislation referred to are:

- Pollution Control Act and Radiation Protection Act for demolition and recycling, import and export of waste, and radioactive waste

- Municipal Health Services Act, the Planning and Building Act for the siting of offshore materials processing.

### 5.3. *The environmental framework*

The environmental framework is designed to deal with environmental pollution (mercury, asbestos, marine growth, and low specific activity), as well as public health issues, fisheries and aquaculture.

The legal basis for environmental health protection measures is provided by the Municipal Health Services Act. The municipal authorities may require a health impact assessment, that the party responsible to provide information remedy the situation or suspend activities, or decide to carry out investigations. The Municipal Health Services Act and regulations under the Act also describe how the environmental health authorities are expected to collaborate with the competent authorities in other sectors.

Legal instruments (such as permits being issued) are also in place to protect the fisheries, any problems are largely related to the offshore phase of decommissioning, and include restrictions on access to areas, the impacts of pollution (including noise) (Norwegian Climate and Pollution Agency, 2011).

### 5.4. *The financial framework*

Through Statoil (50% State owned) the Norwegian government has an active role in the ownership of oil installations and, thus, bears some liability regardless of any transfers. The costs of decommissioning the roughly 500 installations on the Norwegian continental shelf are uncertain, but a preliminary estimate suggests that the overall cost will be about NOK 160 billion.

The state will cover about 80% of the costs through tax deduction arrangements and its ownership interests in oil and gas fields. The state's share of the decommissioning costs is paid directly to the oil companies at the time of removal, and the main rule for the state's share of the decommissioning costs is the average effective corporate income tax rate the company has faced on the net incomes from the field (which is approximately 80%) (Osmudsen and Tveteras, 2003). This system for tax treatment, which represents an equal tax treatment approach of all fields, is thus a cost-sharing rule (Osmudsen and Tveteras, 2003).

The rationale for why decommissioning costs are given special tax treatment is to avoid discrimination, in the case that at the time of decommission, the oil and gas company may not have had sufficient income generated in Norway to cover the costs, and that the tax provisions are not to reduce the Norwegian government's exposure to decommissioning costs (Osmudsen and Tveteras, 2003). Also, such a tax treatment could avoid skewed decisions by the companies to close down production early while they have sufficient revenue, and refrain from building out in to the adjacent reservoir (Osmudsen and Tveteras, 2003), i.e. preventing the maximisation of economic recovery of an oil field (which is what the UK MER strategy is trying to prevent).

If an abandonment decision is made, the Norwegian Government may make an agreement with licensees and owners for the State to take over ownership of redundant installations, provided an agreed decommissioning plan has been properly executed, in return for a contractually agreed financial consideration from the operator(s) to cover the anticipated future liabilities (Norwegian Petroleum Directorate, 1996). For the decommissioning of the substructure in the Odin field, the operator provided three options in which place the substructure on the seabed as artificial reef is the lowest costs at USD 8.4 million, with the removal and taking ashore for recycling costing USD 12.9 million. The operator would only undertake option c if the ownership and liability of the remaining installation were transferred to the Norwegian government, without any compensation to the Norwegian state. Ultimately the Ministry of Petroleum and Energy chose the option of recycling on shore as the savings of USD 4.5 million was not thought to be enough compensation for the environmental effects and transfer of liability. The ministry did not rule out that the sea reef alternative could be relevant for other fields (Osmudsen and Tveteras, 2003).

Under section 10-14 of the Petroleum Activities Act (Consequences of revocation, surrender of rights or lapse for other reasons), the original licensees have certain financial obligations that still apply on fields that they are no longer operating (Norwegian Climate and Pollution Agency, 2011).

## 5.5. *The technical framework*

### 5.5.1. Submission timeline

Under the Norwegian Petroleum Act, a decommissioning plan, including an impact assessment and plans for public consultation, must be submitted between two and five years before an installation is finally taken out of use. The Ministry of Petroleum and Energy makes final decisions on disposal (Norwegian Climate and Pollution Agency, 2011).

### 5.5.2. Pre-Decommissioning

The main guideline for reference is the OSPAR 1998 Decision. Proposals may include continued use in the petroleum industry, other uses, complete or partial removal or abandonment in situ. Any exceptions from removal of the facility must be assessed and grounds given for this option: these cases must also be presented to OSPAR before the Storting (Norwegian government) makes a decision. Decommissioning plans must consist of two parts, a disposal section and an impact assessment (Norwegian Climate and Pollution Agency, 2011). The disposal section consists of sections such as the field history, disposal alternatives, and the recommended disposal solution, a schedule of time against the tasks etc. The impact assessment should consist of the effect of the disposal alternatives, commercially and environmentally, as well as the mitigation measures employed to remedy any discharges or inconvenience (Norwegian Climate and Pollution Agency, 2011).

### 5.5.3. Decommissioning Execution – offshore infrastructure

The decommissioning execution is a broad section covering five areas: offshore infrastructure, reuse standards, waste management, safety standards and debris survey and clearance. Each topic within the decommissioning execution section will be discussed as a sub-section of its own (such as Section 5.5.3 Decommissioning execution – offshore infrastructure, Section 5.5.54 Decommissioning execution – reuse standards, etc)

Offshore infrastructure consists of the following four areas: (i) well plugging and abandonment, (ii) seabed deposits management, (iii) pipelines and associated structures and (iv) structures and facilities.

### *Well Plugging & Abandonment*

Reference is made to the Standards Norway (NORSOK) Guidelines D-10 on Well Integrity in drilling and well operations, Chapter 9 (Sidetracks, suspension and abandonment) (Standards Norway (NORSOK), 2013).

The NORSOK guidelines (Standards Norway (NORSOK), 2013) spell out issues such as load cases, such as the minimum depth or primary and secondary well barriers for each reservoir/ potential source of inflow while taking into consideration of the worst anticipated reservoir pressure for the abandonment period into account; burst limitations on casing string at the depths where abandonment plugs are installed; and collapse loads from seabed subsidence or reservoir compaction. There are four isolation areas, called the (i) primary well barrier (ii) secondary well barrier (iii) crossflow well barrier and (iv) open hole to surface well barrier. In the first three types of well barriers, the base of the well barriers should be positioned at a depth where formation integrity is higher than the potential pressure below. There is no depth requirement with respect to formation integrity for the open hole to surface well barrier. The guideline highlighted five types of permanent well abandonment with respect to the position of the primary and secondary plugs (back-to-back or separated), and also considers if casing cement is present in the annulus. In general the primary plug is about 100m long in the tubing and a minimum of 50 m in the tubing annulus. While the secondary plug ranges from 50 m to 100 m in the tubing and a minimum of 50 m in the tubing annulus. In some cases, such as back-to-back primary and secondary plugs, the

cement in the primary and secondary tubing annulus can be reduced to 30 m each if verified via logging that the casing cement still exists. While mechanical or abrasive cutting is the preferred method for removal of the casing/conductor at seabed, the use of explosives (for example, shaped charges that provide upward and downward protection) to cut casing/conductor is acceptable if the risk to the environment is at the same level as other means of cutting.

With respect to removing equipment above seabed, required cutting depth below seabed should be considered in each case, and be based on prevailing local conditions such as soil, sea bed scouring, sea current erosion, etc. In 2004, the guidelines mentioned that the cutting depth should be 5 m below seabed (Standards Norway (NORSOK), 2004). No other obstructions related to the drilling and well activities shall be left behind on the sea floor. In 2013 the guidelines under Section 9.6.4 (Removing equipment above seabed) removes the 5 m depth requirement, with a requirement that the wellhead and casings should be removed below the seabed at a depth which ensures no stick up in the future, and that required cutting depth should be sufficient to prevent conflict with other marine activities. Also, local conditions of soil and seabed scouring due to sea current should be considered.

The operator is responsible for the abandoned well even after it is plugged and wellhead removed, and liable for any future problems related to the well (Standards Norway (NORSOK), 2013).

### *Seabed Deposits Management*

The Norwegian authorities, like the UK authorities refer to the OSPAR Recommendation for Offshore Cuttings Piles (See 4.5.3 under the United Kingdom) (Norwegian Climate and Pollution Agency, 2011).

### *Pipelines and Associated Structures*

The OSPAR convention does not cover pipelines. Guidelines for managing these offshore structures were set out in a white paper on the disposal of 8 disused pipelines and cables on the Norwegian

continental shelf (Report to the Storting No.47 (1999–2000)) (Ministry of Petroleum and Energy (Norway), 2010).

The guidelines recommended the removal of pipelines and cable, but may be left in place provided that they do not constitute a nuisance or risk for bottom fisheries (Ministry of Petroleum and Energy (Norway), 2010). In the same report to the Storting No. 47 (1999 – 2000) with respect to the disused pipelines in the Ekofisk area in the North Sea, it was reported that after an overall assessment of the potential for future fishing activities and the cost of various disposal solutions, the Odin field pipeline and half of another pipeline to the Frey field should be buried in the seabed, and where one free span Valhall pipeline might post as entanglement risk, the exposed section should be removed. There is also a mechanism called the Removal Grants Act called the “fjerningstilskuddsloven” that provide direct grants to cover a portion of the State’s share of disposal costs (Stortinget (Norwegian Government), 2000). This decision will perhaps influence other decommissioning plans as well for a risk-based analysis of which sections of pipes to remove or to leave behind.

#### *Structure and Facilities*

The Norwegian authorities, like the UK authorities refer to the OSPAR Recommendation for Offshore Structures (See 3.1.5.3.1.4 under the United Kingdom) (Norwegian Climate and Pollution Agency, 2011). However, derogation from the OSPAR convention may be granted for individual installations or parts of installations if an overall assessment of the case in question shows that there are weighty reasons for disposal at sea. Norway has granted two exemptions to leave in place the concrete substructure of the Ekofisk Tank and its protective wall, as well as the concrete substructure TCP2 at the Frigg field (Ministry of Petroleum and Energy (Norway), 2010).

#### 5.5.4. Decommissioning Execution - Reuse standards

The reuse standards would refer to the OSPAR Guidelines on Artificial Reefs in relation to Living Marine Resource (June 1999), if there is a scenario that warrants the use of decommissioned materials

for artificial reefs. So far, all the offshore structure that has been segmentally removed was brought on-shore for recycling or disposal, with the exception of structures that have been allowed to be left behind.

#### 5.5.5. Decommissioning Execution - Waste Management

The decommissioning process is multi-faceted, the dismantling of installations offshore is considered to be part of petroleum activities. Once modules have been loaded on to a barge, they come under the rules for maritime transport. Demolition and recycling are regulated by other legislation (Norwegian Climate and Pollution Agency, 2011)

##### *Demolition and Recycling*

Onshore decommissioning is an important area of consideration as offshore installations would be brought on shore for further action. An onshore decommissioning yard for offshore installations is classed as a waste treatment plant, and requires a permit under Section 11 and 16 of the Pollution Control Act. The authority to issue permits to waste treatment plants, including decommissioning facilities, was delegated from the Climate and Pollution Agency to the County Governors in 2004 (Norwegian Climate and Pollution Agency, 2011).

Important elements that should be considered in the regulation of decommissioning facilities for offshore installations include the suitability of the site based on deep-water presence or distance from neighbours etc, the impermeability of the surface, the emergency response systems, and releases to the environment and mitigation measures.

##### *Import and Export Waste*

The four decommissioning yards in Norway is prepared to accept decommissioning waste from the UK. The movement of a disused or part of installation between the UK and Norway is governed by EU regulation No. 1013/2006 on waste shipments, and is also incorporated into Chapter 13 of the Waste Regulations of Norway. The EU regulation requires a financial guarantee to cover that costs of the

operation cannot be completed as intended. Also, it is required that the waste is sent to a facility that has the necessary permits to handle the waste.

#### *Radioactive Waste*

The Pollution Control Act also includes radioactive waste since 1 Jan 2011. The new regulations on the applicability of the Pollution Control Act to radioactive substances include a provision requiring all waste from the oil and gas industry in which the activity concentration is 10 Bq/g or more to be disposed of in special repositories.

