Interreg
North Sea Region
Decom Tools
European Regional Development Fund

EUROPEAN UNION

COST MODELLING FOR OFFSHORE WIND FARM DECOMMISSIONING

DECOMTOOLS 2022

Project Acronym:	**DecomTools**
Reference Number:	**Interreg North Sea Region– Project Number: 20180305091606**
Project Title:	**Eco-Innovative concepts for the end of offshore wind energy farms lifecycle**
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Project Partners:

Contents

Abbreviations

AWJC	Abrasive Water Jet Cut
BV	Barge Vessel
CLV	Cable Laying Vessel
DCBV	Derrick Crane Barge Vessel
DP	Decommissioning Plan
HLV	High Lift Vessel
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IF	Inflation Factor
MM	Meteorological Mast
OSV	Offshore Support Vessel
OS	Offshore Substation
OWF	Offshore Wind Farm
JUV	Jack-Up Vessel
PTV	Personnel Transfer Vessel
ROV	Remotely Operated Vehicle
RDV	Rock Dumping Vessel
TB	Tug Boat
TP	Transition Piece
WBS	Work Breakdown Structure
WT	Wind Turbine

1. Introduction

The adverse effects of climate change have accelerated the development of renewable energy systems to reduce greenhouse gas emissions in the energy sector. As one of the main renewable energy resources, the offshore wind power industry plays a crucial role in dealing with the climate challenge. The recent advancements in installation technologies have been significantly boosted offshore wind capacity all over the world [1]. The report published by the International Renewable Energy Agency (IRENA) [2] reveals that the global installed offshore wind power capacity has experienced remarkable extensions during the last decade, extending from 2.13 GW in 2009 to 23.36 GW in 2018. With an offshore wind capacity of 18.52 GW in 2018, the European Union is known as the global leader in the offshore wind energy sector [2]. Recent policies and strategies announced by different countries in the continent reveal that the European Union has decided to keep its role as the global leader in the offshore wind sector by enhancing its offshore wind capacity in the coming years. The European Union plans to meet the overall offshore wind capacity targets of 150 GW and 460 GW in 2030 and 2050, respectively [3-5]. All these extension plans highlight the necessity of considering the cost management and possible environmental impacts of offshore wind installation projects.

According to the current experience in the offshore wind sector, the expected design life of Offshore Wind Farms (OWFs) are typically predicted to be between 20 and 25 years [6]. Thus, the number of OWFs that need to be decommissioned will be remarkably increased in the next decades. In some cases, the extreme weather conditions can make the design life of OWFs even shorter and force the wind farm owners to consider the decommissioning earlier than predicted. Some cases confirm the importance of early decommissioning of OWFs, such as Yttre Stengrund OWF [7] and Utgrunden OWF [8] in Sweden decommissioned after 15 and 18 years of operations, respectively. Literature review shows that several decommissioning plans (DPs) have been proposed for some of OWFs currently under operation. The examples are the DPs proposed for the Sheringham Shoal OWF [9] and Lincs Limited [10] OWFs. The environmental impacts and economic feasibility are two main criteria in the assessment of DPs for OWFs. Therefore, the DPs generated for OWFs should be assessed based on the holistic economic and environmental models.

The cost models developed based on previous experience are typically employed to estimate the life-cycle costs of OWFs. Literature survey reveals that a variety of cost modelling approaches have been developed by researchers for OWF installation projects [11-16]. One of the most important contributions in this field is the work done by Kaiser and Snyder [17], in which a cost modelling approach based on the current technologies and expected market conditions was proposed to predict the stage-specific installation costs of three OWFs in the US, including the Cape Wind, Bluewater Wind, and Coastal Point Galveston. Based on the previously available data and information from the different OWF installation projects, Gonzalez-Rodrigue [18] developed a new cost model which can estimate the installation costs by considering the size of the wind farms. However, due to the sensitivity of costs to the site-specific information, it seems to be unrealistic to define the overall OWF installation cost as a function of wind farm size.

The decommissioning of an OWF can be defined as a set of operations that aim to return the wind farm site to its original state before the construction under some environmental considerations. The current practice shows that the decommissioning operations for OWFs are usually carried out in reverse order of the installation process. The decommissioning operations are typically expected to be faster and less expensive than the installation operations [19,20], as relatively less caution is required for the removal operations. However, the prediction of OWF decommissioning costs is not an easy task due to the lack of information and limited previous experience in the field. In some researches and technical reports, the decommissioning costs of OWFs were considered as a given percentage of the installation costs [12,21]. However, this approach does not seem to be realistic as the data and site-specific information of each OWF are unique, which make it difficult to provide general percentage values to predict the decommissioning costs for all OWFs. Therefore, more efficient cost modelling approaches are needed to predict the decommissioning costs of different OWF projects, in which the different site-specific information is taken into account.

This report aims to review the current practice in OWF installations and discuss the possible decommissioning scenarios. The available experience and information in OWF installation are investigated in detail and the cost formulations for OWF decommissioning are developed. The rest of this report is organised as follows. In Section 2, the current technologies and methods in the installation of OWF assets will be briefly reviewed. Then, Section 3 presents the detailed cost modelling formulations developed for the OWF decommissioning projects. Finally, the concluding remarks will be presented in Section 4.

2. OWF installation

Each OWF consists of different components, including foundations, WTs, inter-array and export cables, OS(s), and MM. In the following subsections, the current practice in the installation of different components of OWF as well as the applied vessels/equipment will be discussed in detail.

2.1. Foundation installation

Foundations are support structural systems that transfer the loads from the topside structure to the soil layers in the seabed. Depending on the water depth, the size and weight of the topsides, sea state, and weather conditions, foundations can be designed in different forms. The survey of OWF commissioned so far shows that different types of foundations have been designed to support WTs, OSs, and MMs. The monopiles, jackets, tripods, and floating structures are examples of foundation systems designed for the OWFs. As the monopile and jacket foundations are mostly applied in the current OWFs, this report will focus on these two types of foundations.

For the OWFs in shallow waters (typically in water depths less than 25 m), the *monopile* is the best option for the foundation due to its simple structure and ease of erection. In the UK, due to the lower water depths, most of the foundations in OWFs are monopile structures. Monopiles are typically steel structures with circular cross-sections which are driven by a hydraulic hammer device into the seabed. The driven depth of monopile foundations depends on the seabed geotechnical features, the weight of the topside structure, and the dimensions of the monopile structure. For the seabed with softer soil, the bigger monopiles would need more time for installation. According to the available data from the wind farm projects in Northern European waters [22], the average installation time for each monopile with TP, including transit time and weather delays, is about 3.6 days. Based on [23], a total installation duration of 3 days can be considered for all installation stages of monopiles. Roughly speaking, the installation operations require about 15 employees working 12-hour shifts, which results in 30 workers for each day [24].

The *Jacket* structures shown in Fig. 1 are more suitable to support the heavy topside structures in OWFs located in deeper waters, ranging from 30 m up to 80 m [25]. Installation of jacket structures is a little bit difficult and more time-consuming operation in comparison to the monopile foundation installation. In the installation of the jacket structures, several piles are driven into the seabed, which can make the installation time longer than predicted. In some references, the piling time required for jacket structures is reported as 2.5 times than those for monopile structures [22,26]. Although the overall installation duration varies depending on the project specifications, 24 hours extra installation time can be considered for jacket structures in comparison to the monopile foundations.

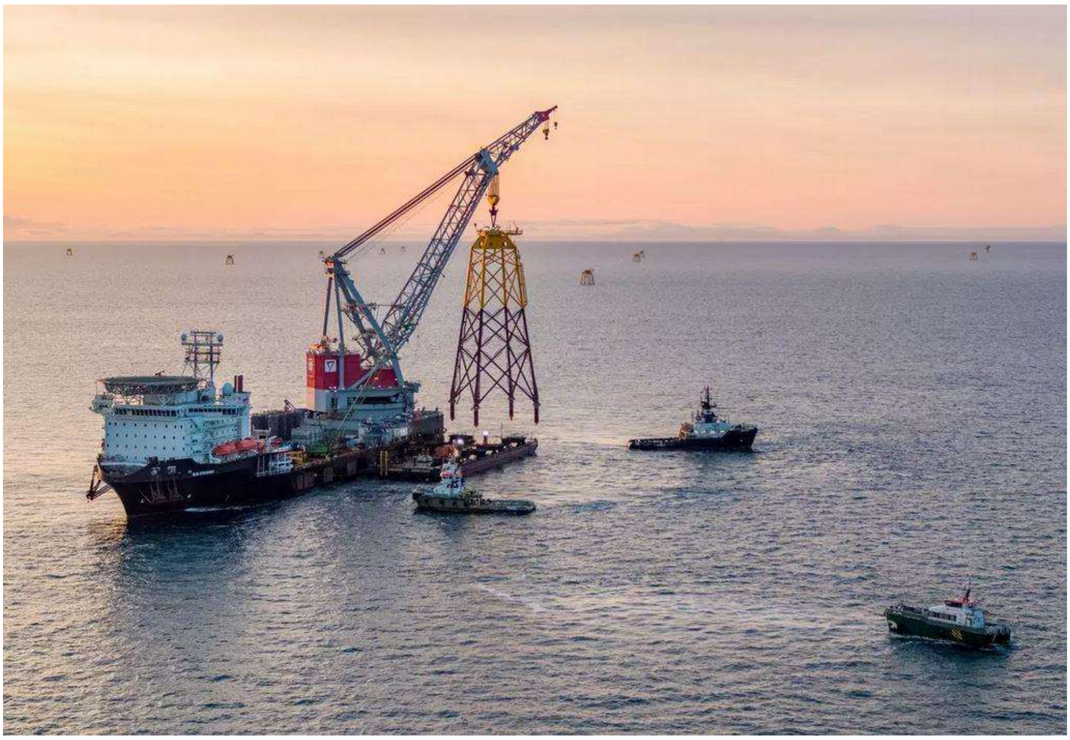

Fig. 1. Jacket installation for WTs in Beatrice OWF, UK[1]

For foundation installation, traditional crane vessels can be employed. However, the application of the Jack-Up Vessels (JUVs) is more common these days. In some cases, a combination of JUV and Offshore Supply Vessel (OSV) are used to reduce the rental duration of JUVs. After monopile installation, the area around the foundation is protected by scour protection.

2.2. TP installation

The TP connects the foundation to the tower section of the WT, which is a circular steel section with the work platform and boat landing areas as well as j-tube cable guides. The TP is usually connected to the tower section through a flanged connection, while it is typically connected to the foundation through grouted connection with an ultra-high-strength grout material. It should be noted the flanged connection between the TP and foundation were also used in some projects. The installation process for the TP is relatively straightforward. It is usually mounted on the top of the foundation as soon as the foundation is driven into the seabed. The TP and foundation can also be installed as a single segment in one offshore lift to reduce the installation time [22]. The current installation reports show that it is relatively common to define the installation of foundations and TPs within a single installation program. Different vessels can be employed for foundation and TP installations. As the TP is fabricated onshore and transported by vessels to the OWF site, an independent installation process of the TP would take a few hours.

[1] Picture source: www.beatricewind.com

2.3. WT installation

The WTs consist of different components, including blades, hub, nacelle, tower, TP, and foundation. This subsection will discuss the WT installation. Current practice in WT installation shows that different strategies have been devised by wind farm installation companies depending on the available vessels/equipment, port facilities, and safety considerations. These strategies include different types of operations and numbers of lifts, which can significantly affect the installation time. The WT installation operations are typically sensitive to weather conditions, and special care is required for each operation. Fig. 2 shows the different installation methods for WTs alongside their required number of offshore lifts. The WT installation methods shown in Fig. 2 can be described as follows:

- **Method I:** In the first method, two sections of the tower are installed in two independent lifts. Then, the nacelle with hub is lifted together to the top of the tower. Finally, the three blades are connected to the hub in three separate lifts. Thus, this method includes 6 lifts. Due to the high lengths of WT blades, the blade installation is very sensitive to the wind speed and it may be interrupted by severe wind speeds.

- **Method II:** In this method, the tower is assembled onshore and installed as a single part in a single lift. Then, the nacelle with a pre-attached rotor hub is mounted on the top of the tower (see Fig. 3). The installation operation is followed by three separate lifts for the blades. Thus, this method includes 5 independent lifts.

- **Method III:** In this method, the nacelle and all parts of the tower are transported to the offshore site and lifted separately. The blades and rotor hub are assembled onshore and transported to the offshore site. Then, the rotor hub with connected blades (i.e. star configuration) is lifted as a single part and connected to the tower (see Fig. 4). This method requires fewer liftings as the blades and rotor hub are lifted in a single lift.

- **Method IV:** In this method, the assembled nacelle and rotor hub with attached two blades (i.e., bunny ear configuration) (see Fig. 5), the tower in two pieces and a single blade are transported to the wind farm site as separate segments. The tower is installed in two lifts, while the nacelle and rotor hub, as well as two blades, are installed through a single lift. Then, the third blade is attached to the hub in a single lift. This method needs four independent lifts.

- **Method V:** This method is similar to the previous method. The only difference is that the different pieces of the tower preassembled onshore and transported to the offshore site for a single lift. This method requires three offshore lifts.

- **Method VI:** In this method, the whole pieces of the WT are assembled at the dockside or on a BV, and installed in a single heavy lift. An HLV with a minimum lifting capacity of 500 tons is required for this method (see Fig. 6).

The installation method is selected based on the weather condition, costs and specifications of available vessels, WT model, and the size of the components. The main disadvantage of the first and second methods is the delay susceptibility of the blades liftings under severe wind speeds. On the other hand, these methods reduce the space occupied by the blades on the deck space and provide easier transportation of the blades to the installation site. For the rest of the installation methods, it seems that the occupied space on the vessel's deck will be more than the first and second methods, which means that the vessels would require more trips from the shore to the wind farm site. Another important issue is the safety considerations for each of these methods. The project schedulers need to assess each WT installation method based on the cost and safety criteria.

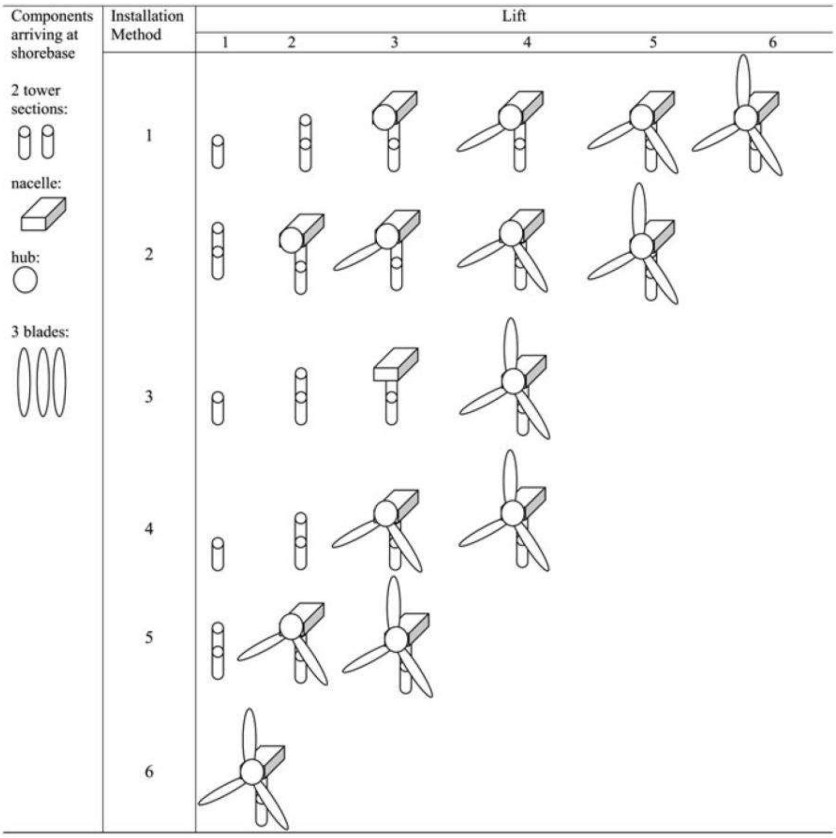

Fig. 2. Different installation methods for WTs [22]

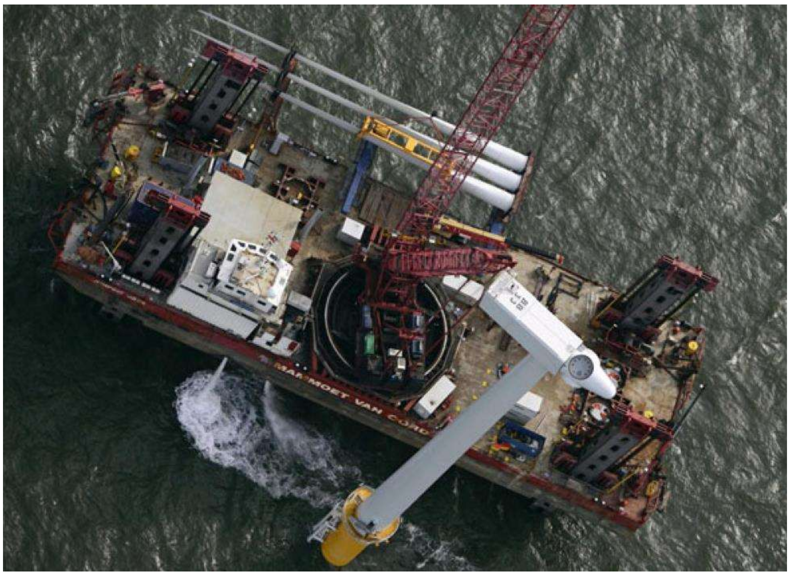

Fig. 3. Installation of nacelle and hub in a single lift at Burbo Bank, Siemens [22][1]

Fig. 4. Installation of the pre-assembled rotor hub and blades in a single lift at Alpha wind farm [22][2]

[1] Picture source: Siemens
[2] Picture Source: Alpha Ventus

Fig 5. Lifting the pre-assembled nacelle, rotor hub, and two blades as bunny ear configuration [22][1]

Fig. 6. Lifting the whole WT in a single lift at Beatrice wind farm [22][2]

Based on the literature survey performed for this report, the duration required for each stage of the abovementioned installation methods is sensitive to the weather condition, vessel type, and the experience of the installation crew. However, approximate durations for different stages of installation methods can be assumed as in Table 1 [23]. It is worth mentioning that the durations listed in Table 1 are approximate. To find more holistic durations for planning installation

[1] Picture Source: DONG
[2] Picture source: REPower

operations, a comprehensive stochastic analysis is required based on the stochastic intervals and site-specific information.

