Assessment of Offshore Wind Farm Decommissioning Requirements

Ontario Ministry of the Environment and Climate Change

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Task and objective:

- To collect and present an international overview of offshore structures decommissioning requirements, regulations, and costs, focusing on the type of structures used in or relevant to offshore wind;
- To design likely scenarios for offshore wind decommissioning in Ontario's fresh water lakes; and
- To develop cost estimates to inform requirements for decommissioning and financial assurance requirements for future offshore wind power plants in the Great Lakes.

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Reference to part of this report which may lead to misinterpretation is not permissible.

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C	17 May 2016	Addressed MOECC comments	G. Smith	D. Faghani	

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List of abbreviations

Abbreviation	Meaning
AC	Alternating current
BOEM	Bureau of Ocean Energy Management (US)
BSH	Bundesamt für Seeschifffahrt und Hydrographie (Germany)
CAD $, CADM $	Canadian dollars, million Canadian dollars
CGBS	Concrete gravity based structures
COP	Constructions and Operations Plan
DAF	Dynamic Amplification Factor, or dynamic load factor
DC	Direct current
DEA	Danish Energy Agency
DECC	Department of Energy and Climate Change (UK)
DNV GL	GL Garrad Hassan Canada Inc.
DP	dynamic positioning systems
DPR	Decommissioning Plan Report (Ontario)
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Assessment
EPR	Ethylene propylene rubber
EU	European Union
FEPA	Food and Environment Protection Act (UK)
GBS	Gravity base structure
GLERL	Great Lakes Environmental Research Laboratory, part of NOAA
GRE, GRP	glass reinforced epoxy, glass reinforced polymer
GW	Gigawatt
HLCV	heavy lift cargo (or construction) vessel
HLV	heavy lift vessel – minimal cargo capacity
Hs	significant wave height
HVDC	High-voltage direct current
IBGS	Inward battered guide structure
ICPC	International Cable Protection Committee
IJC	International Joint Commission
IMO	International Maritime Organization
LNG	Liquefied Natural Gas
M	million
MNRF	Ontario Ministry of Natural Resources & Forestry
MOECC	Ontario Ministry of the Environment and Climate Change
MP	Monopile foundation
MW	Megawatt

Abbreviation	Meaning
N/A	Not available or not applicable
NDBC	National Data Buoy Center (USA)
NGS	National Geological Survey (USA)
NOAA	National Oceanographic and Atmospheric Administration (USA)
NREL	National Renewable Energy Laboratory (USA)
O&G	Oil & Gas
O&M	Operations and Maintenance
OECD	Organisation of Economic Co-operation and Development
OGP	International Association of Oil & Gas Producers
OOS	Out of service
OSPAR	Oslo and Paris Convention
OSS	Offshore substation
OWF	Offshore wind farm
PMG	Permanent magnet generator
REA	Renewable Energy Approval (Ontario)
ROV	Remotely Operated Vehicle
SBJ	Suction bucket jacket foundation
SCADA	Supervisory, Control and Data Acquisition
SoS	Secretary of State (UK)
TCE	The Crown Estate (UK)
the Soo	Sault Ste. Marie
TLP	Tension-leg platforms
TP	Transition piece
UHP	Ultra-high pressure (water jet cutting)
UKCS	UK Continental Shelf
UNCLOS	United Nations Convention on the Law of the Sea
US	United States of America
WROV	work-class remotely operated (underwater) vehicle
WTG	wind turbine generator
WTIV	wind turbine installation vessel, self-propelled crane jack-up
XLPE	cross-linked polyethylene

List of units and conversions

Unit	**Meaning**	**Conversion**
kV	kilovolt	1 kV = 1,000 V
kW	kilowatt	1 kW = 1,000 W
MW	megawatt	1 MW = 1,000,000 W
kg	kilograms	1 kg = 0.001 te
km	Kilometre, kilometer	1 km = 0.62 miles = 0.54 NM
kt, kts	Knots (nautical miles per hour)	1 kt = 1.85 km/h
m	Metre, meter	1 m = 3.28 ft
mm	Millimetres, millimeters	1 mm = 0.001 m
NM, NMi	Nautical mile	1 NM = 1.85 km = 1.15 miles
te, t	Metric tonne	1 te = 1,000 kg
	Long ton (2,240 lbs)	1 long ton = 1,016 kg
	Short ton (2,000 lbs)	1 short ton = 907 kg

EXECUTIVE SUMMARY

The Ontario Ministry of the Environment and Climate Change (MOECC) retained GL Garrad Hassan Canada Inc. (DNV GL) to provide a study on decommissioning requirements for potential offshore wind projects in the Great Lakes. More specifically, the objectives of the mandate were:

- To collect and present an international overview of offshore structures decommissioning requirements, regulations and costs, focusing on the type of structures used in offshore wind;
- To design likely scenarios for offshore wind decommissioning in Ontario's fresh water lakes; and,
- To develop cost estimates to inform requirements for decommissioning and financial assurance requirements.

By the end of 2015, over 10 gigawatts (GW) of global offshore wind capacity were fully operational, the great majority off the coasts of northern Europe. There are no operational commercial-scale projects in North American waters, though there is significant potential including the Ontario waters of the Great Lakes.

To achieve the above goals in the Study, DNV GL has provided descriptions of current offshore wind technologies and other offshore structures with an emphasis on their relevance to the Great Lakes. In addition, a review has been made of international jurisdictional decommissioning requirements. These overviews are complemented by the definition of potential offshore wind development scenarios in the Great Lakes, the development of a decommissioning cost estimation tool relevant to these scenarios, and the estimation of decommissioning cost ranges that would be anticipated. The costing tool is delivered to MOECC separately for their internal future use.

Offshore wind farms – an overview

An offshore wind farm may comprise up to or over 100 wind turbines supported by foundation structures and electrically linked by array cables buried in the sea-bed. Most offshore wind farms also include an offshore substation to collect the power for transmission to shore via the export cable. Other major elements are the onshore cabling, substation and operations base. Offshore elements may include a meteorological mast.

In over 20 years of offshore wind development, the design of offshore wind turbines has moved from marine versions of onshore turbines to specifically-designed offshore machines, and offshore wind farms have moved from a handful of turbines with a few megawatts (MW) capacity to projects of over 100 machines totalling several hundred MW capacity. In the absence of transportation restrictions offshore, their sizes have grown to over 6 MW with 10 MW machines foreseeable in the near future. Turbine foundation structures may be steel monopiles, lattice or jacket structures, gravity-based structures, tri-piles or tripods, or suction buckets with the selection largely depending on the water depth, turbine size, and the nature of the sea-bed. In deep waters, floating platforms are more recently being developed for support of turbines. Depending on the site conditions, protection against sea-bed scour (erosion of the seabed around the foundation) and against the forces of ice may be needed. Port and shore facilities are required to support offshore construction, maintenance operations and ultimately the decommissioning activities.

More detail of offshore wind energy technologies are given as part of the consideration of decommissioning methods.

Other offshore infrastructure

Offshore Oil & Gas (O&G) and other marine structures, in particular bridges and harbour constructions, provide structural design and marine decommissioning experience that can be transferred, to some extent, into the offshore wind sector.

There are similarities in the range of vessels used in the O&G industry from survey vessels, jack-ups and crane vessels to support vessels; and in techniques ranging from design against corrosion protection and ice forces to the methods for working underwater. Ice cones, concrete collars and ice deflection skirts are some of the designs being employed by the O&G industry where there is floating or fixed ice. The main differences of offshore wind compared with O&G structures arise primarily from the scale and numbers of installations (multiple similar installations compared with mainly one-off designs), generally lower weights and dimensions, the nature of the structural loading with turbines experiencing high overturning moments, and the much lower potential for environmental pollution or risks of accident. Care should therefore be exercised when transferring O&G experience to the offshore wind industry. In the field of decommissioning, the main experiences gained from the O&G industry are the need to take decommissioning into account at the design stage and throughout the operational life, and the developments in underwater cutting and other subsea techniques.

Experience from bridges and ports in the Great Lakes can help inform offshore wind farm design, particularly for withstanding floating and solid ice pressure on support structures. For example, methods of ice protection are well established such as the use of ice-cones around bridge piers. In addition construction techniques are well established though typically in relatively shallow waters and in relatively benign coastal conditions.

Jurisdictional and literature review

The Study reviews existing guidelines, regulations, codes of practice and best practices for decommissioning offshore energy projects, including ensuring adequate financial assurance. The main comparators were the United Kingdom, Germany and Denmark which have the most mature offshore wind industries, with a secondary review of the United States, Canada, the Netherlands, Belgium, Sweden, Norway, Finland, Ireland, Japan, China, Taiwan and South Korea.

The rights and responsibilities of decommissioning offshore energy installations are determined by international, national and regional laws and regulations. The primary international regulation is the United Nations Convention on the Law of the Sea (UNCLoS) which is transposed through the International Maritime Organisation (IMO). In the North East Atlantic, the Oslo and Paris (OSPAR) treaty is also binding.

The basic principles are that

- Ideally, all offshore installations or structures should be completely removed when no longer used. In practice, however, there is some flexibility provided. This is usually on the basis of extreme cost, extreme safety risk, or when removal will cause greater environmental damage than leaving in situ. In some instances, installation may be left in situ if they will serve a new use.
- Polluter pays, with regulators seeking to ensure that developers make adequate provision to meet decommissioning liabilities.

Most nations make an adequate decommissioning concept or plan a requirement for granting either a lease or permission to construct the project. Denmark, however, does not require this plan until fairly late in the life-time of the project. All nations require that some form of financial assurance is made that ensures that decommissioning can be funded. In general, the value is calculated by the project owner and approved by the lead regulatory agency. In all countries an irrevocable bond or cash deposit is acceptable as a guarantee.

According to the IMO convention, it may be permitted in certain cases to allow structures to remain at least partially in place, for example if the removal processes are likely to cause more environmental damage than leaving them in situ. In practice for offshore wind projects, this condition is most likely to apply to piles, to buried cables, and to some scour protection.

Beyond these basic principles of the extent of decommissioning and the provision of financial assurance, main areas to be considered are:

- The strength of legislative backing and the liabilities on developers.
- The flexibility in the provision of guarantees by developers, and the appreciation of by regulators of uncertainties in the estimation of decommissioning methods and costs.
- The balance between ensuring environmental protection while minimising the burden on developers, for example taking into account the differences in pollution risk between offshore wind and oil & gas decommissioning.
- The reflection of broader ideological and cultural approaches in the regulatory involvement. For example in Denmark the regulator has a very active role undertaking the initial decommissioning cost assessment on behalf of the developer; whereas in the UK the regulator issues guidance and works with the developers on a case by case basis to approve the plan.

Technology selection and description

Offshore wind technologies are reviewed with a focus on the selection and description of the most likely technologies for Great Lakes offshore wind projects. The selection of turbine foundation is a critical decision based on the site-specific conditions and the turbine type. Generally an iterative approach is adopted as increasingly detailed data is collected during the development process.

In the Canadian Great Lakes the very wide range of water depths, geological characteristics, wind speeds and extent of fresh-water ice lead to the conclusion that none of the major foundation types for wind turbine generators can be ruled out at this stage. Wind speeds tend to be higher further away from the shore and are greater in Lake Superior and Lake Huron, and therefore more remote from populations. Water depths range from an average 19 m in Lake Erie to 149 m in Lake Superior. Lake bed geology plays an important part in determining the optimum foundation and ranges greatly from regions with very hard bedrock and little overlying sediment which would prevent the driving of piles, to regions with softer sedimentary rock. A particular feature of the Great Lakes is the winter ice cover which will influence the choice and design of foundations and also restricts the length of the shipping season. Ice-free waters occur where water depths are greatest. However, tides and water currents are negligible in the Great Lakes, and wave heights are less restrictive than in the open ocean. There are some limits to marine operations from fog.

The selection of specific locations for offshore wind farms is outside the scope of this Study. Major deciding factors will be the wind speeds, water depths and sea-bed geology, though the selection will also be influenced by other factors such as remoteness from ports, proximity of electrical connections and environmental permitting. For the purposes of the Study, a range of site-types is considered with different combinations of these factors. Similarly, the selection of specific turbine types is not included in this Study and for the more detailed technical descriptions, generic 4 MW and 8 MW turbine sizes are considered.

During the construction or decommissioning of offshore wind turbines, in general jack-up platforms or vessels (lift-boats) are needed. With this static rather than floating base, the crane can work to the precision needed. In Europe, turbines are generally installed using specialised jack-up vessels with integral cranes capable of over 1000 t lift and reaching to the turbine hub heights. Similarly foundations are installed using specialised heavy lift crane vessels capable of handling monopiles and jackets that may weigh well over 1000 t, or greater for gravity base foundations. Offshore substations are installed with similar heavy lift crane vessels, with the jacket and topside installed in separate operations.

Turbine decommissioning involves the reverse of installation techniques using multiple lifts to remove blades, nacelles and towers. Foundation decommissioning involves different techniques from installation, especially for piled structures: cutting monopiles or jacket piles at just below sea-bed level using high pressure water jet techniques; or removing the ballast from gravity base and releasing the foundation; or releasing suction buckets by water injection. In each case a heavy lift floating vessel is generally used to lift out the foundations. With floating support structures, they are released from their moorings and towed to shore; turbines would be removed at shore. Cables are de-buried using ploughs or water jets, similar to installation. Offshore substations are decommissioned by removing the topside using similar heavy lift methods to installation, and then removing the foundation.

In the Great Lakes, the restricted capabilities of vessels are a major issue for construction and similarly for decommissioning operations. This is because vessels wider than 23.7 m (78 ft) cannot enter the St Lawrence Seaway locks into the Great Lakes system and also that the heavy lift vessels within the system are very limited in capability. Mobile cranes on modular jack-up platforms may need to be used for turbine installation as an alternative to the heavy lift jack-up vessels used in Europe. Turbine construction and decommissioning are likely to require mobile crawler cranes mounted on modular jack-up platforms or pontoons with added legs. If a specialised vessel is built within the Lakes it is unlikely to be as capable as those in Europe. Foundation construction and decommissioning is likely to be carried out with the foundations in more than one section to reduce the maximum lift needed. With the larger turbine and foundation sizes, techniques involving floating the pieces in a controlled manner may be adopted to reduce the maximum lifts required. For the topside of offshore substations, which may weigh 2000 t, they would be designed for construction and removal in several modules.

Cost estimates for decommissioning

Indicative cost estimates for the decommissioning of selected offshore wind technologies for different hypothetical scenarios in the Great Lakes are considered. The analysis includes the description and application of a custom-built cost modelling tool that is provided as part of the work.

In general, the main decommissioning cost categories are:

- Pre-decommissioning work to review and fulfill regulations and Environmental Impact Assessment (EIA) requirements, and engineering surveys and planning;
- Marine operations to prepare and remove each of the components;
- Post-decommissioning survey work after completion of the marine operations;
- Overheads covering management costs, insurance, port fees etc.; and
- Costs for materials disposal and potential revenues from recycling.

The cost modelling focuses on notional 75-turbine offshore wind farms in the Great Lakes, each using a 4 MW generic turbine that represents today's established technology. A future 8 MW turbine is expected to require very different methods of decommissioning and therefore its cost modelling is considered too speculative to be included.

The scope of the modelling encompasses all the major types of foundations considered for offshore wind turbines by means of the following main strategies based on the removal logistics:

- Cut, Lift, Carry (e.g. for monopiles and jackets);
- Lift, Float, Tow (e.g. gravity base or suction foundations);
- Detach and Tow (e.g. floating wind); and
- Offshore sub-station (one or two by Cut, Lift, Carry method).

For removing 75 offshore wind turbines, the logistics play a large part in the cost, with the optimum generally utilising separate vessels for the turbine and foundation removal following behind one another, thus reducing the overall duration of the operations and allowing each vessel to make best use of its specialist capabilities. In contrast, for the offshore sub-station the same heavy lift vessel is employed for both the topside and foundation removal. The scope of the costing allows options to include or exclude the removal of array cables, export cables and offshore sub-stations, and to separate out the disposal costs and recycling revenue.

Using the Great Lakes Offshore Wind Decommissioning Cost Tool (the "Tool"), supplied as a separate deliverable in this Study, a series of scenarios is explored as summarised in Figure A. For this modelling, cost estimates for each scenario are derived in CAD $ and using current values which is standard practice. The results presented here are based on inputs at 2015 costs. In the future, the overall costs may change in line with changes due to inflation and market forces, and also changes in the underlying fundamentals of methodologies and equipment used.

In the Base Case, the values of the main inputs are chosen as the most likely "central" values, though the modelling includes a necessary allowance for weather delays and a 10% cost contingency. The other scenarios explore the sensitivity to the main variables and the range of potential foundation types with their different decommissioning methods.

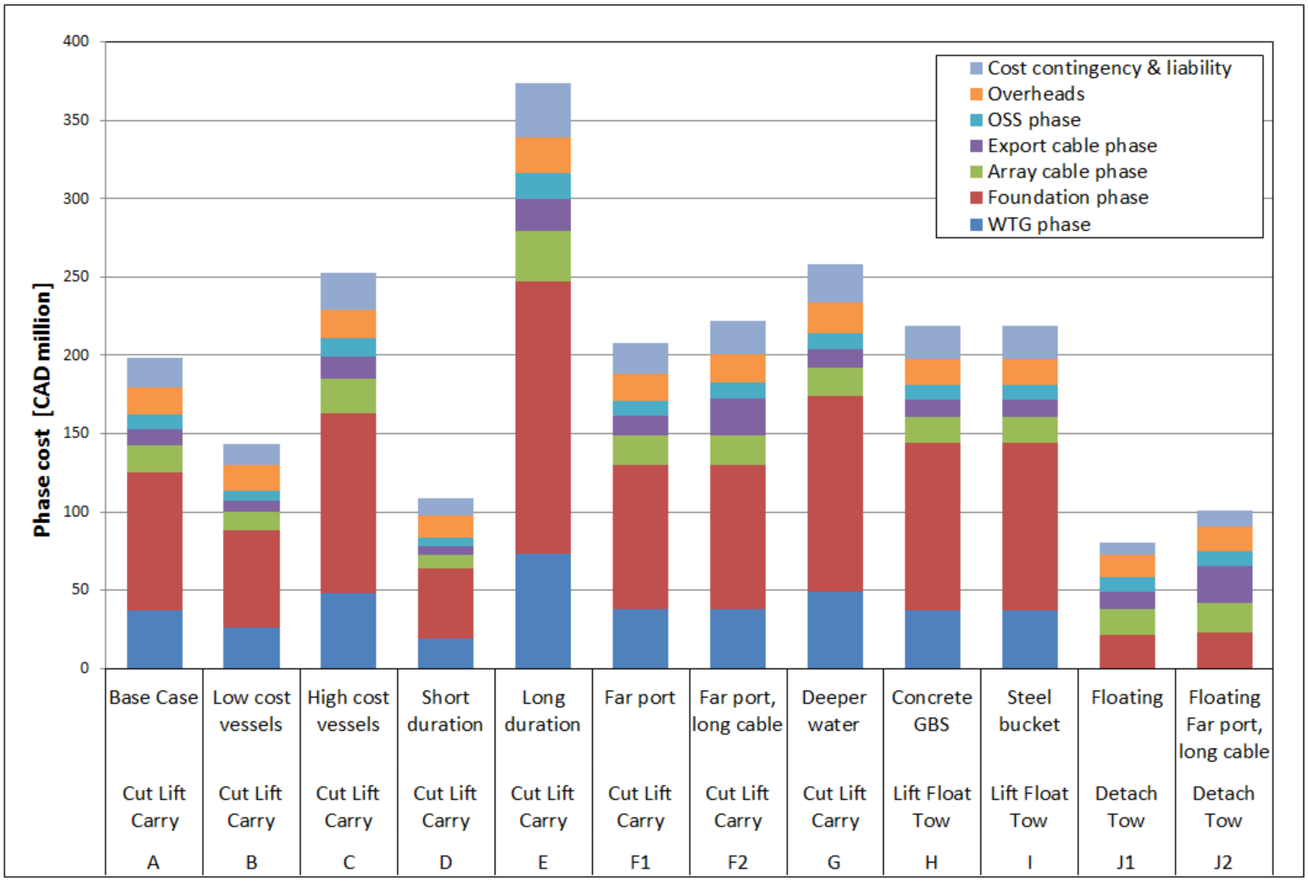


Figure A - Great Lakes cost modelling - breakdown of decommissioning costs by phase

The Base Case scenario of 4 MW turbines on monopile foundations in 25 m water depth and 20 km from the disposal port yields an overall estimated cost of the decommissioning phase of CAD $198 million, or CAD $187 million after recycling revenue is included, representing CAD $2.6 or $2.5 million per turbine. An overall duration of the marine operations of 14½ months is predicted, including estimated weather delays. Charter costs of the main vessels form over 85 percent of the cost, and as a consequence the overall cost is almost linearly proportional to the duration of the marine operations and to the day-rates for the vessels. The overall cost is only weakly dependent on the distance to the disposal port as the transit times form a small proportion of the overall time. An increase in water depth to 40 m results in an approximately 30 percent increase in overall estimated cost because more capable vessels are needed with longer legs for turbine removal and larger crane capacity for foundation removal. Decommissioning costs for a concrete gravity base and for steel suction bucket are slightly higher than the base case (17 percent and 10 percent higher respectively), the only difference in the modelling being the disposal cost analysis with similar durations being assigned to the removal operations. For floating structures the overall decommissioning cost is less than 50 percent of the Base Case.

The design of the cost model Tool provides sufficient detail to allow all the main elements of the decommissioning costs to be captured and the strong dependence on the marine logistics to be explored. The guidance notes for the Tool include indicative ranges of values for the main user inputs and the circumstances affecting the choices.

While the indicative values used in the modelling are all based on DNV GL's experience in the current offshore wind industry, the parameters used are necessarily somewhat generic since the design and location of any Great Lakes offshore wind farm is as yet undecided. The restricted options for suitable decommissioning vessels in the Great Lakes also provides further sources of uncertainty in the cost estimates. In the future, when decommissioning cost estimates are required for a specific offshore wind farms, DNV GL recommends that more detailed and project-specific cost modelling be carried out.

1 INTRODUCTION

The Ontario Ministry of the Environment and Climate Change (MOECC) retained GL Garrad Hassan Canada Inc. (DNV GL) to provide a study on decommissioning requirements for offshore wind projects in the Great Lakes. This report presents the results of DNV GL's analysis.

1.1 Objectives

The primary purpose of this study is to provide a reference source document for use by MOECC to support policy considerations regarding possible future offshore wind farm development in Ontario's Great Lakes waters. An important element of policy analysis and development is to understand potential decommissioning costs of offshore wind farms and related equipment. In order to ensure that the decommissioning work outlined in a closure plan [1] is successfully performed, even in the event that the owner of the equipment faces financial or legal troubles, a financial guarantee may be held in trust by the MOECC. This financial guarantee is known as financial assurance.

More specifically, the objectives of this work are defined as follows:

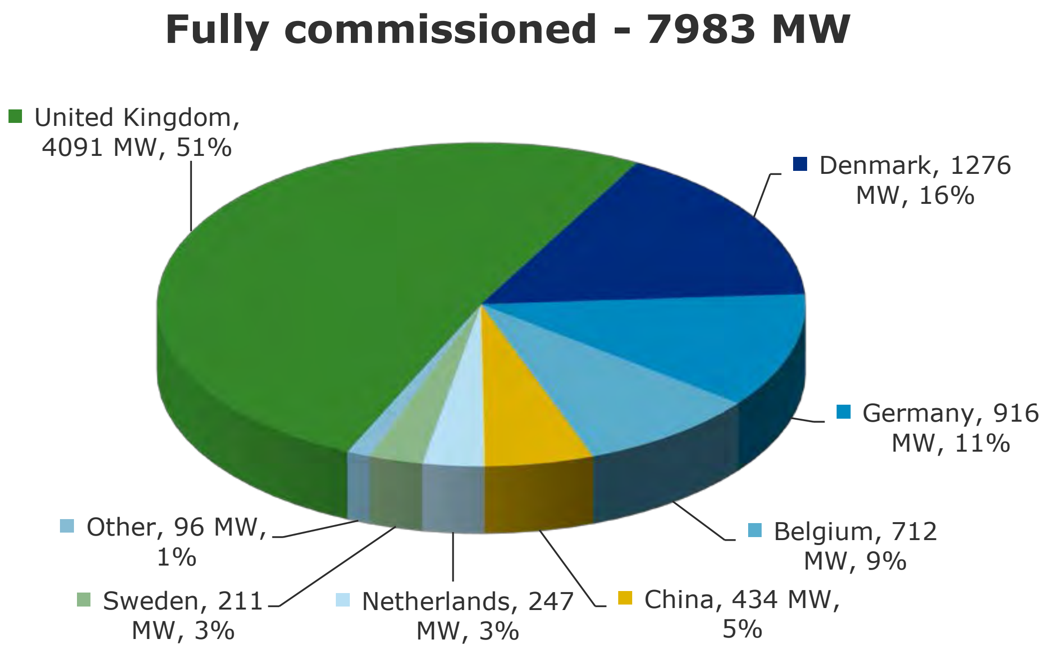
- To collect and present an international overview of offshore structures decommissioning requirements, regulations and costs, focusing on the type of structures used in offshore wind;
- To design likely scenarios for offshore wind decommissioning in Ontario's fresh water lakes; and,
- To develop cost estimates to inform requirements for decommissioning and financial assurance requirements.