#### *Environmental Impact Assessment*

The offshore environmental impact assessment will be submitted to the Ministry of Petroleum and Energy as part of the pre-decommissioning process with a stakeholder consultation period of about 12 weeks before the impact assessment programme is approved (Statoil, 2011). After approval, the impact assessment is executed and an impact assessment report is issued for a similar stakeholder consultation again, before the decommissioning plan is forwarded to the government for a decision (Statoil, 2011).

#### 5.5.6. Decommissioning Execution - Safety standards

There is a requirement to obtain an Acknowledgement of Compliance (AoC), a declaration from the Petroleum Safety Authority of Norway (PSA), which expresses the regulator's confidence that a specific offshore unit can fulfil the requirements for petroleum operations on the Norwegian Continental Shelf (Petroleum Safety Authority (Norway), 2015b). This safety system is similar to that of the safety case regime of the UK. The AoC regulatory framework includes legally-binding acts and regulations, such as the Petroleum Activities Act, Working Environment Act, the Framework Regulations, and the 'softer' legal requirements such as PSA Guidelines, and the Norms and Standards, for example, NORSOK or ISO Guidelines. Some examples are (Petroleum Safety Authority (Norway), 2015a):

- Section 89 Remote Operation of pipes and work strings
- Chapter XVI Maritime Operations

- Chapter XVIII Lifting Operations
- Chapter XVII Electrical Installations

The AoC is a live system that documents the operator's management system, its technical operational description, issues and limitations. A gap analysis is required over general and management system requirements, and over technical requirements (typically specified by PSA regulations) (Petroleum Safety Authority (Norway), 2015b). The gap analysis should list the relevant requirements in the acts and regulations and, alongside each requirement, list the applicant's governing documents which describe how the requirement is met. The compliance status of each requirement should also be specified and if not compliant, a note on how compliance shall be achieved should be included (Petroleum Safety Authority (Norway), 2015b). If nonconformities are identified during the gap analysis, the AOC system allows that the nonconformities be corrected, their causes clarified and measures implemented to prevent recurrence (Petroleum Safety Authority (Norway), 2015b). For nonconformities that entail disproportionately high costs to deal with, the AoC system allows for exemption, such as in using another, documentable equivalent solution than that in a detailed requirement, or a solution that yields a lower level of HSE than ensured from the applicable regulatory requirement (Petroleum Safety Authority (Norway), 2015b). In the final stages of the AoC documentation, the operator selects the types of verification methods (such as certification, audits etc) and then carries out the verification (such as from classification societies) (Petroleum Safety Authority (Norway), 2015b). As the operations transition from petroleum production to decommissioning, the AoC is updated as well.

#### 5.5.7. Decommissioning Execution - Debris Survey and Clearance

There is no specific mention of the drill cuttings handling in the guidelines, but in Section 68 of Petroleum Activities Regulation (Discharge of cuttings, sand and solid particles), the cuttings from drilling and well activities, sand and other solid particles shall not be discharged to sea if the content of formation oil, other oil or base fluid in organic drilling fluid exceeds ten grams per kilo of dry mass.

The operator shall obtain a permit pursuant to Chapter 3 of the Pollution Control Act to inject materials such as cuttings, sand and solid particles (Petroleum Safety Authority (Norway), 2015a).

There is also the Norwegian Oil and Gas Guidelines for Characterisation of offshore drill cuttings piles, that discusses hydrocarbon leaching rate assessment and persistence of contaminants, which forms part of the Total Assessment EIA, where disposal options need to be discussed with the outcome of characterisation laboratory tests (The Norwegian Oil Industry Association, 2003).

#### 5.5.8. Post-Decommissioning

The post-decommissioning process is not specifically mentioned in the guidelines. However, there are numerous permits to close, and this will warrant a system of assessing post-decommissioning activities.

#### 5.5.9. Third-Party Validation

It is not specifically mentioned on the requirements of a third-party validation on any segments of the decommissioning process.

#### 5.5.10. Release of Liability

According to Section 5-4 ('Liability') of the Petroleum Activities Act (1996), if the decision of the fate of an offshore facility is abandonment, the licensee or owner shall be liable for damage or inconvenience caused wilfully or inadvertently in connection with the abandoned facility, unless otherwise decided by the Ministry. If there are more than one party liable, they shall be jointly and severally liable for financial obligations, unless otherwise decided by the Ministry (Norwegian Petroleum Directorate, 1996).

However, if an abandonment decision is made, the Norwegian Government may make an agreement with licensees and owners for the State to take over ownership of redundant installations, provided an agreed decommissioning plan has been properly executed, in return for a contractually agreed financial consideration from the operator(s) to cover the anticipated future liabilities (Norwegian Climate and Pollution Agency, 2011).

Through Statoil being 50% State owned, the Norwegian government has an active role in the ownership of oil installations and, thus, bears some liability regardless of any transfers (Norwegian Climate and Pollution Agency, 2011).

## 6. USA

### 6.1. *An overview of the USA upstream oil and gas industry*

In the USA, the U.S. Department of the Interior (DOI) has the broad authority under the Outer Continental Lands Act to protect natural resources of the OCS. Within the DOI, the Bureau of Safety and Environmental Enforcement (BSEE) is the decommissioning regulation authority. The Bureau of Ocean Energy Management (BOEM) also manages Rigs-to-Reef permits (Bureau of Safety and Environmental Enforcement (USA), 2016a).

The offshore USA upstream Oil and gas industry operates in three areas – the Pacific Outer Continental Shelf Region, the Alaska OCS, and the Gulf of Mexico OCS. The majority of the offshore platforms are located in the Gulf of Mexico. As of September 2012, there are about 2996 platforms in the Gulf of Mexico (Bureau of Safety and Environmental Enforcement (USA), 2016a). There are approximately 23 platforms in the Pacific OCS region as of 2010 (Proserv Offshore, 2010) and 21 platforms in the Alaska OCS as of 2013 (Alaska Oil and Gas Conservation Commission, 2013).

There are two scrap yards in Long Beach and Los Angeles along the Western US Coast, which contain sufficient land and equipment for disposal for the Pacific Ocean continental shelf platforms. For the decommissioned platforms in the Gulf of Mexico, there are several reef-to-rigs sites. As of September 2012, approximately 420 platforms (about 10% of all platforms removed in the Gulf of Mexico) have been converted into artificial reefs (Bureau of Safety and Environmental Enforcement (USA), 2016a). There are also waterfront decommissioning yards in the states of Louisiana and Texas (EMR Group, 2016).

## 6.2. *The legal framework*

The Outer Continental Shelf Lands Act (OCSLA) establish decommissioning obligations to which an operator must commit when they sign an offshore lease under the OCSLA, including the requirement to apply for and obtain a permit for subsequent removal of platforms. Outer Continental Shelf (OCS) leases typically require the operator to remove seafloor obstructions, such as offshore platforms, within one year of lease termination, or prior to termination of the lease if either the operator or the Department of the Interior deems the structure unsafe, obsolete, or no longer useful for operations (Bureau of Safety and Environmental Enforcement (USA), 2016a).

The DOI is the authority on the OCSLA. Within the DOI, the two relevant departments are the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM). However, there are several agencies that are involved during decommissioning as well (discussed below): the U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, U.S. Environmental Protection Agency, U.S. Department of Commerce's National Oceanic and Atmospheric Administration, U.S. Coast Guards, U.S. Department of Transportation and the Office of Pipeline Safety (Bureau of Safety and Environmental Enforcement (USA), 2016a). Some of the agencies will be discussed under the environmental framework.

The state and local agencies also have regulatory jurisdiction over decommissioning operations. One example is in California, whereby such agencies include the California Coastal Commission, California State Lands Commission, California Department of Fish and Game, California Division of Oil, Gas and Geothermal Resources, California State Fire Marshal, County Planning and Resource Management Departments, and local Air Pollution Control Districts (Proserv Offshore, 2010).

### **Bureau of Safety and Environmental (BSEE)**

The Bureau of Safety and Environmental Enforcement (BSEE) is responsible for regulatory, safety, environmental and conservation compliance for the development of the nation's offshore oil and gas and

renewable energy resources. BSEE ensures the regulatory requirements for decommissioning of oil and gas platforms are met. These regulations allow the appropriate conversion of decommissioned platforms to artificial reefs when such platforms are permitted for that purpose by the U.S. Army Corps of Engineers.

The Iron Idle Policy (under the BSEE and formally known as the Notice to Lessee 2010-G05 “Decommissioning Guidance for Wells and platforms”) states that any platform that became “idle” or not useful for lease operations is expected to be decommissioned no later than 5 years after the platform became “idle”, due to the wake of several destructive hurricanes between 2004 and 2008 in the Gulf of Mexico.

#### **Bureau of Ocean Energy Management (BOEM)**

The BOEM, also within DOI manages the exploration and development of the nation's offshore resources. BOEM has a role in Rigs-to-Reefs to conduct the environmental review required under the National Environmental Policy Act and the National Historic Preservation Act for the removal of obsolete structures in support of the removal permit issued by BSEE. BOEM analyzes the environmental and cultural effects of BSEE’s action in issuing the permit through the mechanism of a Site-Specific Environmental Assessment and may impose actions to mitigate those effects, both at the removal site and the reefing location if that is proposed outside the approved reefing areas.

#### **U.S. Army Corps of Engineers (USACE)**

The USACE permits certain structures or work in or affecting navigable waters of the United States pursuant to section 10 of the Rivers and Harbors Act of 1899 to prevent obstruction to navigation by artificial islands, installations, and other devices. Also under section 404 of the Clean Water Act, USACE regulates certain activities, such as the placement of dredged or fill material (which includes the placement of an artificial reef), in the waters of the United States. USACE permitting applies to placement of decommissioned platforms under State Rigs-to-Reefs programs on the OCS

#### **U.S. Coast Guards**

The U.S. Coast Guard's responsibility in the proper removal of decommissioned platforms addresses the safety, security, and efficiency of marine navigation. Coast Guard regulations provide that any solid structure must have a minimum clearance of 85 feet and be marked with navigational buoys.

### *6.3. The environmental framework*

As continued from the legal framework, some of the following organisations forms part of the environmental framework of the decommissioning programme (Bureau of Safety and Environmental Enforcement (USA), 2016a):

#### **U.S. Fish and Wildlife Service**

The U.S. Fish and Wildlife Service administers the Federal Aid in Sport Fish Restoration Program, which provides funding to the States to undertake sport fish restoration and boating access projects. Money for this program is collected from excise taxes on fishing tackle and motorboat fuels. The program provides reimbursement to State fish and wildlife agencies for 75% of the cost of eligible projects, subject to the overall annual funding apportionment to each state, which is determined by a formula in the Act. Costs to State fish and wildlife agencies for artificial reef projects designed to provide or improve recreational fish habitat are eligible for reimbursement under the program.

#### **U.S. Environmental Protection Agency (EPA)**

The U.S. Environmental Protection Agency (EPA) reviews proposed reefing projects to ensure that only acceptable material is used as artificial reef material and that the placement of these materials on the ocean floor will not violate Federal laws or regulations that protect the marine environment. EPA is consulted for applications for USACE permits for placement of artificial reefs, and confirms authorization of sites to receive certain materials for the purpose of enhancing the aquatic environment.

#### **National Oceanic and Atmospheric Administration (NOAA)**

The U.S. Department of Commerce's National Oceanic and Atmospheric Administration (NOAA) implements the National Artificial Reef Plan, working with State and Federal agencies to promote

responsible and effective artificial reef use based on the best scientific information available. NOAA serves in a consultative role for activities such as providing comments on the creation, siting, and permitting of artificial reefs as well as standards for the transfer, cleaning, and preparation of certain reef materials.

Under the Magnuson-Stevens Fishery Conservation and Management Act, NOAA approval of the Regional Fishery Management Council essential fish habitat designation is required, and NOAA provides advisory conservation recommendations to federal agencies on actions that may adversely affect essential fish habitat, including individual lease sales, the removal of oil and gas platforms, and the creation of artificial reefs. Under the Endangered Species Act, NOAA consults under section 7 on Federal actions that may affect listed species. A programmatic consultation for Outer Continental Shelf Federal waters was completed in August 2006.