Table 1. Offshore lifting duration required for each component of a WT [23]

Installation operation	Duration (hours)	Allowable wind speed (m/s)
Each single blade	4	8
Assembled rotor	5	8
Nacelle	4	10
Tower	6	12
Complete WT	12	7

2.4. OS installation

The OS consists of two main components, including the foundation and topside. The foundation of the OS can be a monopile or a jacket structure, depending on the water depth, topside weight, and the distance from the shore. In comparison to the monopile foundation, the installation duration is expected to be longer for the jacket foundation. Both the foundation and topside superstructures are fully fabricated onshore and transported to the wind farm site. Fig. 7 shows the OS with monopile foundation in Sheringham Shoal OWF in England. The installation of the foundation can be performed independently or as a part of the general foundation installation plan of the wind farm. Thus, the required duration for the foundation installation of OSs will be similar to those discussed for the WT foundations. Therefore, only the installation of the topside will be discussed in this subsection.

The topside installation of the OS is a heavy lift operation of about 2000 tons[1], which requires an appropriate vessel crane capacity. Most of the vessels, which can perform this heavy lift operation, do not have enough deck space to carry the topside of the OS. Therefore, an additional vessel (e.g., BV) is required to transport the topside of the substation from the quayside to the installation site. The OS installation can be performed by using the sheerleg crane, BV, HLV, and semisubmersible vessels. The day rates for these vessels are very sensitive to the market situation.

Literature survey shows that there are no reliable data on the installation duration of the OS. For the foundation, it seems that the installation duration could be considered the same as it is for the WT foundations. The topside installation is a heavy lift operation performed by HLVs, which typically have slower manoeuvre capabilities. The proposed plan for Cape Wind Energy [28] project in the US has considered one month for the full OS installation. However, the most time-consuming part of the OS installation is related to the finishing works, which are usually done without expensive vessels. The topside installation by an HLV can be ideally done in a single day.

[1]Between 500 to 2000 tons [27]

However, due to the slow manoeuvre capabilities of the employed vessels, it is expected to take more than one day to mount the topside on the foundation [22].

Fig. 7. OS with monopile foundation in Sheringham Shoal OWF, England[1]

2.5. Installation vessels

The vessel type selection for the installation of different components plays an important role in the management of OWF installation costs. Most of the wind farm installation vessels belong to the category of JUV or self-propelled vessels. There are a wide variety of vessels with different specifications and capabilities provided by different companies in the North sea region. Some of them were originally designed for OWF installation tasks, while some vessels were originally developed for the oil and gas industry. Generally speaking, the vessel selection in an OWF installation project mainly depends on the market situation, duration of the project, and size of the components. Sometimes, an appropriate selection of vessels can minimise the loading/off-loading times and reduce the transportation costs of OWF installation. In the following subsections, the main installation vessels applied in the recent OWF installation projects will be briefly discussed.

A. JUVs

Generally speaking, the JUVs can be categorised into jack-up barges and self-propelled JUVs. The JUVs consist of three or more support legs, which are jacked down onto the seabed before starting the installation process. The vessels use a preloading mechanism to provide adequate legs penetration to the seabed. Then, the vessel is lifted to a given height by a jacking system. By using the jacking system, not only the easy access of crane to the installation area is provided, but also the barge hull is not subjected to the tidal and loading acts. One of the limitations of JUVs is their

[1] http://sheringhamshoal.co.uk/newsdownloads/gallery.php

leg lengths, which practically limit their application for the installation of OWFs in deeper waters. The daily rates for these vessels are typically do not include the fuel prices. Hence, in the rental cost calculations for these vessels, the daily fuel consumption may also be added to the daily rental price. The *jack-up barges* are not self-propelled and they usually require TBs to be towed o the installation site.

The JUVs with several moveable legs can perform the installation tasks at a given height. The jacking speeds of the moveable legs depend on the vessel specifications and are usually between 0.35 m/min to 0.8 m/min. Generally, the jacking process is subjected to some limitations, such as maximum wind speed, water depth, and wave height. For example, Fig. 8 shows the JB-114 jack-up barge developed in 2009 and applied for the installation of Alpha Ventus and Belwind OWFs. The JB-114 has four moving legs with 73.15 m length and 3.00 m diameter. The jacking-up and jacking-down speeds of the legs are 0.4 m/min and 0.6 m/min, respectively. The crane capacity of the JB-114 is about 300 tons with a radius of 22 m. In addition, the operational performance of the vessel is limited to the maximum wind speed and wave height of 8 m/s and 15 m, respectively. Other detailed specifications for each model of the jack-up barges are accessible in related online resources. Depending on the specifications and capabilities, jack-up barges can carry two up to eight WTs. The *self-propelled* JUVs usually consist of equal or more than four legs, which can carry ten or more WTs. Fig. 9 shows the Seafox 5 self-propelled JUV used in Dan Tysk OWF in Germany for the foundation installation, which is consisted of four legs and an available deck area of 3,750 m^2. Fig. 10 shows the Wind Lift I self-propelled JUV used for foundation installation in BARD Offshore I wind farm, UK. The main crane capacity of the Wind Lift I vessel is 500 t at 31 m radius and the available deck space area is equal to 2,224 m^2.

Fig. 8. Jack-up barge J-114 applied for the installation of Alpha Ventus and Belwind windfarms[1]

[1] Picture source: https://www.jackupbarge.com/wp-content/uploads/2014/12/JB-114-Header-image-1920x830.jpg

Fig. 9. Seafox 5 self-propelled JUV applied for foundation installation in Dan Tysk OWF[1]

Fig. 10. Wind Lift I self-propelled JUV used for foundation installation in BARD Offshore I OWF

[1] Picture source: http://www.shipspotting.com/gallery/photo.php?lid=2808792

B. HLVs

HLVs with high crane capacities are attractive options for heavy lift installations in OWF projects, such as foundation installation and the whole WT tower lifting operation. They are not self-elevating vessels and they usually use dynamic positioning systems which make them able to fix their position during the installation process. However, some of HLVs use conventional mooring systems. Because of their high crane capacity, the HLVs have been widely used to install the foundations and OSs in OWF projects. The deck cranes of these vessels may be either rotatable or fixed. One of the main limitations of these vessels is their limited deck space, which necessitates the use of additional BVs. Fig. 11 shows the Oleg Strashnov HLV with a crane capacity of 5,000 t and deck space of 3,950 m^2, which has been employed for foundation installation in Sheringham Shoal, Trianel Windpark Borkum 1, Borkum Riffgat, and Meerwind OWFs. The Stanislav Yudin shown in Fig.12 is another HLV with a crane capacity of 2,500 t and an available deck space of 2,500 m^2.

Table 2 lists some of the applied vessels for the OWF installations in the EU region. Moreover, Table 3 summarises the installation vessels used for foundation and WT tower installations in different OWF projects.

Fig. 11. The Oleg Strashnov HLV used for foundation installation in Sheringham Shoal, Trianel Windpark Borkum 1, Borkum Riffgat, and Meerwind wind farms[1]

[1] Picture source: https://www.royalihc.com (Royal IHC)

Fig. 12. The Stanislav Yudin HLV was used for foundation installation in Greater Gabbard, Gwynt y Mor, and Global Tech I wind farms

Table 2. The applied vessels for the construction of different wind farms in the EU region [27]

Vessel	Type	Operational water depth (m)	Maximum crane capacity (tons)	Applied wind farms
Sea Jack	Jack-up barge	35	1300	Princess Amalia, Arklow, Scroby Sands
Svanen	Heavy-lift	>100	8700	OWEZ, Rhyl Flats, Gunfleet Sands
Buzzard	Jack-up barge	45	750	Alpha Ventus, Thornton Bank
JB 114 and 115	Jack-up barge	50	280	Alpha Ventus
Thailf	Heavy-lift	>100	14200	Alpha Ventus
Taklift 4	Sheerleg crane	>100	1600	Alpha Ventus
Excalibur	Jack-up barge	30	220	North Hoyle
Lisa A	Jack-up barge	50	600	Rhyl Flats
MEB JB1	Jack-up barge	40	270	Middlegrunden, North Hoyle, Yttre Stegrund
Goliath	Jack-up barge	50	Up to 1200	
Sea Worker	Jack-up barge	40	400	Robin Rigg; Gunfleet Sands

Table 3. Installation vessels used for foundation and WT tower installations [1]

Wind farms		Country	Installation vessels	
			Foundation	Tower
1	Utgrunden I	Sweden	Wind	Wind
2	Middelgrunden	Denmark	Eide Barge 5	MEB-JB1
3	Yttre Stengrund	Sweden	Excalibur	MEB-JB1
4	Horns Rev 1	Denmark	Buzzard, Wind	Sea Energy, Sea Power
5	Rodsand 1	Denmark	Eide Barge 5	Sea Energy
6	Samso	Denmark	Vagant	Vagant
7	North Hoyle	UK	Excalibur, The Wind	MEB-JB1, Excalibur, Resolution
8	Arklow Bank I	Ireland	Sea Jack	Sea Jack
9	Scroby Sands	England/UK	Sea Jack	Sea Energy, Excalibur
10	Kentish Flats	England/UK	Resolution	Sea Energy
11	Barrow	England/UK	Resolution	Resolution
12	Lillgrund	Sweden	Eide Barge 5	Sea Power
13	OWEZ	Netherlands	Svanen	Sea Energy
14	Burbo Bank	England/UK	Sea Jack	Sea Jack
15	Beatrice Pilot	Scotland/UK	Rambiz	Rambiz
16	Prinses Amalia / Q7	Netherlands	Sea Jack	Sea Jack, Sea Energy
17	Lynn & Inner Dowsing	England/UK	Resolution	Resolution
18	Robin Rigg	Scotland/UK	Resolution	Sea Worker, Sea Energy
19	Thornton Bank I	Belgium	Rambiz	Buzzard
20	Rhyl Flats	Wales/UK	Svanen	Lisa A
21	Horns Rev 2	Denmark	Sea Jack	Sea Power
22	Gunfleet Sands I & II	England/UK	Svanen, Excalibur	Sea Worker, KS Titan
23	Thanet	England/UK	Sea Jacks, Resolution	Resolution
24	Rodsand II	Denmark	Eide Barge 5	Sea Power
25	Alpha Ventus	Germany	Odin, JB114	Taklift 4
26	Alpha Ventus	Germany	Buzzard, JB115, Thialf	Thialf, Buzzad
27	Sprogo	Denmark	N/A	Sea Energy
28	Belwind	Belgium	Svanen, JB114	JB114, JB115
29	Greater Gabbard	England/UK	Stanislav Yudin, Javelin, Leviathan	Leviathan, Sea Jack, Kraken
30	Walney 1	England/UK	Goliath, Vagant	Kraken, Sea Worker
31	BARD Offshore I	England/UK	Wind Lift I	Brave Tern; Thor; JB115; JB117
32	EnBW Baltic 1	Germany	Sea Worker	Sea Power
33	Sheringham Shoal	England/UK	Svanen, Oleg Strashnov	Endeavour; Leviathan
34	Ormonde	England/UK	Buzzard, Rambiz	Sea Jack
35	London Array	England/UK	Sea Worker, Adventure, Svanen, Sea Jack	Discovery, Sea Worker, Sea Jack
36	Lincs	England/UK	Resolution, JB114	Resolution
37	Thornton Bank II	Belgium	Buzzard, Rambiz	Neptune, Vagant
38	Walney 2	England/UK	Svanen, Goliath	Leviathan, Kraken
39	Trianel Windpark Borkum 1	Germany	Goliath, Oleg Strashnov, Stanislav Yudin	Adventure
40	Anholt	Denmark	Svanen, Javelin	Sea Power, Sea Worker, Sea Installer, Sea Jack
41	Teesside	England/UK	Sea Jacks, JB114	Adventure
42	Thornton Bank III	Belgium	Buzzard, Rambiz	Goliath, Vagant
43	Borkum Riffgat	Germany	Oleg Strashnov	Bold Tern
44	Gwynt y Mor	Wales/UK	Stanislav Yudin, Friedrich Ernestine	Sea Jack, Sea Worker
45	Karehamn	Sweden	Rambiz	Discovery
46	Meerwind	Germany	Zaratan, Leviathan, Oleg Strashnov	Zaratan, Leviathan
47	Global Tech I	Germany	Innovation, Stanislav Yudin	Thor, Brave Tern, Vidar, HGO Innovation
48	Gunfleet Sands III	England/UK	Ballast Nedam	Sea Installer
49	Nordsee Ost	Germany	Victoria Mathias	Victoria Mathias, Friedrich Ernestine
50	Belwind Haliade Prototype	Belgium	Pacific Osprey	Bold Tern
51	Dan Tysk	Germany	Seafox 5	Pacific Osprey
52	Northwind	Belgium	Neptune	Resolution, Neptune

(continued on next page)

Table 3. (continued)

	Wind farms	Country	Installation vessels	
			Foundation	Tower
53	West of Duddon Sands	England/UK	Pacific Orca, Sea Installer	Sea Installer
54	EnBW Baltic II	Germany	Goliath, Taklift 4	Vidar
55	Humber Gateway	England/UK	Resolution, Discovery	Resolution
56	EnBW Baltic II	Germany	Svanen	Vidar
57	Amrumbank West	Germany	Svanen, Discovery	Adventure
58	Borkum Riffgrund 1	Germany	Pacific Orca	Sea Installer
59	Westermost Rough	England/UK	Innovation	Sea Challenger
60	Butendiek	Germany	Svanen, Javelin	Bold Tern
61	Luchterduinen	Netherlands	Aeolus	Aeolus
62	Westermeerwind	Netherlands	Crane on a barge	De Schelde
63	Gode Wind I & II	Germany	Innovation	Sea Challenger
64	Kentish Flats Extension	England/UK	Neptune	Neptune
65	Gemini	Netherlands	Aeolus, Pacific Osprey	Aeolus, Pacific Osprey
66	Sandbank	Germany	Pacific Orca	Adventure
67	Nordsee One	Germany	Innovation	Victoria Matthias
68	Rampion	England/UK	Pacific Orca, Discovery	Discovery, Adventure
69	Veja Mate	Germany	Scylla, Zaratan	Bold Tern, Scylla
70	Dudgeon	England/UK	Olev Strashnov	Sea Installer
71	Wikinger	Germany	Giant 7, Taklift 4	Brave Tern
72	Nordergrunde	Germany	Victoria Matthias	Victoria Matthias
73	Nobelwind	Belgium	Vole au Vent	Vole au vent
74	Burbo Bank Extension	England/UK	Svanen	Sea Installer
75	Race Bank	England/UK	Innovation, Neptune	Sea Challenger
76	Galloper	England/UK	Innovation	Pacific Orca, Bold Tern
77	Walney 3	England/UK	Aeolus, Svanen	Scylla
78	Walney 4	England/UK	Aeolus, Svanen	Scylla
79	Ajos	Finland	Vole au Vent	Vole au Vent
80	Pori Tahkoluoto	Finland	Vole au Vent	Vole au Vent
81	Blyth Demonstration	England/UK	TBs	Vole au Vent
82	Hywind Scotland	Scotland/UK	N/A	TBs
83	Rentel	Belgium	Innovation	Apollo
84	Arkona	Germany	Fairplayer, Svanen	Sea Challenger
85	Nissum Bredning	Denmark	Crane, Matador 3	Crane on a barge
86	Aberdeen (EOWDC)	Scotland/UK	Asian Hercules III	Pacific Orca

2.6. Cables installation

Before starting the cable installation process, a survey on the seabed is required to identify the possible obstacles and specify the routes of the cables. This survey is also necessary to ensure that the cable paths are free of any dangerous obstacles, such as the position of existing pipes and unexploded weapons, which can be harmful to seabed users. In addition, it is necessary to clear debris from the cable paths, which can be performed by pre-lay grapnel run or other methods.

Generally speaking, the installation process for both of the export and array cables includes the four main steps as follows: i) cable laying, ii) cable burial, iii) connecting cable to tower, OS, and onshore substation, and iv) testing. The types and the number of vessels required for cable installation depend on the seabed condition and the available facilities of the contractor. Various cable installation methods can be categorised as follows:

- **Method I:** This method is performed by using a *cable plough*, in which the cable is fed to plough by a turntable attached to the vessel. Since this method simultaneously inserts and buries the cable into the seabed, the cable installation costs are relatively less than other methods. By using the water jet technology, this method can bury the cables in a 3 m up to 4 m trench below the seabed. However, the applicability of this method depends on the soil specifications. This method has been applied to export cable installation in different wind farm projects. It is worth mentioning that the cable plough method cannot be performed in the vicinity of the WTs or OSs, and an additional operational with trenching ROV is usually required to connect the cable to WTs.

- **Method II:** In some cases, an ROV, which is carrying a given length of cable, is used to lay and bury the cable into the seabed. Since the cable carrying capacity of the ROV is limited, this method is more appropriate for installing inter-array cables.

- **Method III:** This method pre-excavates a trench using a backhoe dredge and lays the cables within the trench by using a CLV. Finally, the cables are buried using the dredge.

- **Method IV:** In some cases, the cable first is laid on the seabed and then, an ROV is used to bury the cable into the seabed.

- **Method V:** In this method, which is applicable only for inter-array cables installation, the cables are pulled between the WTs using a winch and then, the cables are buried into the seabed by using a CLV.

- **Method VI:** In some cases, combinations of the abovementioned methods are used.

Table 4 lists the cable installation methods used by different wind farm projects.