1.2 Background

Ontario's Great Lakes have a well proven wind resource potential for offshore wind energy development [2]. In order to ensure that there are no adverse environmental effects associated with such developments, it is important to ensure that offshore wind farms are properly decommissioned, monitored, and inspected at the end of the project life. This report provides a broad overview of the technical requirements and costs associated with decommissioning.

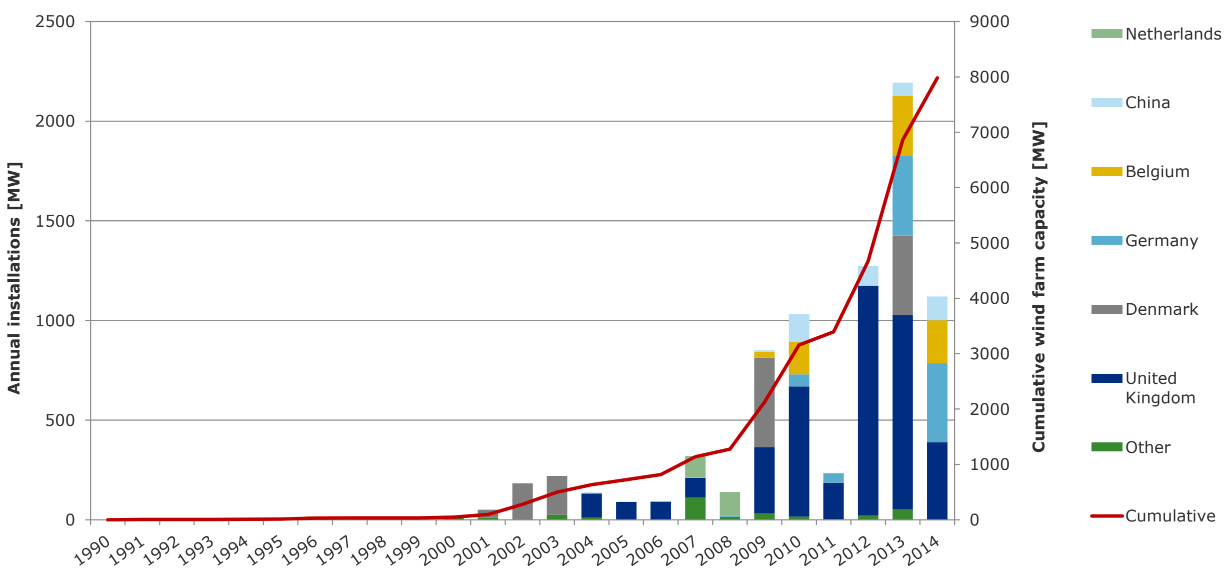
Offshore wind energy represents a growing subsector of the renewable energy industry. Globally, nearly 8 gigawatts (GW) of offshore wind projects were fully operational as of the end of 2014. By comparison, the global onshore wind capacity at the end of 2014 was approximately 370 GW [3]. The majority of the offshore wind capacity installed to date is in a handful of European countries, led by the United Kingdom, Denmark, and Germany. Asia represents an emerging market, with several installed projects in China and Japan, and has ambitious plans for future developments. Figure 1-1 presents the global installed capacity by country while Figure 1-2 shows the annual and cumulative installed global offshore wind capacity through 2014. After the first offshore wind project was installed in Denmark at Vindeby in 1991, the industry grew at a slow pace for several years, but has emerged as a significant industry in recent years. By the end of 2015, over 10 GW of offshore wind capacity were fully operational.

Figure 1-1 and Figure 1-2 are based on data from the DNV GL Offshore Wind Project Database [4], a proprietary bottom-up tool which tracks every offshore wind project around the world. It provides details on developers, project timelines, and technical characteristics of each site (where available), and collates project-specific information to both summarize current industry status and provide bottom-up, experience-based projections regarding future deployment.



Source: DNV GL.

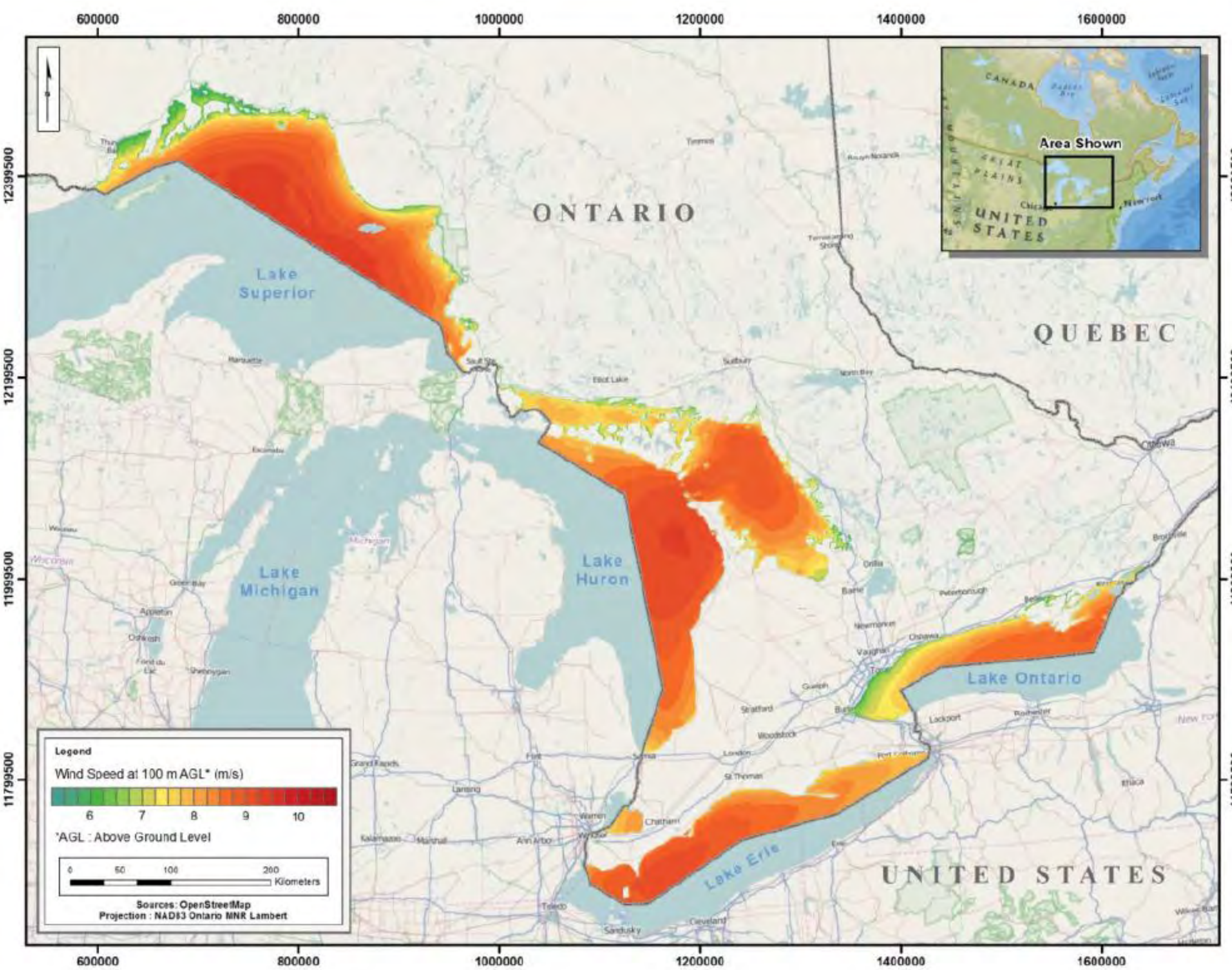
Figure 1-1 Global offshore wind capacity by country, end of 2014



Source: DNV GL.

Figure 1-2 Annual and cumulative installed offshore wind capacity

Although there have been several offshore wind projects proposed, there are still no operating commercial-scale offshore wind installations in North America as of the date of this report. However, the Great Lakes present significant opportunities for offshore wind development [5]. Figure 1-3 shows a map of the wind resource in Ontario [5], showing the strong offshore winds in certain areas of the Great Lakes. A 2008 study for the Ontario Power Authority identified 64 offshore project areas in the Canadian Great Lakes representing approximately 35,000 megawatts (MW) of potential offshore wind capacity [2]. The study noted that other areas could potentially be developed and, given the advancements in technology since that study was conducted, the potential for offshore wind in the Canadian Great Lakes is likely significantly greater than this figure indicates.



Source: Ontario Ministry of Natural Resources & Forestry.

Figure 1-3 Ontario wind resource

Ontario saw several proposals for offshore wind developments between 2006 and 2011. However, on 11 February 2011, the Government of Ontario issued a Policy Decision Notice [6] which effectively established a moratorium on offshore wind development in the Canadian Great Lakes. The Policy Decision Notice stated that although offshore wind energy is a relatively well-understood technology in ocean environments, "*…By contrast, offshore wind power development in freshwater lakes is relatively new and presents technical challenges that do not exist in a saltwater environment, such as the need to manage potential impacts to drinking water and the effects of ice build-up on support structures.*" As a result of this moratorium, the Ministry of Natural Resources & Forestry (MNRF) is not accepting any applications for Crown land for offshore wind development and all pending applications at the time of the Policy Decision Notice were cancelled. The Policy Decision Notice stated, "*When there is greater scientific certainty, consideration of offshore wind development will resume.*"

Although not explicitly stated in the Policy Decision Notice, decommissioning of offshore wind projects represents an area in which there is a need for greater understanding, particularly in the Great Lakes. Given that the great majority of the operating offshore wind projects have still not reached the mid-point of their design lives, direct experience with decommissioning of offshore wind projects is limited. The first offshore wind project to be decommissioned was a single 225 kW turbine at Norgersund, Blekinge, Sweden in 2006. To date, no other offshore wind projects have been decommissioned, though some offshore met masts have been removed. The first multi-turbine offshore wind project to be decommissioned is expected to be the Yttre Stengrund project in Sweden in the summer of 2015. Yttre Stengrund consists of five 2-MW wind turbines. The Beatrice Demonstration project in Scotland, comprising of two 5-MW turbines, is also intended for decommissioning.

Despite the relatively young nature of the industry, decommissioning is a required consideration in all jurisdictions in which offshore wind is currently being developed. As such, there is a fair body of knowledge on this topic. Additionally, there is extensive experience from decommissioning of other offshore installations, primarily associated with the oil & gas industry.

From a technical perspective, decommissioning best practices are well documented and understood. One of the key challenges; however, is the estimation of costs for decommissioning of offshore wind projects, particularly given the uncertainties associated with the long forecast horizon. Understanding the costs associated with decommissioning is critical for financial assurance requirements. Per the provisions of the Ontario *Environmental Protection Act* (EPA) [7] and the *Ontario Water Resources Act* (OWRA) [8], financial assurance, as described in *Guideline F-15, Financial Assurance Guideline* [9], can be required as a condition of an order or approval to:

- Ensure compliance with environmental objectives;
- Ensure that requirements are achieved by a specified deadline; or
- Ensure that funds are available for future clean-up and remediation of landfills and other contaminated sites which require long-term care and monitoring.

1.3 Scope

DNV GL implemented a three-stage approach to achieve the objectives of this work. These stages consisted of a literature review and consultation to inform the decommissioning scenarios for cost analysis; implementation of a procedure to select specific technologies for Ontario's fresh water lakes and provide detailed descriptions of the selected technologies and related decommissioning scenarios; and, development of decommissioning cost models and running evaluation of specific scenarios.

For the first stage, DNV GL summarized all the key components of a large modern offshore wind farm, covering not just the turbines but also the infrastructure for the electrical collection and transmission to shore, plus additional structures such as meteorological masts. The focus was to outline the full range of turbine foundations from the various types of gravity base (including potential future designs), monopile and jackets, through to floating turbines, highlighting the key characteristics, commercial status and limiting features – such as water depth, seabed and other site conditions, and installation requirements. Additionally, DNV GL summarized other offshore structures of relevance, again identifying and describing their main purpose, key characteristics, commercial status and limiting features and providing examples of installations especially in fresh water bodies. This review highlighted the differences and similarities between offshore wind and other technologies.

In addition to a review of offshore technologies, the first stage also consisted of a review of international regulatory requirements and guidelines, with a focus on industry best practices in decommissioning offshore technologies. This also included a review of financial assurance requirements for decommissioning.

The second stage consisted of selecting a set of offshore wind technologies for development of decommissioning cost scenarios. Having identified in the first stage the foundation technologies in use worldwide, for offshore wind and otherwise, DNV GL applied a procedure for selecting the most likely technologies for Great Lakes offshore wind projects taking into account the Great Lakes conditions. The aim was to deduce a range of potential types of support structure and balance of plant systems that may be used in the Great Lakes. For each offshore technology selected, a more detailed profile was then described to feed into the decommissioning cost modelling. The profiles covered a description of the foundation, including materials and methods of construction, methods of installation and methods of decommissioning.

In the final stage, DNV GL developed decommissioning cost models for each technology profile using the Great Lakes Offshore Wind Decommissioning Cost Tool (the “Tool”), supplied as a separate deliverable in this Study. The models identified the main categories of cost to be included in the overall decommissioning costs as well as the main factors that can influence the decommissioning costs. For each profile, two scenarios were modeled representing high and low cost scenarios.

1.4 Report organization

This report is organized into Chapters as described in Table 1-1.

Table 1-1 Report organization

Chapter	Title	Summary
1	Introduction	Introduction to the study and brief context as well as description of the general scope and format of the Study Report.
2	Offshore Wind Farms	Identification and brief description of the component technologies of an offshore wind farm.
3	Other Offshore Infrastructure	Identification and brief description of other offshore infrastructure used in subsectors such as oil & gas, transportation, and other relevant sectors.
4	Jurisdictional and Literature Review	Summary of existing guidelines, regulations, codes of practice and best practices in other jurisdictions for the decommissioning of and determination of financial assurance for offshore technologies.
5	Offshore Technology Profiles	Development and implementation of a selection procedure for the most suitable offshore technologies for Ontario's Great Lakes. Detailed description of selected offshore wind technology profiles including construction and decommissioning methods, considering environmental impacts, navigational safety impacts, and other relevant information.
6	Cost Estimates for Decommissioning	Description of the cost modeling including the main cost components, the key factors influencing cost, methodology and assumptions, and results.

2 OFFSHORE WIND FARMS – AN OVERVIEW

2.1 Chapter introduction

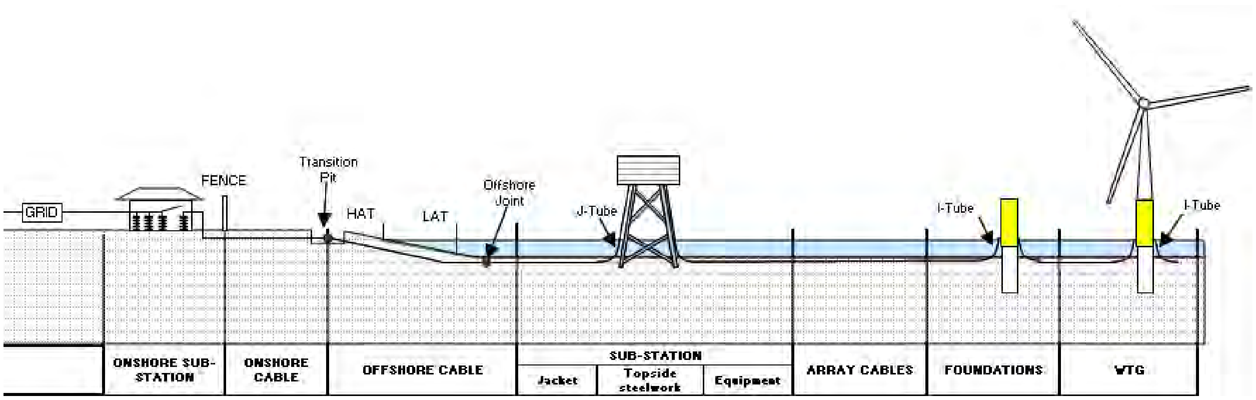
This Chapter identifies and briefly describes the main components of offshore wind farms, sometimes referred to as offshore wind farm or offshore wind projects. More detailed descriptions of the technologies, including methods of installation and decommissioning, are given in Chapter 5.

2.2 Offshore wind farm technology

Offshore wind farms consist of a number of components and systems designed to generate power from an offshore wind resource and transmit that power to an onshore grid. These components include mechanical, electrical, structural, and communications systems as well as safety systems to ensure safe operations and maintenance. A typical offshore wind farm typically consists of the following components:

- Wind turbines, each consisting of the tower, nacelle, and rotor;
- Wind turbine support structures or foundations (hereafter referred to as foundations);
- Subsea cabling including array cables connecting the turbines to an offshore substation (if present) and export cable connecting the wind farm to shore;
- Offshore substation and support structure;
- Onshore substation and onshore cabling;
- Other potential elements;
  - Offshore – e.g., meteorological (met) towers (also referred to as "met masts"), scour protection, and
  - Onshore – e.g., operations base.

Figure 2-1 presents a diagrammatic representation of an offshore wind farm. Equipment is split between the offshore and onshore environments.



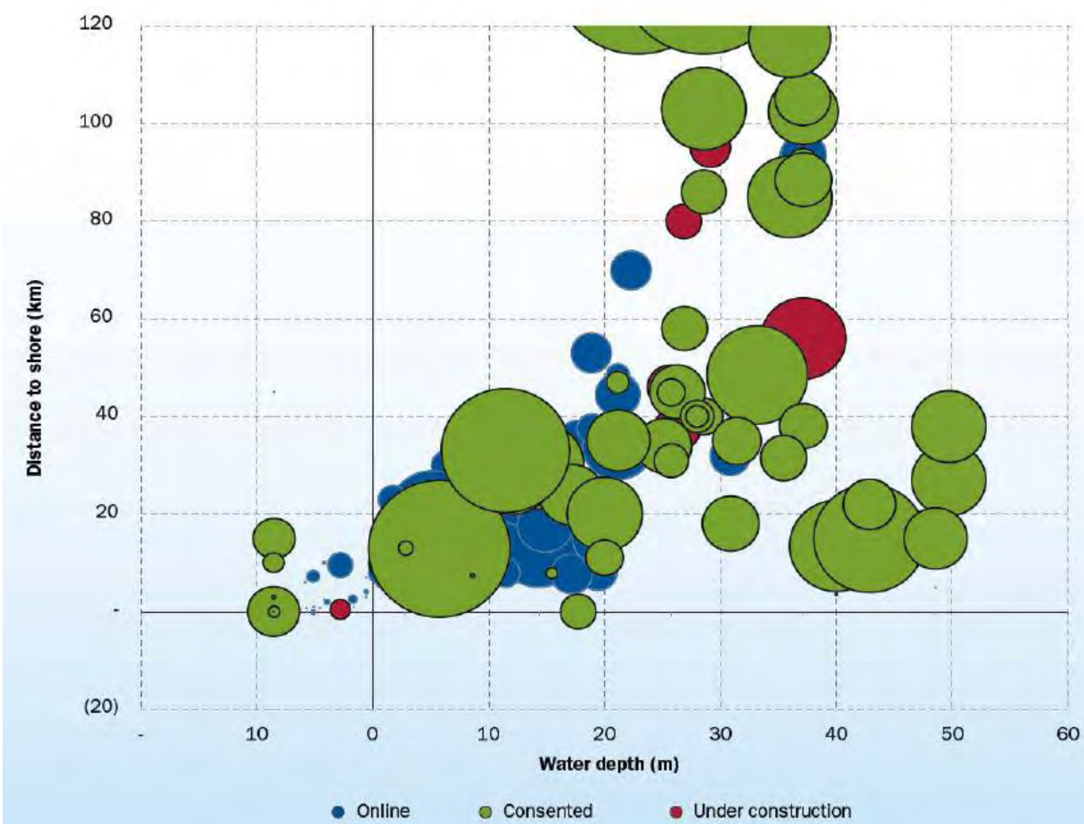
Source: DNV GL

Figure 2-1 Components of a typical offshore wind project

This Figure represents a simplified offshore wind farm. A typical commercial-scale wind farm will include dozens of wind turbines and the offshore substation is typically located amongst or adjacent to the field of wind turbines.

In addition to the components that are presented above, an offshore wind farm relies on various vessels and port facilities to support construction, operations, and decommissioning activities.

The technology that is deployed at offshore wind projects has evolved as the industry has developed and moved from smaller, near-shore projects with individual electrical connections to shore, to larger projects in deeper waters far from shore, in many cases connecting to offshore "hubs" linking multiple wind farms to the onshore grid. Figure 2-2 shows the average water depth and distance to shore for operating, consented, and under construction offshore wind projects in Europe as of the end of 2015, highlighting this trend [10]. The bubble size indicates the project size.



Source: EWEA [10] [1].

Figure 2-2 Average water depth and distance to shore for European offshore wind projects

[1] The Figure is directly reproduced from EWEA report [10] without alteration. DNV GL understands that lower-left bubbles represent near-shore/shallow-water projects.

2.3 Wind turbines

The general purpose of a wind turbine is to convert the kinetic energy from the wind into useful electrical energy. Its main components are:

- The **nacelle** which houses the primary components for power generation equipment and controls including the drive train, yaw system, mainframe, auxiliary structures, auxiliary systems, power converter, power transformer and the control and safety system;
- The **rotor**, including the rotor hub, blades, and blade pitch system; and
- The **tower** which supports the rotor and nacelle and interfaces with the foundation (e.g., jacket, monopile), and normally consists of several main sections (tubular sections with bolted flange connections), and internal structures and systems (ladders, platforms, elevators, etc.).

Figure 2-3 shows the principal components of a typical offshore wind turbine.

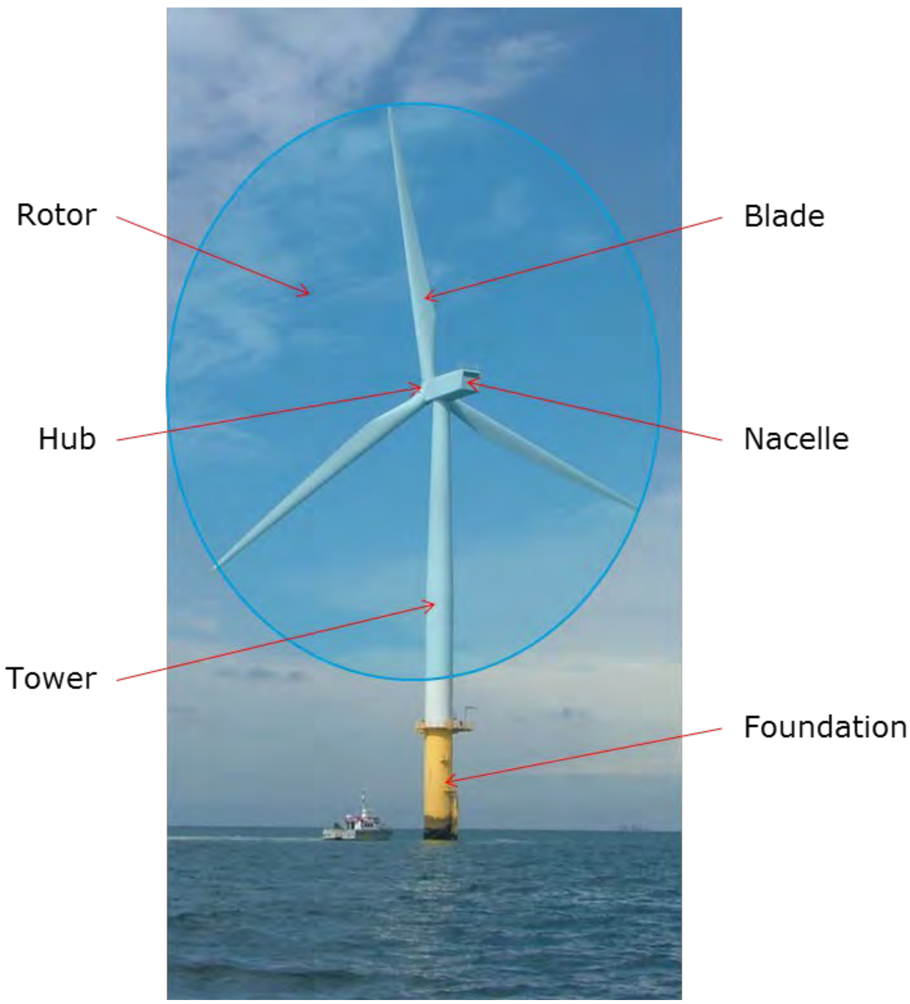


Figure 2-3 Principal components of an offshore wind turbine

Nearly all utility-scale wind turbine designs that are commercially available today utilize an upwind (i.e., the rotor is located upwind of the nacelle and drive train), three-bladed design. Although other designs including two-bladed and downwind designs have been developed, none of these designs are in use or available for commercial offshore wind projects. The general architecture of a typical wind turbine nacelle and rotor is illustrated in Figure 2-4. This example includes a gearbox to step up the shaft speed into the electrical generator. Some designs are direct drive, with no gearbox and electrical generator to suit.