#### *6.4. The financial framework*

There is a very structured financial assurance programme in which the BOEM is the regulatory authority. The main legislation, the Outer Continental Shelf Lands Act and the 30 CFR § 556 provides the BOEM with the authority to require bonds or other forms of financial assurance on the OCS (Celata, 2016). There are 2 stages of bond required – the first stage is the General Lease Surety bond, which covers exploration plans, development production plans or pipelines. The second stage is the supplemental bond, which provides additional coverage for all types of lease obligations.

The regional directors currently set the supplemental bond amount at BSEE-determined decommissioning liability. In the legislation 30 CFR § 556, the guidelines look into areas such as the financial capacity of a company in view of existing and other obligations, the estimated value of existing lease production and proven reserves of future production, the company's reliability based on its business for the past 5 years, credit ratings or trade references (Celata, 2016).

A 2010 study by Proserv Offshore, commissioned by the predecessor of the BSEE, estimated decommissioning costs for the POCSR, with a breakdown of each of the platform, and the depth and structural type. The corresponding estimates, ranged from USD 12 million for the Gina platform at 95 feet depth to USD 155 million for the Harmony platform at 1,198 feet in depth (Proserv Offshore, 2010).

The supplemental bond is cancelled after decommissioning completion is certified by BSEE clearance for outstanding payments (Celata, 2016).

## *6.5. The technical framework*

### 6.5.1. Submission timeline

In the regulations, 30 CFR §250 on Decommissioning Activities, in the Pacific Outer Continental Shelf (OCS) Region/ Alaska OCS Region, the operators must submit the application to the Regional Supervisor at least 2 years before production is projected to cease.

In the Gulf of Mexico OCS Region, initial platform removal application is not required, but before removing a platform or other facilities, a final removal application is required (Government of USA, 2014b).

### 6.5.2. Pre-Decommissioning

The first step in the process involves preparing an Execution Plan that provides a detailed description of proposed project activities, the associated equipment and personnel requirements, and the schedule for completing the activities (Bureau of Safety and Environmental Enforcement (USA), 2016a). The Execution Plan is prepared to support the application process needed to secure permits from Federal, State and local regulatory agencies. During this phase of the process, environmental baseline information is collected and field surveys are conducted to evaluate the project site.

Once the Execution Plan and project application packages are deemed complete by the Bureau of Safety and Environmental Enforcement (BSEE) and the lead State and/or local agency (CSLC and/or a County

Planning and Development Department), the agencies will conduct a joint environmental review of the project pursuant to the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA) (Bureau of Safety and Environmental Enforcement (USA), 2016a).

To coordinate the process and minimize duplication of effort, the BSEE and the lead CEQA agency generally prepare a joint Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the project. The EIS/EIR analyses the environmental impacts of the project and describes mitigation measures proposed by the project applicant or recommended by agencies to eliminate or minimize those impacts. Upon completion, the draft EIS/EIR is circulated for public and agency review, including review by the California Coastal Commission (CCC) which must issue a Coastal Development Permit (CDP) for any activities that could impact the coastal zone. Following action by the CCC, the BSEE and the lead CEQA agency then proceed with approving the project by respectively issuing a Record of Decision (ROD) and Notice of Determination (NOD) for the project.

A pre-decommissioning survey is also required.

### 6.5.3. Decommissioning Execution – offshore infrastructure

The decommissioning execution is a broad section covering five areas: offshore infrastructure, reuse standards, waste management, safety standards and debris survey and clearance. Each topic within the decommissioning execution section will be discussed as a sub-section of its own (such as Section 6.5.3 Decommissioning execution – offshore infrastructure, Section 6.5.4 decommissioning execution – reuse standards, etc)

Offshore infrastructure consists of the following four areas: (i) well plugging and abandonment, (ii) seabed deposits management, (iii) pipelines and associated structures and (iv) structures and facilities.

#### *Well Plugging & Abandonment*

Requirements of the 30 CFR 250.1715 specifies the technical details such as (Government of USA, 2014b) the depth below the bottom or above the top of the oil, gas and fresh-water zones for fluids isolation. One example specification is that cement plug(s) should be set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata. In the annular space, a cement plug that is at least 200 feet long must also be set. For a well completed above the ocean surface, each casing annulus must be pressure tested to verify isolation. There are also specifications of the types of cement plugs (non-exhaustive), such as cement retainer, bridge plug, tubing plug etc. The depth of removal of wellheads and casings are identified as 15 feet below the mudline, unless the District Manager approves an alternate depth.

The District Manager may approve an alternate removal depth for special circumstances. One example is that the wellhead or casing does not become an obstruction to other users of the seafloor or area, and geotechnical and other information demonstrate that erosional processes capable of exposing the obstructions are not expected. Alternative removal depth may also be approved if the removal at 15 feet below the mudline requires divers (and that this requirement is also concurred by the BSEE), and that the seafloor sediment stability poses safety concerns. Third, if the water depth is greater than 2, 624 feet (800 meters).

### *Seabed Deposits Management*

Drill cuttings are managed under the USEPA promulgated oil and gas Extraction Effluent Guidelines and Standards 40 CFR Part 435 (Government of USA, 2014a). The regulation covers produced water, produced sand, drilling fluids, drill cuttings, well treatment, work-over and completion fluids.

Drill cuttings may be left in place if they meet acute toxicity tests such as no discharge of free-oil or diesel oil, specific metal concentrations, and passing the USEPA mysid shrimp toxicity test, among other tests (Government of USA, 2014a).

Shell mounds may be left in place, depending on the negotiation with authorities, if they fulfil the following – that the shell mounds do not interfere with other uses, they pose no substantial risk, they provide useful habitat for some species (when platform structures are left in place as an artificial reef), or removing them may cause more bottom impacts and/or contamination than leaving them in place (because removal would necessitate dredging, which would disturb the bottom and re-suspend in-place materials) (Government of USA, 2014a).

### *Pipelines and Associated Structures*

Under the 30 CFR §250 on Decommissioning Activities, specifically 30 CFR 250. 1762 (Government of USA, 2014b) The regulations allow an operator to decommission a pipeline or power cable in place if the BSEE determines that the pipeline or power cable “does not constitute a hazard (obstruction) to navigation and commercial fishing operations, unduly interfere with other uses of the OCS, or have adverse environmental effects. For in-situ abandonment, the pipeline must be pigged, flushed, filled with seawater. Following that there will be the cutting and plugging of each end of the pipeline. The pipeline should then be buried at least 3 feet below the seafloor or covering each end with protective concrete mats. All pipeline valves and other fittings that could unduly interfere with other uses of the OCS must be removed.

In the Pacific OCS Region, since 1990, there is also the requirement of pipeline operators to conduct biennial ROV pipelines to assess a pipeline's external integrity and to monitor 3rd party impacts. The outcome of these surveys showed that the majority of pipelines historically have not been obstructions and could therefore be decommissioned in place (Proserv Offshore, 2010). In general, a decision on the final disposition of a specific pipeline or power cable cannot be made until a thorough technical and environmental review is conducted during the decommissioning permitting process.

### *Structure and Facilities*

The structures referred to are the platform, deck and jacket. The following is required as per 30 CFR 250.1762 (Government of USA, 2014b) .

There is a requirement that the operator must remove all platforms and other facilities (including templates and pilings) to at least 15 feet below the mud line. Similar to the Wells Plugging and Abandonment, an alternate removal depth will be approved for the same criteria (demonstrating erosional processes of exposing obstructions are not expected, diving required, seafloor sediment stability poses safety concerns or a water depth greater than 2,624 feet/ 800 meters).

#### 6.5.4. Decommissioning execution - reuse standards

For the use of former structures as an artificial reef, the Regional Supervisor may grant a departure from the requirement to remove a structure by approving partial structure removal or toppling in place for conversion to an artificial reef if the operator meets the requirements of the National Artificial Reef Plan (Guidelines for siting, construction, development and assessment of artificial reefs) (National Oceanic and Atmospheric Administration (USA), 2007) as permitted by several U.S. Federal agencies. The guidelines provides details on materials criteria, biological consideration such as reef configuration, circulation patterns surrounding reef materials, to ensure that a rig is purposefully relocated.

A coastal state managing the proposed artificial reef also has to have an approved, state-specific artificial reef plan. All five Gulf of Mexico coastal states have approved artificial reef plans: Alabama, Florida, Louisiana, Mississippi, and Texas. The structure thus becomes part of a State reef program that complies with the National Artificial Reef Plan. The State agency then acquires a permit from the U.S. Army Corps of Engineers and accepts title and liability for the reefed structure once removal/reefing operations are concluded (Bureau of Safety and Environmental Enforcement (USA), 2016b).

When the proposed structure and reef site have been permitted, the state and operator negotiate the terms of an agreement for a donation from the operator to the state. In most cases, half of the cost benefits to the operator are donated to the state's artificial reef program. If decommissioning a structure costs

\$800,000 to remove, transport and scrap on shore, and reefing the structure will cut costs to \$400,000, the operator would donate \$200,000 to the state to assist with the management of their artificial reef program (Bureau of Safety and Environmental Enforcement (USA), 2016b).

#### 6.5.5. Decommissioning execution - waste management

Reference is made to the Federal agencies requirements, and state and local agencies that have regulatory jurisdiction over decommissioning operations (such as those in California). The waste refers to marine growth, cement, drilling muds and cuttings, and chemical wastes from the process modules on the platform (Proserv Offshore, 2010).

Some examples of the organisations are: Federal agencies that have regulatory authority over various aspects of decommissioning projects include the BSEE, National Marine Fisheries Service, U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency, U.S. Coast Guard, and the U.S. Department of Transportation, Office of Pipeline Safety.

State and local agencies having regulatory jurisdiction over decommissioning operations in California include the California Coastal Commission, California State Lands Commission, California Department of Fish and Game, California Division of Oil, Gas and Geothermal Resources, California State Fire Marshal, County Planning and Resource Management Departments, and local Air Pollution Control Districts.

#### 6.5.6. Decommissioning execution – safety standards

The regulations 30 CFR 250.1900 to 1933 (Government of USA, 2014b) states the requirement for the lessor/operator to develop, implement, and maintain a safety and environmental management system (SEMS) program, that address the elements described in §250.1902, American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75) (as incorporated by reference in §250.198), and other

requirements as identified in the above-mentioned subpart. This refers to a more prescriptive system for ensuring safety standards.

#### 6.5.7. Decommissioning execution - Debris Survey and Clearance

For verification on debris survey and clearance, 30 CFR 250.1743 (Government of USA, 2014b) requires documentation such as a letter signed by an authorized company official certifying that the platform or other facility site area is cleared of all obstructions and that a company representative witnessed the verification activities. Other crucial details of the documentation includes the date the verification work was performed and the vessel used, the extent of the area surveyed; the survey method, and the results of the survey including a list of debris removed or a statement stating no objects were recovered, as well as a post-trawling plot or map showing the trawled area.

#### 6.5.8. Post- Decommissioning

In the guideline, there is no specific mention of a post-decommissioning process. However, for each decommissioning event, such as well P&A, rigs-to-reef, there is an appropriate process of closure of the respective permits.

One example is that for Well P&A, where the permit must be closed within 30 days of permanent plugging, via the submission of BSEE-0124 Application for Permit to Modify to a District Manager. Report details must include (Government of USA, 2014b) information such as final well schematic, description of the plugging work, the nature and quantities of material used in the plugs and if the casing string has been pulled and cut, there should also be a description of the methods used (including information on explosives, if used), the size and amount of casing removed; and the casing removal depth.