Table 4. Applications of cable installation methods in different OWF projects [27]

Cable types/ Installation method	Wind farm projects
Inner-array cables/Method I	Rhyl Flats, Scroby Sands
Export cables/Method I	Scroby Sands, North Hoyle, Barrow, Rhyl Flats, OWEZ, Lynn and Inner Dowsing, and Gunfleet Sands.
Inner-array cables/Method II	North Hoyle, Barrow, and Lynn and Inner Dowsing
Inner-array and export cables/Method III	Lillgrund and Middlegrunden
Inner-array cables/Method IV	Kentish Flats, Gunfleet Sands, and Horns Rev 2
Export cables/Method IV	Princess Amalia
Inner-array cables/Method V	Horns Rev 1
Export cables /Method VI	Barrow

The day rate for each of the equipment utilised in different cable installation methods is listed in Table 5. In [21], the general cost for the CLV for inner-array cables is reported as 91,000 €/day and for export cables, it is assumed as 114,000 €/day. These prices include the prices of ROV, cable-handling equipment, cranes, etc. Moreover, the ranges for installation durations of the inter-array and export cables are reported in Table 6.

Table 5. Daily rates for different equipment used in cable installation [29]

Equipment	Daily rate
Cable plough	£5,000
Trenching ROV	£10,000
Vertical injector	£10,000
Jetting sled.	£8,000

Table 6. Installation durations for cable installation [27]

Cable type	Installation rate (day per km)		
	Minimum	Maximum	Average
Inner-array cables	0.15	0.60	0.30
Export cables	0.20	1.40	0.70

3. OWF decommissioning

As it was mentioned in the introduction, the design life of the OWFs is expected to be between 20 and 25 years. Nowadays, the governments of some countries request the DPs from the developers/owners for the new OWFs. In the DPs for the OWFs, the economic, environmental, as well as technical concerns, should be fully addressed in detail. The cost predictions within these DPs should be regularly updated by OWF developers/owners to take into account the cost uncertainties.

The OWF decommissioning operations are performed by expensive vessels/equipment with significant cost uncertainties which can potentially affect the decommissioning costs. On the other hand, some components of OWF should be entirely removed, while some others need to be left in their situ as their removal operations would be more harmful to the environment and marine life. For example, the marine life formed around the foundations and cables during the lifetime of OWF makes the total removal operations too risky from the environmental viewpoint and it is usually preferred to be left in their situ.

Project management plays an important role in decommissioning cost calculations of OWFs. The different stages of OWF decommissioning can be categorised into several work packages. The different work packages are usually represented by the Work Breakdown Structure (WBS) in practical engineering projects. Due to a lack of experience in OWF decommissioning, available experience in the Oil and Gas (O&G) industry will be employed in this report to develop a suitable

WBS for OWFs. The O&G UK proposes a WBS for offshore O&G decommissioning projects [30,31]. In this report, a similar WBS will be adapted for the OWF decommissioning projects as shown in Fig. 13. In the following subsections, the decommissioning options and operations related to each component of WBS will be discussed and the related cost calculation formulas will be explained in detail.

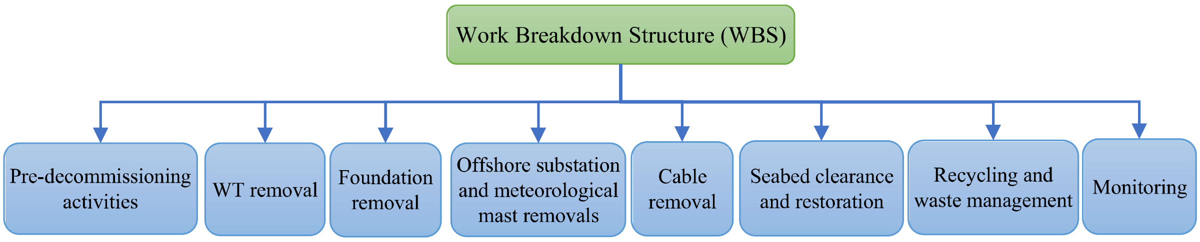

Fig. 13. The WBS for OWF decommissioning [30,31]

It should be noted that this report will not consider the monitoring and recycling and waste management activities. The cost related to each decommissioning activity will be denoted by $Cost_{\mathrm{WT}}$, $Cost_{\mathrm{F}}$, $Cost_{\mathrm{OS}}$, $Cost_{\mathrm{MM}}$, $Cost_{\mathrm{C}}$, and $Cost_{\mathrm{SC}}$, which are the costs of WT removal, foundation removal, OS removal, MM removal, cables removal, and seabed clearance and restoration, respectively. In the following subsections, each decommissioning activity will be explained and their cost formulations will be presented.

3.1. Pre-decommissioning activities

Before starting any removal operations, a set of activities should be performed to prepare the different components of the OWF for the removal operations. The OWF assets preparation can significantly affect the removal durations and costs. The general pre-decommissioning activities usually include but are not limited to, the disconnection of WTs from the grid, preparing lifting points at various components for cranes, cutting cables at removal points such as the cables between the nacelle, tower, and TP, preparation of bolts at removal points for removal operations, providing temporary power to turn the rotor during the removal operations, removal of hazardous fluids inside the nacelle, cutting the J-tubes, seabed survey around the foundations and cables, and de-energisation of the OS. Usually, the costs related to the pre-decommissioning activities $Cost_{\mathrm{P}}$ are estimated as a percentage value of the total decommissioning cost. For example, in Sheringham Shoal [9] DP, the costs related to the preparation activities were estimated to be about 9% of the total decommissioning cost.

3.2. WT removal

Decommissioning of a WT includes the removal of blades, nacelle, TP, and foundation. Currently, available decommissioning methods are in the reverse order of the installation methods. However, some researchers have been proposed new approaches for the decommissioning of WTs. Due to the availability of several installation methods, multiple types of removal techniques are available for WT decommissioning. As the weights of the WT components remain unchanged, the required lifting capacities are the same as those in the installation process and the same installation vessels can be applied for the WT removal. In this report, we have assumed that the same installation vessels would be applied for the cost modelling of the WT removal operation.

The first step in the removal of WT is energy isolation, which can be performed for either all gird or a single WT. After energy isolation, all of the fluids, lubricants, and hazardous material within the hub and nacelle must be removed to prevent their leakages to the sea. The tower section of WT can be removed through unbolting or cutting techniques.

There are various removal methods for WTs defined based on the reverse scenarios of current installation methods as shown in Fig. 2. The total removal cost of the WTs can be mathematically expressed as follows:

$$Cost_{\mathrm{WT}} = C_{\mathrm{mob}}^{\mathrm{JUV}} + \alpha C_{\mathrm{mob}}^{\mathrm{BV}} + {}^{1}\!/_{24}\left(C_{\mathrm{D}}^{\mathrm{JUV}} + \alpha C_{\mathrm{D}}^{\mathrm{BV}} + \beta C_{\mathrm{D}}^{\mathrm{TB}}\right) \times t_{\mathrm{WT}} \tag{1}$$

where:

$Cost_{\mathrm{WT}}$: represents the removal cost of the WTs (pounds)

$C_{\mathrm{mob}}^{\mathrm{JUV}}$: the mobilisation/demobilisation cost of the JUV (pounds)

$C_{\mathrm{mob}}^{\mathrm{BV}}$: the mobilisation/demobilisation cost of the BV (pounds)

α: is the number of applied BVs for the transportation

$C_{\mathrm{D}}^{\mathrm{JUV}}$: is the daily rate for the JUV (pounds/day)

$C_{\mathrm{D}}^{\mathrm{BV}}$: indicates the day rate for the BV (pounds/day)

$C_{\mathrm{D}}^{\mathrm{TB}}$: is the daily rate for the TB (pounds/day)

β: is a constant parameter to consider the required number of TBs. The value of this parameter is equal to the number of BVs (i.e., $\beta = \alpha$) if a self-propelled JUV is used for the lifting process. Otherwise, it is taken as $\beta = \alpha + 1$.

t_{WT}: represents the total duration for the removal of each WT (hours)

The removal duration of WTs, represented by t_{WT}, is determined based on the work time of the most expensive vessel, which is the JUV in this case. The value of this parameter depends on the applied removal method. To explain the different WT removal methods, Figs. 14-20 illustrate different stages for different WT removal scenarios. According to the Figs. 14-20, the cost formulations for various WT removal methods can be mathematically expressed as below.

In all cost formulations, it is worth mentioning that a single JUV is assumed in this report for lifting operations and the BVs are considered for the transportation of WT components to shore. In addition, it is assumed that the BVs are used to transfer the removed components to the port without any delay in the working schedule of JUVs. This assumption means that the JUVs have always access to at least one BV to lay down the removed parts at any time. The removal duration of WTs t_{WT} for each method can be expressed as follows:

- **Method I:**

$$t_{\mathrm{WT}} = n_{\mathrm{t}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + 3t_{\mathrm{B}} + t_{N} + 2t_{\mathrm{T}/2} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{2}$$

n_{t}: is the number of WTs in the OWF.

$t_{\mathrm{pos}}^{\mathrm{JUV}}$: represents the required time for the positioning of the JUV to start the removal operation (hours)

$t_{\mathrm{up}}^{\mathrm{JUV}}$: is the jacking-up duration of the JUV (hours)

t_{B}: is the removal duration of an individual blade of WT (hours)

t_{N}: represents the removal duration of the nacelle (hours)

$t_{\mathrm{T}/2}$: is the removal duration of one segment of the tower (hours)

$t_{\mathrm{down}}^{\mathrm{JUV}}$: represents the jacking down duration of the JUV (hours)

- **Method II:**

$$t_{\mathrm{WT}} = n_{\mathrm{t}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + 3t_{\mathrm{B}} + t_{N} + t_{\mathrm{T}} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{3}$$

where t_{T} represents the removal duration of the whole tower of the WT in a single lift operation (hours). The definitions for the rest of the parameters are similar to those in the method I.

- **Method III:**

$$t_{\mathrm{WT}} = n_{\mathrm{t}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + 3t_{\mathrm{R,3B}} + t_{N} + 2t_{\mathrm{T}/2} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{4}$$

where $t_{\mathrm{R,3B}}$ is the removal duration for the three blades with the rotor (i.e., star configuration) in a single lift (hours).

- **Method IV:**

$$t_{\mathrm{WT}} = n_{\mathrm{t}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{B}} + t_{N,R,2B} + 2t_{\mathrm{T/2}} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{5}$$

in which $t_{N,R,2B}$ represents the removal duration for the nacelle, rotor and two blades (i.e., bunny ear configuration) in a single lift (hours). The rest of the parameters are similar to those of other WT removal methods.

- **Method V:**

$$t_{\mathrm{WT}} = n_{\mathrm{t}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{B}} + t_{N,R,2B} + t_{\mathrm{T}} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{6}$$

- **Method VI:**

$$t_{\mathrm{WT}} = n_{\mathrm{t}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{3B,R,N,T}} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{7}$$

in which $t_{\mathrm{3B,R,N,T}}$ represents the removal duration of the whole WT in a single lift (hours).