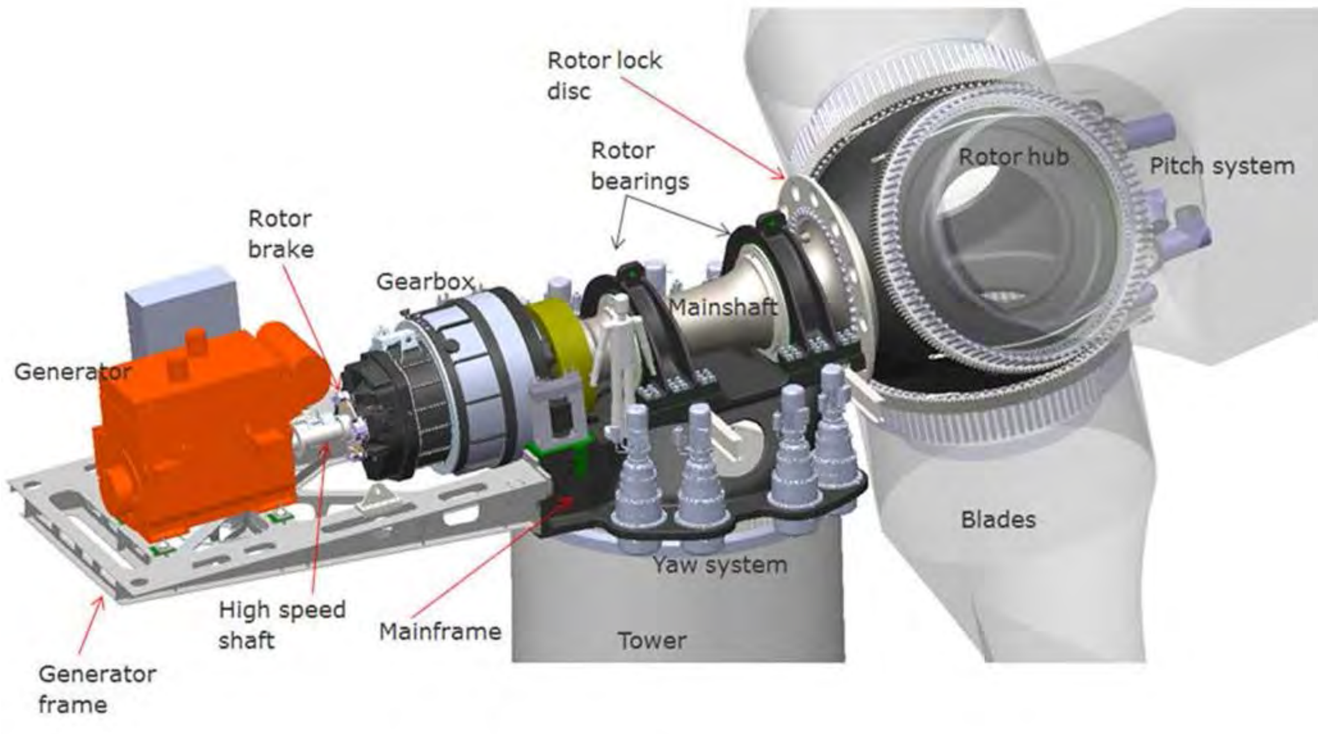
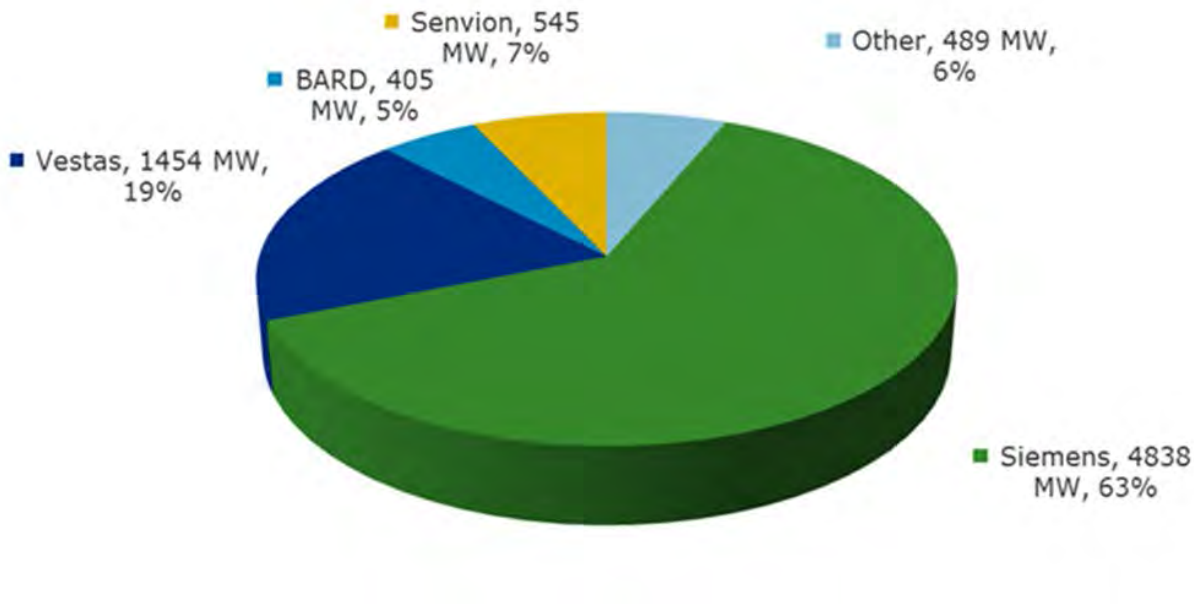


Figure 2-4 Wind turbine nacelle and rotor components

The turbine technology that is currently in use reflects the evolution of offshore wind turbines, from small turbines used on early projects that were designed for onshore applications and adapted to the offshore environment, to the current suite of large, multi-megawatt turbines designed specifically for offshore use. Driven by the need to reduce cost and improve reliability, offshore wind turbine designs have become larger and more specialized to their operating environment. Furthermore, the growth in offshore turbine sizes has been aided by the lower constraints to transportation and visibility. A broader range of products is becoming available to the industry and there is now a significant focus on improving reliability, which historically has been variable.

There are a number of manufacturers that have supplied turbines for offshore wind projects but the market has been dominated by Siemens and Vestas, together supplying 82% of the installed capacity as of the end of 2014. Figure 2-5 shows the installed offshore wind capacity by turbine manufacturer based on the DNV GL Offshore Wind Project Database.



Source: DNV GL.

Figure 2-5 Installed offshore wind capacity by turbine manufacturer

The currently installed turbine technology may not be representative of turbine technology that will be deployed in the future. The early turbine models installed in the 1990s were less than 1 MW. In 2000, multi-megawatt turbines started to be deployed in large numbers and the average turbine size deployed in Europe increased from approximately 2 MW in 2000 to nearly 4 MW in 2014 [10]. The offshore turbine models currently being installed or selected for proposed projects are in the 4 MW to 8 MW range. Table 2-1 lists the basic characteristics for a selection of offshore wind turbine generator (WTG) models representing the technology that is currently commercially available. This selection of turbine models is representative of the technology that will be available in the next five years, but as the technology continues to evolve, even larger turbines of 10 MW or more may emerge beyond this timeframe.

Table 2-1 Basic characteristics of historical, current and selected forthcoming offshore wind turbine generators

Manufacturer	Wind Turbine Model	Rated Power, MW	Rotor Diameter, m	Hub Height, m	Nacelle Weight, t
Alstom (GE)	Haliade 150-6.0	6.0	150	100	400
MHI Vestas (joint venture between Mitsubishi Heavy Industries and Vestas)	V164-8.0	8.0	164	105	390
	V112-3.3	3.3	112	site specific	175
Senvion	6.2M126	6.15	126	95/96.5	325
	6.2M152	6.15	152	97-100	350
Siemens	SWT-7.0-154	7.0	154	site specific	N/A
	SWT-6.0-154	6.0	154	site specific	360
	SWT-4.0-120	4.0	120	90	140
Guodian United Power	UP6000-136	6.0	136	95	N/A
Sinovel	SL6000	6.0	128	N/A	N/A
Adwen (joint venture between Gamesa and Areva)	AD 5-135 (formerly Areva's M5000-135)	5.0	135	site specific	370
	AD 5-132 (formerly Gamesa's G132-5.0)	5.0	132	95/120/140	N/A

2.4 Wind turbine foundations

The offshore wind farm market is now entering its third decade; over this time several types of foundations have actually been deployed while a far greater variety have been proposed but as yet remain unproven or as demonstration units.

Over this relatively short time the sizes of the turbines used has increased by over an order of magnitude, and this change in scale needs to be borne in mind when assessing the applicability of past designs and techniques for future applications. In the following sections, only the commonly used foundations will be reviewed. Their suitability for deployment in Great Lakes conditions, to support turbine types and sizes anticipated to be commonplace in the near future, will be discussed in Chapter 5.

2.4.1 Introduction to wind turbine foundations

The primary purpose of the foundation is to provide the structural support for the wind turbine. Additionally, the foundation typically includes secondary structures such as boat access, ladders, and platforms to facilitate access and I-tubes or J-tubes for cables. A range of foundation types exist, each with unique characteristics related to the range of suitable site conditions, manufacturing requirements, installation requirements, and cost. The options for foundations typically fall into one of the following general categories that have been used for offshore structures:

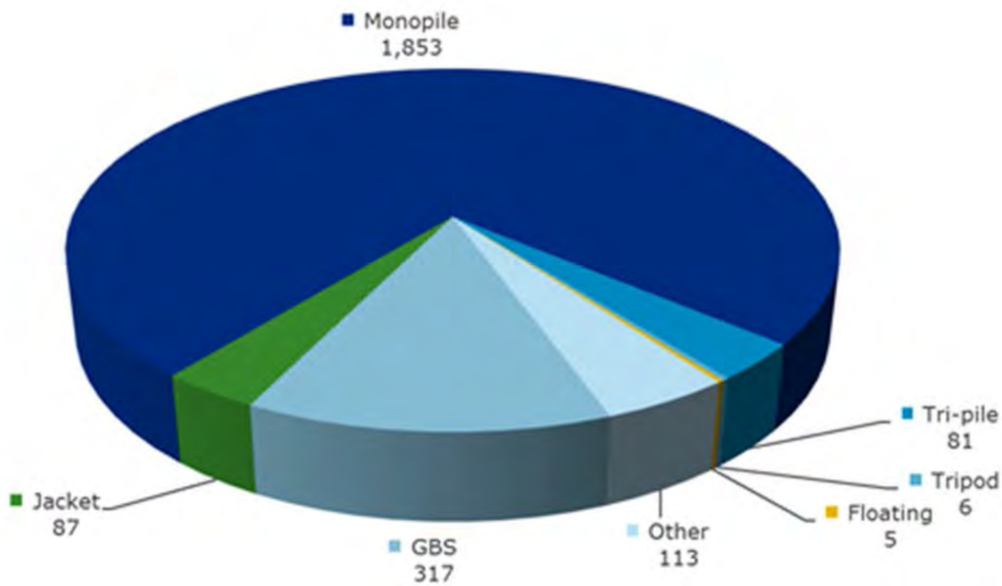
- Piled structures;
- Gravity-based structures;
- Skirt and bucket structures; and
- Moored floating structures.

For offshore wind turbines, the structural configuration of foundations can be categorized into the following basic types:

- Monopiles;
- Lattice or jacket structures;
- Gravity-base structures (GBS);
- Tri-piles or tripods;
- Suction buckets; and
- Floating structures.

Various hybrids of these general categories may be utilized, combining different features of these concepts.

To date, the industry has been dominated by monopile foundations as shown in Figure 2-6. As the industry moves to deeper waters with larger wind turbines, the techno-economic balance is expected to shift away from monopile technology towards more complex multi-member structures, including jackets. However, the emergence of extra-large "XL" monopiles is challenging this trend. GBS are likely to continue to exploit niche opportunities in particular where soil conditions are strong. Floating support structures are moving from demonstration to pilot project status. Other more innovative concepts are emerging from R&D and into demonstration, although full commercialisation is not expected until after the end of this decade.



Source: DNV GL.

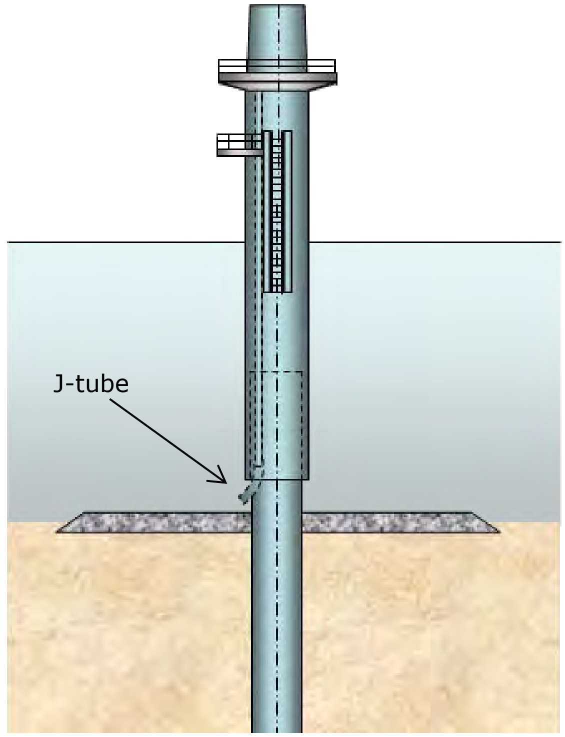
Figure 2-6 Number of foundations by type

For Great Lakes waters, with their regular covering of ice in many areas, there is a requirement to review whether these foundation types that have been deployed elsewhere are capable of survival. The suitability of the various foundation types for deployment in the Great Lakes as well as the challenge of decommissioning the various foundation concepts will be discussed in Chapter 5. The following sections provide a brief description of each foundation type, explaining their major characteristics and their commercial status.

2.4.2 Monopiles

A monopile foundation consists of a single steel pile, which is embedded into the seabed by driving or drilling. Figure 2-7 below shows a typical monopile foundation design. The depth of pile embedment, the pile diameter and wall thickness are determined principally by the maximum water depth and rated capacity of the wind turbine, with the detailed design varying slightly at each individual turbine location in a wind farm.

The maximum water depth used in the design corresponds to the highest probable combination of high tide and storm surge. The exposure of the site (in terms of the extremes of wind and wave environment) and the seabed conditions at the site will also influence the design of the monopile. The size of the wind turbine is related to its installed capacity and hence the larger the machine, the larger the pile diameter and the greater the seabed penetration will tend to be.



Source: DNV GL.

Figure 2-7 Example of a typical monopile foundation design with grouted transition piece

Typically, the turbine tower is mounted onto the foundation via a transition piece which itself is fixed onto the pile. In most designs, the transition piece is sleeved over the top of the monopile and grouted in place, usually with mechanical keying or coning of the joint to allow sharing of the load transfer. In these cases the grouted joint can be used to take up any misalignment tolerances. Although issues surrounding the integrity of these grouted joints were discovered in earlier designs, these issues have now been overcome. The transition piece also serves to support the secondary steelwork including the platform. In other more recent designs, the transition piece may be connected to the monopile using a bolted joint; or the tower may be bolted directly onto the top of the monopile with the secondary steelwork added as a surrounding cage. These designs take advantage of the greater verticality now possible during pile driving and sufficient alignment is possible using shims at the bolted joints.

The level of the top of the transition piece above the sea, or more specifically the level of the platform, is determined by the necessity to maintain adequate air clearance above the wave crests during storm conditions. On exposed sites with high tidal ranges this can place the platform up to 20 m or more above the water level shown on navigation charts.

The J-tube (or I-tube), illustrated in Figure 2-7 above, is a steel tube extending from the platform to the base of the foundation that protects the electrical cable leading either from the turbine to the next turbine or from the turbine to the substation. The tube may be internal or external to the foundation.

Monopile weights vary with water depth and turbine size, as well as wave environment severity, and seabed soil strengths, and have typically ranged between 250 and 800 metric tonnes to date. Heavier monopiles are starting to be ordered that exceed 1000 t as the design limits are pushed.

Monopile structures have been proven as economic solutions in Europe across various seabed soil conditions and water depths. Steel monopile foundations feature in 73% of all operational offshore projects, and will be used in 75% of projects currently under construction or contracted. Hence, steel monopiles offer a well understood design solution.

The monopile foundation benefits from the combined advantages of simplicity of fabrication, and ease of installation. In addition, the monopile structure, due to its simplicity, offers potentially good resistance against the fatigue loads produced by the wind turbine.

A disadvantage of the monopile is that, at the sizes which can be relatively easily installed by piling, there is a lack of structural stiffness in deeper waters to maintain the structural resonant frequency range required by turbine manufacturers. Monopiles are therefore well suited for sites ranging in water depth from 0 m to 35 m. The new generations of XL monopiles with increasingly large diameters, however, have the potential to extend this depth range beyond 35 m.

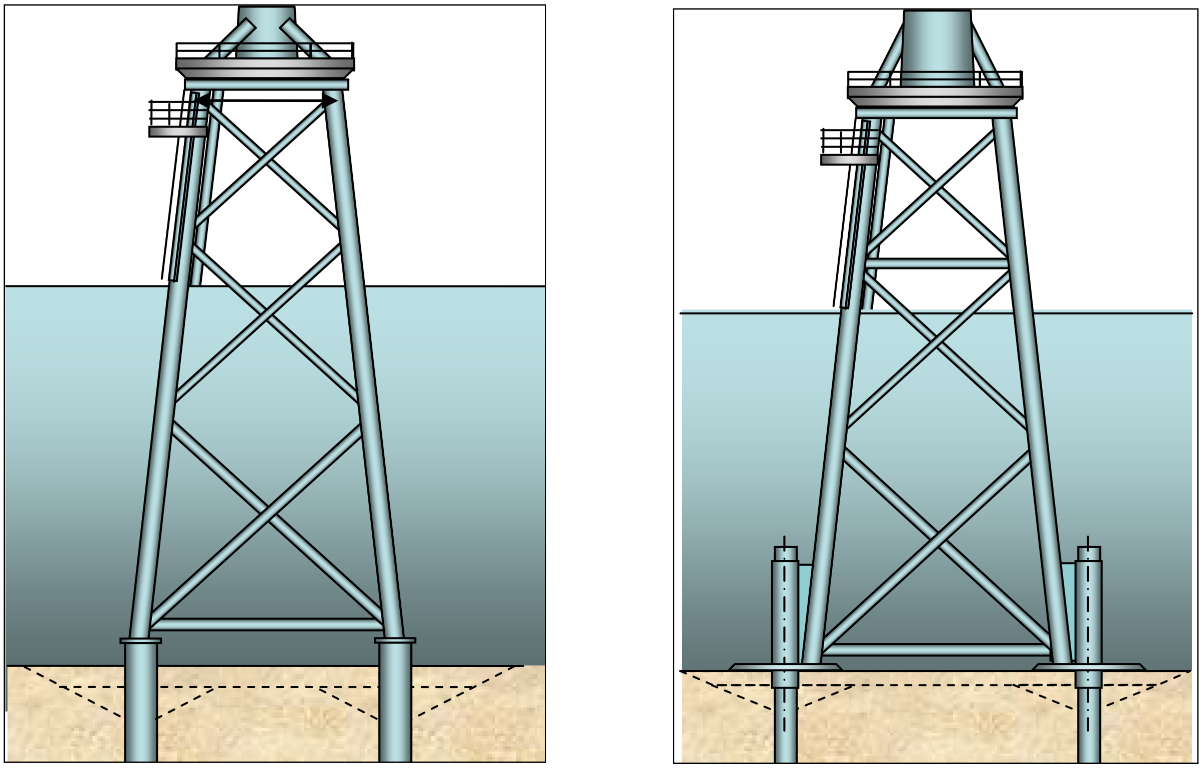
Figure 2-8 provides images of monopile foundations and transition pieces from offshore wind farms in Europe.

Sources: Weldex (a) and DNV GL (b – d).
(a) monopile at quayside, (b) monopile installation at Teesside Wind farm in the UK, (c) installed transition piece at Teesside, and (d) fully operational turbine on a monopile at North Hoyle Wind farm in the UK.

Figure 2-8 Example monopile foundations

2.4.3 Jackets

Jacket foundations (also referred to as lattice structures) are multi-member steel support structures that typically consist of three or four corner members or legs interconnected by cross members. Jacket foundations are typically connected to the seabed via pilings. A transition piece typically connects the main jacket structure to the turbine tower. The nature of the jacket concept lends itself to a considerable number of variant geometries. These include shortened jackets which do not emerge above sea level, 3- and 4-legged jackets, jackets which might be piled in-leg, alternative leg inclination angles and so on. In practice the majority of jackets used for offshore wind turbines are 4-legged. The general configurations for jacket foundations are illustrated in Figure 2-9, showing the pre-piled and post-piled variants – according to how they are installed.



Pre-piled jacket.   Post-piled jacket.

Source: DNV GL.

Figure 2-9 Typical jacket foundation concepts (pre-piled & post-piled)

Secondary steelwork such as boat landings, working and intermediate access platforms are mounted on the main lattice and would be entirely pre-installed at the fabrication yard. J-tubes or I-tubes are generally mounted to the brace members and are enclosed within the lattice.

A significant installation decision is whether to utilize pre-installed piles or post-installed piles. The use of pre-installed piles negates the need for pile sleeves, saving an appreciable amount of steelwork. This form of solution would utilize a seabed template through which the piles are installed. Once the piles are installed, the jacket is then lowered onto the piles and levelled by jacking the jacket structure level, reacting against the pile tops. The jacket structure is then grouted into place on the piles. The pile-jacket interface may also be achieved by swaging in some circumstances[2]. The suitability of the pile for swaging would have to be examined in terms of strength or fatigue endurance.

In the post-piled case, the jacket structure is first placed on the seabed, resting on mud-mats on its underside; the piles are then driven through the pile sleeves, the structure leveled and grouted in place.

Similar to monopiles, jacket weights vary with water depth and turbine size, as well as site conditions. Jacket weights have ranged between 500 and 900 t to date, although heavier jackets are likely in the future

[2] In this application, swaging is the local expansion of the pile into an internal recess (groove) in the pile sleeve to create a mechanical lock rather than using grout.

as projects move to deeper waters with larger turbines. Jackets are typically well suited to waters ranging in depth from 20 m to 50 m, although projects are currently being proposed for deeper water depths (up to 60-70 m) that may utilize jacket foundations.

Because of their greater rigidity, jacket structures appeared to be favoured over monopiles for the support of wind turbines in the 5 MW to 7 MW range. However, recent developments in monopiles have extended their range into this size class. The fabrication complexity of jackets makes them relatively expensive, in particular because each will be a different size according to the water depth at each turbine location. Furthermore the complexity at the interface with the tower is a specific issue that needs to be resolved, though several forms of simplified transition structure are in development. Alternative forms of transition structure are also often dictated by design for natural frequency limits.