Site clearance procedures for decommissioning a platform and associated pipelines and power cables in the POCSR will typically involve the following four step process: (1) pre-decommissioning survey, (2)

post decommissioning survey, (3) Remotely Operated Vehicle (ROV)/diver target identification and recovery, and (4) test trawling. A survey vessel equipped with high-resolution side-scan sonar is used to conduct the pre- and post- decommissioning surveys. The pre-decommissioning survey documents the location and quantity of suspected debris targets. The survey is also used to map the location of pipelines, power cables, and sensitive environmental habitats (hard bottom areas and kelp beds) to ensure that the deployment and retrieval of anchors is done in a safe and environmentally sound manner. The post-decommissioning survey identifies debris lost during the project and documents any impacts from the operations such as anchor scars. An ROV and divers are deployed to further identify and remove any debris that could interfere with other uses of the area. Test trawling is conducted to verify that the area is free of any potential obstructions (Government of USA, 2014b).

#### 6.5.9. Third-Party Validation

Third-party validation is required in certain sections of the decommissioning workflow. In terms of the site clearance stage (typically referred to the Section 4.5.7 Debris Survey and Clearance), the operator must submit the documentation by the certified surveyor within 30 days of completing site verification activities (Government of USA, 2014b). In other stages of decommissioning, third-party validation is only required as part of the procedure, such as waste management and testing of samples via a certified laboratory that can conduct sampling to USEPA standards. In terms of the BSEE assessing an operator or lessor's financial ability to carry out obligations, the financial reports of the facility owner or operator need to be independently audited (Celata, 2016).

#### 6.5.10. Release of Liability

Lessees and owners of operating rights are jointly and severally responsible for meeting decommissioning obligations for facilities on leases, including the obligations related to lease-term pipelines, as the obligations accrue and until each obligation is met. The operator is bound by a BOEM-specified surety instrument (supplemental bond) to indemnify the operator/lessor from loss or damage,

these bonds are cancelled after decommissioning is complete or certified by BSEE and Office of Natural Resources Revenue (ONRR) (Celata, 2016).

For partial removal options (reef to rigs), there is discussion that the lessors/ operators will continue to hold responsibility for the objects left behind or re-used as reef-to-rigs, however, this is not yet formalised. As of now, the state which accepts the Artificial Reef accepts title and liability for the reefed structure once removal/reefing operations are concluded (National Oceanic and Atmospheric Administration (USA), 2007).

## 7. The General Legal Framework in Asia Pacific

ASCOPE is the council on petroleum of countries belonging to ASEAN. ASEAN refers to the ten South East Asian countries listed in Table 2. The ASCOPE Decommissioning Guideline (ADG) outlines the options of flexibility that the ASCOPE Member Countries have within the existing legal framework, enabling each to achieve a defensible and balanced decommissioning solution for each decommissioning project. The options include categories of decommissioning and disposal, planning for decommissioning, impact assessment, environmental impact assessment, residual liability. Table 2 below shows the summary of ASCOPE member countries and their respective international obligations.

*Table 2 Summary of ASCOPE member countries and international obligations. Source: (ASEAN Council on Petroleum (ASCOPE), 2012).*

ASCOPE Member Country	Geneva Convention 1958	UNCLOS 1982	London Dumping Convention 1972	London Convention 1996 Protocol	Basel Convention 1992	COBSEA Regional Seas <sup>+</sup>
Brunei Darussalam		X			X	X
Cambodia	X				X	X
Indonesia		X			X	X
Laos		X			X	
Malaysia	X	X			X	X
Myanmar		X				
The Philippines		X	X		X	X
Singapore		X			X	X
Thailand	X	X			X	X
Vietnam		X			X	X

<sup>+</sup> COBSEA – *Coordinating Body on the Seas of East Asia, a UNEP Regional Seas Programme to oversee the implementation the ‘Action Plan for the Protection and Sustainable Development of the Marine and Coastal Areas of the East Asian Seas Region’*

Apart from international regulations, there exists other instruments which may affect Asia Pacific’s decommissioning activities, such as national laws, decommissioning clauses in production agreements and industrial or operator guidelines.

### 7.1. National laws and regulations applicable to Decommissioning

This will be elaborated in sections 8 and 9 that are describing the Thai and Malaysian national laws and regulations.

### 7.2. Decommissioning Clauses in Production Agreements

In a Production Agreement, the state, as the owner of mineral resources, engages an Independent Oil Company (IOC) as a contractor to provide technical and financial services for exploration and development of the operations. In these agreements, the state is normally represented by the government or one of its agencies, such as the national oil company. Many factors determine the nature of the contract, such as the maturity of the oil sector, the fiscal regime, import or export dependency, geological aspects, costs and the overall, changing regulatory framework.

There are three major types of legal frameworks for production agreements, these include:

### **Concession or Royalty/Tax system**

The older concession or royalty/tax system typically grants that the IOCs the exclusive rights to explore, develop and export petroleum (Bindemann, 1999) with the host country receiving payment based on production. The later concession or royalty/tax system of the 1970s provided for shorter contract periods, a work obligation, relinquishment clause, towards the IOCs and higher royalties, and bonus payments for the host country (Bindemann, 1999). The concession or royalty/tax system invariably relies upon a completely separate and distinct set of national laws to govern the decommissioning process. The concession documents do not contain any direction on what is required to complete the decommissioning process. In most ASCOPE member countries, there are no suitable laws to provide clarity during the decommissioning phase.

### **Production Sharing Agreements**

In production sharing agreements, the oil is owned by the state which brings in a foreign company to explore and, in case of commercial discovery, develop the resource. The IOC operates at its sole risk and expense, and receives a specified share of production as reward. Thus, the main difference to concessions is the ownership of the mineral resource (Bindemann, 1999). Whereas under concessions all crude oil produced belongs to the IOC, under PSAs it is owned by the host government, and the share of production allocated to the IOC can be regarded as payment or compensation for the risk taken and services rendered.

Production sharing agreements (PSA) are considered to be stand-alone regulation in many jurisdictions which use them, especially when there is no petroleum law that governs petroleum operations. In most cases, the specific PSA provides the sole source of how petroleum operations are initiated and decommissioned, unfortunately, earlier PSAs contained very little details on abandonment and/or decommissioning (Bindemann, 1999).

**Risk Service Agreements**

Some forms of Risk Service Agreements (RSA) are similar to PSAs. The IOC is the sole bearer of the financial risk and engages in exploration and development for an agreed fixed fee or other form of compensation. As the name of the contract implies the IOC supplies services and know-how. It has, however, no equity position in the venture. Risk service agreement also contains very little details on abandonment and/or decommissioning (Bindemann, 1999).

*Table 3 Types of production agreements and the corresponding ASCOPE member country*

<b>Concession or Royalty/tax</b>	<b>Production Sharing Agreement</b>	<b>Service Agreement</b>	<b>No production agreement</b>
Thailand Brunei Darussalam	Brunei Cambodia Indonesia Laos Malaysia Myanmar The Philippines Vietnam	Malaysia The Philippines	Singapore

**7.3. Non-Governmental instruments applicable to Decommissioning.**

Non-governmental instruments refer to documents like operator standards, industry body guidelines, the World Bank – International Finance Corporation – EHS Guidelines, the Equator principals (a credit risk management framework for determining, assessing, managing environmental and social risk in project finance transactions) (ASEAN Council on Petroleum (ASCOPE), 2012).

## 8. Thailand

### 8.1. *An overview of the Thai Upstream Offshore Oil and Gas Industry*

In 2003, the Thai government was restructured and established the Department of Mineral Fuels (DMF), under the Ministry of Energy as the regulator to the oil and gas industry. In 2006, the DMF set up the Decommissioning Guidelines project, with representatives from other government departments, the industry and the Petroleum Institute of Thailand, a neutral, independent, non-profit organization for the Thai petroleum industry, with emphasis on human resources development, information services, technical services, public policy and regulatory support, to ensure sustainable development and competitiveness of the industry and the country.

In 2009 there was draft decommissioning guidelines issued and remain the most updated documents as of today. The DMF is of the opinion to approve the first few decommissioning plans on a case-by-case basis, and obtain decommissioning data and guide the next phase revision of the decommissioning guidelines better.

In the Gulf of Thailand the water depth is typically in the range of 60-80 metres. The shallow waters have resulted in the development of separate platforms having unique functions in wellhead platforms, central processing, living quarters platforms etc (Tularak et al., 2007). These platforms are in turn served by a network of 2,000 km of subsea pipelines, which consists of “Y” junctions, “T” junctions and Pipeline End Manifolds. Pipelines originating from the central processing plants are operated by the government authority, Petroleum Authority of Thailand (PTT), and not under the responsibilities of the Independent Oil Companies (Tularak et al., 2007).

Table 4 Summary of Thai offshore infrastructure components (Tularak et al., 2007)

<b>Item no</b>	<b>Facility Type</b>	<b>No.</b>
1	Wellhead Platform	183
2	Compression platform	1
3	Central processing platform (CPP)	10
4	Living quarters	9
5	Production platform	8
6	Riser platform	2
7	Flare support platform	12
	<b>Total</b>	<b>225</b>

## 8.2. *The legal framework*

The over-arching regulations in Thailand governing the offshore decommissioning is the Petroleum Act B.E. 2514 (1971), with the latest amendment in 2007. Within the Petroleum Act, there are Ministerial Regulations No 1 to 20 (B.E.2534) that covers topics such as concession agreements (Petroleum Institute of Thailand, 2008):

- Clause 40 of Ministerial Regulation No.12 B.E.2524 (1981): Prescribing rules and procedures for production operations. The clause requires concessionaires to decommission their installations, and restore relevant onshore and offshore production areas to their former conditions and that all installation must be removed entirely within three months unless otherwise directed by the Director-General.
- Clause 15 (4) of Model Concession, DMF/P 2, annexed to Ministerial Regulation No.17 B.E.2532 (1989): Concession Agreement. The clause requires that at the end of the concession agreement, concessionaires must transfer certain parts of their installations to the government without any remuneration and as per the above clause, complete the remaining decommissioning portions within three months.
- Section 80 of the Petroleum Act B.E. 2514 (1971) also prescribed that concessionaires need to operate under sound principles and good petroleum industry practice regardless of whether the concessions have been terminated. In addition, the Petroleum Act imposes two general obligations of forbidding unjustifiable interference with the use or conservation of the sea and living resources and taking appropriate measures under good petroleum practice to prevent pollution arising from oil, mud and any other substance.
- Petroleum Act (No.6) B.E. 2550 (2007). In the 2007 updated Petroleum Act, Section 80 requires a decommissioning program inclusive of estimated decommissioning costs for the approval of the Director-General before decommissioning begins. A security must be then be placed to ensure that their decommissioning obligations are observed under the approved program.

In addition to the laws above, the 2008 Draft Decommissioning Guidelines (Petroleum Institute of Thailand, 2008) and references to international practices, including United Nations Convention Law of the Sea 1982 (UNCLOS), International Maritime Organization (IMO) Guidelines and Standards and London Convention (LC) and the London Protocol will be employed to cover the details of decommissioning.

### *8.3. The environmental framework*

The environmental framework consists of 3 main arms, (i) Environmental Principles and (ii) Decommissioning Environmental Assessment (DEA) and (iii) Environmental Compliance Audit and are addressed in Article 5 of the 2008 Draft Decommissioning Guidelines for Upstream Installations and in Attachment A of the 2008 Guidelines (Petroleum Institute of Thailand, 2008).

The environmental principles are used to direct globally-accepted environmental concepts derived from international environmental law into Thailand's decommissioning framework. Some examples of the environmental principles are the Precautionary Principle, Agenda 21, Environmental Friendly Technologies, Polluter-Pays Principle and the Rio Declaration on Environment and Development. The key considerations of the environmental framework is that, in the event of uncertainty when considering the decommissioning option for contaminated pipelines, the environmental assessment should assume the worst-case scenario and choose the best practical option based on this assumption. The Rio Declaration on Environment and Development also emphasizes on public access to information, participation and justice in decision-making affecting the environment. This principle is relevant to the environmental assessment and the transparency of the process, especially in revealing information on hazardous materials and activities in the vicinity and the right for nearby communities to have a say in what goes on in their 'backyard'. This is especially relevant to the location of dismantling yards, and the final destination of hazardous materials.