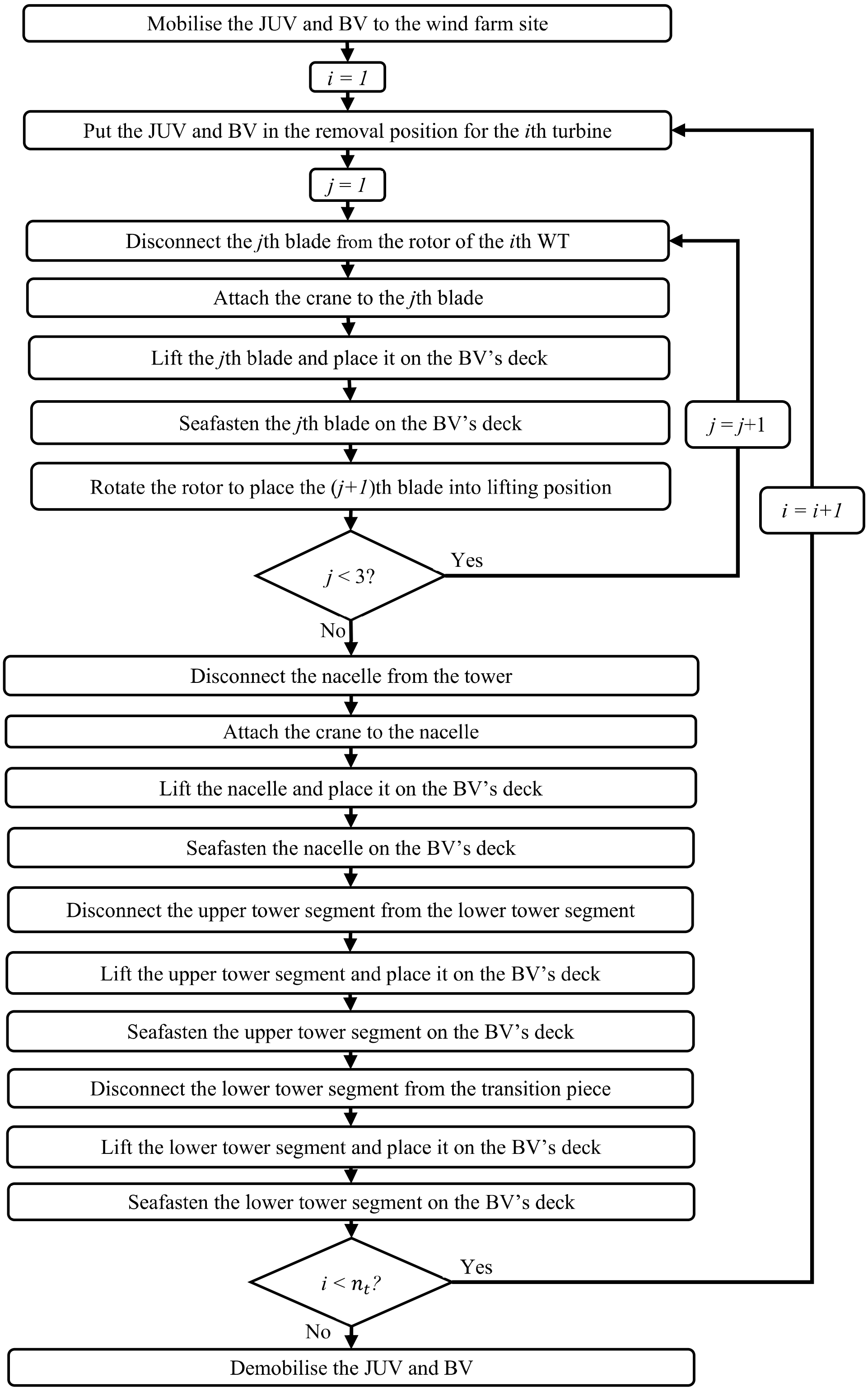

Figure 14. The main steps of method I for WT removal

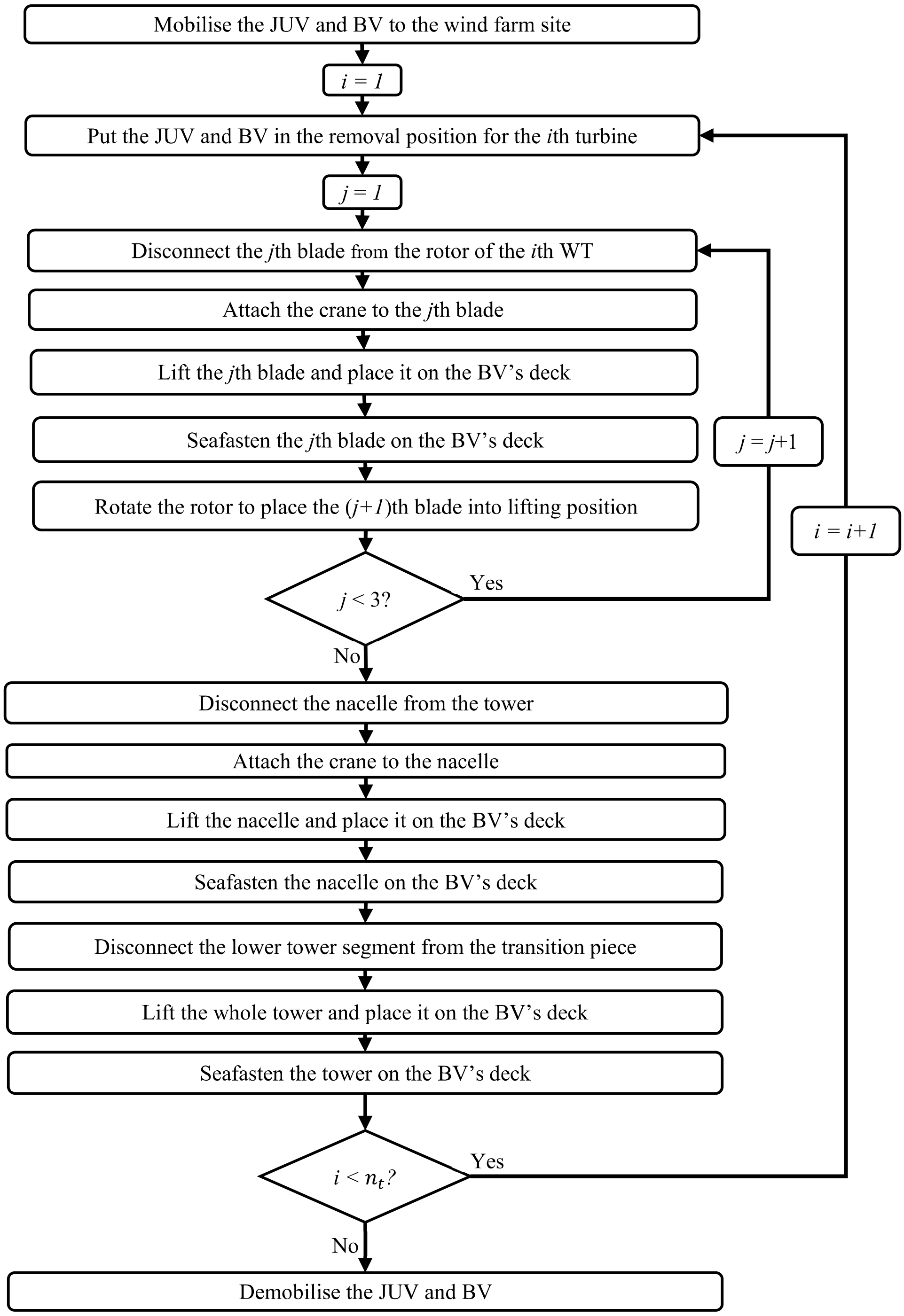

Figure 15. The main steps of method II for WT removal

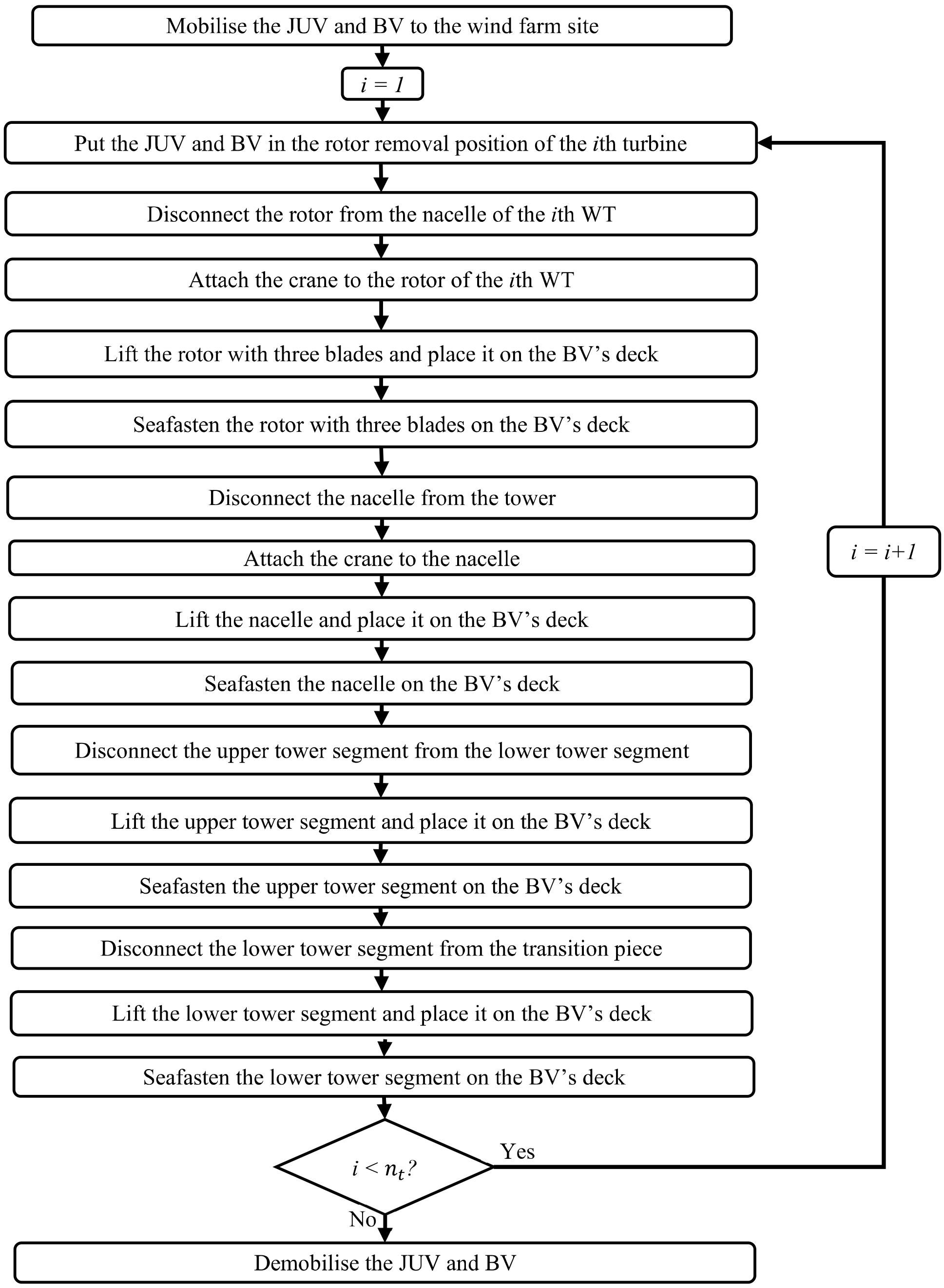

Figure 16. The main steps of method III for WT removal

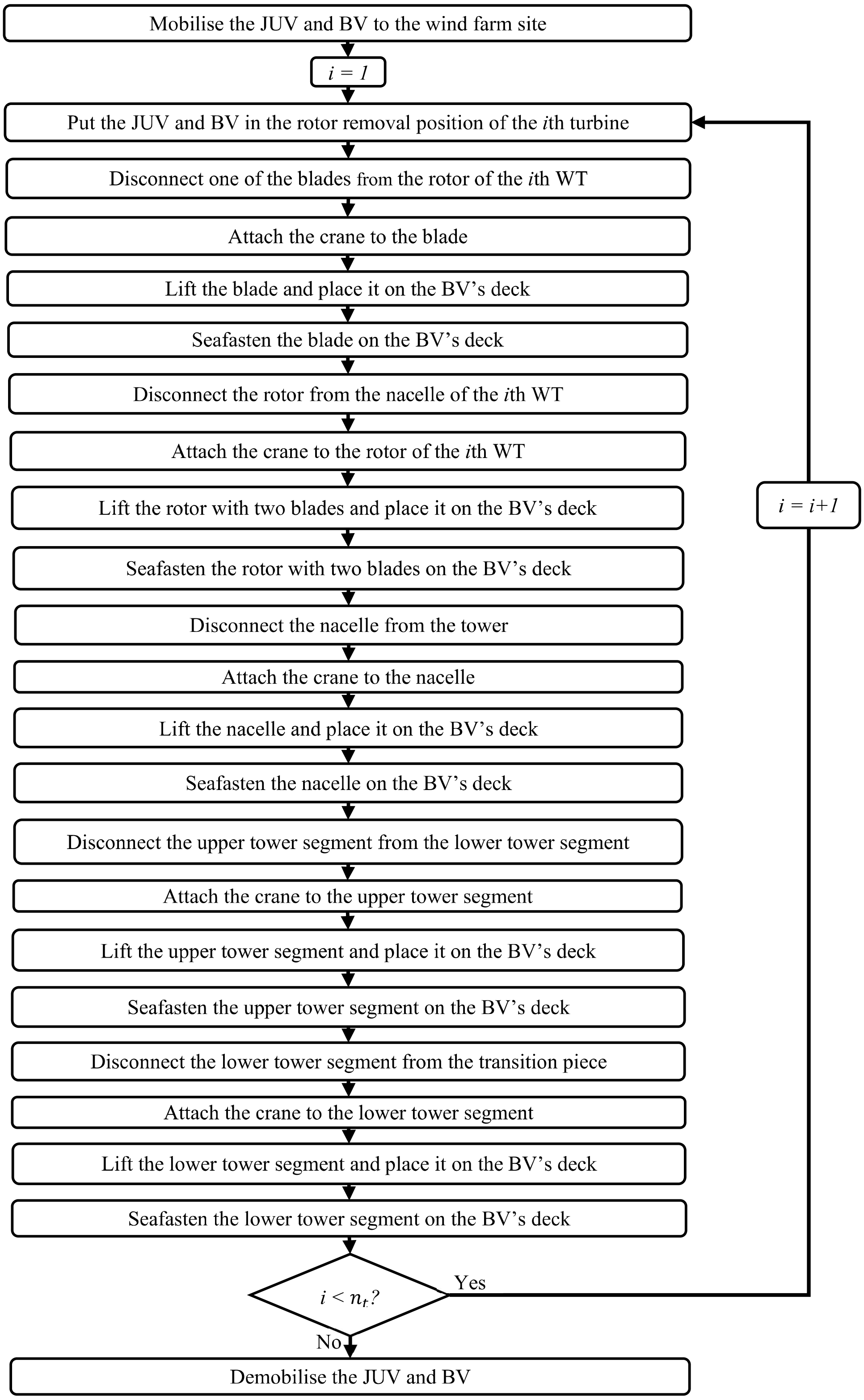

Figure 17. The main steps of method IV for WT removal

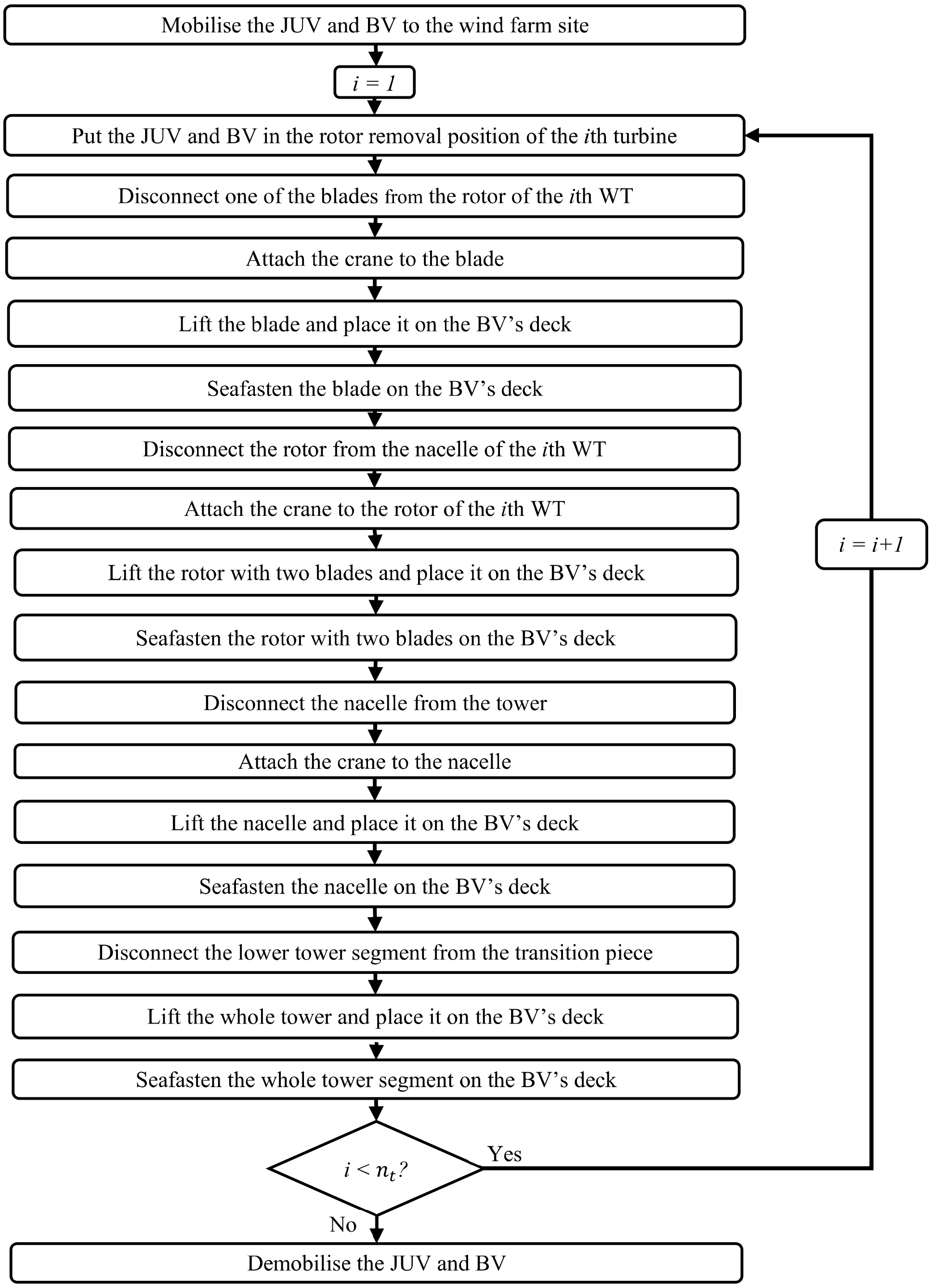

Figure 18. The main steps of method V for WT removal

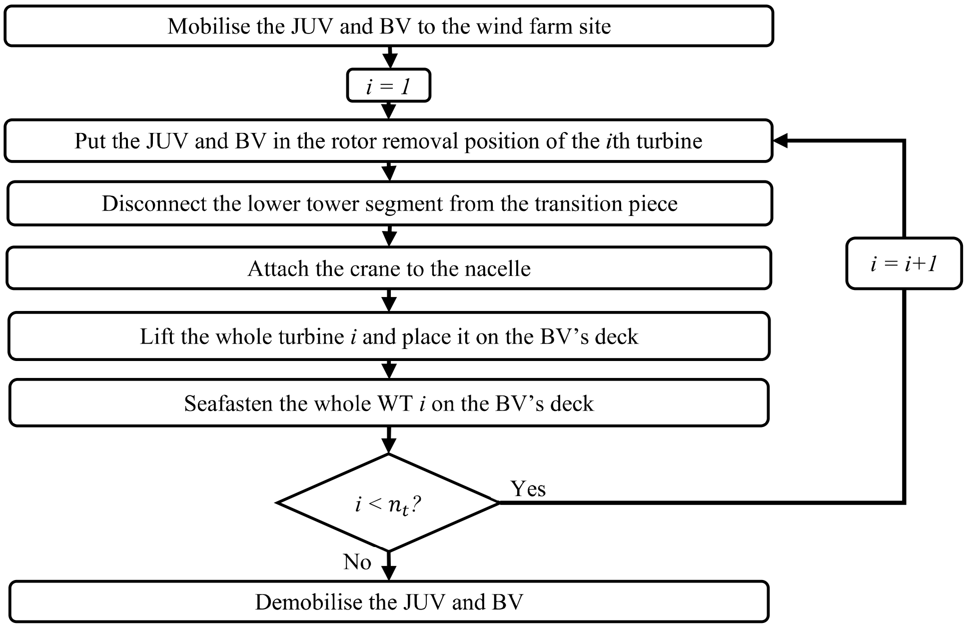

Figure 19. The main steps of method VI for WT removal

- **Method VII:** The WT removal process is a relatively time-consuming procedure as it requires multiple lifts. In some cases, some alternative methods are proposed in the literature to minimise the decommissioning costs of WTs. Kaiser and Snyder [27] suggested a new WT removal method to reduce the disassembly costs, in which the WT removal process is similar to cutting a tree. In their method, all of the fluids and hazardous material are first removed from the nacelle. Then, the three blades are removed in separate lifts. The tower is cut and allowed to fall under given conditions. The falling process of the tower is controlled by some winches placed at the opposite side of the falling direction, which are tied to the workboats or on a nearby WT foundation. In this method, both the tower and nacelle are made watertight to keep them undamaged as much as possible. The important part of this method is making the tower and nacelle float after the failing process. In this method, a given flotation cushion is attached to the nacelle to prevent the tower from floating vertically. After the falling process, the tower and nacelle can be lifted to a large crane barge. Alternatively, the lifting weights can be reduced by cutting the tower and dividing it into several sections. The authors stated that a combination of falling and traditional methods can be considered for WT dismantling. Figs. 21 and 22 illustrate the main steps of this method. The main issue in using this method is the level of risk and concerns from the safety viewpoint.

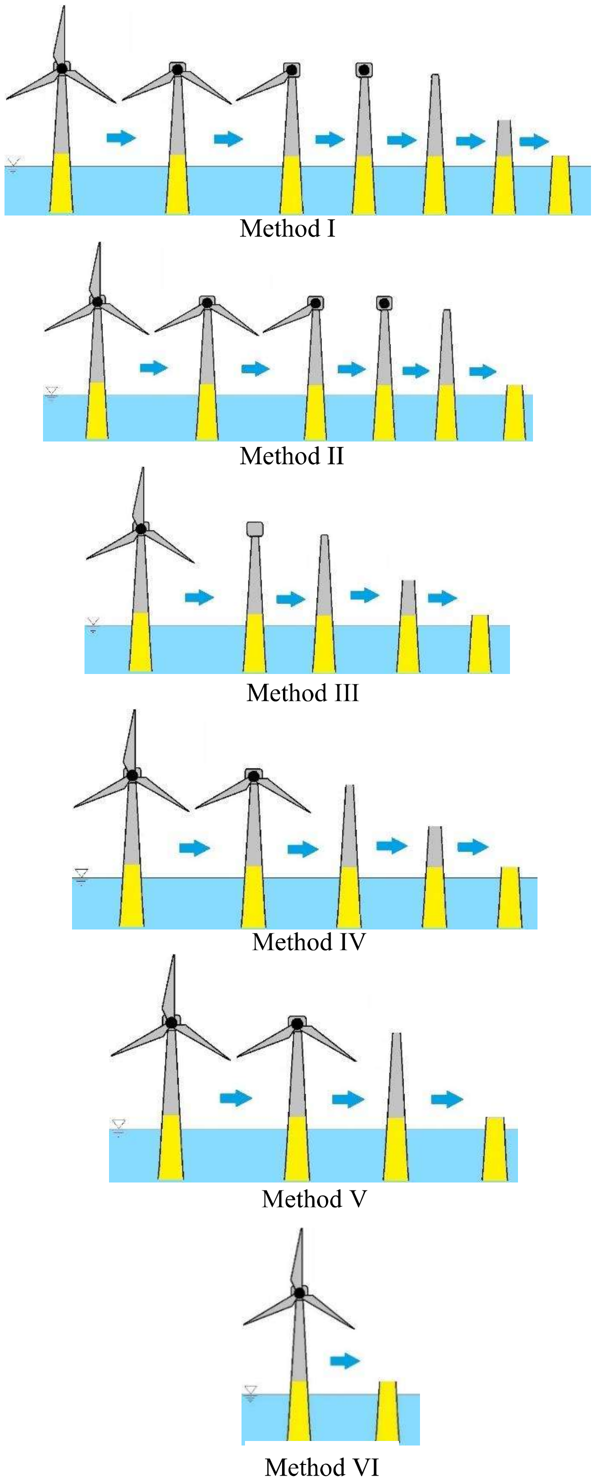

Fig. 20. Illustration of main steps for different WT removal methods

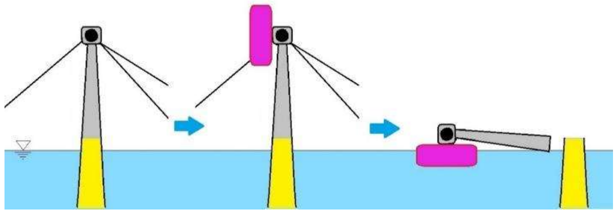

Figure 21. Illustration of main steps for WT removal method VII (based on Kaiser and Snyder [27])