In recent years, jacket structures have been developed to support REpower[3] 5 MW wind turbines at the Beatrice demonstrator site off northeastern Scotland (commissioned 2007), at the Alpha Ventus wind farm in the German North Sea (2010) and at the Ormonde wind farm in the Irish Sea (2012). These deployments cover a wide range of water depths, from approximately 20 m at Ormonde, to 30 m at Alpha Ventus, to 45 m at the Beatrice demonstration site. More recently Nord See Ost has employed jackets with 6.2 MW Senvion turbines. Jacket foundations are also frequently used to support offshore substations.

Together, these sites indicate that jacket foundations are viable options for larger wind turbines in a fairly broad range of water depths.

Novel jacket structures have been proposed including the Inward Battered Guide Structure (IBGS), also known as the "twisted jacket", designed by Keystone Engineering. The designers of the IBGS, one of four winners of the Carbon Trust Offshore Wind Accelerator foundation competition, claim that the design significantly reduces capital costs due to having fewer nodes and components than a traditional jacket structure and is safer and easier to install and manufacture. This design has been used for a met tower in the UK as well as two offshore oil and gas platforms in the Gulf of Mexico, but to date has not been installed for support of a wind turbine. Two demonstration projects in the U.S. are proposing to use IBGS foundations.

Figure 2-10 and Figure 2-11 show examples of jacket foundations.

[3] REpower changed their company name to Senvion in 2014.

Source: Vattenfall.

Figure 2-10 Jacket foundations at Ormonde offshore wind farm in the UK

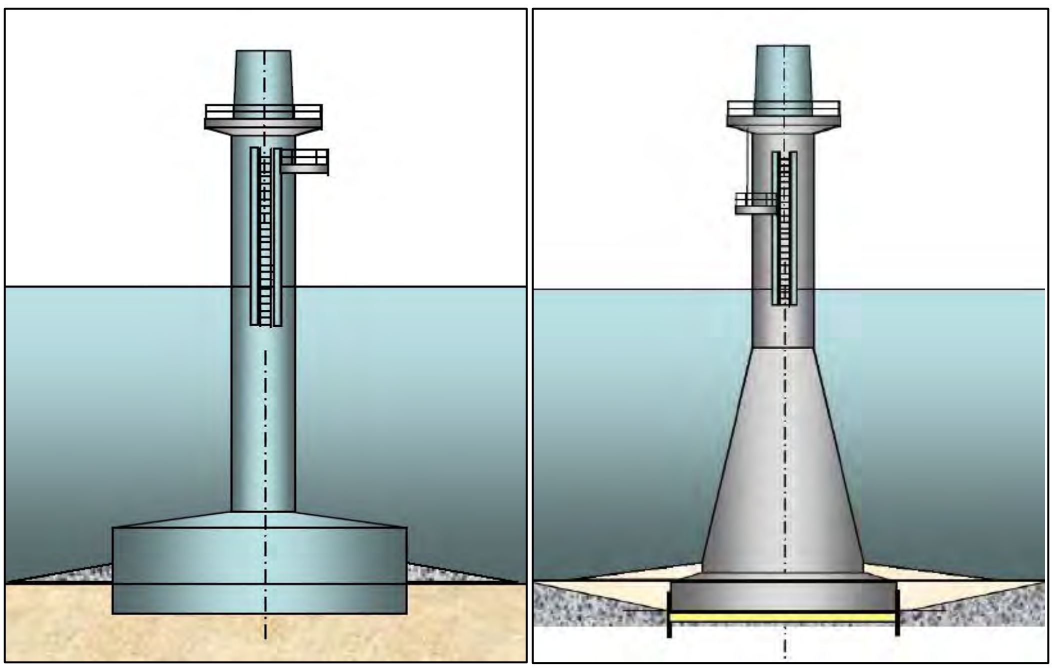
Source: The Carbon Trust.

Figure 2-11 IBGS ("twisted jacket") foundation at Hornsea met mast in the UK

2.4.4 Gravity base structures

Gravity foundations, often referred to as Gravity Base Structures (GBS), are designed with the objective of avoiding tensile loads (lifting) between the bottom of the support structure and the seabed (unlike piled foundations). This is achieved by providing sufficient dead loads such that the structure maintains its stability in all environmental conditions solely by means of its own gravity. GBS foundations typically take one of the two forms illustrated in Figure 2-12. Although steel GBS foundations have been proposed, those which have been deployed to date have been made of concrete, for reasons of fabrication cost. Hence, this type of structure is sometimes termed a Concrete Gravity Structure or Concrete Gravity Base Structure.

The main concept is that the structure rests on a pre-prepared seabed. It may be towed to site or carried with a floating crane. Once lowered into position, it is weighted by the addition of ballast, either in the form of rocks in external pockets or as sand in internal chambers. The platform and secondary steelwork are then added to the main structure.



Source: DNV GL.

Figure 2-12 Typical Gravity Base Structures – narrow shaft and conical

Because no piling is involved, GBS foundations are particularly suitable for seabed composed of very hard rock. However, the main technical limitation is their sensitivity to seabed conditions and good quality soil data is essential to minimize risks. They are not suitable for seabeds with very soft deposits, though in some locations, soft layers can be dredged and levelled to a stronger layer.

A key challenge for GBS foundations is their weight, which is considerably more than for other foundation types. For example the Thornton Bank GBS foundations had a dry weight of over 3,000 t. This has impacts on the onshore construction facilities required and on the equipment needed for installation.

Concrete gravity bases of both narrow shaft and conical form have been used on a number of offshore wind farms in Northern Europe, including the Baltic Sea. Many of these foundations have been of the narrow shaft form, such as Vindeby, Rodsand 2, and the recently built Karehamn. In contrast larger GBS foundations in deeper water with larger turbines have been of the enclosed conical design such as those supporting the 5 MW turbines at the Belgian Thornton Bank project in approximately 25 m water depth.

Figure 2-13 presents GBS foundations during fabrication, preparation, and transportation as well as an example of GBS featuring an ice cone (top-left) commissioned at Lillgrund offshore wind farm in Sweden.

Sources: DNV GL (a and b), Jan de Nul (c) and Scaldis (d).
(a) Lillgrund in Sweden – note the ice cone, (b) quayside fabrication of conical GBS foundations for Thornton Bank in Belgium, (c) GBS foundations en route to Kårehamn in Sweden, and (d) preparing Thornton Bank foundations for transport

Figure 2-13 Example GBS foundations

2.4.5 Tri-piles/tripods

Tri-piles and tripods are multi-member foundations that have been deployed in limited numbers using various concepts.

The tripod is a standard three-legged structure made of cylindrical steel tubes. The central steel shaft of the tripod acts as the transition to the turbine tower. The tripod can have either vertical or inclined pile sleeves onto or into which corresponding pin-piles are grouted. The base width and the pile penetration depth can be adjusted to suit the actual environmental and ground conditions. The piles in this case would be relatively thin with respect to monopiles at nominally 1.5 to 3 m in diameter. Figure 2-14 shows a typical tripod design.

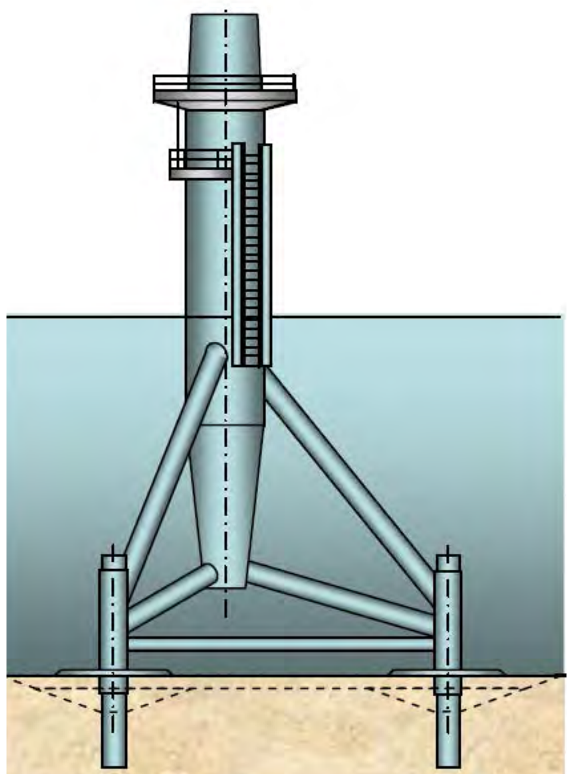


Figure 2-14 Example of a tripod foundation design

Tri-piles consist of three foundation piles connected via a transition piece to the turbine tower with the transition piece located above the water level. BARD has patented a specific version of this concept which consists of a transition piece with three pins that slot in to the three pre-installed piles. A design objective was to balance the weight of these four components to ease the challenges of handling and installation. It is understood that this design is relatively heavy and that the transition piece will be challenging to fabricate due to the complex load paths and heavy welding required, hence the tri-pile concept is likely to be more expensive than alternatives. Note that the first offshore wind turbine commissioned at Nogersund in Sweden in 1990 was a 220 kW Windworld unit constructed on a tri-pile type design. Figure 2-15 shows a typical tri-pile design.

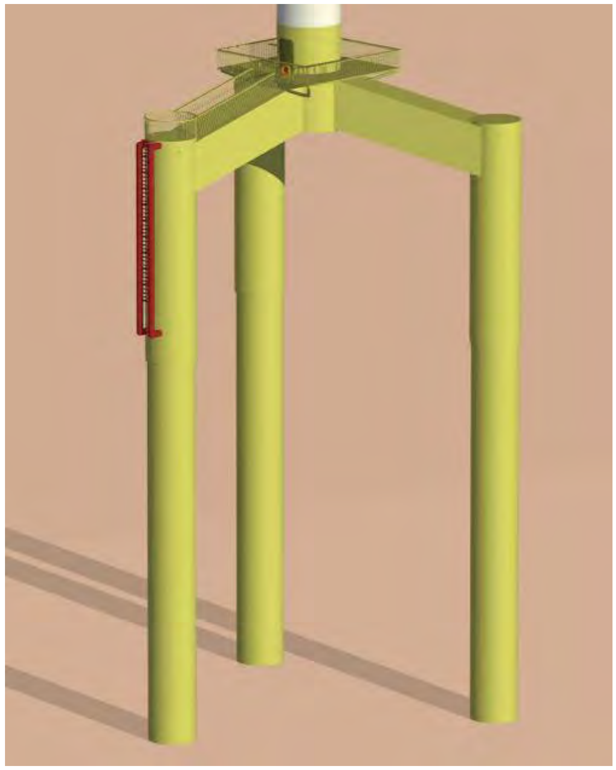


Figure 2-15 Generic tri-pile foundation design

As with monopile designs, it is expected that the dimensions of multi-pod foundations will increase with turbine installed capacity but will also be linked to the site wave environment and water depth. The pile separation for the anticipated turbine range of interest for offshore wind projects which are planned to come online in the next 5 years, assuming a tripod multi-pile arrangement, is indicatively 20 to 40 m. This type of structure is well suited for sites ranging in water depth from 20 to 50 m. Tripods are heavy structures and typically beyond the capability of all but the heaviest-lift jack-up vessels.

Figure 2-16 shows tripod foundations that were installed at the Alpha Ventus project in Germany while Figure 2-17 the tri-pile foundations at BARD Offshore 1, also in Germany.

Sources: Areva.

Figure 2-16 Tripod foundations for Alpha Ventus in Germany

Source: BARD.

Figure 2-17 Tri-pile foundations at BARD Offshore 1

2.4.6 Suction buckets

The suction bucket steel structure consists of a centre column connected to a steel bucket through flange-reinforced shear panels, which distribute the loads from the centre column to the edge of the bucket. The wind turbine tower is connected to the centre tubular piece above mean sea level. The steel bucket consists of vertical steel skirts extending down from a horizontal base resting on the soil surface. The bucket is installed by means of suction and when installed behaves as a gravity foundation, relying on the weight of the soil encompassed by the steel bucket with a skirt length of approximately the same dimension as the width of the bucket. The stability is ensured because there is not enough time for the bucket to be pulled from the bottom during a wave period. When the bucket is pulled from the seabed soil during the passing of a wave, a cavity will tend to develop between the soil surface and the top of the bucket at the heel. However, the development of such a cavity depends on water to flow in and fill up the cavity and thereby allow the bucket to be pulled up, but the typical wave periods are too short to allow this to happen. This type of structure is well suited for sites with water depth ranging from 0 to 25 m, but is heavily dependent on appropriate seabed soil conditions.

The suction bucket foundation has been utilized for a number of demonstrations such as:

- Frederikshavn, Denmark - wind turbine in 4 m of water
- Horns Rev II, Denmark, - met mast
- Dogger Bank, UK - two met masts
- Borkum Riffgrund, Germany - A hybrid jacket structure with suction buckets supporting a Siemens 4.0 MW wind turbine

Figure 2-18 shows the Horns Rev II met mast being prepared for float out to the installation site.

Source: DONG.

Figure 2-18 Suction bucket foundation for Horns Rev II met mast

2.4.7 Floating structures

It is expected that in the coming few years large European offshore wind farms will be built in unprecedentedly deep waters, in particular within the German sector of the North Sea. The costs of the support structures needed, in terms of both fabrication and installation, are significantly higher than the monopiles and GBS used for the offshore wind farms currently under construction. As depths increase further, the costs of such support structures increases similarly and it is apparent that costs must become prohibitively expensive at some point if the same technology is to be used. However, as depths and costs increase, alternative options for supporting the turbine become viable, including floating support structures.

Utilization of floating support structures will deliver a number of important benefits, principally:

- Greater choice of sites and countries, including the Mediterranean (France, Spain, Italy), Norway, U.S. (East and West coasts) and East Asia (China, Japan, Korea);
- Consistency of floating structure hull design in all water depths;
- Reasonable cost, potentially similar to fixed structures in medium water depths in the 30-50 m range, although this remains to be demonstrated in practice;
- Less dependence upon seabed soil conditions;
- Greater flexibility of construction and installation procedures; and
- Greater ease of removal/decommissioning.

However, the dynamics of floating foundations introduces a number of new challenges, including:

- Minimization of turbine and wave - induced motion;
- Additional complexity for the design process, including understanding and modeling the coupling between the support structure and the wind turbine (moorings and control);
- Electrical infrastructure design and costs, in particular the dynamic cable and underwater interconnectors; and
- Construction, installation, and operations and maintenance (O&M) procedures.

Floating foundations generally fall into three classes of structures: spars, semi-submersibles, and tension-leg platforms (TLP). These concepts are illustrated in Figure 2-19. Of these, all are technically and practically viable and are being actively developed. Each class has different characteristics and strengths: the spar and semi-submersible floaters have the benefit of using predominantly widely-used and proven technology, while the semi-submersible and TLP types can be used in shallower waters than the spar (down to 50 m or less).

Source: NREL.
i) spar (left), ii) semi-submersible (middle), and iii) TLP (right).

Figure 2-19 Floating support structure concepts

To date, several demonstrations of floating offshore wind structures have been deployed including the following:

- Hywind, Norway – In 2009, Statoil installed a spar structure supporting a 2.3 MW Siemens wind turbine. Statoil is currently planning a pilot project (Hywind Scotland) that will consist of five 6 MW turbines in waters exceeding 100 m.
- WindFloat Atlantic, Portugal – Deployed in 2011, Principle Power installed a semi-submersible supporting a 2.0 MW Vestas wind turbine. Principle Power is currently planning a pilot project off the coast of Oregon in the US that will consist of five 6 MW turbines in waters approximately 350 m deep.
- Fukushima, Japan – A consortium of Japanese organizations installed a semi-submersible supporting a 2.0 MW Hitachi wind turbine in 2013.
- Volturnus 1:8, Maine, US – The University of Maine installed in 2013 a 1:8-scale demonstration turbine on a concrete semi-submersible. This was the first grid-connected offshore wind turbine installed in the US, although it has since been decommissioned.

2.5 Offshore cabling

2.5.1 Array cables

The array cables (often referred to as "inter-array" cables) connect the wind turbines into strings and then connect the strings to the offshore substation platform(s). The cables between adjacent wind turbines are relatively short in length (typically 1 to 2 km) depending on the wind farm layout. The cables between the offshore substation and the wind turbine strings may be longer. At present, array cables in Europe are typically operated at a voltage level of 33 kV; in North America, 33 kV or 34.5 kV is expected to be the norm. Typical conductor cross sections range from 120 mm^2 to 630 mm^2 depending on usage and capacity; this range of cable could carry between approximately 20 MW and 35 MW. In the future, it is expected that cables will be operated at around 66 kV, which would enable savings through the use of fewer wind farm array circuits. Figure 2-20 below shows a typical cross-section of a cross-linked polyethylene (XLPE) insulated 3-core cable with fiber optic communications medium. The steel wire outer armouring provides mechanical protection for the cable.

XLPE insulated cables are the most commonly used cables for offshore wind projects; almost all offshore wind farm cables (array and export) use XLPE as insulating material. Ethylene propylene rubber (EPR) can be an alternative insulation that has higher water resistance and greater flexibility than XLPE, but incurs higher dielectric losses.

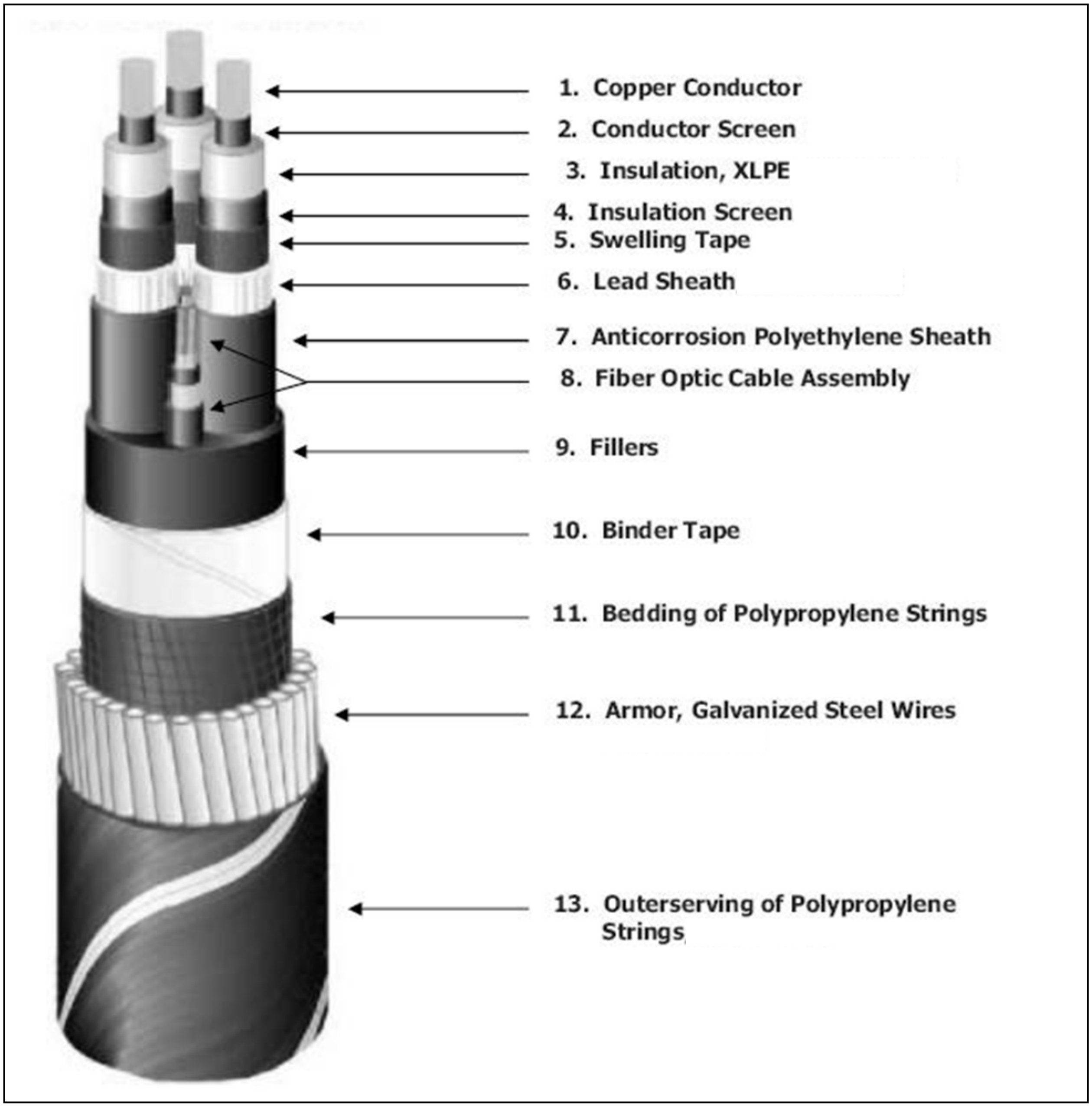


Figure 2-20 Cross-section for typical 34.5 kV XLPE submarine cable

2.5.2 Export cables

The export cables transmit the electricity from the offshore substation(s) to the designated onshore landfall point. Alternating current (AC) export cables are similar in construction to the array cables, although the conductor sizing and insulation requirements are more significant. The primary difference between export cables and array cables are the lengths, diameters, and weights involved. Export cables are typically in excess of 200 mm in diameter with weights exceeding 80 kg/m and often sufficient length to span the entire distance from the project to the shore. Due to the continuous process for fabricating the cable, the maximum cable length is limited by the spool or vessel carrying capacity. For export routes which exceed the maximum length of cable on a spool, joints will need to be made to stitch multiple sections of cable together. Due to the significant diameters and weights involved, bending radius and support during laying are even more critical than for array cables. Clearly, the vessels and plant involved in export cable laying and burial are therefore significantly larger than those required for array cable works.

Although most projects currently use AC technology, some projects far from shore (typically over 50-100 km, although this depends on numerous factors) are looking to high-voltage direct current (HVDC) technology as discussed in Section 2.6.1 below. Although the construction for HVDC cables is similar to AC cables, they are much simpler, as shown in Figure 2-21 below. In most cases, two such cables will be required: a send and return or positive and negative.

Figure 2-21 Components of a HVDC export cable

At the landing point, the cable is typically brought to shore either through an excavated trench or, more often, a horizontally drilled duct from an offshore point to an onshore junction box or transition pit where the export cable is terminated.

2.5.3 Cable protection

Burial is typically used as the primary method of protection of a cable to provide adequate physical and economic mitigation against hazards that may exist along the cable route. Submarine cables are typically buried to a depth of 1-2 m. However certain circumstances may require deeper burial to achieve appropriate protection. In the event that non-burial protection is required, either because the seabed soil does not provide adequate protection, or burial is not possible due to the nature of the seabed, it may be necessary to adopt alternative cable protection methods. This may consist of concrete mats or other geo-fabric based solutions laid over the cable, or a layer of deposited rocks. This affords the opportunity to design easily installed custom solutions and is particularly useful for complex areas like other cable or pipeline crossing. Many companies provide a range of solutions to protect cables and allow cable crossings. Such cable protection solutions may also be used if the seabed sediment is particularly mobile, to avoid cables becoming uncovered.

2.6 Offshore substations and support structures

The majority of offshore projects to date have included at least one offshore substation, although the electrical losses from small projects located close to an onshore substation may not merit this additional infrastructure. Whether an offshore wind farm has an offshore or onshore substation depends primarily on the size of the wind farm, distance from shore and distance from the grid connection point. Typically, wind farms farther than approximately 10 km from land have substations offshore. The substation accommodates the transformers required to increase the distribution voltage (typically 33 kV) of the inter-array cables to a higher voltage of typically 110 – 245 kV. From the offshore substation, the export cables then carry the power to the landfall location.

Substations usually provide facilities for service technicians working either on the substation or servicing the project’s wind turbines, though are not used for overnight hoteling. In one case (at Horns Rev 2), an accommodation module is built on a separate foundation adjacent to an offshore substation. In general, manned substations must be designed with an additional level of safety compared with unmanned substations.

2.6.1 Power export technology: HVAC or HVDC

Eventually, when distances are large, efficiently transporting power using High-Voltage Alternating Current (HVAC) becomes technically challenging and may justify the use of HVDC technology, which is a step change in the size of the required electrical infrastructure. Figure 2-22 presents an approximation for the optimization of the power export technology as a function of the distance from the shore and the capacity of the wind farm.

If the power is to be exported from the wind farm to shore using HVDC, a separate offshore platform may also be installed to house the plant which converts the AC power that is generated by the wind turbines to DC for the transmission of the power to shore.