The Decommissioning Environmental Assessment (DEA), is based on a regional approach and consists of two key development stages, namely a regional development stage (consisting of a Regional

Decommissioning Environmental Assessment (RDEA) report) and a project development stage (consisting of two sub-processes, namely Best Practical Environmental Option (BPEO) and Decommissioning Environmental Management Plan (DEMP).

The RDEA is an EIA report at a regional level, and assesses cumulative impacts and their significance. Decision-making public participation (PP) is required at two different stages - the early scoping stages and during review of the draft document stage.

The BPEO is an assessment that compares the relative merits of different options based on pre-defined assessment factors - technical feasibility; environmental concerns, including waste management; risk and safety; costs; and public acceptance. The BPEO process yields the best practicable option under a given situation and an auditable trail to support the final decision. This allows trade-offs, priorities and value judgments to be made consistently and transparently. In performing BPEO, consultation-level PP is required as input for the BPEO tool to identify the preferred decommissioning option.

The DEMP is a document containing environmental management plans with respect to potential impacts of a selected decommissioning option. Based on the results of RDEA, DEMP focuses on the selected decommissioning option, field-specific technology, mitigation measures and monitoring plans. It is performance-based with an emphasis on achieving the environmental objectives stated in the RDEA, and is used more as a tool for improved environmental design and management. Public participation is also required to inform stakeholders about the selected decommissioning option, mitigating measures and monitoring plans contained within DEMP.

The environmental compliance audit is a process of third-party verification and audits are required for decommissioning process including cleaning and implementation and effectiveness of proposed mitigation plans, and post-decommissioning monitoring plans.

#### 8.4. *The financial framework*

Section 80/2 of the Petroleum Act requires concessionaires, including co-venturers, associate assignors and assignees, and third-party assignees, to place a financial security to ensure both decommissioning and post-decommissioning monitoring, is carried out in its entirety. The details are addressed in Article 6 of the 2008 Draft Decommissioning Guidelines for Upstream Installations and in Attachment B of the Guidelines (Petroleum Institute of Thailand, 2008).

A number of types of financial security can be placed, either individually or a combination and this exists as a security or a surety. A security is an irrevocable standby letter of credit, performance bonds, government and state-enterprise bonds, cash placed in escrow accounts, and alternative forms of securities approved by DMF. A surety is a parent or associated company guarantees or alternative forms of sureties approved by DMF.

The financial-strength test is made-up of two levels – (i) concession-level test and (ii) company-level test.

The concession-strength evaluates the financial strength of each concession based on the remaining reserve or net cash flow under the following conditions.

**Condition 1:** Total remaining reserve is at least 40% of initial reserves

**Condition 2:** Concession's net cash flow after-tax exceeds 1.25 times of the anticipated decommissioning cost

If the total remaining reserve is at least 40%, the concessionaire will not be required to undergo the Condition 2 test. Passing the Condition 1 test means passing the financial strength test, in which case the concessionaire is not yet required to place financial security for decommissioning.

If the total remaining reserve is lower than 40%, the concessionaire must evaluate its net cash flow to determine whether it satisfies Condition 2 above. Failure to satisfy both conditions is tantamount to failing the concession-level test and the concessionaire must move on to the company-level test.

The company-level test assesses the financial strength of a company holding one or more concessions by evaluating the company's net worth or net cash flow. In this test, the concessionaire is required to assess its financial strength based on one of the following options:

**Option 1:** The company's net worth/shareholder equity certified by a third-party auditor, reflecting only assets in Thailand, exceeds twice the total anticipated decommissioning costs of all concessions held by the company. (The company's net worth must be allocated in proportion to the investment cost under a particular tax regime.)

**Option 2:** The company's net cash flow after tax and liabilities, reflecting only assets in Thailand, exceeds 1.25 times the total anticipated decommissioning cost. (The company's net cash flow after tax and liabilities must be calculated in proportion to the relevant tax regime.)

The concessionaire may select either option. If it fails the selected option, it is considered to have failed the financial-strength test and must place the financial security. Once the concessionaire fails the test or once the extended production period is equal to five years, whichever is earlier, it is required to place financial security. If the failure of the financial strength test occurs first, the concessionaire must place financial security on a prorated schedule on a total remaining reserve/net cash flow basis. If there is equal to five years remaining under the concession agreement, the concessionaire is required to place financial security in full.

The guidelines further require that the anticipated decommissioning cost should be certified by a third-party auditor and re-certified every three years. In addition, the financial-strength test must be updated annually and submitted to DMF within 150 days from the end of the calendar year. The DMF will release the financial security, either in part or in full, upon the concessionaire's completion of the decommissioning obligations. A portion of the financial security may be released if a closeout report for the completed part is submitted and approved by the Director General.

With the exception of sureties, the financial security placed in the above-mentioned context is treated as petroleum business expenditure and is tax deductible, which will be amortized under the straight-line method for the remaining life of the concession or remaining production period.

## 8.5. *The technical framework*

### 8.5.1. Submission Timeline

The submission of the decommissioning programmes must include the financial-strength test report, when certain conditions are triggered during/at (i) production period (ii) extension period (iii) revocation of concession or (iv) voluntary decommissioning.

During the production period, if the total remaining reserve is less than 40%, the initial program must be submitted within 2 years from that point in the production period. If the total remaining reserve is greater than or equal to 40%, the final decommissioning program must be submitted at least 2 years from the commencement of decommissioning, and that at the point in which the total remaining reserve is greater than or equal than 40%, it is less than 5 years to the commencement of decommissioning (Petroleum Institute of Thailand, 2008).

During the extended production period, the concessionaire must submit an initial decommissioning program within the first two years of the extended production period. Then, a final decommissioning program must be submitted at least two years ahead of the commencement of decommissioning or the end of the extended production period, whichever is earlier (Petroleum Institute of Thailand, 2008).

If the concession has been revoked (under Section 51 of the Petroleum Act), the concessionaire is required to submit its final decommissioning program to the Director-General within six months of the issuance of the official revocation order. It is also required to place its financial security in the full amount of the anticipated decommissioning cost estimated by the Director-General (Petroleum Institute of Thailand, 2008).

The concessionaire may voluntarily submit a final decommissioning program at any time before the two years ahead of the actual commencement of decommissioning (Petroleum Institute of Thailand, 2008).

### 8.5.2. Pre-decommissioning

At this stage, the selection of decommissioning options is carried out. The recommended tool is the BPEO tool, which helps to identify the preferred decommissioning option that has the least environmental impact as a whole, with consideration of public health, safety and acceptability and technical feasibility at an acceptable cost.

The BPEO tool is made up of five areas:

- Offshore pipelines
- Onshore pipelines
- Jackets
- Seabed deposits and
- Cutting methods and depth

There are 6 assessment criteria for each of the significant activities. For each item of the respective assessment criteria, there are definitions for 5 levels: high, medium – high, medium, medium – low.

*Table 5 Assessment Criteria for Best Practices Environmental Tool*

<b>Assessment Criteria</b>					
<b>Technical Criteria</b>	<b>Waste Management Criteria</b>	<b>Environmental Criteria</b>	<b>Health and Safety Criteria</b>	<b>Cost Considerations</b>	<b>Public Acceptability</b>
<ul style="list-style-type: none"> <li>• Operational feasibility</li> <li>• Established Technology &amp; Techniques</li> <li>• Dismantling yard</li> </ul>	<ul style="list-style-type: none"> <li>• Reuse/Recycle opportunity</li> <li>• Hazardous/Non-Hazardous wastes</li> <li>• Onshore disposal facilities availability</li> </ul>	<ul style="list-style-type: none"> <li>• Energy consumption</li> <li>• Air emissions</li> <li>• Water quality</li> <li>• Landuse</li> <li>• Sediment quality/ seabed disturbance</li> <li>• Terrain</li> <li>• Ecology</li> <li>• Coastal/ Near-shore impacts</li> <li>• Onshore impacts</li> <li>• Resource users and potential</li> </ul>	<ul style="list-style-type: none"> <li>• Occupational health and safety</li> <li>• Public health and safety</li> <li>• Public health through secondary impact</li> <li>• Navigational/Fishing vessel safety</li> </ul>	<ul style="list-style-type: none"> <li>• Potential residue responsibilities costs</li> <li>• Decommissioning costs</li> <li>• Post-decommissioning costs</li> </ul>	<ul style="list-style-type: none"> <li>• Degree of consultation/ time to solve issues</li> <li>• Amount of compensation</li> </ul>

*Table 6 Assessment Criteria level for each criteria for Best Practices Environmental Tool listed in Table 4*

<b>Assessment Criteria level</b>				
<b>High</b>	<b>Medium – High</b>	<b>Medium</b>	<b>Medium - Low</b>	<b>Low</b>
Option is practical, easy to execute with no problems and has been used before successfully	Option is easy to execute with only minor difficulties which are easily controllable	Option has practical difficulties in execution; has been used before with minor problems encountered but which are controllable	Significant difficulties faced in execution of option	Potential difficulties in execution of option are unknown

### 8.5.3. Decommissioning Execution – offshore infrastructure

Under offshore infrastructure, the components are (i) well plugging and abandonment, (ii) seabed deposits management, (iii) pipelines and associated structures, (iv) structure and facilities.

#### *Well Plugging and Abandonment*

The minimum requirements of well plugging and abandonment involve setting plugs at critical intervals to prevent the wellbore from becoming a conduit for fluid migration. The prevention of fluid migration delivers the primary objectives of well abandonment operations which are, specifically, to confine hydrocarbon resources in their respective strata and protecting fresh water aquifers.

Appendix H in the 2008 Guidelines addresses the requirements of plugging uncased and cased portion of a wellbore, and the effective segregation of both portions. The guidelines also specify the acceptable methods such as the “displacement” and “down squeeze” methods. The plug must pass the following test to verify plug integrity: pump pressure of at least 2,500 pounds per square inch with a result of maximum 10% pressure drop for a minimum of 15 minutes. In the same guidelines, the depth of the plug varies from 50 feet to 200 ft depending on the methodology employed (displacement or down squeeze method). For the displacement method, it refers to 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata and/ or freshwater stratums. In terms of the annular space, any annular space open to the mud line and in communication with open hole must be plugged with cement at least 200 feet

long to seal the annular space. The use of explosive cutting for removing the subsea wellheads or mudline hanger systems is prohibited. It is observed that the Thai guidelines take reference from the US regulations.

All wellheads and casings are to be cut at least 15 feet below mud line. In addition, pilings, and other obstructions shall also be removed to a depth of at least 15 feet below mud line level or to a depth approved by the Director General (Petroleum Institute of Thailand, 2008).

### *Seabed Deposits Management*

Seabed deposits are defined as drill cuttings, mud chemicals and produced water discharges.

Limited information from the Gulf of Thailand will initially require a case by case approach to the management of seabed deposits with site specific investigations and environmental evaluations (Petroleum Institute of Thailand, 2008). The physical, chemical and biological characteristics of the seabed deposits should be established.

Apart from the international laws (UNCLOS, London Convention), the following Thai laws and regulations are relevant to seabed deposits and refer to pollution prevention, restoration and criteria for hazardous substances:

- Thailand Petroleum Act BE 2514 Section 75;
- Ministerial Regulation No. 12;
- Enhancement and Conservation of National Environmental Quality Act, B.E. 2535; and
- Hazardous Substance Act B.E 2535 (1992)

Limitations due to unproven effectiveness of some of the management options will require initial field trials and extensive monitoring to determine their feasibility. Pre and post decommissioning monitoring is required for the seabed deposits management, on-condition that the field trials and extensive

monitoring demonstrate no significant risk to the environment, in-situ methods (undisturbed or capping) or ex-situ/removal methods (onshore disposal, re-injection).