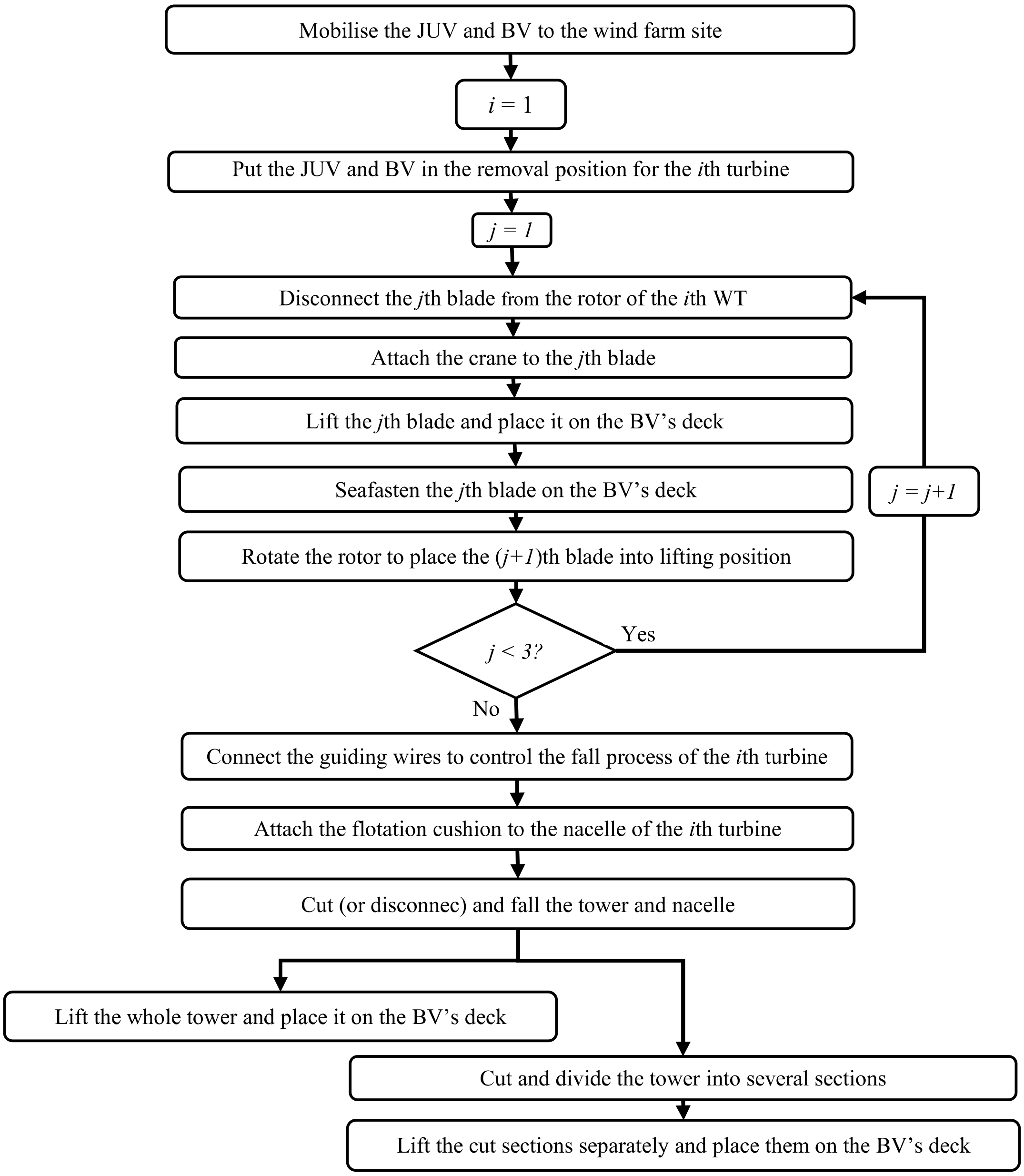

Figure 22. The main steps of method VII for WT removal

A. Parameters

As it was mentioned before, the removal operations are expected to take shorter than the installation operations. In the removal processes explained for the WTs, the removal durations are required to calculate the removal costs. A literature survey has been performed and the ranges for different parameters of the WT removal operations have been reported in Table 7. As it can be seen from this table, most of the durations are adopted from the available references or reports. In this report, only the removal duration for the bunny ear configuration $t_{\mathrm{N,R,2B}}$ is assumed to be 6 hours. The related rental costs for the vessels will be discussed in a separate section.

Table 7. The assumptions for different parameters of WT removal operations

Parameter	Description	Durations	
		Minimum	Maximum
$t_{\mathrm{pos}}^{\mathrm{JUV}}$	Positioning duration of the JUV (hours)	3 [9]	8 [9,30]
$t_{\mathrm{up}}^{\mathrm{JUV}}$	Jacking-up duration of the JUV (hours)	6 [9]	10 [9]
t_{B}	Removal duration of an individual blade (hours)	2 [9]	3.33 [9]
t_{N}	Removal duration of the nacelle (hours)	2.5 [9]	6 [9]
$t_{\mathrm{R,3B}}$	Removal duration of rotor with three blades (star config.) (hours)	5 [12]	5 [12]
$t_{\mathrm{N,R,2B}}$	Removal duration of the rotor with two blades (bunny ear config.) (hours)	**6***	**6***
t_{T}	Removal duration of both tower segments in a single lift (hours)	6 [12]	6 [12]
$t_{\mathrm{T/2}}$	Removal duration of a single segment of the tower (hours)	2.5 [9]	6 [9]
$t_{\mathrm{down}}^{\mathrm{JUV}}$	Jacking-down duration of the JUV (hours)	1 [9]	4 [9]
$t_{\mathrm{3B,R,N,T}}$	Removal duration of the whole WT in a single lift (hours)	12 [12]	12 [12]

*Assumed in this report

3.3. Foundation removal

The foundation removal is one of the most important parts of the decommissioning program which includes heavy lift, underwater excavation and cutting operations. In some cases, the foundation and TP are lifted in a single crane operation. Current practice in foundation removals is to partially remove the foundation under the mud line and leave the remained part in the situation, as the total removal scenario would impose significant damage to the environment and marine life. As the removal operations, in this case, are performed underwater, ROVs would be required to perform the excavation and cutting operations. The foundation should be cut from a given depth (15 feet in [27] and 1 m in [29]) below the seabed and lifted to the BV. The foundation cutting can be performed externally and internally by divers, mechanical methods, diamond wire, and explosives or Abrasive Water Jet Cuttings (AWJCs). In the external cutting, it is necessary to excavate the mud around the pile to provide the required access space for cutting machines. Hence, the external methods are expected to be more expensive than the internal methods. It is worth mentioning that the hole resulting from the foundation removal should be covered by landfilling [20]. In the following subsections, commonly used diamond wire saw and the AWJC methods will be explained.

A. Diamond wire saw

By using the diamond wire saws as an external method, the steel and concrete foundations can be efficiently and safely cut underwater. There are a variety of diamond wire saws with different cutting speeds and diameter capacities available in the industry that can be applied for foundation removal. For example, Fig. 23 shows a diamond wire saw provided by MIRAGE with a cutting diameter capacity of 36-60 inches. The thickness and the material properties of the cutting edge can also affect the cutting speed. Usually, the diamond wire saw is lifted by the crane from the vessel and fixed in the cutting position. In some cases, an ROV is used to fix the cutter in the cutting position. After cutting the foundation, it is lifted by the crane and placed on the BV. As it was mentioned earlier, the diamond wire saw is an external method and needs enough space around the foundation to perform the cutting process. Therefore, the space around the foundation should be pumped and cleaned before starting the cutting process to provide access of the cutter to the cutting area.

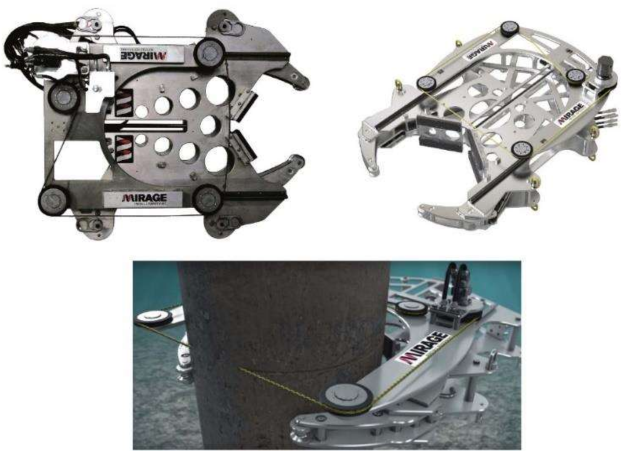

Fig. 23. Subsea diamond wire saw provided by MIRAGE (model MDWS3660-H)[1]

[1]Picture source: https://www.enerpac.com (Enerpac)

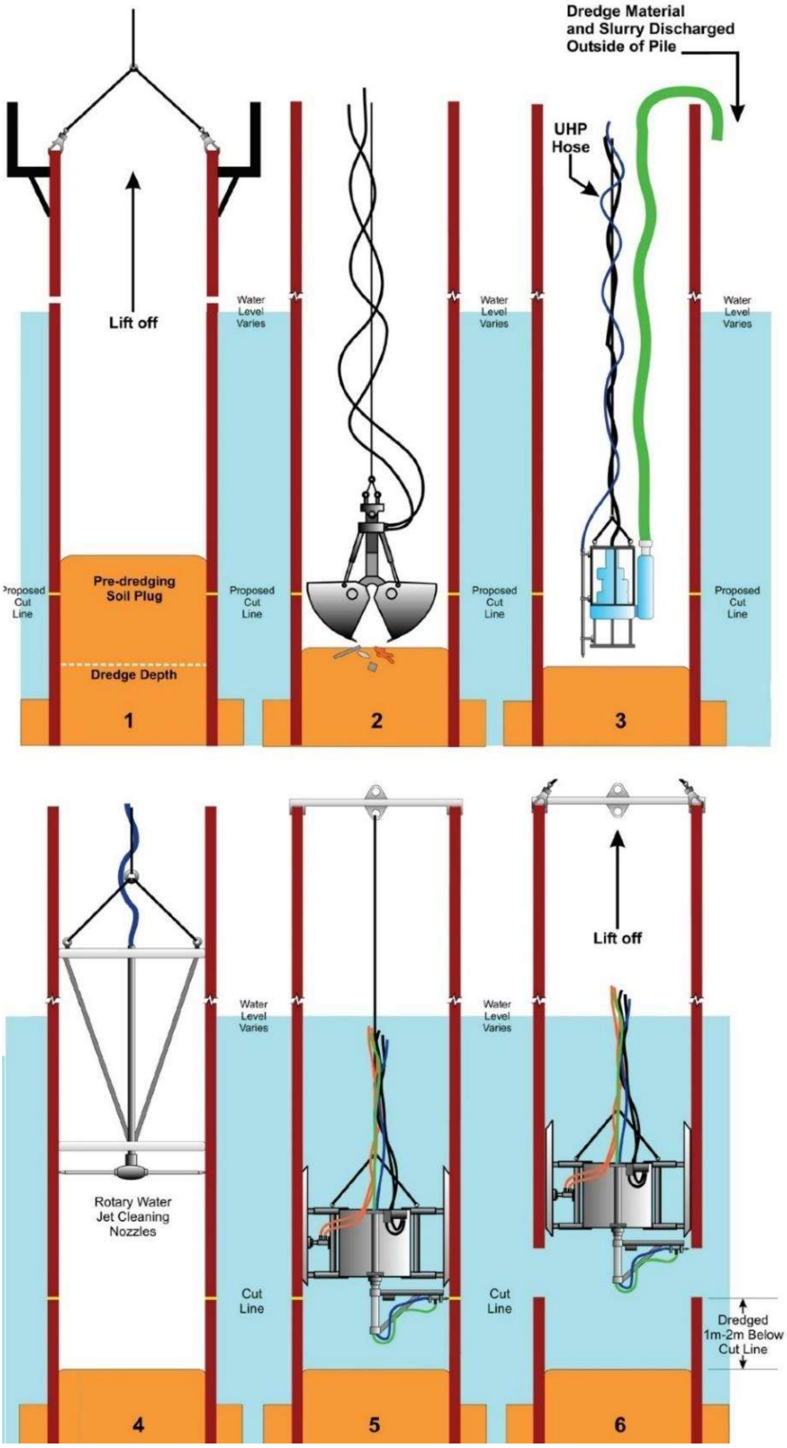

Fig. 24. Main steps of the AWJC technique for internal cutting[1]

[1]Picture source: www.rglservices.co.uk (RGL)

B. AWJC

As a mechanical method developed in the 1980s, this method cuts the foundation by thin water jets with high pressure. This method can provide both internal and external cuttings and is suitable for both steel and concrete materials. The main steps of this method for internal cutting are shown in Fig. 24. In the first step, any structure on the top side of the foundation should be cut and lifted to the vessel. Then, to provide cutter access to the cut line, a hydraulically operated dredge is used to remove the large debris/foreign objects and lift them to the disposal area of the vessel. In the third step, a pump dredger fitted with a UHP cutting nozzle is used to remove the small size debris resulting from the second step. In the fourth step, the cutter rig is fixed to the cutting position and the cutting process is started. Finally, the cutter and foundation are lifted to the vessel. The cutting speed depends on the thickness of the section.

C. Vessels for foundation removal

For foundation removal, a combination of vessels can be used to perform the removal process. In practice, a JUV is typically used for supporting the cutting process, lifting the foundation, and placing it on a BV. However, the expensive JUV may keep waiting when the preparation and cutting operations are performed. In some cases, an Offshore Supply Vessel (OSV) is used as the support vessel for the cutting process. Then, as soon as the cutting is finished, the JUV is mobilised to the site for lifting the foundation. This approach can reduce the duration and costs required for renting JUVs. It is worth mentioning that, in all of the cases, it is very common to place the lifted foundation on a BV.

D. Different scenarios for foundation removal

First of all, the cable(s) in the vicinity of the foundation should be cut before starting the foundation removal process. From the vessel type point of view, the applied JUV can be self-propelled or non-propelled. In the case of using the non-propelled vessels, additional TBs will be required for towing them to the site. Based on the mentioned points, the foundation removal process can be done through four methods as follows:

- **Method I:** In the first method, a non-self-propelled JUV is used as the supporting vessel for foundation removal, lifting the foundation and placing it on the BV. In this method, two or more TBs are required for pulling the JUV and BV. The main steps of this method are illustrated in Fig. 25.

- **Method II:** In the second method, a self-propelled JUV is used for supporting the cutting and lifting process, in which TBs are needed only for pulling the BV. Fig. 26 shows the different steps for the second method.

- **Method III:** In the third method, as it is demonstrated in Fig. 27, an OSV is used as the support vessel for the cutting process, and the lifting process is performed by a non-self-propelled JUV. In this method, the TBs are required for pulling both JUV and BV.

- **Method IV:** Fig. 28 shows the main steps of the fourth method. In this method, an OSV is used as the support vessel for the cutting process, and a self-propelled JUV is used to lift the foundation. In this method, only TBs are required to pull the BV.

Table 8 shows the types of lifting vessels and the number of BVs required for each method of foundation removal.