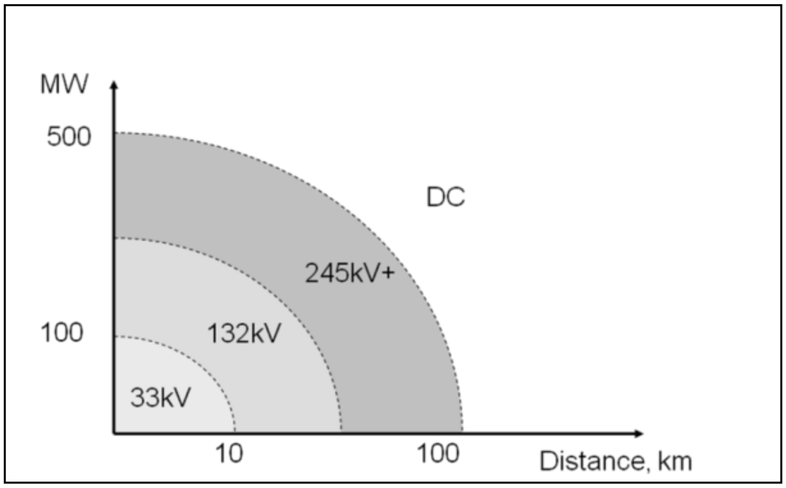


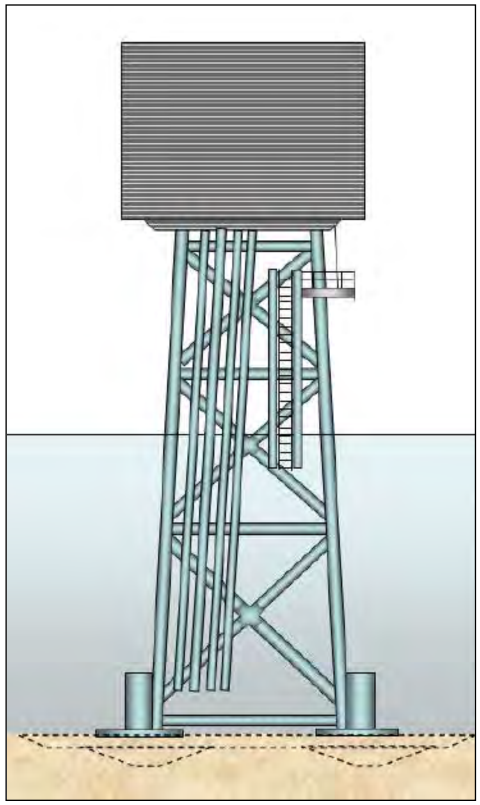
Figure 2-22 Export cable technology vs. distance

The approach of utilizing several substations for large projects and for projects with HVDC output is considered to be a likely trend as the European offshore wind industry progresses and projects move farther offshore. Assuming a wind farm layout with multiple AC step-up substations rather than a single substation, shorter lengths of array cable with lower voltages and losses, as well as a reduced weight per substation can be achieved. Having a separate HVDC substation reduces individual topside weight and therefore enables quicker and cheaper installation. The tendency to divide substation tasks across a number of substation units will limit the growth of substation size, though this is difficult to predict as the optimal breakdown is site specific.

2.6.2 Substation foundations

The substations require foundations on which to place the topside that contains the equipment mentioned above. Options for the foundation design are similar to those for turbine foundations but the topside weights involved mean that the substation foundations are often significantly larger.

The substation foundation unit is likely to use one of the design concepts described above for the wind turbines, most probably a jacket structure. Figure 2-23 below shows typical configuration for a jacket mounted offshore substation, and Figure 2-24 shows the substation at Thornton Bank in Belgium.



Source: DNV GL.

Figure 2-23 Offshore substation on jacket foundation

Source: ABB.

Figure 2-24 Thornton Bank substation

2.7 Onshore substations and cabling

The export cable typically comes to shore and terminates at an onshore junction box at which point the export cable is connected to onshore cables (either overhead or buried) that connect to the onshore substation. The onshore substation typically is the point of interconnection to the onshore grid and includes electrical equipment such as step-up transformers, switch gear, bus structures, control buildings, and other equipment. All substation equipment is typically contained within a fenced area for security.

2.8 Other elements

2.8.1 Meteorological towers

Meteorological towers (met towers or met masts) are typically commissioned to primarily measure the wind resource and climatic conditions at a project site. Offshore met towers are also equipped with additional instruments and sensors to provide oceanographic – and sometimes environmental – data at a project site.

The conventional hub-height met mast, fitted with cup anemometry such as that shown in Figure 2-25, is the most prevalent technology type. Despite a range of alternative measurement technologies emerging in recent years, such as floating light detection and ranging (Lidar) devices, measurements from cup anemometers mounted on mast structures are the long-established standard in the wind energy industry.

Figure 2-25 Example of offshore met mast

Met masts are typically installed on support structures similar to what is used for wind turbine support structures, although the sizes are considerably smaller. Met masts have been used to demonstrate novel support structure concepts, such as the aforementioned suction bucket and IBGS structures.

2.8.2 Scour protection

Vertical piles, particularly monopiles, present a large obstruction to the flow of water and, if deployed in areas where currents, tidal flows, or wave-induced erosion are commonplace as well as areas featuring fine or mobile seabed sediment, the result is that these structures are prone to erosion of the soil around their base, known as scour. Figure 2-26 shows a scour hole around a jack-up leg.

Figure 2-26 Scour hole around a jack-up leg

Scour protection will then typically be required to maintain sufficient burial. In some cases, however, it is accepted that scour will occur and reach an equilibrium depth, and the foundation design takes this into account.

To apply scour protection, the methodology generally employed is to lay a filter layer of small aggregate material, with maximum particle size normally around 100 mm diameter, before piling to act as temporary scour protection immediately after the pile is driven. Subsequently, heavier aggregate material is deposited over the filter layer, to permanently protect the seabed from erosion by wave, tide, or current action. In areas where there is severe wave action, and relatively shallow waters, rock armour with individual component weights in excess of a half-ton is not uncommon. Clearly, care needs to be taken to ensure an appropriate cable route through or underneath the scour protection without exceeding cable bending radius limitations or damaging the cable.

In shallow sites, when large waves churn the seabed during heavy sea conditions, this can lead to seabed migration, and erosion due to horseshoe vortices around the pile may require that scour protection be deposited.

2.8.3 Operations facilities

Onshore operations facilities are typically located at or near a port facility out of which the operations and maintenance crews will operate, stores of spare parts, tools, and equipment are kept, and operational administration is based.

2.9 Chapter summary

Table 2-2 summarises the elements of offshore wind farm technology as briefly described in this Chapter. More detail is provided in Chapter 5.

Table 2-2 Summary of offshore wind farm technology

Component	Description	Comments
Wind turbines	Offshore wind turbine designs utilise the standard 3-blade upwind configuration. Up to 2015, typical sizes installed were of 3 to 4 MW capacity with typical hub heights of 90 m and rotor diameter 120 m.	Offshore wind turbine generators (WTGs) are now moving from marine versions of onshore turbines to specifically-designed offshore machines. In the absence of any transportation limits offshore, their sizes have grown to 6+ MW and 10 MW machines are foreseeable in the near future.
Wind turbine foundations	The foundation provides structural support for the wind turbine and fulfills secondary functions such as boat access and power connection to the array cables. The main types of foundation are: • Monopiles; • Lattice or jacket structures; • Gravity-base structures (GBS); • Tri-piles or tripods; • Suction buckets; and • Floating structures.	The selection and design of foundations depends largely on the water depth, the sea-bed geology and the size of WTG. With larger turbines and more remote offshore sites, the current trend is likely to move from traditional monopiles to GBS, jackets and floating technologies.
Offshore cabling	Wind turbines are connected in strings to the offshore substation(s) by array cables buried in the sea-bed. The export cable(s) then take the electric energy to the shore.	Array cables are typically medium-voltage AC cables, while the export cable is a high-voltage conductor using AC or DC current, the latter being more efficient for longer distances to shore. Cable protection is of primary concern, to maintain power export and to avoid conflict with fishing trawls and ships anchors.
Offshore substations and support structures	The majority of offshore projects to date have included at least one offshore substation connecting the array cables to the export cable.	The main function of the offshore substation is to step up the electric voltage for export to shore. The support structure for the substation is selected according to the size and site conditions, and is often a jacket type.
Onshore substations and cabling	The onshore substation is typically the point of interconnection to the onshore grid.	At shore, the sub-sea export cable is connected to onshore cables at a junction box. The onshore cables (either overhead or buried) then connect to the onshore substation for transformation and transmission to the main electric grid.
Other elements	Additional project-specific structures or equipment offshore and onshore.	May include: • scour protection (rocks, sandbags etc.) • meteorological tower for wind measurement • port facilities to support offshore construction and operations.

3 OTHER OFFSHORE INFRASTRUCTURE

3.1 Chapter introduction

The focus of this Chapter is to provide a high-level evaluation of the offshore infrastructure in industries other than offshore wind, with the aim of providing comparisons with the offshore wind industry.

A major focus of the Chapter is the offshore oil and gas (O&G) industry, including the status of decommissioning activities and their degree of applicability to offshore wind. Further sections describe other marine structures, in particular bridges and harbour constructions; and designs in ice-infested waters. In each topic, the transferability of experience into the offshore wind sector is again highlighted.

3.2 Offshore oil and gas

3.2.1 O&G infrastructure

In the O&G industry the main offshore structures include production platforms; drilling rigs; floating production, storage, and offloading units (FPSO); floating storage units (FSU) and similar.

A key consideration in the O&G industry is the geographic location of hydrocarbon deposits which dictate the position of drilling rigs and offshore structures. As hydrocarbon deposits are found in highly diverse and often technically challenging locations, this more or less dictates that technical solutions to develop resources are customised to some degree and the design of any offshore structure is virtually always, in some respects, unique to the location.

The usual process, following award of a concession to an oil company, is for the concession area to be evaluated by seismic survey. Once stratigraphy has been identified that looks promising, exploration drilling is carried out normally from a semi-submersible drilling rig, or a drill ship (in deep water), or from a jack-up rig in moderate depths. Exploration drilling may also be carried out from a barge in shallow water.

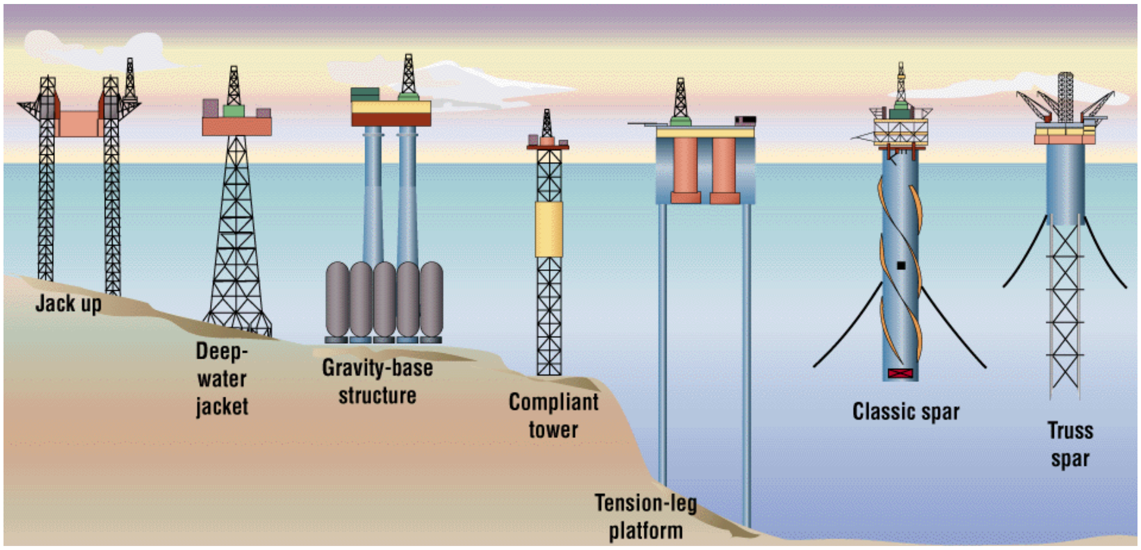
As a consequence of this sequence of activities, the O&G industry comprises a wide range of infrastructure.

The offshore O&G industry dates back to the 19th century in the Caspian Sea and in California, though is now widespread around the world. Much takes place in relatively shallow coastal waters such as around Africa, whereas O&G exploitation in the northern North Sea and north Atlantic takes places in waters many hundreds of metres deep. The current estimated total number of offshore O&G platforms is approximately 10,800 worldwide.

It would not be unreasonable to assume that about 15% are shut-down awaiting decommissioning, though they will still be operational to some degree to maintain them in a safe condition.

The main types of offshore oil industry infrastructure are: conventional steel jack-ups and jacket structures, concrete gravity base structures, compliant towers, tension leg platforms, floating spar structures, semi-submersibles, FPSOs and wholly subsea completions tied back to an existing host facility. The main types are illustrated below in Figure 3-1 showing schematically the transition between technologies with increasing water depth.

The following sub-sections describe the types of structure in more detail and the status of installations worldwide including approaches to decommissioning.



Source: Oil & Gas Journal.

Figure 3-1 Main sub-structures for oil and gas installations

3.2.2 Oil survey vessels

In the early stages of O&G exploration, detailed seismic surveys are performed to augment existing stratigraphic and seismic data. These surveys use dedicated vessels which tow streamers containing detectors that pick up the reflected waves from a transducer towed by the seismic vessel, as shown below in Figure 3-2.

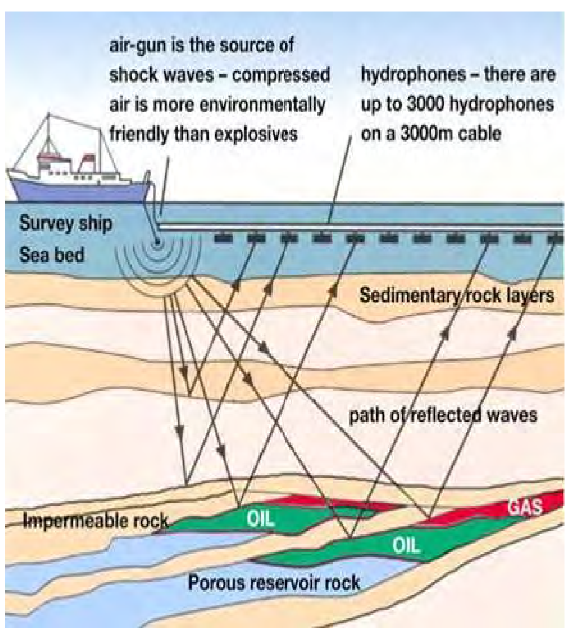


Figure 3-2 Typical seismic vessel streamer arrangement

For offshore wind purposes, similar geophysical surveys are carried out to determine the water depth and seabed topography, and the location and nature of different rock strata. This information is used primarily to determine the optimum type and location of foundations.

3.2.3 Offshore O&G exploration - drilling rig options

Once a viable hydrocarbon deposit has been identified, the seismic survey results are usually confirmed by exploration drilling. The type of drilling rig will depend upon water depth, environmental conditions, expected reservoir pressure, etc. but the primary function is that the rig is movable and less permanent than the subsequent production facilities. In general, shallow water oil fields are usually drilled from jack-up rigs or from a barge. In deeper waters, semi-submersible drilling rigs (Figure 3-4) are used, which may be moored or dynamically positioned. In more benign weather regions, deep water wells are also drilled using drill ships, which are usually dynamically positioned.

The world-wide offshore mobile drilling rig fleet currently consists of over 600 units, though not all will be active at any one time. Jack-ups form 66% of the fleet, with over 400 units. There are over 170 semi-submersibles and 40 drill-ships [11]. Major operators are Transocean and Noble Drilling. Of the top ten largest owners, nine are based in the USA and North America (Gulf of Mexico) is the main focus of rig employment. The most significant European region is the North Sea and there is increasing activity in Asia/Pacific in particular India, Indonesia, China, Malaysia and Australia.

Average new-building prices for a jack-up with water depth of approximately 100 m have almost doubled since 2004, from US $102M to over US $190M in 2015. For semi-subs, new-building prices for rigs that can operate in 1,000 m of water have increased from US $250M in 2000 to approximately US $300M in 2015. New-build drill-ship prices are approximately US $620M.

Jack-up drilling rigs form the majority of drilling rigs and are capable of operating in water depths from (about) 15 to 130 m. A typical O&G rig has three legs, as shown in Figure 3-3.

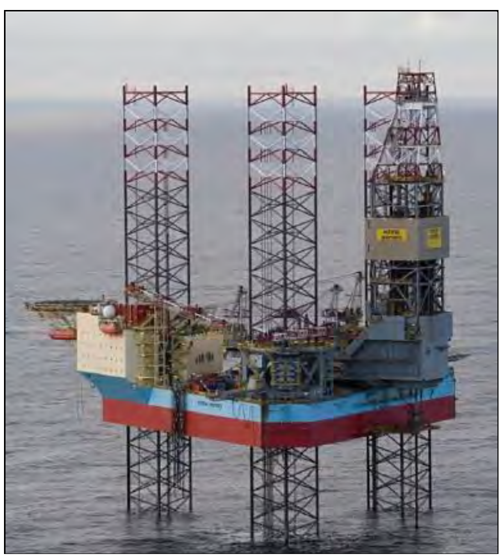


Figure 3-3 Typical modern jack-up drilling rig

Jack-ups may also be used for O&G accommodation platforms and jack-ups with heavy lift cranes are currently being used for O&G decommissioning where suitable for the water depths.

In the offshore wind industry, towed jack-ups were used in the construction of early projects and are still used in more benign water depths and sea conditions, where the advantages of specialised offshore wind construction vessels are less relevant. However, in general, jack-ups used in offshore wind construction have operating characteristics tuned to suit the purpose. Typically a jack-up used for offshore wind is equipped with a crane and has at least four legs which lessens the risks if one of the footings is not firm, given that the jack-up will be making many changes of location; it may also have higher jacking speeds allowing higher limiting wave heights for jacking operations. Some jack-up platforms and self-propelled jack-up vessels are promoted for multi-purpose use in both O&G and offshore wind applications. In both O&G and offshore wind sectors, jack-ups are used in geotechnical investigations.

Semi-submersible drilling rigs come in many forms, dependent upon age and design working depth, and are capable of working in water depths ranging from (about) 30 m to 3,000 m. Semi-submersibles designed for working in extreme depths are almost always dynamically positioned. An illustration of a typical semi-submersible drilling rig, which is shown ballasted down to working draft is shown below in Figure 3-4.

The semi-submersible capability provides a more stable working platform than a conventional floating structure. Such technology is encountered in the offshore wind industry in some crane vessels and in very modified forms in some floating wind turbine support structures as described elsewhere in this study.

Figure 3-4 Typical semi-submersible drilling rig

Drill ships are mono-hulls, which drill through a 'moon-pool' and as they are most suited to drilling in deeper water, almost all are dynamically positioned. An advantage of drill ships is that they can transit at a reasonable speed from one location to another without assistance. However, being mono-hulls they (generally) are less suited to extreme environmental conditions, so are preferentially used in the more benign weather areas of the world. An illustration of a typical drill ship is shown below in Figure 3-5.

Figure 3-5 Modern drill ship

3.2.4 Offshore O&G production - fixed platforms

The size, weight and structural complexity of any conventional fixed platform are primarily influenced by the required function, water depth and environmental conditions at the location. Consequently, the weight of fixed platforms for producing O&G, or some other function (dependent upon the design of the field infrastructure) can vary from (about) 50 t in shallow water to >100,000 t in deep water.

3.2.4.1 Jacket support structures

Conventional steel fixed platforms (or jackets) constitute the great majority of all offshore platforms presently in place. Steel jackets are a lattice of steel tubes, fabricated by welding onshore, secured to the seabed using piles. They can be installed in a variety of ways:

- transported to site on a barge for lift-off and emplacement by heavy-lift vessel (HLV);
- transported to site on a partially submersible barge, which would launch the jacket for emplacement on the seabed, with submergence being regulated by controlled buoyancy; or
- by towing the jacket (afloat) from the build location to the site for placement on the seabed by controlled submergence.

Steel jackets, generally speaking and depending on water depth, are cheaper than more sophisticated solutions such as tension leg platforms (TLP), or floating production, storage and offloading units (FPSO)s. However, compared with those alternative solutions jackets are usually more challenging and expensive to decommission and remove. Figure 3-6 shows the jacket support structure at Brent Alpha production platform.

Figure 3-6 Jacket support structure of Brent Alpha

Jackets may be used to support platforms for offshore drilling, O&G production and pumping for emplacement in around 50 m ~ 200 m water depth. Figure 3-7 shows a complex of linked platforms for both personnel and services.

Figure 3-7 Multi-platform field complex linked by bridges

In the offshore wind sector, jackets have been used particularly for supporting offshore substations as well as some offshore turbines. Decommissioning techniques developed by the O&G industry for removing jacket piles are relevant for the decommissioning of offshore wind monopiles and jacket foundations.

3.2.4.2 Concrete gravity base platforms

Concrete gravity-based platforms were first used in the UK North Sea in 1973. Since then, around 50 major concrete offshore structures have been built. One of the primary drivers was the very deep inshore waters of the Norwegian fjords, which made it possible to build these very large structures by continuous concrete slip-forming and allowed an offshore platform to be built whilst in a safe inshore location. The almost complete structure could then be towed into position thereby minimising offshore construction operations which are particularly difficult and costly in the northern North Sea. After towing afloat into position, it would then be ballasted down to settle on the seabed in a controlled manner. An example of such an operation is the Troll A with a dry weight of 656,000 t and 472 m high with 369 m underwater concrete structure. Figure 3-8 shows it being towed out in 1996.

Figure 3-8 Troll A platform under tow from inshore Norway to Troll field

The platform stands on the sea floor 303 m below the sea surface. The walls of Troll A's legs are over 1 m thick made of steel reinforced concrete. The four legs are interconnected by a reinforced concrete box designed to damp out unwanted potentially destructive wave-leg resonances. Each leg is also sub-divided into independent watertight compartments. 40 m tall groups of vacuum-anchors hold it in the mud of the sea floor.

Figure 3-9 shows a gravity base platform, at Brent in the North Sea, showing the structure in place on the seabed and illustrating the large subsea storage chambers typical for such O&G structures.

Figure 3-9 Brent gravity base O&G structure at location, showing subsea storage vessels

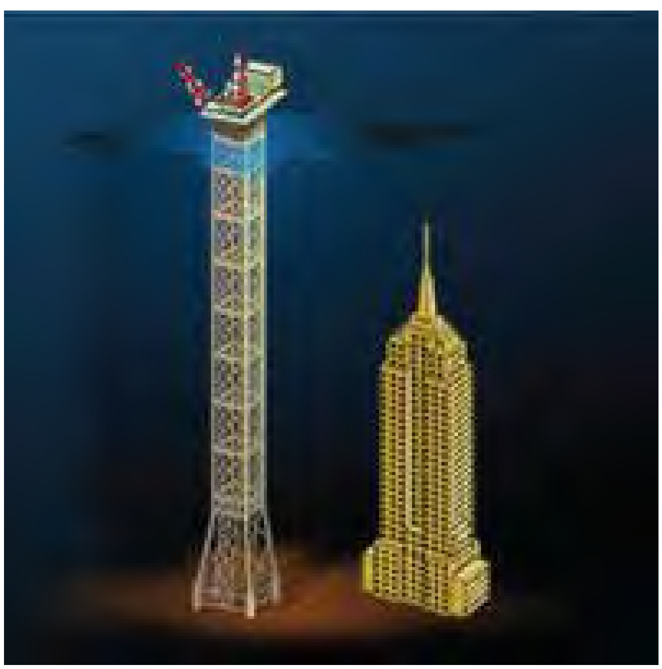
In offshore wind applications, concrete gravity base foundations are less massive and less complex than the structures described above. However, the principles of installation and decommissioning will be similar, as will techniques for cutting and disposal of reinforced concrete. One key difference is the storage chambers that are typical of O&G gravity base structures which require decontamination and disposal. These will be absent in offshore wind structures.

3.2.4.3 Compliant towers

The majority of offshore fields have been developed with conventional fixed steel platforms. These structures, as any structure, have a natural resonance frequency, and related resonance period, which notably depend on structure stiffness. The designer must ensure that there is a sufficient margin between the natural period of the structure and the period of the external forcing resulting from the combined action of water (waves) and air (wind) motion. Should the forcing period be sufficiently close to the natural period of the structure, the structure becomes dynamically responsive, that is, it experiences oscillations of significant amplitude where the stress inside the structure may reach values close to the design envelope. In such instances the structure suffers mechanical fatigue and premature wear. If incorrectly designed, the structure could even enter resonance where the oscillation amplitude increases exponentially, leading to a catastrophic failure of the structure.