### *Pipelines and Associated Structures*

The 2008 Guidelines governs the management of the decommissioning of pipelines and its associated structures (Petroleum Institute of Thailand, 2008). Pipelines and associated structures cover pipelines and subsea equipment including pipeline end manifolds (PLEM), wyes, and tees. Alternatives of pipeline decommissioning include leaving them in situ, removal and reuse. The preferred option is decided through BPEO, and the selected option must be approved by the designated authority. However, if pipelines contaminated with heavy metals are to be left in situ or reused, verification of decontamination will be a key issue (Petroleum Institute of Thailand, 2008). While there is no further mention on this verification, it could take on the same requirements such as field trails and extensive monitoring as per seabed deposits management.

Associated structures protruding above the seafloor and posing hazards to fishing, navigation or other users of the sea must be removed and disposed onshore. Any such items should be cleaned to a level that is safe for handling and transportation.

### *Structure and Facilities*

From the 2008 guidelines (Petroleum Institute of Thailand, 2008), the decommissioning of offshore structures and facilities is divided into topside and substructure decommissioning work. Topside decommissioning covers process equipment, piping, topside structures, living quarters, electrical and instrument equipment, etc. Topsides, where applicable, must be cleaned and decontaminated to an acceptable level before their removal for reuse, recycling and/or disposal. The cleanliness and decontamination must be audited by a third party to ensure compliance with the proposed DEMP. For substructure decommissioning, the alternatives are to reuse, dispose of, or implement Rigs-to-Reefs. BPEO must be conducted to select the preferred option.

#### 8.5.4. Decommissioning Execution – Reuse Standards

Reuse of structures and facilities is a preferred option for decommissioning because of several factors including low amount of generated waste, low environmental and safety impacts and less engineering complications (Petroleum Institute of Thailand, 2008). However, the integrity of aging structures and facilities is also a critical factor.

Before their reuse, integrity assessment has to be undertaken, using any appropriate techniques, typically non-destructive examination (NDE) ones; however, destructive examination (DE) techniques can be applied when required (Petroleum Institute of Thailand, 2008).

After integrity assessment, a technical evaluation should be conducted to ensure that the structures and facilities are appropriate for future use under new operating conditions. If current integrity does not meet the requirements for future use, a further feasibility study is required to verify if any corrective action including repairing, refurbishment and replacement can be taken (Petroleum Institute of Thailand, 2008).

#### 8.5.5. Decommissioning Execution – Waste Management

From the 2008 guidelines (Petroleum Institute of Thailand, 2008), the fundamental management of decommissioning waste is the waste management hierarchy reduction, reusing, recycling, recovery, treatment, and disposal. The concessionaire must demonstrate that the waste management hierarchy has been considered and applied where feasible. In addition, the concessionaire must ensure that the waste management contractor's facilities and services command the technological standards by having the contractor and its facilities periodically audited.

#### 8.5.6. Safety standards

From the 2008 guidelines (Petroleum Institute of Thailand, 2008), the decommissioning plan must include a safety management plan that demonstrate that all decommissioning activities are performed safely under safe work practices and industrial standards. It must also ensure that all risky activities are identified and their mitigation plans are set up to properly manage all risks concerning decommissioning activities or reduce them to an As-Low-As-Reasonably-Practicable (ALARP) level.

#### 8.5.7. Debris survey and clearance

The scope of the debris survey is subject to the selected decommissioning options and the occurrence of any accident. If debris is found within the defined range, a wider corridor or radius may be required until no debris is found. The 2008 guidelines (Petroleum Institute of Thailand, 2008) allows flexibility from the concessionaire to propose the range, scope, appropriate technique, and schedule to perform its survey and clearance in the Final Decommissioning Program. The results of the survey and clearance must be included in the Closeout Report for Decommissioning.

#### 8.5.8. Post-Decommissioning

A project close out report is required, and the contents consist of 2 stages: decommissioning and post-decommissioning. The Closeout Report for Decommissioning must be submitted after the completion of decommissioning activities, while the Closeout Report for Post-Decommissioning must be submitted after the completion of post-decommissioning monitoring (Petroleum Institute of Thailand, 2008).

There are also post-decommissioning monitoring requirements to assess environmental implications for the seabed deposits management (Petroleum Institute of Thailand, 2008).

#### 8.5.9. Third-Party Validation

Third-party verification is required for specific decommissioning activities to ensure proper implementation of activities. Third-party undertaking generally applies for auditing and

consultancy. In each case, the concessionaires must propose a qualified third party to the designated authority for acceptance.

Decommissioning activities requiring third-party work consist of (Petroleum Institute of Thailand, 2008) reserve verification, decommissioning cost estimate (every three years), the development of RDEA report on potential impacts of decommissioning activities in each defined area, the development of Decommissioning Environmental Management Plan and its consistency with that of the RDEA report.

#### 8.5.10. Release of liability

There are three liabilities for consideration: decommissioning liability, residual liability and transfer of installations.

##### *Decommissioning Liabilities*

The concessionaire, co-venturers, associated assignors and assignees, and third-part assignees are released from the decommissioning liabilities under Section 80/1 of the Petroleum Act once the concessionaire completes the decommissioning activities and post decommissioning monitoring activities of installations under the approved decommissioning program and the closeout report for decommissioning, prepared under relevant ministerial regulations and guidelines.

##### *Residual Liabilities*

The concessionaire, co-venturers, associated assignors and assignees, and third-part assignees are liable for any damages if it can be proved that decommissioning activities caused damage to the environment, people or other parties.

##### *Transfer of Installations*

Where the installations are transferred, any liabilities incurred after the transfer must be paid for by the transferee. The transferor is not liable to civil and criminal claims instituted after the transfer.

## **9. Malaysia**

### *9.1. An overview of the Malaysian Upstream Offshore Oil and Gas Industry*

Malaysia has a national oil corporation, PETRONAS, which acts as the custodian and statutory manager of the national petroleum resources in Malaysia. The agreements that typically govern the exploration and exploitation of petroleum resources in Malaysia are Production Sharing Contracts (ASEAN Council on Petroleum (ASCOPE), 2012), thus Malaysia has the obligation to address the process of decommissioning of all disused upstream structures and installations.

Wan Abdullah et al (2012) reported that Malaysia has about 300 shallow water platforms, operating in three different locations: the Peninsular Malaysia, the Sarawak Operation and Sabah operation. Most of these platforms are shallow water platforms (50 – 70 m) (Zawawi et al., 2012). Most of the platforms are over 20 years of age and 48% of the platforms have exceeded their 25-year design life. For these aged platforms, approximately 28% of these platforms are off Sarawak, 12% off the Sabah region, and the remaining 8% off the Malaysia Peninsular (Zawawi et al., 2012).

In August 2000, PETRONAS issued an overarching document entitled “PETRONAS Procedures and Guidelines for Upstream Activities (PPGUA)” and serves as a guideline for decommissioning in Malaysia. The most updated version is “Revision 2 Aug 2008” (PETRONAS, 2008).

### *9.2. The legal framework*

At present, there is no specific decommissioning regulation for the oil and gas industry; however there are provisions in several Acts which decommissioning activities need to abide by. The relevant national laws of Malaysia are:

- Section 485A of Merchant Shipping Ordinance 1952, stipulates that new regulations may be made for the purpose of ensuring the safety of and control over offshore industry structures, mobile units and vessels.
- Section 6 of Continental Shelf Act 1966 stipulates that new regulations may be made for the purpose of providing for the removal of abandoned or disused installations or devices constructed above the continental shelf.
- Section 23 of the Economic Zone Act which stipulates that the owner of any subsea cable or pipeline fallen unto disused or beyond repair must inform the government, and if directed by the government, remove the cable or pipeline within the directed timeline.
- The Environmental Quality Act 1974 prohibits the discharge of oil (Section 27) and wastes into Malaysian waters (Section 29).
- Environmental Impact Assessment Guidelines for Petroleum Industries”: an administrative guideline issued in 1997 which states the requirement to submit an EIA report.

In addition, international regulations will also be referred to, including United Nations Convention Law of the Sea 1982 (UNCLOS), International Maritime Organization (IMO) Guidelines and International Convention for the Prevention of Pollution from Ships, 1973 and the modifying Protocol, 1978 (MARPOL 73/78) Protocol.

### *9.3. The environmental framework*

The guidelines “PPGUA Revision 2 2008” organised the information in three major phases: pre-decommissioning, decommissioning execution, post-decommissioning (PETRONAS, 2008).

Environmental concerns are highlighted in all three phases, where it is recommended that a Decommissioning Options Assessment is to be conducted to evaluate potential decommissioning options (similar to the proposition of Thailand, or the ASCOPE guidelines), with the inclusion of removal options, ranking of strengths and weaknesses of each options.

Under the requirements of an Environmental Management Plan (EMP), the pre-decommissioning assessment will cover baseline studies, chemical and waste inventory, pollution control, risk assessment such as potential hazards and consequential impacts of the option selected. The guidelines also specified on the contractor to assist PETRONAS in the event of a public consultation process.

The PS Contractor shall conduct the Post Environmental Assessment (PEP) within three (3) months from the date of completion of decommissioning work, to ensure that there are no adverse impacts on the surrounding marine and land environment. This Assessment shall be consistent with the Post Decommissioning Environmental Assessment Plan as per the approved PEP.

#### *9.4. The financial framework*

The financial framework details are less specific. The main requirement is that after the approval of the decommissioning plan, the PS Contractors shall provide budget provisions for platform decommissioning in the immediate forthcoming WP&B. Details of information required shall be consistent with pre-budget guidelines. The decommissioning activities shall commence after PETRONAS approves the decommissioning work plan and budget (WP&B).

#### *9.5. The technical framework*

##### *9.5.1. Pre-decommissioning process*

In the PPGUA Guidelines (PETRONAS, 2008), the pre-decommissioning process considers the establishment of decommissioning options, the decommissioning plan, the Health, Safety and Environment Requirement and consultation and liaison, as well as the work programme and budget.

The establishment of decommissioning options considers 5 categories of structures: the sub-structures, the topsides, the pipeline, well abandonment and mobile and floating facilities. The decommissioning

options consider total or partial removal, relocate/reuse and specifically mentioned that artificial reef is a viable option, or the option of mothballing for future reuse.

The Health, Safety and Environment considerations will vary with the decommissioning options assessment. An Environmental Management Plan (EMP) together with the comparative environmental risks associated with different decommissioning alternatives will be required for submission to PETRONAS for review and subsequent submission to the Department Of Environment for approval six (6) months prior to the decommissioning of any platform. In the case where Environmental Impact Assessment (EIA) is applicable, the EMP needs to be consistent with the EIA requirements.

In the event that a public consultation process becomes necessary in certain cases, the PS Contractors may be required to assist PETRONAS to initiate and manage the dialogue process to obtain the community and stakeholders' views and concerns. PS Contractors together with PETRONAS shall liaise with various Government departments as and when required.

After approval of the decommissioning plan, budget provisions for platform decommissioning in the immediate forthcoming WP&B must be provided. The decommissioning activities shall commence after PETRONAS approves the decommissioning WP&B.

#### 9.5.2. Decommissioning Process

At this stage, a Project Execution plan is required for each decommissioning activity. The decommissioning process is divided into segments based on the structural components – substructures, topside, pipeline, well abandonment, marine facilities.

The Project Execution plan has to be submitted to PETRONAS for review at least one month prior to execution. The report requires details such as cost estimate, cost monitoring and control, taxation, disposal plans, and the HSE and Environmental Assessment plan.

### *Sub-structures decommissioning*

The integrity of the sub-structure needs to be revalidated by certified parties prior to decommissioning work based on latest reassessment report incorporating any underwater findings. There are three scenarios considered: partial removal, total removal and topple in place. In the partial removal and topple scenario, the structure must have a minimum of 55 meters water clearance from the highest structure. For total removal, the depth of cutting shall be a minimum of 1 meter below the mudline, subject to cutting method and seabed conditions such as siltation rate, erosion rate etc.