Table 8. Different methods based on the applied vessels for foundation removal

Removal method	Type of the support vessel	No. of TBs	No. of BVs	Lifting vessel
Method I	Non-self-propelled JUV	2	1	Non-self-propelled JUV
Method II	Self-propelled JUV	1	1	Self-propelled JUV
Method III	OSV	2	1	Non-self-propelled JUV
Method IV	OSV	1	1	Self-propelled JUV

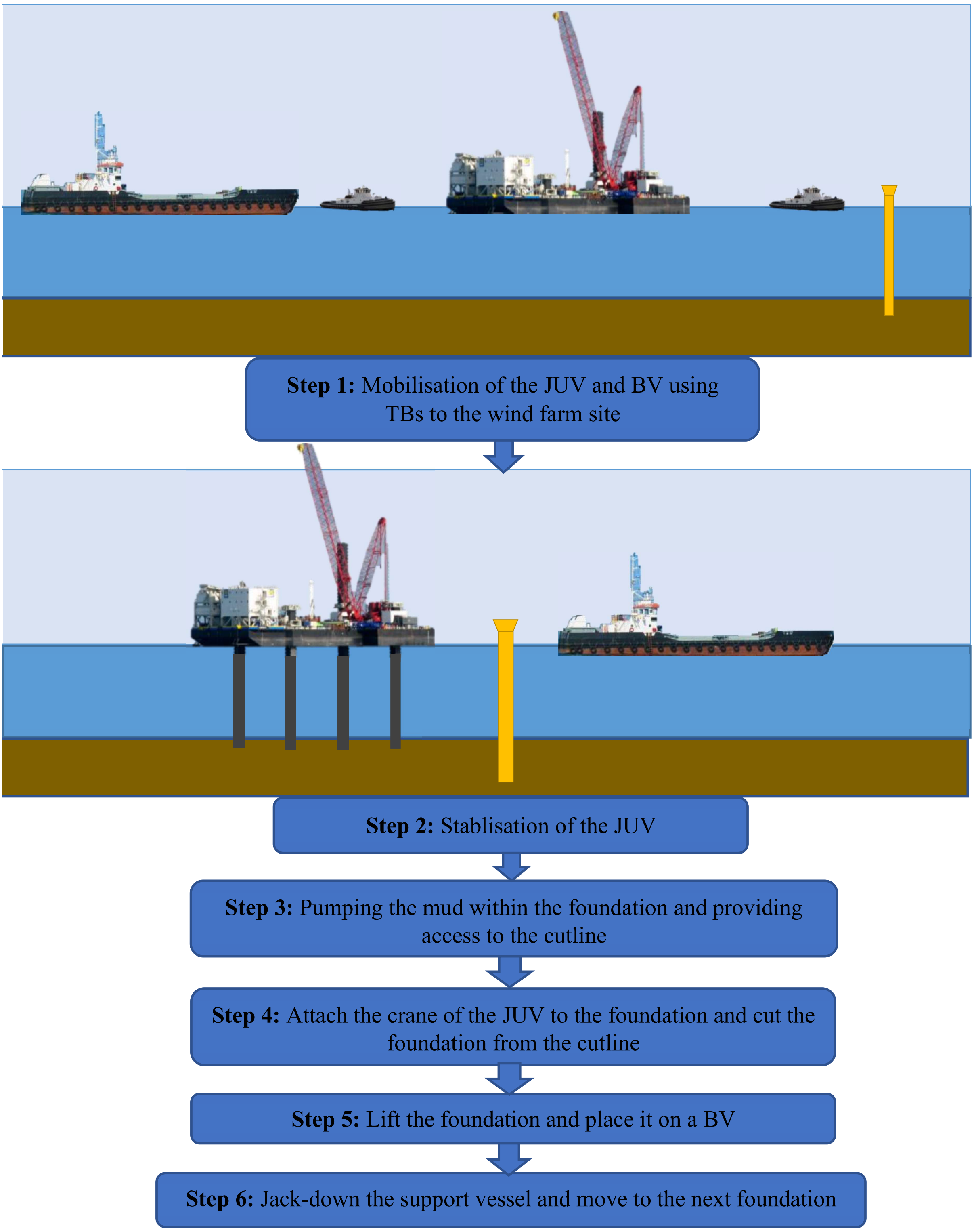

Fig. 25. Main steps of the method I for foundation removal[1]

[1]The pictures of vessels used in this figure are from: https://www.offshorewind.biz/ and https://www.vlmaritime.com

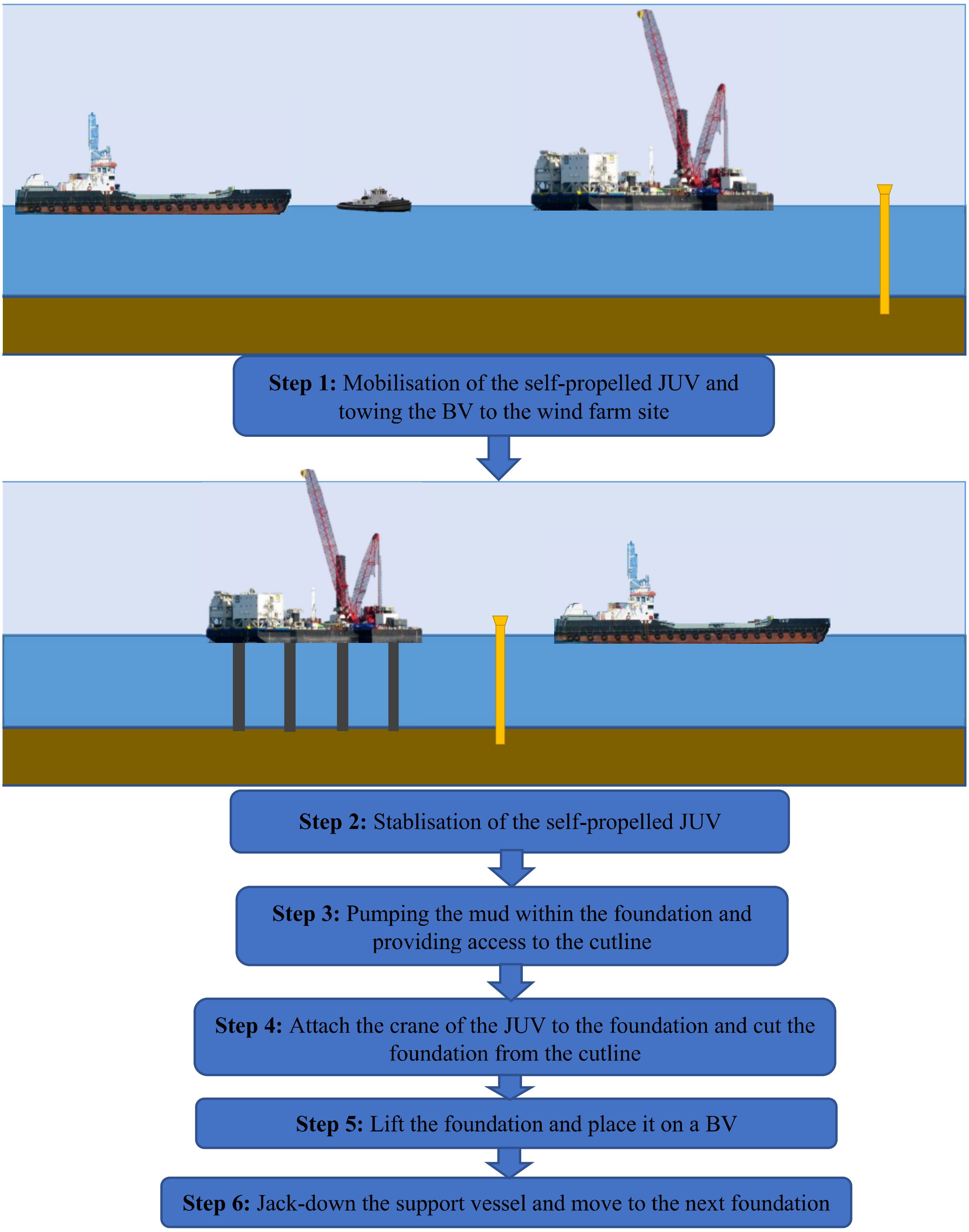

Fig. 26. Main steps of method II for foundation removal[1]

[1] The pictures of vessels used in this figure are from: https://www.offshorewind.biz/ and https://www.vlmaritime.com

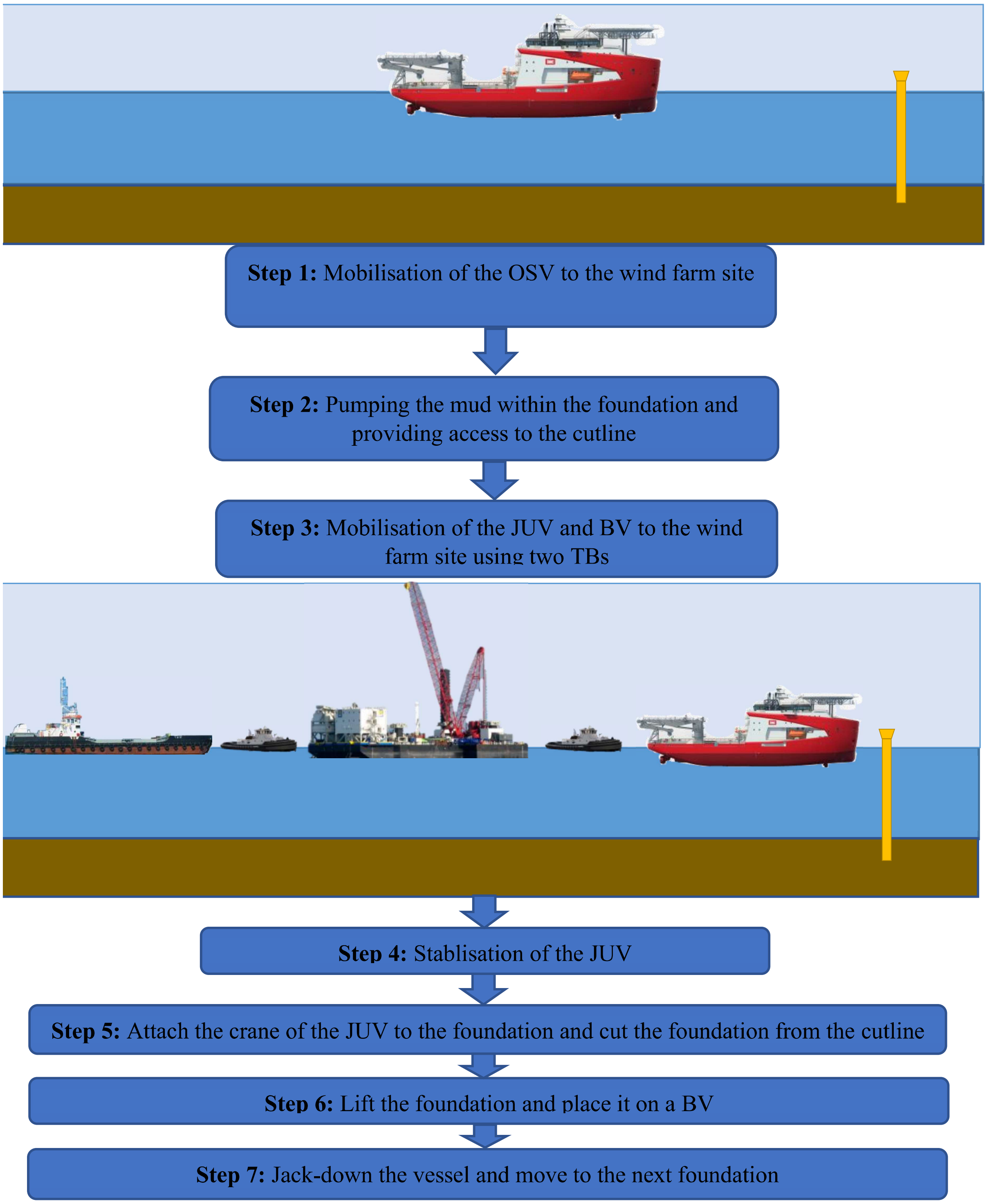

Fig. 27. Main steps of method III for foundation removal[1]

[1] The pictures of vessels used in this figure are from: https://www.royalihc.com (Royal IHC), https://www.offshorewind.biz/, and https://www.vlmaritime.com

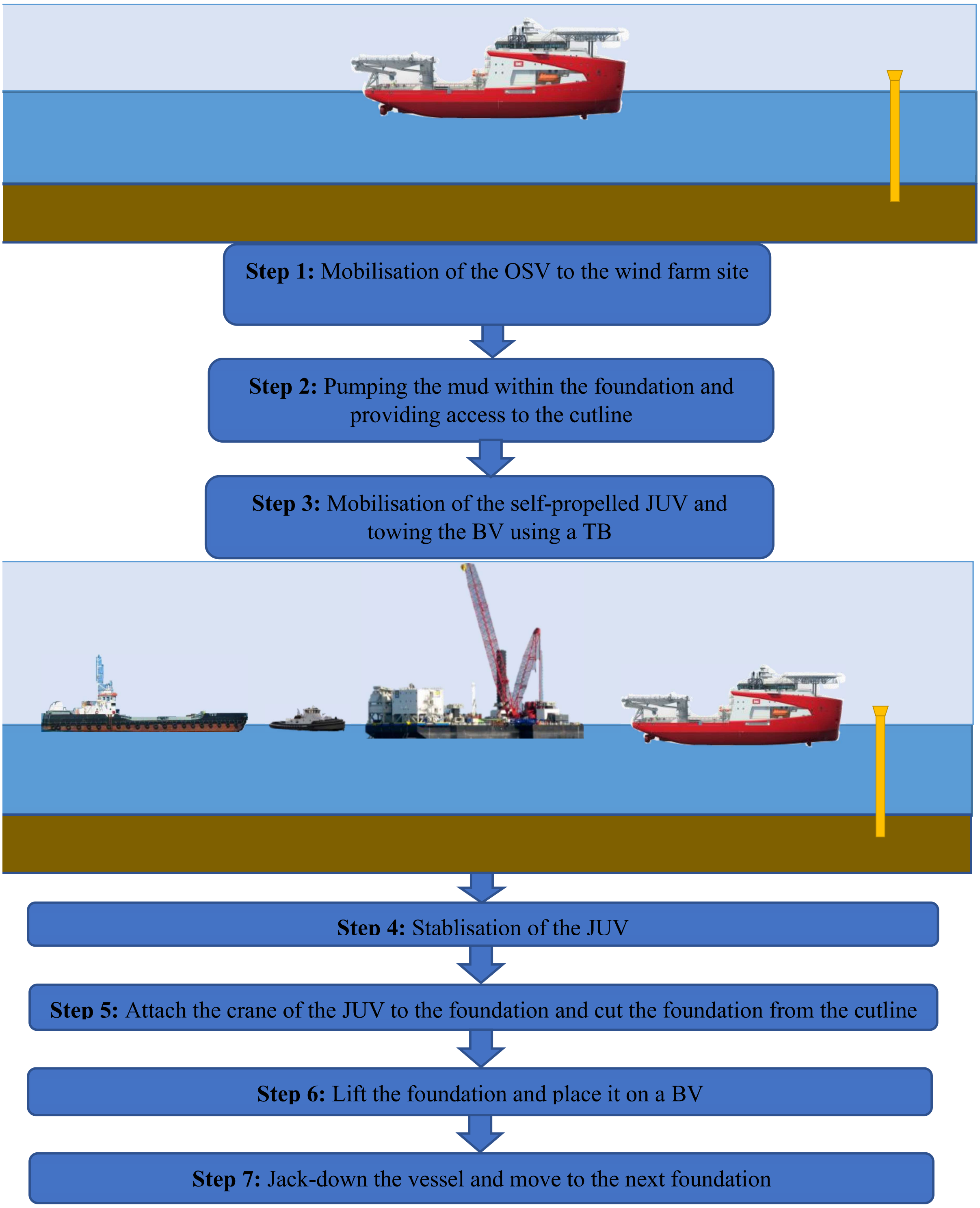

Fig. 28. Main steps of method IV for foundation removal[1]

[1] The pictures of vessels used in this figure are from: https://www.royalihc.com (Royal IHC), https://www.offshorewind.biz/, and https://www.vlmaritime.com

E. Cost estimations for foundation removal

In this report, it is assumed that the removal of the TP and foundation will be performed during the same operation. In the following subsections, the removal cost of the foundation and TP will be explained in detail.

- **Methods I and II:**

In these methods, the support vessel is a JUV and TB(s) are used to pull the JUV or BV. The removal cost for these methods can be formulated as follows:

$$Cost_{\mathrm{F}} = C_{\mathrm{mob}}^{\mathrm{JUV}} + \alpha C_{\mathrm{mob}}^{\mathrm{BV}} + C_{\mathrm{mob}}^{\mathrm{ROV}} + {}^{1}\!/_{24} \left(C_{\mathrm{D}}^{\mathrm{JUV}} + C_{\mathrm{D}}^{\mathrm{ROV}} + \alpha C_{\mathrm{D}}^{\mathrm{BV}} + \beta C_{\mathrm{D}}^{\mathrm{TB}} \right) \times t_{\mathrm{total}}^{\mathrm{JUV}} \quad (8)$$

where:

$C_{\mathrm{mob}}^{\mathrm{ROV}}$: is the mobilisation cost of the ROV.

$C_{\mathrm{D}}^{\mathrm{ROV}}$: indicates the day rate of the ROV.

$Cost_{\mathrm{F}}$ represents the removal cost of the foundation.

$t_{\mathrm{total}}^{\mathrm{JUV}}$: is the total removal duration of the foundation performed by the JUV.

The rest of the parameters in equation (8) are similar to those described in the WT removal section. The parameter β is the number of TBs. The total foundation removal duration $t_{\mathrm{total}}^{\mathrm{JUV}}$ can be calculated as follows:

$$t_{\mathrm{total}}^{\mathrm{JUV}} = n_{\mathrm{F}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{P}} + t_{\mathrm{C}} + t_{\mathrm{L}}^{\mathrm{JUV}} + t_{\mathrm{down}}^{\mathrm{JUV}} \right) \quad (9)$$

where:

n_{F}: is the number of foundations in the wind farm.

$t_{\mathrm{pos}}^{\mathrm{JUV}}$: is the required time for positioning the JUV for foundation removal (hours)

$t_{\mathrm{up}}^{\mathrm{JUV}}$: is the time required for jacking up.

t_{P}: is the time required for pumping the mud inside the monopile (hours)

t_{C}: is the time required for cutting the monopile (hours)

$t_{\mathrm{L}}^{\mathrm{JUV}}$: is the time required for lifting the foundation and placing it on the BV (hours)

$t_{\text{down}}^{\text{JUV}}$: is the jacking-down duration (hours)

In the foundation cutting process using the internal method from a given depth below the seabed, additional space is required to provide enough space for the cutter. Fig. 29 shows a general foundation in the wind farm, in which d_{c} represents the distance between the cutting line and seabed, and e indicates the additional space required for the cutter. Based on Fig. 29, the time required for pumping the mud inside the foundation t_{P} can be obtained as follows:

$$t_{\text{P}} = \frac{V_{\text{pump}}}{Q_{\text{pump}}} \tag{10}$$

where Q_{pump} (m^3/hour) is the pumping rate and V_{pump} (m^3) is the pumping volume. According to Fig. 28, the pumping volume V_{pump} can be calculated as follows:

$$V_{\text{pump}} = \frac{\pi}{4} D^2 (d_{\text{c}} + e) \tag{11}$$

in which D (m) is the foundation diameter, d_{c} (m) is cutting depth below the mud line, and e is the additional space provided for the ease of access to the cutting line.

It should be noted that the cutting duration of the foundation is obtained by $t_{\text{C}} = v_{\text{cut}} D$, in which v_{cut} (hours/m) is the cutting rate per the foundation diameter.