For shallower water depths, steel structures are so designed that their natural period is less than that of the damaging significant wave energy, which lies in the 8-20 second band. As the water depth increases, these structures must be longer and therefore begin to become more flexible, and, as a result, their natural period increases and approaches that of the waves. The consequence of this is that the structure becomes dynamically responsive, and fatigue becomes a paramount consideration as discussed above. Additional steelwork is required to stiffen the structure and reduce the natural frequency back to safe values well below that of significant waves. From an engineering and economic perspective, cost-effective steel-jacket structures are extremely difficult, if not impossible, to design beyond 500 m. To circumvent this problem for water depths beyond 500 m, the industry has developed concepts that work on the other side of the damaging significant wave energy (i.e. structures that have natural periods of greater than 20 seconds).

Compliant towers are 3D steel truss arrangements, which are slender and have a seabed footprint substantially less than an equivalent steel-jacket structure as shown in Figure 3-10. They are suitable for water depths up to 1,000 m.



Source: Amerada Hess.
Empire State Building shown alongside to show scale.

Figure 3-10 Baldplate compliant tower

Compliant towers are not considered as a foundation option for offshore wind. From a structural viewpoint, the flexibility is incompatible with the rotational frequencies and the high overturning forces from wind turbines.

3.2.4.4 Tension leg platforms

TLPs are an alternative solution for an O&G production platform in deep water, comprising a vertically moored floating structure. They are particularly suited for water depths greater than 300 m and less than 1500 m. They have potential for application to 2,000 m or more with further development.

The platform is permanently moored by means of tethers or tendons grouped at each corner as shown in Figure 3-11. A group of tethers is called a tension leg as they bear a tension load in reaction to the buoyancy of the floating structure above.

As they have relatively high axial stiffness (low elasticity), virtually all vertical motion of the platform is eliminated. This allows the platform to have the production wellheads on deck (connected directly to the subsea wells by rigid risers), instead of on the seafloor, leading to a simpler configuration, easier access and easier control of the production.

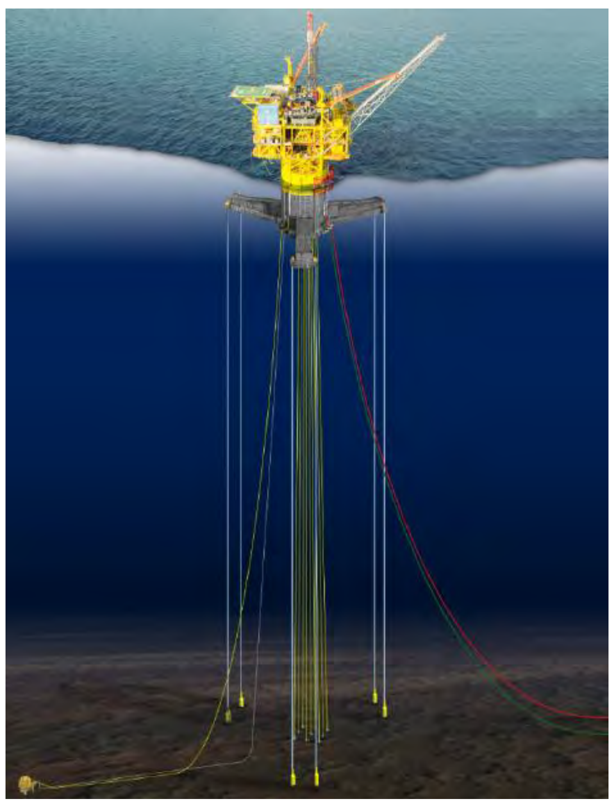


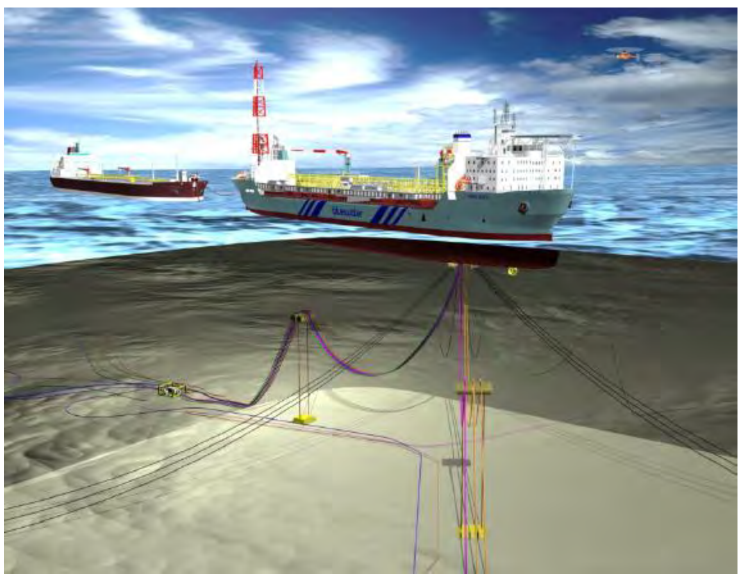
Figure 3-11 Typical TLP arrangement

Tension leg platforms have been explored as an option for offshore wind farms in deeper waters, but have not been adopted to date largely on grounds of cost.

3.2.5 Floating production, storage and offloading units

An FPSO unit is a floating vessel used by the offshore O&G industry for the production and processing of hydrocarbons, and for the storage of oil and is suitable for water depths to 2,000 m. Deep draft floaters are suitable for depths to 3,000 m. Figure 3-12 shows a typical layout of an FPSO.

A FPSO vessel is designed to receive hydrocarbons extracted by itself or from nearby platforms or a subsea template, process them, and store them until they can be offloaded onto a tanker or, less frequently, transported through a pipeline. A vessel used only to store oil without processing it is referred to as a floating storage and offloading vessel (FSO). There are also under construction (as of 2013) floating liquefied natural gas (FLNG) vessels, which will extract and liquefy natural gas on board for onward distribution by LNG tanker.



Source: Bluewater.
Shuttle tanker connected to FPSO for offloading.

Figure 3-12 Typical FPSO

The offshore wind sector is making use of constituent technologies to a limited extent in floating wind, in particular anchoring technologies and in dynamic cables.

3.2.6 Subsea completions

Due to advances in subsea technology and the proliferation of O&G pipelines from existing oilfields to onshore terminals, particularly in mature oil producing regions such as the North Sea and the Gulf of Mexico, it has become possible to develop (usually smaller) oilfields without any need for immediate surface infrastructure. This is accomplished by tying back all wellheads to a subsurface manifold centre, which would be connected to an existing oil platform usually by flexible flow-lines and risers.

Many technical solutions are in use for such subsea developments, and have been greatly enabled by advances in the capability of remotely operated vehicles with heavy duty working capabilities (WROVs). These are deployed from dynamic positioned (DP) construction vessels. These developments also benefit the offshore wind industry.

3.2.7 Status of decommissioning: offshore O&G installations worldwide

3.2.7.1 Gulf of Mexico

The region of the world with the greatest concentration of offshore oil installations is the Gulf of Mexico (GoM), which has a presently estimated 3,420 platforms, with the first offshore platforms installed in the mid-20th century. The great majority of these platforms are located in the shallower waters around the Gulf, generally less than 200 m deep, and it is only in recent years that exploration has extended into the deeper waters.

Decommissioning options in the GoM include the “Rigs-to-Reefs” programme by which disused structures are either: partially removed; toppled in place; or severed and towed to an approved location, the latter being the more common method. The structure then becomes (or continues to be) an artificial reef, providing a conservation area for marine life. At the same time, the option is seen as a less expensive option than removal, and numerous applications were made after hurricane damage to many rigs between 2004 and 2008. It is estimated that about 10% of decommissioned platforms in the GoM have been converted into permanent reefs. However, Rigs-to-Reefs programmes are a matter of debate: opposition in California has prevented such a programme on the West Coast of the USA and similarly environmental opposition has prevented any implementation in the North East Atlantic.

3.2.7.2 Europe and North-East Atlantic (OSPAR) region

The OSPAR database of offshore installations [12] shows that there are currently 1,495 operational offshore installations in the North-East Atlantic maritime area as indicated in Figure 3-13, or more than 600 if sub-sea installations are excluded.

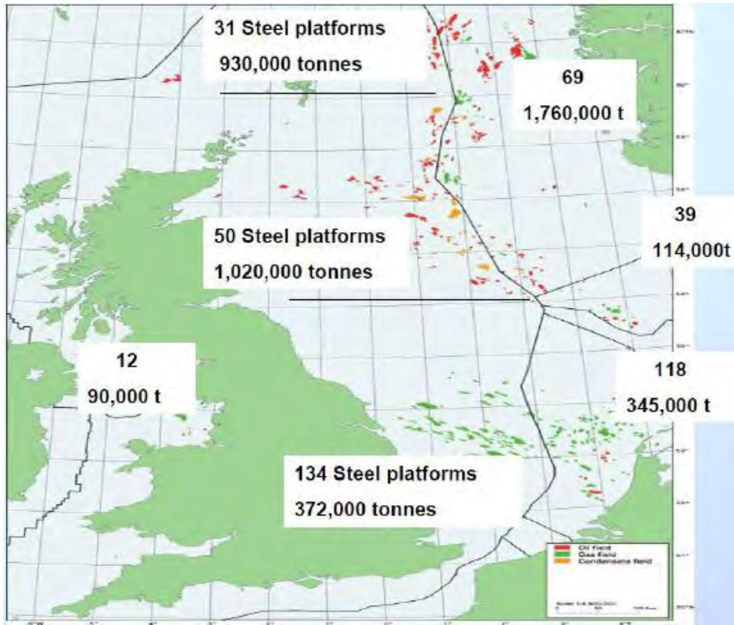


Figure 3-13 General distribution of offshore platforms in the OSPAR region

The OSPAR Convention aims to protect and conserve the North-East Atlantic and its resources and is so named after the original Oslo and Paris Conventions. OSPAR decision 98/3 on the "Disposal of Disused Offshore Installations" came into force in 1999 and requires complete removal once any installation is no longer in operation, whilst allowing partial removal through some exemptions known as derogations. Methods of O&G decommissioning are described in more detail in Section 3.2.9.

Most of the operational installations are sub-sea installations (770) and fixed steel jacket installations (577). According to the latest update of the inventory, 145 installations have so far been decommissioned. Of these, 45 were steel subsea installations, 59 were fixed steel jacket type installations, and 25 were steel floating structures. Of the concrete gravity base installations, 21 are operational and three of the older installations have been decommissioned with some structure left on the sea-bed after individual consideration through a derogation.

The OSPAR decision also allows a derogation category for steel installations of more than 10,000 t. The database records 86 steel installations with a substructure weighing more than 10,000 t with 72 remaining operational. The database also records 16 floating installations weighing more than 10,000 t with nine remaining operational.

It should be noted that even when an offshore installation becomes non-operational (usually due to cessation of production) the installation must remain operational to the extent that it is lit and marked in accordance with the regulations until it is fully removed by a decommissioning operation.

To comply with OSPAR decommissioning derogation requirements, it is usually only necessary to remove structures to -55m relative to sea-level at the lowest astronomical tide (LAT). This is to ensure that shipping can safely pass over a removed structure in the knowledge that there is 55m water depth above any remaining obstructions.

3.2.8 Offshore O&G installations in fresh water bodies

3.2.8.1 Caspian Sea, Baltic Sea and Lake Maracaibo

The greatest concentration of offshore O&G installations in fresh water bodies occurs in the following regions:

- Caspian Sea – however, only the northern part is near fresh water;
- Baltic Sea – however only the northern regions are near fresh water; and
- Lake Maracaibo in Venezuela.

None of the above regions are entirely fresh water, though all have low levels of salinity.

The Caspian Sea is a fresh water lake in its northern portions, due to the inflow of fresh water. It is more saline on the Iranian shore, where the catchment basin contributes little flow. Currently, the mean salinity of the Caspian is one third that of the Earth's oceans. Offshore oil development in the Caspian Sea is amongst the oldest and most mature oil producing region in the world, and consequently there are numerous platforms of all manner of type and design, including a floating city. Actual numbers are incorporated into the global estimate of 10,800 platforms.

Lake Maracaibo is a large inlet of the Caribbean Sea, lying in northwestern Venezuela. It is the largest natural lake in South America extending southward for 210 km from the Gulf of Venezuela and reaching a width of 121 km. The lake water in the southern portion is fresh, but a strong tidal influence makes the northern waters somewhat brackish. The lake is quite shallow except toward the south, and it is surrounded by swampy lowlands.

Lake Maracaibo is one of the world’s richest and most centrally located petroleum-producing regions. The productive area now includes a 105 km strip along the eastern shore, extending 32 km out into the lake. Thousands of derricks protrude from the water and many more line the shore, while underwater pipelines transport the petroleum to storage tanks on the land. Natural gas is also obtained.

In the Baltic Sea, there are currently only four O&G platforms: all are located in the south-eastern part of the region in the oil fields of Kravtsovskoye and B-3.37. Three of the platforms – Baltic Bets, Perto Baltic and G-1 are Polish, operated by Petrobaltic and one, MLSP D-6 operated by Lukoil, is Russian. A Polish oil drilling rig located in the Baltic Sea is shown below in Figure 3-14.

Figure 3-15 shows the D6 Russian complex near Kaliningrad described as ice-resistant.

Figure 3-14 Polish oil/drilling rig in southern Baltic

Figure 3-15 Russian ice-resistant oil production in southern Baltic

3.2.8.2 Canadian Great Lakes O&G development

The following information is based on a selective extract from a paper by Sagira Nazhmetdenova entitled "Should Canada continue drilling for oil and gas under the Great Lakes" [13].

In the past, the U.S. and Canada have tapped into some of the O&G deposits beneath Lakes Michigan, Huron, Erie and Ontario and throughout much of the Great Lakes Basin. O&G production under the bed of the Great Lakes currently occurs in the Canadian portion of Lake Erie via offshore vertical drilling and onshore directional drilling. So far as can be established, all O&G production in the Canadian sections of the Great Lakes is tied back to shore facilities, such that no surface O&G facilities exist above the surface of the Great Lakes.

In 2005, the U.S. imposed a permanent ban on O&G exploration under the Lakes, and the ban was part of the Energy Policy Act signed by President George W. Bush (U.S. Army Corps of Engineers, 2005). This ban only applies to the U.S. sector of the Great Lakes.

The first commercial oil production in North America began in Ontario in 1858 and natural gas production started later in 1889. The area became very attractive for O&G development because of high flows.

In 2006, Ontario's petroleum industries operated over 1,000 oil wells and over 1,000 natural gas wells with some dual production. Erie accommodated 513 of the offshore gas wells and 18 horizontal wells that produced both oil and natural gas from Crown Lands. The province of Ontario currently allows gas wells, but not oil wells in offshore Lake Erie. Ontario allows oil production from below the lake only from wells drilled directionally from onshore surface locations; a number of such directional wells are producing oil from beneath Lake Erie in the Goldsmith/Lakeshore Field [13].

3.2.9 Decommissioning of O&G structures

As described in previous sections, large numbers of the early O&G installations have been removed over the last twenty years and many more will be decommissioned in the next twenty years. In Europe, the OSPAR regulations dominate and worldwide the International Maritime Organisation (IMO) regulations hold. Both sets of regulations stipulate complete removal as the default expectation with some exemptions considered on a case-by-case basis. The main exemptions (or derogations) that are relevant to both O&G and offshore wind concern components on the sea-bed or embedded in the sea-bed, on the basis that the environmental damage and cost of complete removal would be excessive. Thus it is generally permitted that piles are cut just below sea-bed level; that rock protection is left in-situ; and, though more debatable, that cables and buried pipes may be left in place if the risks of becoming exposed are low.

As already outlined, other derogations have resulted in some gravity base foundations being left in place after removing sufficient upper structure to allow 55 m draft for shipping: such derogations were allowed for foundations where complete removal was not sufficiently considered during their design and installation. More recently-designed gravity base structures are intended to be released from the sea-bed and ballast removed to allow them to be re-floated and towed to shore and it is expected that any future gravity-based foundations will need to be designed for complete removal. As noted, derogations have also come into play for steel O&G structures greater than 10,000 t though this is unlikely to be relevant for offshore wind.

In the US states of the Gulf of Mexico and a small number of other locations (*e. g.* Brunei), the Rigs-to-Reefs programme allows a potential option for leaving part of the underwater structure either in-situ or towed to an approved location. However such strategies are a matter of debate primarily on environmental grounds and also through the obstructions caused. In the early days of North Sea O&G decommissioning in the 1990's, towing to a deeper location was the intended disposal method for the Brent Spar floating storage unit, after decontamination. However, opposition led to the unit being brought to shore for disposal and this policy has become adopted.

The decommissioning of O&G structures is already a large industry in itself, with an extensive body of knowledge and literature available. For example, reports and guidance have been issued by the International Association of Oil & Gas Producers (OGP) [14], the UK Government [15] and the industry body Oil & Gas UK [16] with equivalent documents available from many other jurisdictions, for example Norway [17] and Denmark [18].

Focussing on an assumption of onshore disposal, the main processes involved in decommissioning an O&G installation are:

- Preparation – flushing and cleaning tanks and processing equipment, disposal of hydrocarbons, removal of loose equipment, strengthening of steelwork and lifting points
- Plugging and abandonment – sealing the borehole and inserting a temporary or permanent plug depending whether reactivation of the flow needs to be possible in future
- Removal of topside structures – either in pieces or in a single lift. Requires separating at the joints between platform and foundation. Transport to shore.
- Removal of foundation – either in pieces or in a single lift. Piles are cut underwater at 2 to 5 m below seabed level. Concrete foundations are de-ballasted and floated, or lifted; or cut underwater into sections that can be handled. Removed components are transported to shore.
- Decommissioning of pipelines, cables and seabed structures – usually left in-situ if they do not interfere with navigation or fishing.
- Site clearance – Removal of debris and loose materials from seabed.
- Onshore dismantling, disposal and recycling – in specialised facilities where leaks can be contained.

Particularly relevant to offshore wind decommissioning are developments in:

- Cutting techniques, enabling steelwork, concrete structures and cables of ever increasing dimensions to be cut, especially underwater.
- Remotely operated vehicles (ROVs) for underwater surveying and monitoring; and work-class ROVs (WROVs) for heavy duty operations such as cutting and positioning, in both cases reducing or eliminating the need for divers.

More detailed descriptions of the technical decommissioning methods are provided in Chapter 5.

Relevant lessons learned from O&G decommissioning revolve mainly around the long-term preparedness for decommissioning, in particular:

- Consideration of decommissioning during the design process, for example so that gravity base structures can be released from the sea-bed, joints between the topside structure and the foundation can be separated and lifting points can be established.
- Maintenance of records throughout the life of the structure, for example retaining data on weights and centres of gravity; recording changes of equipment (removal, addition, re-location); and inspection records. Losses of such history through multiple changes of ownership were a big problem in some early O&G decommissioning projects.

3.2.10 Similarities and differences between O&G and offshore wind technologies

The Oil & Gas industry technologies have many similarities in that the installations are built to survive and operate in the open sea, and employ a similar range of support structure concepts encompassing piles, steel jackets, concrete gravity bases and floating structures though often with rather different dimensions. There are similarities in the range of vessels used, from survey vessels, jack-ups and crane vessels to support vessels; and in techniques used from corrosion protection to the underwater operations.

However, although experience from the Oil & Gas industry can be useful, care should be exercised when transferring to the offshore wind industry. Main differences between offshore wind and O&G technologies result from:

- Water depth. Offshore wind installations are typically built in depths of 10–50 m whereas many O&G installations are in hundreds of metres of water.
- Distance. Offshore wind installations are generally closer to shore, typically much less than 100 km though occasionally further. O&G installations, particularly in the North Sea, are often hundreds of km from shore.
- Scale and numbers. At an offshore wind farm there are multiple (of the order of 100) installations that are practically identical, whereas O&G installations are single complex entities. The methods of construction, maintenance and decommissioning are strongly influenced by the logistics. For example the optimum method of addressing multiple installations is usually to use a fleet of specialist vessels working in parallel, and to invest in re-usable sea-fastenings rather than one-off welded fixings. In contrast, marine operations for an O&G installation will usually be "one-off".
- Weights and dimensions. The weight of an offshore wind turbine including the tower is typically around 750 t for a 6 megawatt model, whereas the topside of an oil platform may weigh 10,000 t or more. The largest single weight in an offshore wind farm will be the topside of the offshore substation at rarely more than 2,000 t, though it may occasionally approach 5,000 t for the specialised converter platforms needed for far-offshore high-voltage, direct current transmission. However, monopile foundations used for wind turbines can exceed 7 m diameter whereas any steel piles for O&G structures do not exceed 3 m diameter since the distributed load lends itself better to multiple piles.
- Loads. Being designed to capture the energy from the wind, an operating wind turbine rotor subjects the foundation to high and fluctuating overturning forces, whereas an O&G installation presents primarily a dead-load weight. The regular frequencies of the wind turbine rotation provide potential for resonance in the combined tower and foundation structures which need to be carefully avoided.
- Pollution and explosion potential. Offshore wind installations are generally "clean" containing just small quantities of fluids that are readily removed, whereas O&G structures are often contaminated by hydrocarbon residues as many members are used for storage of oil, drillings and waste lubricant.

3.3 Other marine structures

Although no O&G installations are present in the Great Lakes, many other types of marine engineering has led to expertise and facilities that may or may not be relevant to a nascent offshore wind industry.

In this section, designs of bridges and engineering structures in ports and harbours are outlined, with comments on their relevance. Specific comments on designs for ice are covered in the following section.

3.3.1 Bridges

The main loads experienced by bridge supports are vertical dead-loads from the weight of the structure above. There are secondary live loads, variable and in some cases lateral, from the traffic, wind, currents and any ice loads.

In general, bridge supports in water comprise a foundation (or footing), grounded preferably on the bedrock, with a structure on top (the pier), which supports the bridge spans above.

For relatively shallow water and low loads, each foundation may be a single pile or a cluster of piles with a concrete cap. To spread the load and better resist lateral loads, pile groups may be inclined or "battered" as shown in Figure 3-16. Piles are typically steel or reinforced concrete, which is suitable for the predominantly compressive loading. Piles can be installed with an angled pile driver mounted on a barge.

Figure 3-16 Angled or "battered" piles

For more substantial bridge foundations, construction generally involves the creation of a concrete caisson or steel cofferdam, a watertight retaining structure which is pumped out to provide a dry working environment. It may be constructed by driving interlocking steel sheet-piles into the bed, or using a concrete box which may be pre-fabricated, floated out and sunk at the site. Caissons may be open to the air, or can be sealed at the top and pressurised to keep water and mud out. After excavation of the material inside the caisson, concrete may be poured in directly to construct the foundation, sometimes filling shafts drilled into the bed at the bottom of the caisson. In other cases, usually with a steel cofferdam, the bridge footing is constructed within the protection of the caisson which is subsequently removed. Figure 3-17 shows construction of a bridge pier inside a temporary sheet-pile cofferdam.

Figure 3-17 Partially cast bridge pier within caisson

In some cases, the bridge supports are all pre-fabricated onshore and floated into place, as at the Confederation Bridge across the Northumberland Strait between Prince Edward Island and the New Brunswick mainland. Figure 3-18 shows the pier base, which sits on prepared seabed with the pier shaft then installed on top.