### *Topside*

PS Contractors must comply with Section 11.4.11 of PPGUA: Preservation of Facilities, Structures and Pipelines upon cessation of production (PETRONAS, 2008). The minimum scope of requirements should cover 4 categories of all production and utilities systems on topside:

- Hydrocarbon systems: All separators, process vessels and piping shall be purged and flushed. Residual hydrocarbons shall be collected and dispose at certified onshore disposal site / agency. Radioactive materials shall be handled according to AELB guideline
- Non-hazardous systems: Cooling water, firewater, utility air and instruments need to be depressurised, flushed, drained and isolated.
- Toxic and hazardous chemical systems: Toxic and hazardous materials should be removed. The system shall be purged, flushed and detoxified. Any discharge of the cleaning effluent must satisfy any applicable regulation.
- Electrical power systems: Decommissioning of electrical systems is a planned sequenced shutdown of all motor control centers, switchgear and generators with proper safety procedures.

### *Pipeline*

Pipelines decommissioning and disposal shall be decided by PETRONAS on a case-by-case basis (PETRONAS, 2008). Pipelines decommissioning work involves flushing and cleaning to meet regulatory requirements. Pipelines to be left in-situ shall be flushed, filled with seawater, cut and plugged, with the ends buried minimum one meter below mudline. The risers, tube turns and minimum twelve meters of the pipeline section from the base of the substructure shall be totally removed. The removal can be conducted together with substructure removal where applicable. Where appropriate, special measures and consideration need to be taken for 'hot tap' or other special pipeline-to-pipeline connections to reduce risk and exposure of the remaining section of pipeline.

#### *Well abandonment*

Well abandonment shall be conducted as per PETRONAS' Procedure for Drilling Operations (Section 5). The wellhead shall be totally removed with cutting depth of wellhead system of between zero (0) and two (2) meters below the mudline subject to cutting method and seabed conditions such as siltation rate, erosion rate, type of soil, etc. The substructures requirement for removal shall follow the IMO requirement.

#### 9.5.3. Post-Decommissioning process

The post-decommissioning process largely entails the removal of debris and seabed clearance. Four reports are required: (1) a survey verification report, (2) disposal report, (3) post environmental assessment report and (4) as-built drawings/ documents.

Third party verification is required (through surveying, and highlighting survey method used), for the survey verification report. A Post Environmental Assessment within 3 months from the date of completing the decommissioning work, and to ensure that there are no adverse impact on the surrounding marine and land environment.

Finally, the contractors are required to submit an application to degazette the decommissioning facilities and its relevant area within one month after the submission of the Closeout Report.

Residual liability remains uncertain – as Malaysia is pending the issuance of a National Policy of Oil & Gas Fields, whereby any residual liability of all disused upstream structures and installations shall be finally decided by PETRONAS, in consultation with the relevant Government authorities (PETRONAS, 2008).

## 10. Analysis and Recommendation

The decommissioning regulatory requirement in each country differs, such that some may be more stringent than others. It is also practical to note that, some countries may not require a stricter requirement due to differences in how the IOCs function or the local geographical constraints. It is also expected that some elements of the international requirements could be found in these domestic regulations of the countries relatively more established in decommissioning activities. Some aspects of newly developed guidelines from Thailand showed an interesting, or more thorough solution to any of the problems common to all decommissioning activities. Nevertheless, for the purpose of understanding the strictest requirement that exists, the discussion is organised as per the structure in **Error! Reference source not found.** against a combination of legal, environmental, financial and technical frameworks.

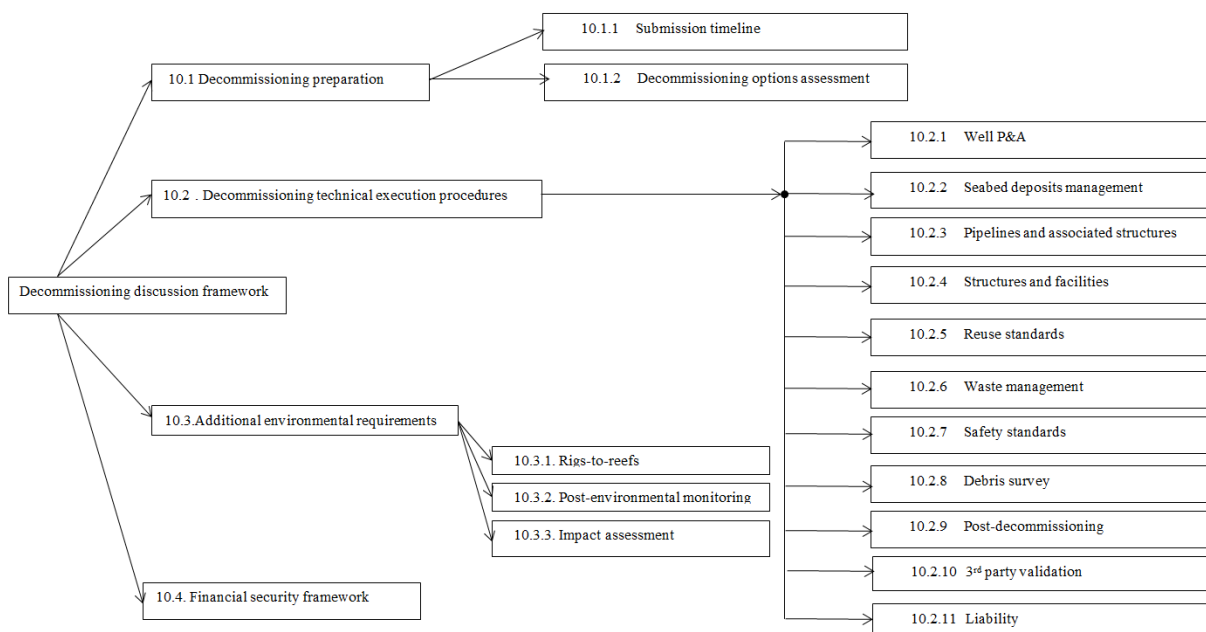


Figure 3 Mind map of the components for comparison of decommissioning regulation.

The following tables (Table 7, Table 8,

Table 9, Table 10) focus on the strictest applicable regulation from each category of decommissioning preparation, decommissioning technical execution, financial security framework and additional environmental requirements.

*Table 7 Results of the strictest applicable regulation and origin of regulation for the category of decommissioning preparation.*

<b>10.1 Decommissioning preparation</b>			
<b>Item no</b>	<b>Subject</b>	<b>Recommendation</b>	<b>Regulation (Summary)</b>
10.1.1	Submission Timeline	Thailand	Apart from Thailand (Petroleum Institute of Thailand, 2008), Norway (Petroleum Safety Authority (Norway), 2015a), (Ministry of Petroleum and Energy (Norway), 2010) and USA (Government of USA, 2014b), (Bureau of Safety and Environmental Enforcement (USA), 2016a) also require the decommissioning programme documents to be submitted between 2 to 5 years before the commencement of the decommissioning programme. Though the UK regulations, only stated the deadline as “a mutually agreed time”, this timing is based on a series of preliminary discussions, hence it includes a sufficient “buffer” as in the 2 – 5 years timeline for Norway and USA. Thailand regulations adjusts the timeline depending on the conditions of trigger of decommissioning, and considers total remaining reserves < or >= 40% during the production period, or if the production period has been extended, or if a concession has been revoked. In most cases, the final programme must be submitted >= 2 years from the commencement of decommissioning.
10.1.2	Pre-decommissioning	ALL	All countries have similar requirements on the selection of decommissioning options, a comparative assessment of the decommissioning options and a corresponding management plan for the selected option (Petroleum Institute of Thailand, 2008), (Petroleum Safety Authority (Norway), 2015a), (Ministry of Petroleum and Energy (Norway), 2010), (Government of USA, 2014b), (Bureau of Safety and Environmental Enforcement (USA), 2016a), (PETRONAS, 2008), (Department for Business Energy and Industrial Strategy UK, 2011).

Table 8 Results of the strictest applicable regulation and origin of regulation for the category of decommissioning technical execution.

**10.2 Decommissioning technical execution**

<b>Item no</b>	<b>Subject</b>	<b>Recommendation</b>	<b>Regulation Description</b>
10.2.1	Well P&A	Norway and UK	<p>Norway removed the requirement that the cutting depth should be 5 m below the seabed in the most updated NORSOK D-010 guidelines (Standards Norway (NORSOK), 2013). Instead Norway now stipulates that the wellhead and casings should be removed below the seabed at a depth which ensures no stick up in the future, and that required cutting depth should be sufficient to prevent conflict with other marine activities. Also, local conditions of soil and seabed scouring due to sea current should be considered, thus the onus is on the operator or facility owner to proof that the selected depth does not cause the well to stick-up in the future. The UK has a similar requirement as well.</p> <p>In terms of well plugging and abandonment, the guidelines also provide scenarios of placement of primary and secondary well barriers, but emphasizes on practicality that the base of well barriers should be positioned at a depth where formation integrity is higher than potential pressure, and with criteria on formation integrity requirements.</p>
10.2.2	Seabed Deposits management	UK, USA, Norway, Thailand	<p>The 4 countries have a similar system involving Stage 1 for Initial Screening of all cuttings piles, and a Stage 2 for the BAT and/or BEP assessment. Some BAT and/or BEP assessment options (not limited to) refer to onshore treatment and reuse, onshore treatment and disposal, offshore injection, bioremediation, covering or natural degradation in situ.</p> <p>The UK and Norway refers to the OSPAR Recommendation 2006/5 on Management Regime for Offshore Cutting Piles (Ministry of Petroleum and Energy (Norway), 2010), (Department for Business Energy and Industrial Strategy UK, 2011) (OSPAR Commission, 2009), while USA refers to the USEPA guidelines (Government of USA, 2014a) and Thailand (Petroleum Institute of Thailand, 2008) refers to the decommissioning guidelines.</p>
10.2.3	Pipelines & Associated Structures	Norway and UK	<p>While all countries' regulations allow for three options of removal, monitoring (decommissioned in place), re-use or deferral (Petroleum Institute of Thailand, 2008), (Petroleum Safety Authority (Norway), 2015a), (Ministry of Petroleum and Energy (Norway), 2010), (Government of USA, 2014b), (Bureau of Safety and Environmental Enforcement (USA), 2016a), (PETRONAS, 2008), (Department for Business Energy and Industrial Strategy UK, 2011), Norway has a structure and</p>

			<p>funds to handle the cost of pipelines removal under a Removal Grants Act “fjerningstilskuddsloven” that provides direct grants to cover a portion of the State’s share of disposal costs, and which has been utilised in 2000 to remove part of the disused pipelines decommissioned before 2000 to prevent entanglement risk. For the UK, pipelines decommissioned in place will be subject to a suitable monitoring programme agreed with BEIS in consultation with other government departments.</p>
10.2.4	Structure and facilities	UK & Norway; USA	<p>The UK and Norway refers to OSPAR Convention (Ministry of Petroleum and Energy (Norway), 2010), (Department for Business Energy and Industrial Strategy UK, 2011), (OSPAR Commission, 2009), (OSPAR Commission, 2013), where concrete footings or part of the concrete footings, or footings of fixed steels structures &gt; 10,000 tonnes may be left in place. The OSPAR convention is strict on what may be left at sea.</p> <p>For piles, the USA requires a removal up to 15 feet below the mud line (similar to Well P&amp;A), while for the OSPAR convention, piles should be cut below natural seabed level at such a depth to ensure that any remains are unlikely to become uncovered (Government of USA, 2014b) .</p> <p>For structure re-use as an Artificial Reef, the USA has the most developed guidelines on Rigs-to-Reef (Bureau of Safety and Environmental Enforcement (USA), 2016b)</p>
10.2.5	Reuse Standards	USA	<p>The National Artificial Reef Plan (Guidelines for siting, construction, development and assessment of artificial reefs) provides details on materials criteria, biological consideration such as reef configuration, circulation patterns surrounding reef materials, to ensure that a rig is purposefully relocated (Bureau of Safety and Environmental Enforcement (USA), 2016b).</p>
10.2.6	Waste Management	Norway and UK	<p>All countries have regulations on waste, however Norway has also considered the capacity of local decommissioning yards and local waste treatment facilities, and the regulations are also thorough as it includes radioactive waste from the oil and gas industry, and the incorporated an EU regulation into its national regulation on the import and export of waste (Waste Regulation and Pollution Control Act) (Petroleum Safety Authority (Norway), 2015a).</p> <p>The UK requires that the Chemicals used offshore must be notified through the Offshore Chemical Notification Scheme (OCNS) and chemicals are ranked by hazard quotient, using the Chemical Hazard Assessment and Risk management (CHARM) model. Applications for permits are</p>