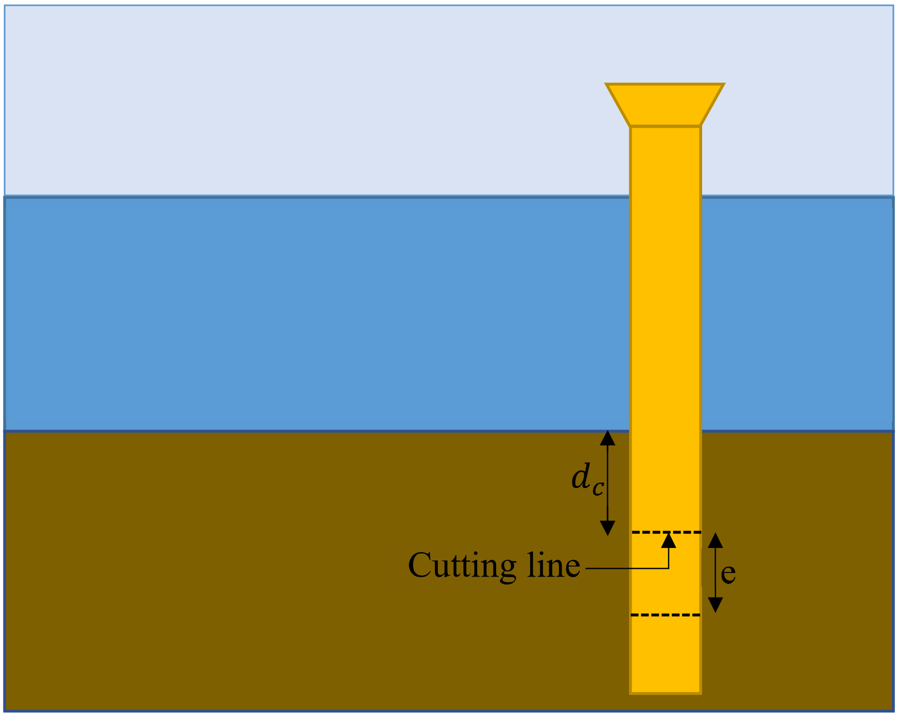

Figure 29. Foundation of a WT

• **Method III and IV:**

In the third and fourth methods, an OSV is used as the support vessel for the removal preparation and cutting process of the foundation. Thereafter, a JUV is arriving for lifting the foundation. Depending on the type of the JUV, TBs are required to pull the JUV and BV. These removal methods reduce the working duration of JUV by using OSV for the removal preparation. Generally speaking, the rental rate of the OSV is significantly cheaper than the JUV. The removal cost for these methods can be formulated as follows:

$$\begin{aligned} Cost_{\mathrm{F}} = {} & C_{\mathrm{mob}}^{\mathrm{JUV}} + \alpha C_{\mathrm{mob}}^{\mathrm{BV}} + C_{\mathrm{mob}}^{\mathrm{ROV}} + C_{\mathrm{D}}^{\mathrm{OSV}} \times t_{\mathrm{total}}^{\mathrm{OSV}} \\ & + {}^{1}\!/_{24} \left(C_{\mathrm{D}}^{\mathrm{JUV}} + \alpha C_{\mathrm{D}}^{\mathrm{BV}} + \beta C_{\mathrm{D}}^{\mathrm{TB}} \right) \times t_{\mathrm{total}}^{\mathrm{JUV}} + C_{\mathrm{D}}^{\mathrm{ROV}} \left(t_{\mathrm{total}}^{\mathrm{OSV}} + t_{\mathrm{total}}^{\mathrm{JUV}} \right) \end{aligned} \tag{12}$$

where:

$C_{\mathrm{D}}^{\mathrm{OSV}}$: indicates the daily rate of the OSV (pounds)

$t_{\mathrm{total}}^{\mathrm{OSV}}$: is the total working duration of the OSV for the preparation of the foundation to be removed (hours)

$t_{\mathrm{total}}^{\mathrm{JUV}}$: is the total working duration of the JUV for lifting the foundation and placing it on the BV's deck (hours)

β: is the number of TBs, which is equal to 2 and 1 for the third and fourth methods.

The definitions for the rest of the parameters are similar to those explained in the previous removal methods. Based on the explanation provided for these methods, the removal preparation activities of the foundation, including the pumping and cutting, are performed by the OSV. Hence, the working duration of the OSV $t_{\mathrm{total}}^{\mathrm{OSV}}$ can be formulated as follows:

$$t_{\mathrm{total}}^{\mathrm{OSV}} = n_{\mathrm{F}} \times \left(t_{\mathrm{pos}}^{\mathrm{OSV}} + t_{\mathrm{P}} + t_{\mathrm{C}} + t_{\mathrm{move}}^{\mathrm{OSV}} \right) \tag{13}$$

where $t_{\mathrm{pos}}^{\mathrm{OSV}}$ (hours) is the positioning time of the OSV, t_{P} (hours) and t_{C} (hours) are the pumping and cutting durations of the foundation, respectively, and $t_{\mathrm{move}}^{\mathrm{OSV}}$(hours) denotes the moving time of the OSV. The total working duration of the JUV for lifting the foundation and placing it on the BV's deck $t_{\mathrm{total}}^{\mathrm{JUV}}$ can be obtained as follows:

$$t_{\mathrm{total}}^{\mathrm{JUV}} = n_{\mathrm{F}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{L}}^{\mathrm{JUV}} + t_{\mathrm{down}}^{\mathrm{JUV}} \right) \tag{14}$$

where the definitions of all the parameters are similar to those explained in the previous methods.

F. Parameters

In the cost formulations for each foundation removal method, the values of some parameters, such as pumping rate Q_{pump}, foundation cutting duration t_{C}, jacking-up duration $t_{\mathrm{up}}^{\mathrm{JUV}}$, and jacking-down speed $t_{\mathrm{down}}^{\mathrm{JUV}}$ depend on the utilised vessel types, the pumping systems, cutting techniques, etc.

As it was mentioned earlier, it is necessary to pump the mud inside the foundation to provide the required space for the cutter to perform the cutting process. According to the available data, the pump rate Q_{pump} is assumed to be between 25 m^3/hour to 50 m^3/hour [27].

Another important parameter is the cutting duration, which can be significantly different for different foundations with different thicknesses, diameters, and materials. According to the information available from the catalogue of the AWJC tool provided by RGL in the UK, which has been previously successfully employed to remove the WT foundations, the cutting speed depends on the thickness of the foundation as shown in Fig. 30. From this figure, it is observed that the cutting speed varies in the range from 25 mm/min to 175 mm/min. However, this range can be different for the cutting tools generated by different companies. In this report, we have assumed a given cutting rate per foundation diameter for the monopile foundation. According to [27], the foundation cutting speed per foundation diameter ν_{cut} can be assumed to be between 10 hours/m and 24 hours/m.

Table 9 lists the ranges for different parameters in the cost formulations of foundation removal. These data are based on the available information gathered from different references. The related rental costs for the vessels will be discussed in a separate section.

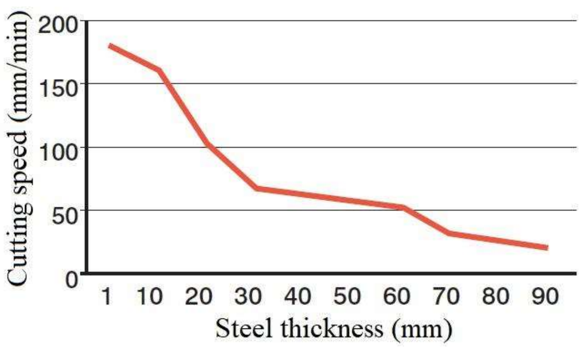

Figure 30. Changes in the cutting speed of the AWJC tool provided by RGL[1]

[1]Figure source: RGL (https://www.rglservices.co.uk)

Table 9. The assumptions for different parameters of foundation removal operations

Parameter	Description	Ranges and selected values	
		Minimum	Maximum
$t_{\mathrm{pos}}^{\mathrm{JUV}}$	Positioning duration of the JUV (hours)	3 [9]	8 [9,30]
$t_{\mathrm{pos}}^{\mathrm{OSV}}$	Positioning duration of the OSV (hours)	0.25 [27]	2 [27]
$t_{\mathrm{up}}^{\mathrm{JUV}}$	Jacking-up duration of the JUV (hours)	6 [9]	10 [9]
$t_{\mathrm{down}}^{\mathrm{JUV}}$	Jacking-down duration of the JUV (hours)	1 [9]	4 [9]
$t_{\mathrm{move}}^{\mathrm{OSV}}$	Moving duration of the OSV (hours)	0.25 [27]	2 [27]
v_{cut}	Cutting speed per foundation diameter (hours/m)	10 [27]	24 [27]
Q_{pump}	Pumping rate (m^3/hour)	25 [27]	50 [27]
$t_{\mathrm{L}}^{\mathrm{JUV}}$	Lifting duration of the foundation	2 [27]	8 [27]

3.4. Cable removal

During the operational lifecycle of the wind farm, the seabed around the buried cables is usually recovered to its original conditions as a result of natural reaction, which means the removal of the cables can cause a re-disruption of the seabed. Since the cable removal operation includes uncovering the buried cables, the cable removal operations can significantly affect the seabed and marine life. Hence, most of the available DPs for OWFs assume that the cables will leave in their situ to reduce the environmental impacts and costs of the decommissioning process. Moreover, if a third-party subsea cable/pipeline is crossed the wind farm cables, the removal of cables can influence the integrity of third party cable/pipeline and they should be remained in their situ to minimise the decommissioning risks. However, the removal of cables is necessary if their existence poses safety risks for shipping and marine activities or they are uncovered as a result of the decommissioning activities. For example, the cables around WTs will need special attention due to the effects of the foundation removals. The exposed parts of the cables can be identified through the ROV survey. In some cases, the OWF DPs suggest weighting the exposed inter-array cables around the foundations and depositing them on the seabed to naturally bury them over time [32].

If it is decided to remove the cables from the seabed, the cables are pulled out of the seabed by using a grapnel device. Alternatively, a mass or controlled flow excavation or a water jet technique can be used for jetting the material and uncovering the buried cables. Then, the uncovered cables can be cut by an ROV and lifted to the vessel. In comparison to other decommissioning operations, the cable removal process can be performed by using relatively cheaper vessels. The BVs and OSVs or CLVs are usually used to support cable removal operations. In this report, we assume a CLV is used for cable removal.

Generally, it is expected that the cable removal process would be faster than the cable installation process. The literature review of available cost models for the cable removal process reveals that most of the cost modelling approaches define the cost of the cable removal operations based on the installation costs. Kaiser and Snyder [27] modelled the cable removal cost based on an IF, in which the removal cost is calculated by dividing the installation rate by IF. For instance, if IF is equal to 2 and the installation rate is assumed as 0.5 km/day, the cable removal rate will be equal to 1 km/day, which means that the removal process is two times faster than the installation process. Kaiser and Snyder [27] assumed IF to be in the range from 1.5 to 3.0 for inner-array cables and from 1.0 to 2.0 for export cables. We have used the same approach in this report to model the cost of cable removal operations. It is assumed that the removal vessels for the inner-array cables include one OSV and one BV, while an additional vessel is required to uncover the buried export cables. Table 10 lists the installation rates, IF and vessel types used for the cable removal operations.

Table 10. The installation rates, IF and vessel types used for inner-array and export cables.

Cable type	Installation rate (km per day)			IF			Vessels
	Minimum [27]	Maximum [27]	Selected	Minimum [27]	Maximum [27]	Selected	
Inner-array cables	0.15	0.60	0.30	1.5	3.0	2.25	OSV and BV
Export cables	0.20	1.40	0.70	1.0	2.0	1.50	OSV, BV, and cable exposing vessel

Let us assume t_{I} and t_{E} are the cable removal duration (days) for the inner-array and export cables in a given wind farm, respectively, which can be calculated as follows:

$$t_{\mathrm{I}} = \frac{L_{\mathrm{I}}}{r_{\mathrm{I}} \times IF_{\mathrm{I}}} \tag{15}$$

$$t_{\mathrm{E}} = \frac{L_{\mathrm{E}}}{r_{\mathrm{E}} \times IF_{\mathrm{E}}} \tag{16}$$

where:

L_{I}: indicates the length of the inter-array cables (km)

L_{E}: represents the length of the export cables (km)

r_{I}: is the cable installation rate for the inter-array cables (km/day)

r_{E}: is the cable installation rate for the export cables (km/day)

IF_{I}: is the IF for the inter-array cables.

IF_{E}: is the IF for the export cables.

According to the abovementioned points, the cable removal cost can be mathematically expressed as follows:

$$Cost_{\mathrm{C}} = C_{\mathrm{mob}}^{\mathrm{CLV}} + C_{\mathrm{mob}}^{\mathrm{ROV}} + \left(C_{\mathrm{D}}^{\mathrm{CLV}} + C_{\mathrm{D}}^{\mathrm{ROV}}\right)(t_{\mathrm{I}} + t_{\mathrm{E}}) \tag{17}$$

in which:

$Cost_{\mathrm{C}}$: represents the cable removal cost (pounds)

$C_{\mathrm{mob}}^{\mathrm{CLV}}$: denotes the mobilisation cost of the CLV (pounds)

$C_{\mathrm{D}}^{\mathrm{CLV}}$: is the day rate of the CLV (pounds/day)

3.5. OS and MM removals

The OS and MM removals consist of topside and foundation. Depending on the distance between the wind farm and shore, the type of electrical equipment installed on the OS can be different. Generally, the topside of the OSs can be an HVAC or an HVDC. The HVAC topsides are used for the wind farms located close to the shore which can weigh in the range from 200 tonnes to 3,000 tonnes. For the OSs located far than 80-100km from the shore, the HVDC topsides are used which can weigh in the range from 12,000 tonnes to 18,000 tonnes [29]. For the wind farms located closer than 80 km to the shore, the HVAC topsides are more economical than the equivalent HVDC [29].

The OS removal includes the topside and foundation removal operations. The top side should be prepared for the removal operation before the vessels arrive at the wind farm site. The topside of the OS will be removed by an HLV (e.g., JUV), placed on a BV, and shipped to the onshore facility for dismantling, reusing, and recycling. The topside lifting of the OS is a significantly heavy-lift procedure, which requires special attention to reduce the costs and safety risks. The main structural connection between the topside and foundation of the OS is provided by the four welded cow horn structures as shown in Fig. 31, which need to be cut during the topside preparation process.

The foundation of OSs can be monopile or jacket. For the case of the monopile foundation, the cost calculation is similar to those explained for the monopile foundations in Section 3.2. For the case of jacket structure, the removal durations are expected to be longer, as several piles of the jacket structure need to be cut below the seabed. An OSV is also typically needed to support the diving and cutting activities of the foundation. The lifting of the jacket structure is performed by the JUV. Hence, it is assumed that the JUV, OS, and BVs stay on the site during the whole OS removal operation.

Fig. 31. Installation of the topside of the OS in Gemini offshore wind farm in the Netherland[1]

Fig. 32 shows the general steps of OS removal. The removal cost of the OS can be expressed as follows:

$$Cost_{\mathrm{OS}} = C_{\mathrm{mob}}^{\mathrm{JUV}} + C_{\mathrm{mob}}^{\mathrm{ROV}} + C_{\mathrm{mob}}^{\mathrm{BV}} + {}^{1}\!/_{24}\left(C_{\mathrm{D}}^{\mathrm{JUV}} + C_{\mathrm{D}}^{\mathrm{OSV}} + C_{\mathrm{D}}^{\mathrm{ROV}} + \alpha C_{\mathrm{D}}^{\mathrm{BV}} + \beta C_{\mathrm{D}}^{\mathrm{TB}}\right) \times t_{\mathrm{total}}^{\mathrm{OS}} \tag{18}$$

where $Cost_{\mathrm{OS}}$ denotes the removal cost of the OS, $t_{\mathrm{total}}^{\mathrm{OS}}$ (hours) represents the total removal duration of the OS, including the topside and foundation, and the definitions for the rest of the parameters are similar to those explained in previous subsections. The total removal duration of the OS $t_{\mathrm{total}}^{\mathrm{OS}}$ can be calculated as follows:

- If the foundation is a jacket structure:

$$t_{\mathrm{total}}^{\mathrm{OS}} = n_{\mathrm{OS}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{c,top}} + t_{\mathrm{L,top}} + t_{\mathrm{c,p}} + t_{\mathrm{L,j}} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \tag{19}$$

where:

n_{OS}: is the number of OSs in the wind farm.

$t_{\mathrm{c,top}}$: indicates the cutting and disconnecting duration required for the topside removal (hours)

$t_{\mathrm{L,top}}$: represents the lifting duration of the topside by the JUV (hours)

$t_{\mathrm{c,p}}$: is the cutting duration of the piles under the seabed (hours)

[1] Picture source: Smulders (https://www.smulders.com/en/)

$t_{\mathrm{L,j}}$: is the time required by the JUV to lift the jacket structure (hours)

- If the foundation is a monopile structure:

$$t_{\mathrm{total}}^{\mathrm{OS}} = n_{\mathrm{OS}} \times \left(t_{\mathrm{pos}}^{\mathrm{JUV}} + t_{\mathrm{up}}^{\mathrm{JUV}} + t_{\mathrm{c,top}} + t_{\mathrm{L,top}} + t_{\mathrm{P}} + t_{\mathrm{C}} + t_{\mathrm{L}}^{\mathrm{JUV}} + t_{\mathrm{down}}^{\mathrm{JUV}}\right) \quad (20)$$

where the parameters t_{P} is the pumping duration of the mud inside the monopile (hours), t_{C} represents the cutting duration (hours), and $t_{\mathrm{L}}^{\mathrm{JUV}}$ is the lifting duration of the monopile. The definitions for the rest of the parameters are similar to those explained in previous sections.

Since the removal of the topside of the MM includes significantly lighter lifting operation, the lifting time for the top side of the MM is shorter than the lifting duration for the topside of the OS. In this case, the removal cost of the MM can be expressed as similar to equations (19) and (20). The differences are the durations for the $t_{\mathrm{c,top}}$, $t_{\mathrm{L,top}}$, t_{P} and t_{C}, which are assumed to be shorter for the MM than those for the OS.