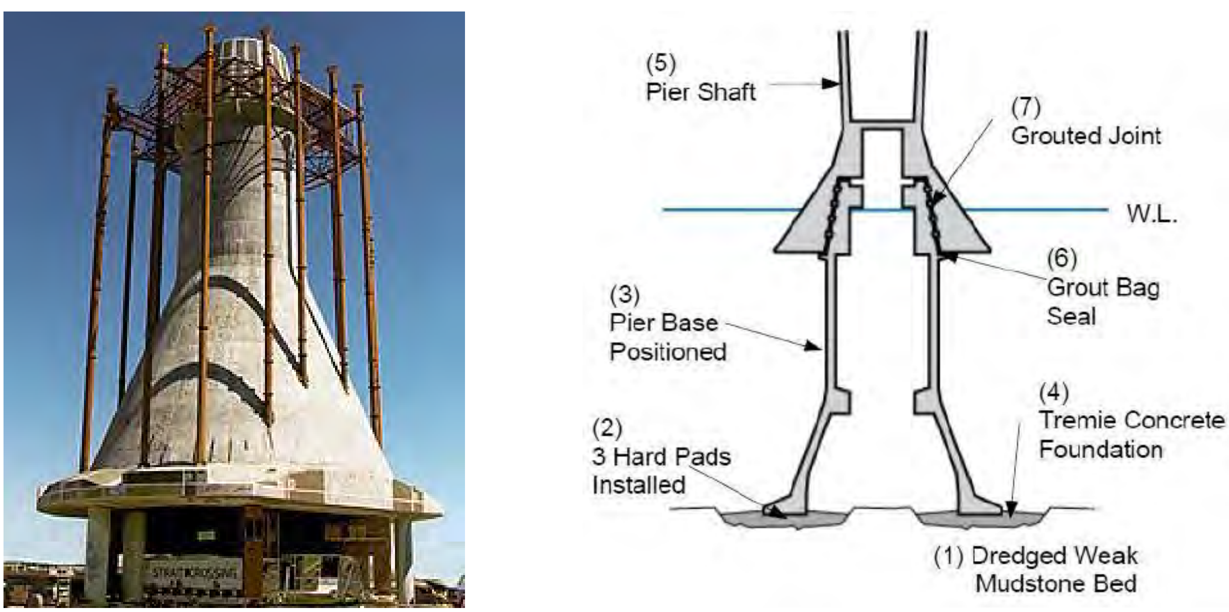


Figure 3-18 Pre-fabricated pier base for Confederation Bridge

Once the piers have been constructed and depending on the bridge design, they can be used to support cranes for building the rest of the bridge. In some cases, installation of bridge spans may be by floating crane as shown in Figure 3-19, working in Denmark.

Figure 3-19 Shearleg crane vessel installing bridge span

Another example is the 5 km long second Severn Crossing in the south west of the UK, completed in 1996. The construction method had to take account of the very large tidal range (up to 14.5 m) and strong currents leading to tidal operating windows of around 2 hours. The foundations of the bridge piers were made of 37 precast concrete caissons weighing up to 2,000 t each and 53 m long. Once in position, these were filled with concrete taking 12 to 20 weeks to cast.

Placing the main caissons involved two of the largest vessels in the marine fleet at that time. The SAR3 is a specially modified flat barge, used to transport the caissons and bridge spans into position. Whilst the barge was held "on station" to 0.5 m tolerance with four Jimecal thrusters under computer control, the Lisa A jack-up crane barge lifted the caisson off the barge (Figure 3-20) allowing it to return to its berth.

Figure 3-20 Caisson lifted by jack-up crane

After the tide had gone out, Lisa A placed the caisson on the dried out river bed. In some instances, the bedrock was still covered in water and then grout bags were fixed at the bottom of the caisson which burst to create a seal. Exact positioning was achieved using the satellite and land based systems, and then the 300 mm joint between caisson and bed was sealed and the inside filled with a mass concrete plug followed by reinforced concrete to form the completed foundation. With the sealed caisson acting as a "cofferdam" the filling operation was free of interruption from normal tides.

Both the Severn Crossing and the Confederation Bridge were strongly affected by tidal currents, which will not be an issue in the Great Lakes. Nevertheless they provide examples of construction techniques used in major bridge projects.

3.3.2 Ports and harbours

Quays at ports and harbours are generally constructed from deep piles of reinforced concrete, steel or timber with concrete caps and in-fill of compacted rock and rubble.

Dolphins are man-made marine structures extending above the water level and not connected to shore, usually to provide pier extensions, mooring points and to cushion ship impacts similar to a fender. They are designed to take lateral loading and are fendered in such a way that shock loading is minimized. Typically they are constructed by driving piles into the seabed, capped to provide a platform. Piles are generally steel or reinforced concrete and are typically angled to optimize the resistance to lateral loading as shown in Figure 3-21.

Figure 3-21 Dolphin under construction showing angled piles

Figure 3-22 shows the Canaport LNG terminal comprising a loading platform and dolphins to either side it was built by Weeks Marine in the Bay of Fundy, with steel jacket structures in water depths up to 40 m with steel piles up to 60 m long and involving the drilling of rock sockets up to 12 m.

Figure 3-22 Canaport LNG terminal in the Bay of Fundy

Breakwaters may be constructed using caissons, or piles capped with concrete or may be simply piles of dumped rubble of different grades if the water is very shallow (<3 m). In some cases, concrete-filled bags are used. For large constructions, cranes on barges are generally used with core material dumped using hopper barges. In ice-infested waters, the sides may be smooth and angled to deflect the ice as in Figure 3-23.

Figure 3-23 Pier at Port Colborne, Lake Erie

Where wave action is a major threat, the energy may be dissipated by rocks or specially shaped armour blocks such as the concrete tetrapods in Figure 3-24.

Figure 3-24 Tetrapod armour blocks providing protection from wave erosion

3.3.3 Implications in the Great Lakes

Bridges spanning the waterways of the Great Lakes are unlikely to see such demanding conditions from floating ice as the Confederation Bridge because of the much lower currents and tides, but nevertheless will experience floating and solid ice. Figure 3-25 shows the Mackinac Bridge over the straits between Lake Michigan and Lake Huron where in many winters the ice freezes solid forming "ice bridges" across the strait.

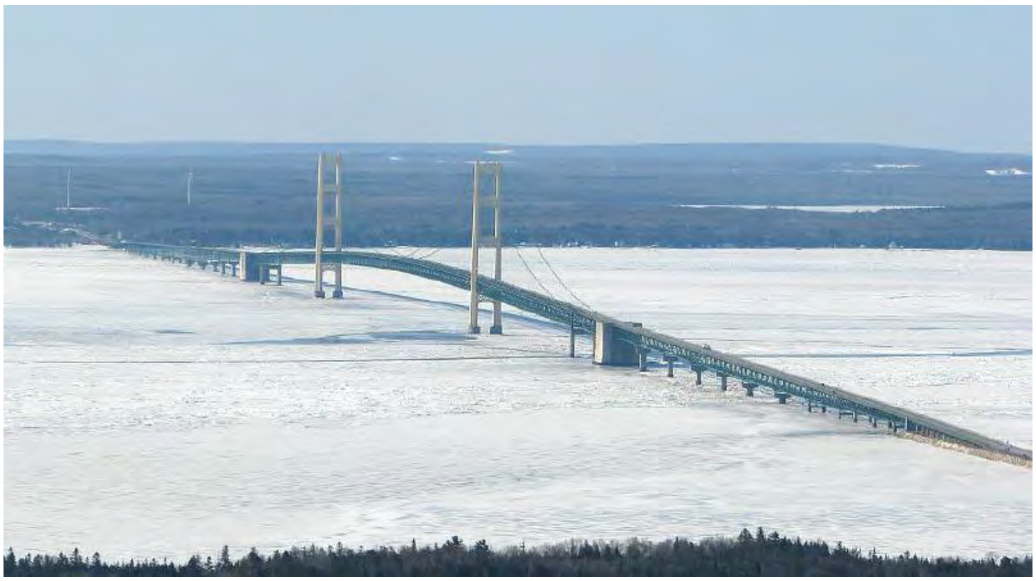


Figure 3-25 The Mackinac Bridge in the Great Lakes

The present 8 km long bridge was opened in 1957. The maximum water depth is 43 m at the piers. For the two main concrete tower footings, caissons were floated to the site and sunk, the material inside dredged out and concrete poured. The remaining, smaller piers were constructed using cofferdams.

Other notable bridges in the Great Lakes are the 2.3 km long Ambassador suspension bridge between Windsor, Ontario and Detroit, Michigan (Figure 3-26) opened in 1929 which has one footing in water; and the Blue Water bridge between Sarnia, Ontario and Port Huron, Michigan though with both piers on land. However, the majority of bridges in the Great Lakes have relatively short spans and do not require underwater footings.

Figure 3-26 Ambassador Bridge between Detroit and Windsor, Ontario

More relevant marine engineering structures within the Great Lakes are the structures of the major ports. For example, Thunder Bay extends along 45 km of shoreline and includes extensive breakwaters as well as multitudes of quays, visible on the right of Figure 3-27. The maximum vessel draft is 8.2 m.

Figure 3-27 Thunder Bay Port, Keefer Terminal

3.4 Installations in ice-infested waters

The primary factors to take into account where temperatures are low enough for ice formation are:

- icing on topside structures,
- ice-floes,
- solid ice when surrounding waters are frozen, including forces from ice ridges.

The issues of icing on topside structures are well known, occurring in many offshore installations already though often the salinity of the waters prevents floating and fixed ice formation.

Issues of floating ice floes are also commonplace, requiring designs to deflect the floes and prevent them building up to exert unacceptable forces. For most bridges the directional flow through the arches means that floating ice comes from a predictable direction and can be deflected by structures forward of the main bridge supports. In other instances, floating ice is held back by ice booms to avoid potential problems from pile-ups of ice. Figure 3-28 shows the ice boom put in place during the winter to prevent floating ice entering the Niagara River at the north end of Lake Erie.

Figure 3-28 Ice boom at mouth of Niagara River, Lake Erie

Design for ice loading on foundations is routinely applied for ports structures and offshore structures such as lighthouses.

During O&G exploration, when drilling rigs are present temporarily, it may be sufficient for the water immediately around the rig to be kept ice-free through the constant use of guard vessels circling the rig and available to deflect any approaching floes. For more permanent structures, angled deflection cones may be incorporated as seen on the piers of Confederation Bridge (Figure 3-18 and Figure 3-32).

Issues of solid ice also require deflection of the loads and strengthening of the general structures. The Oil & Gas industry has been working in the Arctic for many years and over this time techniques and design tools have been developed to calculate the loads under a variety of ice conditions. These include forces from ice ridges dragging along the seabed as well as the ice loads on fixed and floating installations. Amongst recent work on better defining standards and procedures, the ICESTRUCT Joint Industry Project [19] which started in 2009 and led by the Arctic technology research team at DNV GL Group is exploring the modifications to design standards required for O&G structures operating in the Arctic, extending the new ISO standard 19906 "Petroleum and Natural Gas Industries – Arctic Offshore Structures" and aiming to produce a revised recommended practice DNV-RP-C209. The DNV Barents 2020 project looked at similar topics [20].

Designs against ice loads have included:

- construction of artificial islands;
- structures with a deflector skirt, for example the Russian platform shown in Figure 3-29;
- concrete collars around each leg, for example in Figure 3-30; and
- cone deflectors around each leg, for example the Chinese platform in Figure 3-31.

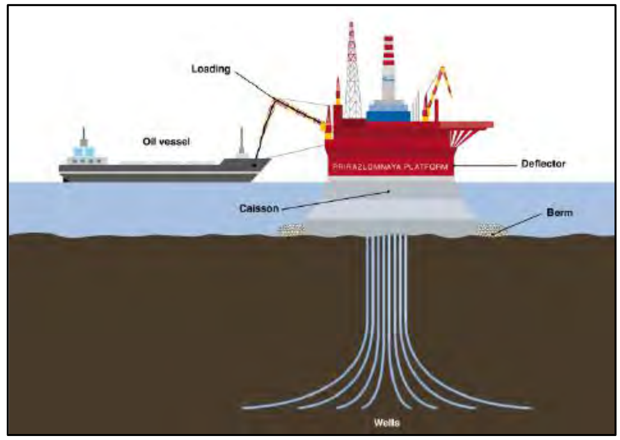


Figure 3-29 Deflector skirt at Prirazlomnaya oil platform

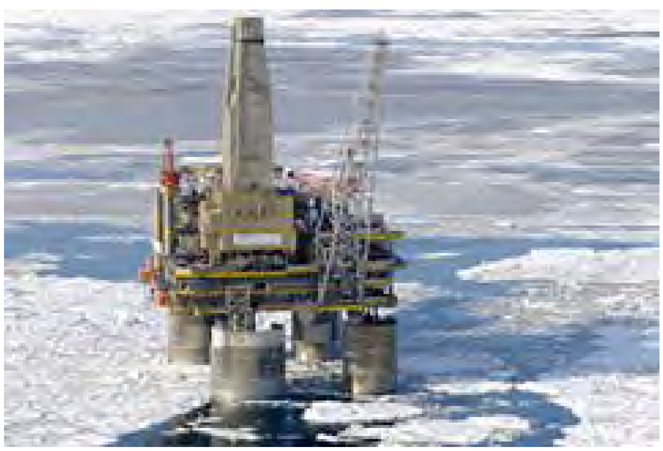


Figure 3-30 Concrete collars at Sakhalin-2 oil platform

Figure 3-31 Conical ice deflectors in Bohai Bay, China

Where bridges cross waters subject to floating ice, ice-resistant structures may be built out from the upstream side of the piers to deflect the ice and protect the piers. An example is in the design of the Confederation Bridge – See Figure 3-18 and Figure 3-32.

Figure 3-32 Conical ice shields at the waterline of Confederation Bridge piers

The bridge is subjected to dynamic ice floes moving in response to winds, currents and tides through the narrow straits. Collisions between the floes results in large rubbly ice masses. The bridge supports were therefore designed to be cone-shaped at the waterline to help bend and break the ice, so that the ice cracks and flows around the supports. Steel cones used to shape the cast concrete were left in place on some piers, as shown in Figure 3-32.

3.5 Chapter summary

Table 3-1 Summary of other offshore technologies

Topic	Description	Comments
Offshore Oil & Gas	With more than 10,000 offshore platforms worldwide, the O&G industry has a solid track record of installing, operating and decommissioning offshore structures. This includes structures in fresh waters.	There are many similarities with offshore wind with respect to the range of support structure concepts, the range of vessels used, and in techniques used ranging from corrosion protection to the underwater operations. However, care should be exercised when transferring the know-how to offshore wind energy due to the many differences such as scale and number, weight and dimension, nature of loading, water depths and environmental and H&S issues where the two technologies diverge significantly. In the Canadian sections of the Great Lakes, O&G extraction is tied back to shore facilities so direct offshore O&G experience is limited.
Other marine structures	Bridges, ports and harbours – notably in the Great Lakes – are examples of marine engineering that have led to expertise and facilities that may be leveraged for application in an offshore wind industry.	Experience with bridge foundations and harbour structures in the Great Lakes may be applied to offshore wind, particularly for construction methods. In terms of design, the majority of bridge loading is vertical dead loads unlike the pronounced over-turning and variable loads on WTGs. Another main difference is that bridge foundations are limited to shallow water depths. However, the designs for bridges, harbours and any offshore structures all need to consider wind, currents and ice loading.
Installations in ice-infested waters	The primary factors to be considered are • icing on topside structures; • ice-floes; and • solid ice when the surrounding waters are frozen, including forces from ice ridges.	Design in ice-infested waters is routinely addressed by engineers in many fields. Some applicable techniques to offshore wind include foundation design for ice loading, structural strengthening and the incorporation of cones or deflectors.

4 JURISDICTIONAL AND LITERATURE REVIEW

4.1 Chapter introduction

When considering decommissioning, it is important to bear in mind that experience in decommissioning of offshore wind structures is very limited, as described in Chapter 1. Although there is substantial experience with decommissioning of offshore oil and gas (O&G) structures as discussed in Chapter 3, decommissioning policy for offshore wind is relatively immature in many regions and countries, particularly in those just starting offshore wind programmes and/or with no offshore oil and gas experience.

Taking the above into account, this study focuses on the three most mature offshore wind markets (UK, Germany and Denmark) while providing a high level review of other markets in particular the federal regulations in the USA. For these 'other' markets we have sought to focus on anything unique to or different from the more established markets.

4.1.1 Objective and scope of review

This study seeks to review and summarize existing guidelines, regulations, codes of practice and best practices in other jurisdictions for decommissioning and determination of financial assurance for offshore energy technologies.

4.1.2 Methodology

The information in this document has been sourced from an internal knowledge capture exercise within DNV GL, literature review of publicly available information, engagement with key government stakeholders, and wind energy associations such as the Irish Wind Energy Association.

4.2 Introduction to key decommissioning terms

This section provides a brief introduction to some of these terms used in the following sections to aid understanding.

4.2.1 What are territorial waters and the exclusive economic zone?

Under the United Nations Convention on the Law of the Sea (1982) [21] (arts 2&3), territorial waters are considered to be an extension of a nations' sovereignty into the sea. The limit of the territorial waters is 12 nautical miles (nm) from the coast of a nation. While not technically sovereign land, the exclusive economic zone (EEZ) is the area of sea between 12nm and 200nm from a nation's shore which is granted special legal status by the convention. Beyond 200nm is considered international waters. In the EEZ, a nation has "*sovereign rights for the purpose of exploring and exploiting, conserving and managing the natural resources*" (art. 56,1(a)). This designation is generally accepted to include offshore wind energy development. Nevertheless, within the EEZ, coastal nations are not entirely sovereign and activity such as decommissioning of energy installations is governed by the regulations of the International Marine Organization (IMO).

The Great Lakes are within the US and Canadian EEZ.

4.2.2 What is a lease? How does this vary by country?

Governance of access to the seabed for the purposes of offshore wind development varies significantly by country. For example, the UK seabed is managed on behalf of the British Crown by a statutory corporation known as The Crown Estate (TCE). TCE has authority to enter into a commercial lease with a project developer (lease holder). The lease provides a form of tenure that allows the developer to occupy the seabed but it is legally separate from any other permitting or authorisation to construct a wind farm. In the United States the Bureau of Ocean Energy Management (BOEM) plays a similar role on behalf of the Federal Government.

The main alternative approach taken is for the permitting and leasing of sites to be combined in a single process. For example, receiving permission from the German federal authorities to construct and operated a wind farm in the EEZ automatically confers on the developer the tenure afforded by a lease. For this reason, in Germany and Denmark the terms 'lease' and 'lease-holder' are not used.

4.2.3 What is an accrual fund?

Decommissioning securities are typically paid through an accrual fund which is where, based on the expected decommissioning costs, the developer pays a certain amount into a bank account. Over time this fund is expected to accrue and cover the eventual cost of the wind farm decommissioning. This is in contrast to an upfront payment, which due to the time value of money, may be perceived as more costly by the developer.

4.3 International regulation

A number of international and regional agreements apply to decommissioning of offshore wind. The two most important in Europe are the United Nations Convention on the Law of the Sea (UNCLoS) which has been ratified by Canada and the Oslo and Paris Conventions (OSPAR), covering the Northeast Atlantic. DNV GL understands that the Great Lakes are within Canada's EEZ and therefore UNCLOS would apply in Ontario. As OSPAR does not cover Canadian waters, DNV GL does not believe that OSPAR would be relevant to offshore wind within the Great Lakes.

4.3.1 United Nations Convention on the Law of the Sea

The United Nations Convention on the Law of the Sea (UNCLOS [21]). is an international agreement that defines the right and responsibility of nations with respect to their use of the oceans, providing guidelines for businesses, the environment, and the management of marine resources. Canada ratified UNCLOS in 2003. Article 60 states, in regard to installations and structures in the exclusive economic zone (EEZ), that: "*Any installations or structures which are abandoned or disused shall be removed to ensure safety of navigation, taking into account any generally accepted international standards established in this regard by the competent international organization. Such removal shall also have due regard to fishing, the protection of the marine environment and the rights and duties of other States. Appropriate publicity shall be given to the depth, position and dimensions of any installations or structures not entirely removed."*

4.3.2 International Maritime Organisation

The IMO is the competent international organisation for the purposes of Article 60 of UNCLOS.

Regulations of the IMO [22] cover any continental shelf and EEZ and requires that the coastal 'State' that has jurisdiction ensures that the abandoned or disused offshore installations are decommissioned as soon as reasonably practicable and that by default the structures are removed entirely, in line with international agreements. Removal should be performed in such a way as to cause no significant adverse effects upon navigation or the marine environment.

In certain cases it may be permitted to allow structures to remain at least partially in place if the removal processes are likely to cause more environmental damage than leaving them in situ. In practice this condition is most likely to apply to piles, to buried cables, and to some scour protection. The IMO specifies that this may be deemed acceptable in the following circumstances:

- If the installation weighs more than 4000 tonnes (in air) or is standing in more than 100 m of water (more applicable to oil and gas);
- If the installation will serve a new use, such as enhancement of a living resource (such as marine habitat);
- If entire removal is not technically feasible (although IMO standards stipulate that from 1998 onward, the design and construction of all installations and structures placed on a continental shelf or EEZ should be such that entire removal would be feasible);
- If entire removal would involve extreme cost;.
- If entire removal would involve unacceptable risk to personnel;
- If entire removal would involve an unacceptable risk to the marine environment.

The decision on whether parts of a structure can remain is to be evaluated by the coastal State with jurisdiction over the installation or structure on a site-by-site basis, according to the guidelines and standards set out by the IMO (reviewing the effects on navigation, deterioration of material, risk that material will shift, costs, new use, etc.). The term 'State' is assumed to be mean at the Federal level as it is the country that ratifies the agreement but that responsibilities could be transposed to state or regional level as per the regulations within a jurisdiction. No further guidance on what constitutes 'extreme cost', 'unacceptable risk to personnel or the marine environment' is provided.

The coastal State should ensure that the remaining structures are indicated on nautical charts, etc. and satisfy itself that the remaining materials will not move so as to cause hazard to navigation. The coastal state should also identify the party responsible for monitoring the remaining installation.

No guidance on financial assurance is provided.

This would appear to be the key international agreement, which is applicable to Ontario. However the federal government has a role to play and not all decisions will be within Ontario discretion. As shown by the recent signing of the "Canada-Ontario Agreement on Great Lakes Water Quality and Ecosystem Health, 2014" [23], the federal and provincial governments work together extensively on the Great Lakes.

4.3.3 OSPAR

The Oslo and Paris Convention (OSPAR) is a regional international convention for cooperation in the marine environment between the fifteen governments[4] that surround the Northeast Atlantic.

[4] The fifteen Governments are Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom. Finland is not on the western coasts of Europe, but some of its rivers flow to the Barents Sea, and historically it was involved in the efforts to control the

Two documents relate to decommissioning:

- Decision 98/3 on the disposal of disused offshore installations in the O&G sector [24]
- Guidance on Environmental Considerations for Offshore Wind Farm Development [25]

The first is a binding decision for the oil and gas sector. It highlights certain derogations, for instance, excluding topsides, large gravity based concrete structures or steel installations weighing more than 10,000 tonnes in air.

No such binding decision has been made for offshore renewables, but OSPAR has produced the guidance note which countries are encouraged to follow.

This guidance note states that: "*In line with OSPAR's policy on waste disposal at sea, the removed components of an offshore wind farm should generally be disposed of entirely on land taking into account the waste management hierarchy of avoidance, reduction, re-use, recycling, recovery, and residue disposal. If the competent national authority decides that a component of the wind farm should remain at site (e.g. parts of the piles in the sea-bed, scour protection materials), it should be ensured that they have no adverse impact on the environment, the safety of navigation and other uses of the sea. The status of remaining parts should be monitored and if necessary, appropriate measures should be taken.*"

In terms of financial assurance: "*In line with the polluter pays principle, the licensee or, if deemed appropriate, other suitable body should ensure that adequate financial reserves (e.g. bonds) are available to enable the appropriate removal and subsequent disposal on land (in the sense of the waste management hierarchy). Furthermore, the licensee should bear any costs for necessary monitoring of the status of components which remain at site and cost for any associated necessary measures.*"

4.3.4 International Association of Oil and Gas Producers

The International Association of Oil and Gas Producers (OGP) has released guidance relating to decommissioning of offshore concrete gravity based structures (CGBS) in the OSPAR maritime area and other global regions [26]. The guidance references the regulations given by the IMO and OSPAR's Decision 98/3. It is noted that the guidance focuses on large CGBSs used in the oil and gas industry and may not be directly relevant to offshore wind farms.

Large CGBSs remain a derogation category according to Decision 98/3; therefore all or part of the structure can remain in place as long as a permit is obtained from a coastal State that has jurisdiction over the structure. In order to obtain a permit, the operator must identify and assess a range of decommissioning options, including reuse at existing location, full removal, partial removal or leave wholly in place. The guidance summarises the risks associated with each approach and draws upon experience already gained, concluding:

"*…the removal or partial removal of a CGBS poses significant technical challenges, carries high safety and environmental risks and would incur disproportionately high costs compared with the benefits to society. For large CGBS structures such risks are likely to be beyond an acceptable level of good industry practice.*"

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dumping of hazardous waste in the Atlantic and the North Sea. Luxembourg and Switzerland are Contracting Parties due to their location within the catchments of the River Rhine

4.3.5 International Cable Protection Committee

The International Cable Protection Committee (ICPC) establishes internationally agreed upon standards and recommendations for submarine cable installation, protection, and maintenance. ICPC Recommendation #1 [27], relates to submarine cable systems that are redundant or have been taken out of service (OOS). In terms of removal, Recommendation #1 states: *"Under UNCLOS and customary international law, there is no requirement for the removal of OOS Cables. If a coastal nation requires removal of undersea cables outside its territorial seas, cable owners should request the jurisdictional basis for such a requirement. In the absence of a valid jurisdictional requirement, such a requirement is a violation of international law and may be challenged."*

Given that there is no international requirement, the responsibility for the removal of OOS cables beyond territorial waters lies with the cable owners. The recommendation provides guidance and a number of considerations for planning, removal and salvage of OOS cables.