			made via the submission of the relevant PET system permit application (Department for Business Energy and Industrial Strategy UK, 2011).
10.2.7	Safety Standards	UK and Norway	All countries require a safety management system in place, but the UK has an additional requirement of a Safety Case under the Offshore Installations (Safety Case) Regulations 2015, while Norway has a similar system called Acknowledgement of Compliance (Petroleum Safety Authority (Norway), 2015b), whereby both systems are goal – setting in nature, and place the onus to the operator to prove that they have a system in place that is safe enough.
10.2.8	Debris survey and clearance	USA and UK	<p>The USA regulation specifies the requirements of a verification work required – such as the extent of area surveyed, the survey method used and over trawling).</p> <p>The UK has similar requirements as compared to the USA regulation, but has an additional requirement that the minimum required will be a radius of 500 metres from the location of an installation.</p> <p>However, while over-trawling is required in the US, for the UK, the advisability of post decommissioning over trawling to confirm that the area is clear of debris will be considered on a case by case basis and will be dependent upon the extent of any cuttings piles and any other relevant circumstances.</p>
10.2.9	Post-Decommissioning	UK	<p>All countries require a close-out report or permit closure requirement. However the UK is the most detailed in its requirement (Department for Business Energy and Industrial Strategy UK, 2011).</p> <p>Based on UK regulations, a Close-out Report must be submitted within four months of the completion of offshore work, including debris clearance and post decommissioning surveys. The report should explain major variations from the decommissioning programme based on milestones, major variances from the programme such as sludge amounts, and costs, any independent verification reports and future schedule for monitoring.</p>
10.2.10	3 <sup>rd</sup> party validation	Thailand	For most countries, third party verification is required for financial estimates or as post-decommissioning surveying. Thailand has a more robust system as the service agreement in Thailand is based on a royalty system, such that the IOC is involved in the exploration, production and export of fuels, and the Thai authorities may not be as involved as countries which have NOC.

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Thailand requires third-party verification work for reserve verification, decommissioning cost estimate (every three years), the development of RDEA report on potential impacts of decommissioning activities in each defined area, the development of Decommissioning Environmental Management Plan and its consistency with that of the RDEA report (Petroleum Institute of Thailand, 2008).

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10.2.11	Liability	UK	If the decision is abandonment, the licensee or owner shall be liable for damage or inconvenience caused wilfully or inadvertently in connection with the abandoned facility, unless otherwise decided by the Ministry. If there are more than one party liable, they shall be jointly and severally liable for financial (Department for Business Energy and Industrial Strategy UK, 2011)
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Table 9 Results of the strictest applicable regulation and origin of regulation for the category of environmental requirements.

<b>10.3 Environment</b>			
<b>Item no.</b>	<b>Subject</b>	<b>Recommendation</b>	<b>Regulation (Summary)</b>
10.3.1	Impact Assessment	UK	The decommissioning programme must be supported by an EIA (Department for Business Energy and Industrial Strategy UK, 2011), and the EIA also extends consultation of the relevant area, such as fishing to other users of the North Sea, such as the Scottish Fishermen's Federation (SFF), Northern Irish Fish Producers' Organisation (NIFPO), Anglo North Irish Fish Producers Organisation (ANIFPO), National Federation of Organisations (NFFO) and VisNed (Association of Dutch Demersal Fishers).
10.3.2	Post-Environmental Monitoring	Thailand	<p>Limited information from the Gulf of Thailand will initially require a case by case approach to the management of seabed deposits with site specific investigations and environmental evaluations. The physical, chemical and biological characteristics of the seabed deposits should be established (Petroleum Institute of Thailand, 2008).</p> <p>Limitations due to unproven effectiveness of some of the management options will require initial field trials and extensive monitoring to determine their feasibility. Pre and post decommissioning monitoring is required for the seabed deposits management, on-condition that the field trials and extensive monitoring demonstrate no significant risk to the environment, in-situ methods (undisturbed or capping) or ex-situ/removal methods (onshore disposal, re-injection).</p>
10.3.3	Rigs-to-Reefs Management	USA/ Thailand	<p>USA issued Guidelines for siting, Construction, Development and Assessment of Artificial Reefs that includes social economic considerations, environmental and biological considerations (Petroleum Institute of Thailand, 2008), (Bureau of Safety and Environmental Enforcement (USA), 2016b).</p> <p>For example: Prospective reef builders should have an understanding of the limiting factors involving the fauna and flora that will utilize an artificial reef site. Builders should identify the habitat type and/or species targeted for enhancement and determine which biological, physical, and chemical site conditions will be most conducive to meeting the objectives. Once these siting criteria are determined, they should be used in identifying potential construction sites and materials to be used. Infaunal communities in the area where the reef is to be built should be considered prior to placement. Artificial reefs should not be constructed on many types of natural habitats, or in such a manner that would threaten the integrity of natural habitats, such as existing coral reefs, beds of aquatic grasses or macroalgae, oyster reefs (except for shell stock replenishment) scallop, mussel, or clam beds; or existing live bottom.</p>

*Table 10 Results of the strictest applicable regulation and origin of regulation for the category of financial requirements.*

<b>10.4 Financial Security</b>			
<b>Item no.</b>	<b>Subject</b>	<b>Recommendation</b>	<b>Regulation (Summary)</b>
10.4.1	Financial Security Requirement	UK and Thailand	The Thai framework is very detailed in terms of setting out the conditions in which financial security is required (Petroleum Institute of Thailand, 2008). The UK framework is even more robust, as its newly amended Energy Act (2016) established the Oil & Gas Authority (UK) as an independent regulator with additional powers such as having access to company meetings, data acquisition, and imposing sanctions (Department for Business Energy and Industrial Strategy UK, 2011), in short, being able to take action should there be ‘what if’ scenarios of the operators not meeting these criteria.

## **11. Conclusion**

The choice of decommissioning procedure is subject to stringent and extensive international regulations. However, considerable discretion is still left to national governments. The majority of the regulations covering the technical section are similar – the requirement states that the removal of items must take place up to a safe level below the mud-line, or if it is not feasible due to pressing safety concerns, an alternative proposal may be accepted. If items are allowed to be left behind, there must be proof that the items left behind are stable or with a leaching rate that is within regulations, or that an on-going post-decommissioning monitoring plan is in place to ensure that the risks to the human health and the environment or to any commercial interests are as low as possible. Generally, the requirements have a criteria to meet, but also allows for alternatives to be proposed due to other pressing, legitimate concerns.

The major differences lay in the overall philosophies of the framework – with the USA, Thailand taking a more prescriptive role with stricter requirements, and with the UK and Norway taking a goal-setting regime, in which there is liability to the operator to meet its own goals, but goals to be set are not 100% free of boundaries – the goals are also delimited by some form of the regulatory limit. The goal – setting regime works in the North Sea as there has been a long-standing history of such a mechanism (since the Piper Alpha incident), starting from when operators are applying to explore or produce hydrocarbons, up to the decommissioning process. Hence, there has been a sufficient transition period such that the North Sea operators are familiar with these goal-setting requirements.

There are less technical areas which may require more attention, such as financial capability of the company to withstand the decommissioning costs, minimisation of costs while meeting regulatory requirements, transfer of liability if other decommissioning options are accepted, and the movement of wastes from offshore to onshore.

### **Financial Capability / Ability to impose sanctions**

The area which requires extra attention is whether the operators or lessors possess the financial capabilities to successfully execute the decommissioning project. In some cases in the Gulf of Mexico, there may be trends for large companies to transfer sunset properties to smaller, less experienced companies, in which these

smaller companies are more financially-sensitive to volatility in the market, which may render them incapable of completing the decommissioning project. Another consideration is the differences in how the resources are managed. Norway has a 50% state ownership in the North Sea operations via Statoil, whereas countries like Thailand have a concessions or royalty/tax system, where the exploration, production and exporting of oil resources is managed by the IOCs and Thailand receives payments based on these activities. This also suggests that in such systems, the Thai government is more removed from the operations at the drilling floor, and the company's performance. Hence the Thai guidelines have a much stricter requirement on providing proof of financial capabilities, or even require the security bonds to minimise risks of financial inability to decommission a facility.

An important mechanism to the strict financial requirement of operators is for a body to be able to impose sanctions on the company should they fail to meet the requirements. The UK government has considered that and amended the Energy Act 2016 to allow the Oil & Gas Authority to take pre-emptive action, such as having access to company meetings, data acquisition so that any impending signs in which an operator is unable to fulfil its obligation is highlighted while there is still room to take other assistive actions. Also, the Oil & Gas Authority is allowed to impose sanctions should any operator fail to meet its commitment.

### **Minimisation of costs while meeting regulatory requirements**

Currently, only the UK government has a strategy on a well plugging and abandonment optimising programme as part of the bigger decommissioning workflow. Well plugging and abandonment costs make up the majority of decommissioning costs. The output will be a published guide that focuses on reducing well plugging and abandonment costs, as part of their strategy of maximising economic recovery. The key feature of the programme is to encourage collaborative working, and perhaps the adoption of improved contracting models (such as for heavy lift vessels) and stimulate the work-sharing campaigns. With a framework and structured environment towards work-sharing, such as in optimising well identification well plugging sequencing and timing, there will be a lower cost work environment which may reduce the number incidences of operators being ill-financed to follow through the decommissioning programme.

### **Residual liability for liability transferred / Commitment to long-term monitoring and maintenance**

Climate suitability and sub-sea topography may allow rigs-to-reef projects to flourish. In areas such as Thailand, Malaysia, and the Gulf of Mexico, the guidelines promote rigs-to-reef projects as a highly viable and economical decommissioning option. In such cases, the liability of the rigs-to-reef is then transferred to the respective states / government. Some mechanisms need to be further developed such that operators would donate the decommissioned platform to the state and contribute a portion of the avoided decommissioning costs to a designated fund. The mechanism would require a detailed procedure for calculating avoided costs and defining tax consequences.

In the North Sea, and in the area governed by Norway, there are some structures in which they have been left behind, such as the 1.2 million tonnes concrete substructure of the Ekofisk field, which have been allowed by the Norwegian government to be left behind due to the immense difficulty and risk associated with removing it. Most of the time, the pipeline networks, whether in the North Sea or the Gulf of Mexico, are allowed to remain in the seabed if it had been cleaned pigged and cap and covered with concrete mats etc. While there may be potential gains in the form of improved technology in removal of large structures like the concrete substructures in the future, there should be proper monitoring and maintenance for the structures such as the pipelines which might remain in perpetuity. It is thus crucial to have funding mechanism, such as the Removal Grants Act in Norway in which a similar grant mechanism can set aside funding for any potential future liability incurred such as the resurfacing of disused pipelines from natural erosion process.

### **Movement of waste from offshore to onshore**

The act of decommissioning offshore facilities involves moving the pieces back to onshore for further processing. In South-East Asia there is concern that there are insufficient yards to process the wastes. In establishing yards, requirements of siting such a polluting industry must also be developed. In addition, specialised waste management treatment is required for mercurial or radioactive wastes from the oil and gas industry.

In summary, technical regulations across countries are similar and allow bandwidth for alternatives, and more attention should be paid to ensuring sufficient financial capability, practical liability transfer and meeting environmental concerns of waste movement. Regulations aside, perhaps a more pressing concern of the decommissioning industry is in the execution of the project. Requirements of heavy lift machinery such as the

derrick barges needing to be ordered years in advance, and engineering analysis of modular structural removal while considering a continuously changing risk profile or unknown structural integrity makes decommissioning a complex and cost-intensive activity.

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