It is worth mentioning that the values of some parameters, such as topside and jacket lifting durations ($t_{\mathrm{L,top}}$ and $t_{\mathrm{c,j}}$), and cutting duration of the topside ($t_{\mathrm{c,top}}$), depend on the weight of the topsides, cutting method, weather conditions, etc. Table 11 lists the assumed parameter values for the OS and MM. The related rental costs for the vessels will be discussed in a separate section.

Table 11. The ranges for different parameters of OS and MM removal operations

Parameter	Description	OS	MM		
		Minimum	Maximum	Minimum	Maximum
$t_{\mathrm{pos}}^{\mathrm{JUV}}$	Positioning duration of the JUV (hours)	3 [9]	8 [9,30]	6 [9]	6 [9]
$t_{\mathrm{up}}^{\mathrm{JUV}}$	Jacking-up duration of the JUV (hours)	6 [9]	10 [9]	8 [9]	8 [9]
$t_{\mathrm{down}}^{\mathrm{JUV}}$	Jacking-down duration of the JUV (hours)	1 [9]	4 [9]	2 [9]	2 [9]
$t_{\mathrm{c,top}}$	Cutting and disconnecting duration required for the topside removal (hours)	12 [27]	-	4 [27]	-
$t_{\mathrm{L,top}}$	Lifting duration of the topside by the JUV (hours)	3 [27]	-	3 [27]	-
$t_{\mathrm{c,p}}$	Cutting duration of the jacket piles under the seabed (hours)	48 [27]	-	36 [27]	-
$t_{\mathrm{L,j}}$	The time required by the JUV to lift the jacket structure (hours)	3 [27]	-	3	-

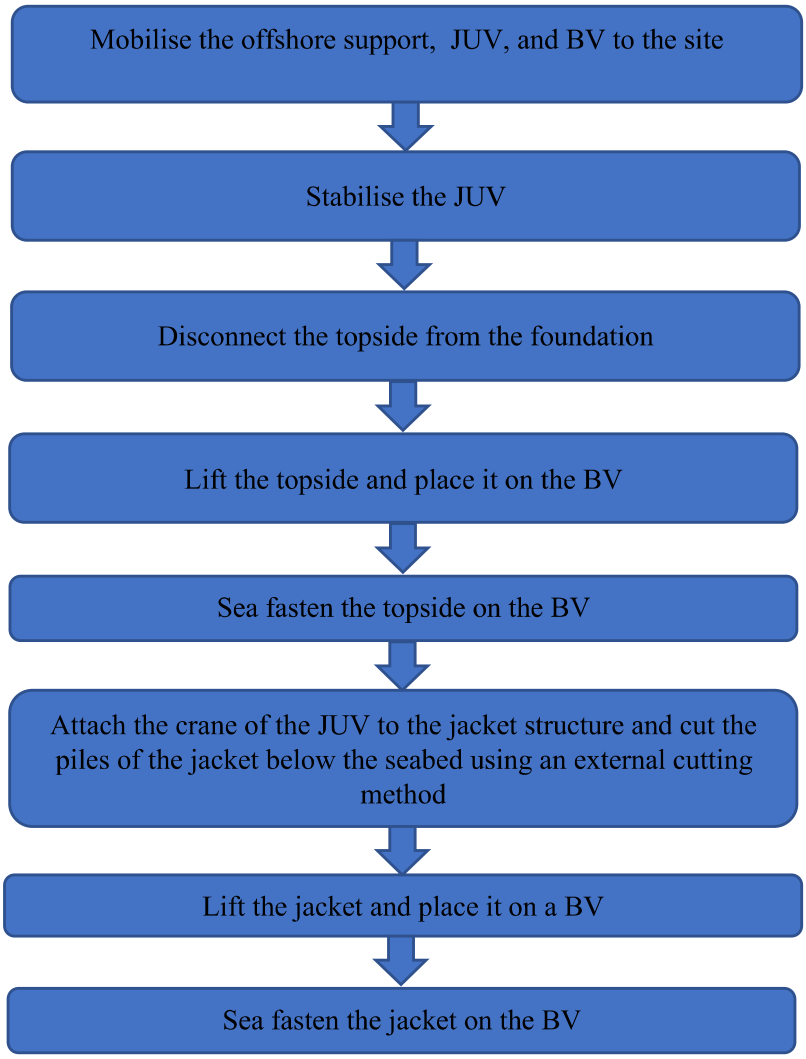

Fig. 32. Main steps for the OS removal

3.6. Seabed clearance and restoration

After the removal operations, some activities should be performed to return the seabed to its original state as much as possible. These activities include filling the holes on the seabed resulting from the removal operations and the removal of scour protections. The total cost related to the seabed clearance and restoration activities can be expressed as follows:

$$Cost_{\mathrm{SC}} = Cost_{\mathrm{SP}} + Cost_{\mathrm{RD}} \tag{21}$$

where $Cost_{\mathrm{SC}}$ represents the total cost of the seabed clearance and restoration activities, $Cost_{\mathrm{SP}}$ is the cost of the scour protection removal operation, and $Cost_{\mathrm{RD}}$ denotes the cost related to the rock dumping operation. In the following subsections, the costs related to the seabed clearance and restoration will be described.

A. Scour protection removal

The areas in the vicinity of the offshore foundations can be subjected to the scour phenomenon as a result of the increase in the sediment transport capacity by currents or by a combination of currents and waves [15], which can significantly affect the stability of the foundations. Hence, in most wind farm projects, the scour protections are built around the foundations to avoid possible instabilities caused by the scour phenomenon. In some of the wind farm projects, the scour protections are also designed to protect the inter-array and export cables.

There is a wide variety of scour protection designs for the wind farm projects, such as dumped stone riprap, stone or concrete pitching, soil-cement bagging or grouted fabric mattress [33]. However, due to its availability and lower cost, the combination of rocks and stones is more popular than others. The scour protections usually consist of two main layers as follows: filter layer and armour layer.

Over the service life of wind farms, scour protection can become a habitat for marine species and organisms. Therefore, in most of the available OWF DPs, the scour protections are left in situ to reduce the environmental impacts and save marine life. However, in some cases, the partial or entire removal of the scour protection is inevitable. For example, in the foundation removals using external cutting methods, it is necessary to remove the scour protection to provide required access for the cutting tool. The removal of scour protection can be performed by a mechanical dredging tool (e.g., DCBV) and a BV. The removed materials are usually re-used or dumped to a previously approved location in the sea.

According to the wind farm decommissioning literature, predicting the scour protection removal cost is not straightforward. The removal cost is directly proportional to the rock volumes used in the scour protections around the foundations. The removal duration of scour protection may depend on the applied technology and method, which make it difficult to estimate the total removal duration. However, we have assumed that a DCBV with a clamshell bucket is used to retrieve the scour materials around the foundation. The removal duration of scour protection materials depends on the size of the clamshell bucket and the crane speed [34]. According to the DP of the Cape Wind [34], with the assumption of the clamshell bucket with a capacity of 6 m^3, by assuming 2.5 minutes for fill and dump duration, the removal rate of scour protection materials would be roughly 144 m^3/hour.

In this report, we have formulated the removal cost of the scour protection as follows:

$$Cost_{\mathrm{SP}} = C_{\mathrm{mob}}^{\mathrm{DCBV}} + \alpha C_{\mathrm{mob}}^{\mathrm{BV}} + C_{\mathrm{mob}}^{\mathrm{ROV}} + {}^{1}/_{24}\left(C_{\mathrm{D}}^{\mathrm{DCBV}} + \alpha C_{\mathrm{D}}^{\mathrm{BV}} + \beta C_{\mathrm{D}}^{\mathrm{TB}} + C_{\mathrm{D}}^{\mathrm{ROV}}\right) \times t_{\mathrm{total}} \qquad (22)$$

$$t_{\text{total}} = (n_{\text{t}} + n_{\text{OS}} + 1) \times \left(t_{\text{pos}}^{\text{DCBV}} + t_{\text{a}}^{\text{DCBV}}\right) + \left(\sum_{i=1}^{n_{\text{t}}} \frac{V_i^{\text{WT}}}{r_{\text{ret}}} + \sum_{i=1}^{n_{\text{OS}}} \frac{V_i^{\text{OS}}}{r_{\text{ret}}} + \frac{V^{\text{MM}}}{r_{\text{ret}}}\right) \tag{23}$$

where:

$Cost_{\text{SP}}$: indicates the total removal cost of the scour protections in the wind farm.

$C_{\text{mob}}^{\text{DBV}}$: is the mobilisation cost for the DCBV (pounds)

$C_{\text{mob}}^{\text{BV}}$: is the mobilisation cost for the BV (pounds)

$C_{\text{D}}^{\text{DCBV}}$: represents the daily rate of the DCBV (pounds)

C_{D}^{BV}: is the daily rate of the BV (pounds)

C_{D}^{TB}: is the daily rate of the TBs (pounds)

t_{total}: indicates the total removal duration of the scour protections in the wind farm (hours)

$t_{\text{pos}}^{\text{DCBV}}$: is the positioning duration of the DCBV to start the removal operation (hours)

V_i^{WT}: represents the scour protection material volume around the *i*th WT in the wind farm (m^3)

r_{ret}: is the removal rate of scour protection materials (m^3/hour)

n_{t}: is the number of WTs in the wind farm.

n_{OS}: is the number of OSs in the wind farm.

V_i^{OS}: represents the scour protection material volume around the *i*th OS in the wind farm (m^3)

V^{MM}: indicates the scour protection material volume around the MM (m^3)

$t_{\text{a}}^{\text{DCBV}}$: represents the time required by the DCBV to retrieve its anchors (hours)

As can be seen from equations (22) and (23), the removal cost of the scour protection depends on the different parameters, such as the vessel costs, removal rate, vessel positioning durations, and volumes of the scour protection. Table 12 lists the assumed values for the vessel repositioning and removal rate. The assumed vessel costs will be discussed in the related section.

Table 12. The assumptions for different parameters of scour protection removal operations

Parameter	Description	Assumed values
$t_{\text{pos}}^{\text{DCBV}}$	Positioning duration of the DCBV to start the removal operation (hours)	6 [34]
r_{ret}	The removal rate of scour protection materials (m^3/hour)	144
$t_{\text{a}}^{\text{DCBV}}$	The time required by the DCBV to retrieve its anchors (hours)	8 [34]

B. Rock dumping

As it was mentioned before, the wind farm site needs to be returned to its original state before the installation and the environmental impacts of the decommissioning operations should be minimised. The holes on the seabed resulting from the foundation removal operations should be filled with appropriate material. For example, the decommissioning program for Sheringham Shoal OWF [9] suggests evening out the holes through a rock dumping operation. A rock dumper operation was assumed to perform this operation, which can fill 8 foundation locations in a day. In addition, an ROV is required for inspection purposes.

According to the abovementioned points, the rock dumping cost can be calculated as follows:

$$Cost_{\mathrm{RD}} = C_{\mathrm{mob}}^{\mathrm{RDV}} + C_{\mathrm{mob}}^{\mathrm{ROV}} + \left(C_{\mathrm{D}}^{\mathrm{RDV}} + C_{\mathrm{D}}^{\mathrm{ROV}}\right) \times t_{\mathrm{total}} \tag{24}$$

$$t_{\mathrm{total}} = \frac{(n_{\mathrm{t}} + n_{\mathrm{OS}} + 1)}{r_{\mathrm{rd}}} \tag{25}$$

where:

$Cost_{\mathrm{RD}}$: represents the cost of the rock dumping (pounds)

$C_{\mathrm{mob}}^{\mathrm{RDV}}$: is the mobilisation cost of the RDV (pounds)

$C_{\mathrm{D}}^{\mathrm{RDV}}$: indicates the day rate of the RDV (pounds)

t_{total}: is the total rock dumping operation (days)

r_{rd}: is the rock dumping rate (locations/day)

The r_{rd} is assumed as 8 locations/day and the rest of the unknown parameters in equations (24) and (25) will be discussed in the vessel costs section.

3.7. Vessel rates

In the derived formulations, the removal costs of different wind farm components depend on the mobilisation/ demobilisation and day rates of different vessels. Some of the offshore removal vessels, such as JUV and CLV, are expensive to mobilise and hire which demand special attention for their optimal use. On the other hand, due to weather conditions, the offshore operations may be interrupted, and the decommissioning expenses could be significantly more than predicted. The vessel/equipment rates are rather sensitive to the market. Meanwhile, the vessel rental contracts should be performed earlier than the project starting time, which could be up to two years before the project start time in some cases. Hence, the project managers need to optimise the vessel utilisation throughout the project. In this report, the available experience and statistics on the vessel rates from different references will be considered to assume holistic vessel/equipment rates for cost calculations.

Table 13 lists the different vessel/equipment types required for the different decommissioning activities, assumed based on the available experience in the OWF decommissioning. It should be noted that the type and number of different vessels/equipment may be different depending on the characteristic features of a given OWF decommissioning project.

The rental rates for different removal vessels/equipment from multiple references in the literature are presented in Table 14. From Table 14, it can be seen that the rates provided by different references are quite different for different vessel/equipment types. The reasons for these differences may come from the fact that the rates have been reported by references in different years with the different market situations and inflation rates.

Table 13. The required vessels for the different decommissioning activities

Activity	Vessels	Quantity	Comment(s)
Pre-decommissioning activities	PTV	1	
WT removal	JUV	1	- Depending on the removal strategy, a different number of JUVs may be used.
	BV	2	- We assume 2 BVs
	TB	1 or 2	- Depending on the type of the JUV, 1 or 2 TBs may be required.
Foundation removal	JUV	1	- Depending on the removal strategy, a different number of JUVs may be used.
	BV	2	- 2 BVs are considered.
	OSV	1	- One ROV is required.
	TB	1 or 2	- Depending on the foundation removal strategy, JUV or OSV may be used.
	ROV	1	
OS removal	JUV	1	- Depending on the topside weight, a JUV or HLV may be utilised.
	HLV	1	- Depending on the type of the JUV, 1 or 2 TBs may be required.
	BV	1	- We assume 1 BV.
	TB	1 or 2	- A ROV is required for foundation removal
	ROV	1	
MM removal	JUV	1	- A ROV is required for MM foundation removal
	BV	1	
	ROV	1	
Cable removal	CLV	1	
	ROV	1	
Seabed clearance and restoration	DCBV	1	- One BV is considered.
	BV	1	- A ROV is required for inspections
	RDV	1	
	ROV	1	

Table 14. The assumed values for the vessel/equipment rates in OWF decommissioning

Vessel/equipment	Mobilisation/Demobilisation		Day rates	
	Notation	Rate (£)	Notation	Rate (£)
JUV	$C_{\mathrm{mob}}^{\mathrm{JUV}}$	400k-445k [35]	$C_{\mathrm{D}}^{\mathrm{JUV}}$	- 200k [31][1] - 100k-125k [35] - 138.8k-169k[2] [12]
HLV	$C_{\mathrm{mob}}^{\mathrm{HLV}}$	500k [35] 862k [36][2]	$C_{\mathrm{D}}^{\mathrm{HLV}}$	- 135k [35] - 350k-400k [31][1] - 232.8k [36][2]
CLV	$C_{\mathrm{mob}}^{\mathrm{CLV}}$	445k [35]	$C_{\mathrm{D}}^{\mathrm{CLV}}$	- 80k (inter), 100k (export) [35] - 40k-50k [31][1] - 78.5k (inter), 98.27k (export) [21][2]
OSV	$C_{\mathrm{mob}}^{\mathrm{OSV}}$	N/A	$C_{\mathrm{D}}^{\mathrm{OSV}}$	3.9k [36][2]
DCBV	$C_{\mathrm{mob}}^{\mathrm{DCBV}}$	100k[3]	$C_{\mathrm{D}}^{\mathrm{DCBV}}$	50k [31][1]
RDV	$C_{\mathrm{mob}}^{\mathrm{RDV}}$	10.6k [35]	$C_{\mathrm{D}}^{\mathrm{RDV}}$	11.9k [21][2] 13.8k [35]
BV	$C_{\mathrm{mob}}^{\mathrm{BV}}$	172.4k [36][2]	$C_{\mathrm{D}}^{\mathrm{BV}}$	30k [21][2] 12.9k [36][2]
TB	$C_{\mathrm{mob}}^{\mathrm{TB}}$	N/A	$C_{\mathrm{D}}^{\mathrm{TB}}$	13.8k-15.5k [12][2] 19.4k [21][2] 8.6k [36][2]
ROV	$C_{\mathrm{mob}}^{\mathrm{ROV}}$	34.48k [36][2]	$C_{\mathrm{D}}^{\mathrm{ROV}}$	20k-40k [31][1] 3.45k [36][2]
PTV	$C_{\mathrm{mob}}^{\mathrm{PTV}}$	N/A	$C_{\mathrm{D}}^{\mathrm{PTV}}$	3.25k [35] 10k-20k [31][1]

[1]Based on 2017 market
[2]Exchanges rate is applied: 1£=1.16€
[3]Assumed due to the lack of the data

4. Concluding remarks

With the expected design life of current OWFs, the number of OWFs needed to be decommissioned will be remarkably increased in the next decades. The decommissioning of an OWF can be defined as a set of operations that aim to return the wind farm site to its original state before the installation under some environmental considerations. Due to the lack of information and limited previous experience in the field, the cost estimation of OWF decommissioning projects is not an easy task. In this report, the cost estimation formulations were developed for different OWF decommissioning activities, including WT removal, foundation removal, OS removal, MM removal, cables removal as well as seabed clearance and restoration operations. The derived cost formulations suggest that the decommissioning costs depend on a set of parameters that should be carefully selected to obtain realistic cost estimations. A literature survey has been performed and the ranges for different cost parameters were extracted based on the current experience and available data. Due to market situations and availability of vessels, the mobilisation/demobilisation and day rates of the different vessels are subjected to a high level of uncertainty which can cause budget miscalculations or overruns. Moreover, the applied vessel/equipment and removal technology for a given OWF may depend on a wide variety of factors which make it difficult to provide a general cost estimation approach for all OWFs. The findings of this report also suggested that the decommissioning cost estimations are unique for each OWF, which necessitates the comprehensive study of the characteristics feature and site specifications of each OWF to provide holistic cost estimations.

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