No guidance on financial assurance is provided.

4.4 United Kingdom

4.4.1 Offshore wind

4.4.1.1 Regulations and guidance notes

In addition to international regulations, the most relevant documents relating to the decommissioning of offshore wind structures in the UK are:

- Energy Act 2004 and amendments made in Energy Act 2008 [28].
- Department of Energy and Climate Change (DECC) Guidance Note: "Decommissioning of offshore renewables energy installations under the Energy Act 2004" [29]. This Guidance Note is based on the decommissioning provisions in the Energy Act 2004 and applies to installations that are used for purposes connected with the production of energy from water or winds, permanently rest on (or are attached to) the bed of the waters, and are not connected with dry land by a permanent structure providing access at all times. The note incorporates international obligations including IMO, OSPAR, and others and summarises the range of UK legislation that is relevant to decommissioning activities, such as the Food and Environment Protection Act (FEPA) 1985 and Health and Safety legislation. As with any of the rules and guidelines, the DECC guidance may change with time. The latest revision was issued in January 2011.
- The Crown Estate (TCE) Lease. The Crown Estate owns much of the seabed in UK waters and has rights to lease renewable energy activity out to the EEZ. The lease provides exclusive rights to the seabed to developers. The UK Government and The Crown Estate work together to avoid duplication with developers only required to submit one decommissioning plan, one financial security with no additional provisions provided by the Crown Estate.
- Planning Consent – Before constructing an offshore wind farm, planning consent is required from the relevant competent authority, DECC in English and Welsh territorial waters and Marine Scotland in Scotland. Decommissioning requirements for onshore works are covered within these planning documents and are in line with standard onshore license conditions.

- Marine licenses – in addition to planning consent and a lease a specific license is required to deposit, construct or remove anything from the seabed. This license is termed a Marine License and for offshore wind is granted as part of the planning consent process.

4.4.1.2 Process

Within the UK, DECC seeks to provide a 'one-stop shop' in relation to decommissioning. A separate decommissioning approval is required.

The steps which a developer needs to take are as follows:

1. TCE awards agreement for lease.
2. Developer assesses impacts as part of the Environmental Impact Assessment (EIA) and undertakes preliminary discussions with DECC regarding decommissioning.
3. Consent is granted, usually with a condition that states that construction cannot begin until a decommissioning programme has been submitted. For instance, "*No offshore works must commence until a written decommissioning programme, including addressing the possibility of abandonment or decay, in compliance with any notice served on the undertaker by the Secretary of State pursuant to section 105(2) of the 2004 Act(b) has been submitted to the Secretary of State for approval*." [30]
4. DECC and the developer undertake detailed discussions. The developer then submits a draft decommissioning programme (including proposed financial security provisions), informed by EIA (already undertaken prior to consent) and consults with interested parties and statutory consultees. DECC will consult with Government Departments (including TCE) and send written comments to the developer. DECC provides guidance on the content of the decommissioning programme in Annex E of the Guidance Note [29] and notes that "*the detail provided under each heading in a decommissioning programme should reflect the level of uncertainty for that issue*", for instance, a detailed description can be provided on the items to be decommissioned, but precise time schedules will be much more uncertain.
5. Developer incorporates comments and submits final decommissioning programme for approval.
6. The Secretary of State may approve as it stands, approve with modifications/subject to conditions, reject and require a new one, or prepare a decommissioning report and recover the expenditure. [5]
7. Once approved, the developer reaches the final investment decision on the wind farm, with relevant financial security provisions enacted.
8. Wind farm is constructed and commissioned.
9. Decommissioning plan is updated as appropriate. In practice developers appear to be reviewing every five years.
10. Approximately two years prior to decommissioning, final review and decommissioning plan submitted, developer obtains consents required.
11. Once commercial operation has ceased, decommissioning is undertaken.

[5] Various examples can be found online, for instance: http://sse.com/media/92981/GGOWL_DecommissioningProgramme.pdf

12. Following decommissioning (generally within four months), the developer submits a report to the Government showing the approved programme has been implemented. This report should include: a) confirmation that decommissioning has been carried out, b) information on the outcome, and c) confirmation that the appropriate bodies have been notified and appropriate aids to navigation installed.
13. Developer implements arrangements to monitor and manage any remains that may still exist.

4.4.1.3 Definition of decommissioned

Consistent with IMO, the general presumption of the DECC guidance is that installations should be completely removed, whilst recognizing there may be circumstances where parts may be allowed to remain. The DECC guidance stresses that decisions will always be made on a case-by-case basis and notes various examples of where parts may be allowed to remain.

For instance, on foundations (Para 7.13c):

> *"Foundations and structures below sea-bed level: where an installation's foundations extend some distance below the level of the sea-bed, removing the whole of the foundations may not be the best decommissioning option, given the potential impact of removal on the marine environment, as well as the financial costs and technical challenges involved. In these cases, the best solution might be for foundations to be cut below the natural sea-bed level at such a depth to ensure that any remains are unlikely to become uncovered. The appropriate depth would depend upon the prevailing sea-bed conditions and currents. Contingency plans should be included in the decommissioning programme, to describe the action proposed if the foundations do become exposed."*

For sea-bed that is stable, a depth of cut at one to two metres below the natural sea-bed level is thought likely to be acceptable. If the sea-bed is mobile, a greater depth of cut is likely to be required.

Example on array cables (Para 7.13d):

> *"Where cables remain buried at a safe depth below the sea-bed, there may be a case for leaving them there, given the potential impact of removal on the marine environment, as well as the financial costs of removal. Concerns might arise if the cables were to become exposed by natural sediment dynamics, as exposed cables might pose a risk to other maritime users, with the possibility that fishing gear or an anchor might foul a cable. The option of cables being left in place may be considered if they are buried at a safe depth below the sea-bed, such that they do not pose a risk to other maritime users. The appropriate depth will depend upon the prevailing sea-bed conditions and currents. Where it is proposed to leave cables in place, cable burial depth should be monitored over and beyond the life of the installation, to assess the risk of cables becoming exposed after decommissioning. Contingency plans should be included in the decommissioning programme, to describe the action proposed if the cables do become exposed."*

Example on scour protection materials (Para 7.13e):

> *"Where scour protection materials have been used, there may be a case for leaving them there, to preserve any marine habitat established over the life of the installation, where they do not have a detrimental impact on the environment, conservation aims, the safety of navigation and other uses of the sea."*

In terms of timing, DECC expects that the removal, repowering or other re-use of installations will not be delayed unless a robust case demonstrates definite re-use opportunities or justifiable reasons for deferring decommissioning.

Any residual liabilities will remain with the owner at the time of decommissioning, unless the developer has proposed to remove the object entirely but the decision has been taken by the Government that it should be left in situ.

4.4.1.4 Financial assurance

Overall, the general principles to be followed is that the "polluter pays", with the developer liable for ensuring that there are sufficient funds available. This is a statutory provision with the Secretary of State (SoS) having powers to take remedial action and recover any expenditure. The SoS does not need to wait until the shortfall is encountered but through the regular review process may also ask developers to increase their financial provision if reviews suggest the security is insufficient to meet decommissioning liabilities. Even if the developer sells the asset, there is no automatic change in liability on transfer of ownership; instead the SoS needs to approve change and take account of any potential increase in risk of default.

DECC is relatively flexible in terms of acceptable security – potentially accepting cash, letters of credit (issued from a Prime Bank[6] with a draw down facility), bonds, early/mid-life and continuous accrual decommissioning funds. Other mechanisms such as insurance and collective schemes such as an industry fund could also be acceptable. These will be assessed on a case-by-case basis, with developers submitting details of their proposed security within the decommissioning programme. In contrast, DECC suggests the following will be unacceptable, representing unacceptable risk of default: Parent Company Guarantees and late (in the project life) accrual funds.

The developer is responsible for providing the initial cost estimate (although this is often undertaken by subcontractors) and it is then submitted to DECC as part of the decommissioning programme. DECC suggests that the programme should include an overall cost estimate in £ sterling, a breakdown of the major component parts and include removal of the installation, management of the waste, any surveys and post-decommissioning monitoring, maintenance and management of the site. DECC can request an independent audit (determined on a site-by-site basis), although DNV GL is not aware of any having been done.

DECC recommends that "*it is in the developer's best interest to undertake reviews of decommissioning programmes*". DECC does not specify a time period but as a general guide suggests reviews could be undertaken: "*once the wind farm has been operational for 2 years; 2 years prior to provision of financial security (e.g. payment into accrual fund); 2 years prior to the mid-point of accrual fund.*"

4.4.1.5 Key points

DNV GL would note the following interesting characteristics of the UK approach:

- Proportionality and flexibility
  - DECC is clear about seeking the right balance between ensuring that the developer that constructs, extends, operates or uses an installation is responsible for meeting the cost of decommissioning in a safe manner, while at the same time appreciating the potential burden on

[6] 'Prime Banks' are banks established in Organization for Economic Co-operation and Development (OECD) countries, which has an AA rating or better (Standard & Poor) or Aa2 rating or better as defined by Moody's.

companies and therefore seeking the most cost effective solutions. This leads to a flexible, case by case approach, with clear guidance and regular reviews, backed up by strong legislative powers.

- Strong legislative basis
  - The SoS has statutory powers to ensure that those responsible undertake decommissioning in accordance with the programme approved by the SoS. The SoS may require remedial action if the programme is not met and a person guilty of an offense is liable to a fine or imprisonment for up to two years. There is no automatic change in liability on transfer of ownership, with approval needed by the SoS. Amendments made in the 2008 Energy Act extend the SoS power to request additional information, issue parent companies with decommissioning notices and ensure that funds are ring fenced[7] and clearly stated within companies annual returns. This strong basis appears to allow a more flexible approach to implementation.
- Early consideration of decommissioning
  - DECC strongly encourages early consideration of the decommissioning approach, with construction unable to start before the SoS has approved the decommissioning programme.
- Coordination between departments
  - DECC and TCE both require decommissioning programmes, including details of financial assurance, but work together, with developers only having to submit one decommissioning plan.

4.4.2 Oil and Gas

4.4.2.1 Regulations and guidance notes

The regulatory background for oil and gas is very similar to offshore wind, with the key legislative provisions contained within the Petroleum Act 1998 as amended by the Energy Act 2004.

The key guidance note is DECC's: "Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998" [31]. This guidance applies to oil and gas installations and pipelines on the United Kingdom Continental Shelf (UKCS) and incorporates international obligations including IMO and OSPAR Decision 98/3. As usual, DECC guidance may change with time. The latest revision was issued in March 2011.

4.4.2.2 Process

The process starts when a field development is approved and construction has commenced. DECC will issue a notice under section 29 of the Petroleum Act 1998, to the relevant parties (those who will derive financial or other benefit from the installation e.g., licensees, operator, owners). This places an obligation on those parties to submit a decommissioning programme. The notice will specify the date by which the decommissioning plan must be submitted (for example 3 years in advance of the planned cessation of the facility). If, under the OSPAR Convention, a concession is available for derogation in-situ, a longer lead time would likely be required (for example 5 years). Other factors affecting the lead time include the availability of offshore heavy lifting vessels and barges, which can be booked up many years in advance.

[7] That is to say that the funds cannot be accessed for anything other than decommissioning.

The submission of a decommissioning programme for offshore oil and gas uses a similar process to offshore wind. However, it can be a highly iterative process, as all decommissioning options need to be evaluated prior to the final plan being approved. Given that offshore oil and gas structures tend to be very large and complex structures, there can be more potential options for decommissioning, compared to an offshore wind farm. The process is summarised as follows:

1. Preliminary discussions with DECC.
2. Detailed discussions and submission of consultation draft programme to DECC, other interested parties and the public for consideration.
3. Formal submission of a programme and approval under the Petroleum Act.
4. Commence main works and undertake site surveys (operator will have to satisfy DECC that the approved programme has been implemented, which usually involves submission of a Close-out Report within 4 months of completion of offshore work).
5. Monitoring of site (scope and duration to be agreed between the operator and DECC).

Separate decommissioning programmes are required for the main structures and pipelines.

4.4.2.3 Definition of decommissioned

Consistent with the IMO and OSPAR Decision 98/3, the DECC guidance takes the position that all parts of the installation are to be removed, except in derogation cases where it may be considered appropriate to leave parts of the structure in place. The DECC guidance applies the same derogations as the OSPAR Convention (see 4.3.3).

It is noted that there are no international guidelines for the decommissioning of disused pipelines, and so DECC will refer to UK specific policy, on a site-by-site basis.

4.4.2.4 Financial assurance

Overall, the general principle to be followed is that the "polluter pays", and the cost of decommissioning the offshore oil and gas installations and pipelines should be met by those who have received a notice from DECC. A cost estimate should be provided as part of the decommissioning programme and the DECC guidance includes reference to guidelines on decommissioning cost estimations issued by Oil and Gas UK [32]. It is noted that in the UK operators can claim tax relief against the cost of decommissioning at the point when the decommissioning occurs, which can be crucial in enabling participants to meet the overall cost of decommissioning.

Amendments to the Petroleum Act 1998 under the Energy Act 2008, address the issues of security, particularly those relating to the changing structure of the UK oil and gas industry and the increasing number of smaller companies obtaining licenses. These amendments enable the SoS to: make all relevant parties liable for decommissioning (e.g., where a license covers multiple sub-areas); require decommissioning security at any time during the life of an oil or gas field if the risk to the taxpayer is deemed to be unacceptable; and, to protect the funds put aside for decommissioning (so in the event of insolvency, the funds remain available to pay for the decommissioning). For new developments, it is likely that this will be addressed at the field development plan stage.

4.5 Denmark

4.5.1 Offshore wind

4.5.1.1 Regulations and guidance notes

The Danish Energy Agency is responsible for the regulation of decommissioning in Denmark.

There is no specific decommissioning guidance note in Denmark, instead precedent is set and contained within the contract terms that form part of the tender documents that grant the developer rights to develop an offshore wind farm (e.g. Final Tender Conditions for Horns Rev 3 [33]). These contracts transpose relevant international obligations and have evolved over time.

The transmission system operator is responsible for the grid connection in Denmark and so is responsible for decommissioning these assets.

4.5.1.2 Process

Denmark has two potential routes to lease award – government tender or open door approach, whereby unsolicited lease applications from developers are considered – with government tender the primary route. It is not clear how the decommissioning provisions would change between the two and so the rest of the chapter assumes a government tender process.

1. DEA identifies sites and specifies an amount within the tender documents that developers need to guarantee. The rate varies on a case by case basis. On Horns Rev 3 at least DKK 400 million (CND 73 million[8]) was requested [34].
2. Site is tendered on a competitive basis, following pre-qualification on technical and financial capability.
3. The lease holder signs a contract with the DEA to develop, operate, and decommission the site. The lease holder is legally obliged to restore the area to its former condition but no decommissioning plan or guarantee is required at this stage.
4. No later than 11 years and 6 months after delivery of the first kWh to the collective grid from the first turbine, the lease holder (termed Concessionaire) shall present a plan to the DEA with details of how the guarantee will be provided.
5. No later than 12 years after delivery of the first kWh, the approved guarantee must be provided.
6. Two years before decommissioning, the developer submits a decommissioning plan which includes an EIA. The method for decommissioning will be to follow best practice and the legislation at that time. The plan shall include an account of the removal of the offshore wind farm, assessment of the plan's environmental and safety related impact and time-schedule.

4.5.1.3 Definition of decommissioned

The latest tender documents released by the DEA (Horns Rev 3 Technical Project Description [35]) states that:

[8] Using DKK/CND exchange rate on 1st June 2015 with no account of inflation

"The objectives of the decommissioning process are to minimize both the short and long term effects on the environment whilst making the sea safe for others to navigate. Based on current available technology, it is anticipated that the following level of decommissioning on the wind farm will be performed:

- *Wind turbines – to be removed completely.*
- *Structures and substructures – to be removed to the natural seabed level or to be partly left in situ.*
- *Infield cables – to be either removed (in the event they have become unburied) or to be left safely in-situ, buried to below the natural seabed level or protected by rock-dump.*
- *Export cables – to be left safely in-situ, buried to below the natural seabed level or protected by rock-dump.*
- *Cable shore landing – to be either safely removed or left in-situ, with particular respect to the natural sediment movement along the shore.*
- *Scour protection – to be left in-situ"*

4.5.1.4 Financial assurance

In Denmark, the Concessionaire is legally obliged to restore the area to its former condition and to decommission the offshore wind farm pursuant to a plan approved by the DEA. If the Concessionaire should fail to comply with the obligation to clean up, the clean-up expenses shall be paid by the guarantor to the extent that the security covers such expenses. This obligation is contained within the lease agreement.

The amount to be guaranteed is specified by the DEA, unless the DEA approves of a lower amount (e.g., if a developer can provide evidence that costs will be lower before 11.5 years after first production). For Horns Rev 3 (in 2014) this was at least DKK 400 million (CND 73 million[9]), a reduction from the DKK 600 million for Anholt (in 2009[10]. DNV GL understands this done to help drive a lower cost (and therefore overall subsidy) for the project.

At least DKK 100 million (CND 18 million) of the security shall be provided in the form of a guarantee from a financial institution, an insurance company, or similar. The financial institution or the insurance company, or similar, providing the guarantee shall comply with the rating requirements specified by the DEA prior to the deadline for establishing the security. The remaining part of the security may instead be provided in the form of a parent company guarantee. In that case, the guarantee shall cover all potential costs connected with the clean-up obligation. In order for the DEA to accept a parent company guarantee for the remaining part of the security, the parent company shall have sufficient financial capacity, such capacity to be assessed by the DEA. The parent company shall furthermore, every 5 years, submit new documentation for the financial capacity of the company to the DEA so that the Agency may periodically ascertain compliance with financial capacity requirements.

It is not possible to transfer rights and obligations under the Agreement without written consent of the DEA.

4.5.1.5 Key points

DNV GL would note the following interesting characteristics of the Danish approach:

- Late approval and provision of the guarantee

[9] Using CND/DKK exchange rate on 1st June 2015 with no account for inflation
[10] Using CND/DKK exchange rate on 1st June 2015 with no account for inflation since 2009

- The Danish system can be seen as relatively laissez faire, in that although there is clear obligation on the lease holder to decommission, the DEA does not require the guarantee until 12 years into the operation of the wind farm. This suggests the DEA has sufficient confidence in the robustness of the contract that, if something did happen in the first 12 years, damages could still be brought against the developer. This is quite different from the UK approach which requires approval of the 'how' as opposed to just providing an obligation.

- Decommissioning cost estimates are provided by the government
  - The DEA undertakes a significant amount of pre-development activity in Denmark to seek to effectively de-risk the site before tender. As part of this, they undertake work to assess expected decommissioning costs which forms the basis of the contract awards. This may be done to ensure a common playing field across developers when bidding and is clearly in keeping with the strong role which the state plays in Denmark.

- Parent company guarantees
  - Unlike in the UK, the DEA is willing to accept parent company guarantees as part of package of measures to provide the guarantee.

4.6 Germany

4.6.1 Offshore wind

4.6.1.1 Regulatory background

The Bundesamt für Seeschifffahrt und Hydrographie (Federal Maritime and Hydrographic Agency) s the national level authority responsible for managing the development of offshore wind in German waters. The construction and operation of installations in the EEZ for commercial purposes is subjected to an approval process led by the BSH, although the BSH is not responsible for onshore elements of the wind farm. The BSH is much more involved than other regulators, issuing and then approving against its own design standards.

The key BSH standards are:

- "Standard Design of Offshore Wind Turbines" - This standard is intended to provide legal and planning security for development, design, implementation, operation and decommissioning of offshore wind farms within the scope of the Marine Facilities Ordinance. [36]
- "Standard for environmental impact assessment (STUK4)" - Within the framework of the approval procedure for offshore wind farms in the EEZ, potential adverse impacts of the planned facilities on the marine environment have to be assessed [37].
- Additional sub-regulations for underwater sound monitoring are also applicable [38] [39] [40].

The Marine Spatial Planning regulations are also relevant provisions that primarily relate to the removal of cables [41].

Decommissioning of any onshore works is normally described in the building permit delivered by the relevant local authorities.

Two transmission system operators (50 Hertz and Tennet) are responsible for the grid connection in Germany and therefore are responsible for decommissioning these assets.

4.6.1.2 Process

The various steps to be undertaken for decommissioning are described in the following extract from the BSH standard "Design of offshore wind turbines"

1. Following secondary approval by the BSH and at least one year before installation, the developer undertakes design and 'implementation planning' which includes preparation of a decommissioning concept.
2. This is certified by a registered inspector and approved by the BSH.
3. Six months prior to construction, the developer is advised to provide calculations on the amount needed to be guaranteed for decommissioning.
4. No later than one day prior to the transportation of equipment to the construction site the guarantee/security will be deposited.
5. Developer builds, commissions, and operates the offshore wind farm.
6. "*In good time before completion of the operating phase"*, the decommissioning concept submitted during the planning phase will be reviewed and submitted for review and approval. This plan will be based on the decommissioning environmental study.
7. Decommissioning is undertaken.
8. Approval of successful decommissioning shall be provided upon satisfying delivery of the following documents:
    a. Test reports for the decommissioning plan by the certifier/registered inspector[11]
    b. Inspection reports and certificate of conformity for the decommissioning by the certifier/registered inspector
    c. Evidence of the decommissioning and proper disposal is provided and inspected.

4.6.1.3 Definition of decommissioned

The STUK 4 or 'Standard for Environmental Impact Assessment' from the BSH clearly states that *"The wind turbines including their foundations have to be removed completely, with subsequent onshore disposal."* However, in practice individual consent documents allow the foundation to be cut off to a depth that *"will ensure the remaining stumps are not exposed"*, which for one site with certain geological conditions, was considered to be: *"a depth of more than 1m"*. The exact specification however is likely to vary on a case by case basis but the principle is that the foundations can be cut away to a certain depth.

Regarding subsea cables, the Marine Spatial Plan [41] requires subsea pipes and cables to be decommissioned and removed after their use, unless the removal will cause more significant negative

[11] The offshore wind turbine including the structures used for its foundation and the transformer substation as well as cabling within the farm shall be inspected by an expert institution, person or group of persons (certifier/registered inspector) recognized by the BSH on a case-by-case basis. The certifier is employed by the project owner. [36]

environmental effects than the abandonment and causes no impact on security or maritime traffic. To date, the BSH has not implemented a requirement to remove the cables. It is believed that the state of the art removal technologies are not efficient enough and that the costs of the operations, both financial and environmental, do not justify the removal of subsea cables, taking into account their burial depth. Should the state of the art technology evolve to a point where efficient cable removal is achievable, then the requirements from the BSH might change.

The BSH requires the offshore wind farm owner to dispose of all components in a controlled manner.

4.6.1.4 Financial assurance

The offshore wind farm owner is obliged to establish provisions for the decommissioning phase. Without these provisions, the authorization to go into operation will not be provided. Should the guarantee become invalid, the planning permission becomes void.

This is expressed through a clause within the consent granted by the BSH, for instance:

"Prior to the erection of the facilities, a directly enforceable guarantee, issued by a bank or guarantee insurer certifiably licensed in the EU, to cover the expected decommissioning costs of the facilities, shall be provided to and deposited with the consent authority for each individual unit. Traceable proof of the calculations of the expected decommissioning costs will need to be presented."

In terms of timing: *"The guarantee shall be deposited no later than one day prior to the transportation of any equipment, which will (later) have to be decommissioned, to the construction site for secure installation.*

No later than at the time a bank guarantee is furnished and deposited, shall calculations be provided upon which the guarantee amount shall be based with reference to the planned technical lifespan of the installations. In order to avoid risking a possible discontinuation of the construction work due to a failure to provide an adequate guarantee amount, companies are advised to submit appropriate presentations, which have been checked by experts, for the purpose of calculating guarantee amounts, no later than six months prior to the planned erection of the facilities." The expert body has to be approved by the BSH, but it is the project owner that contracts the expert.

DNV GL understands from discussion with a developer that if the operating company goes bankrupt, there will be time given to find new investors. Should this fail, the authorities can request from the banks, the use of the funds put aside for decommissioning purposes.

4.6.1.5 Key points

- Strict, hands-on role of the BSH in inspecting and approving design and method statements, with third party review by the certifier / registered inspector.
  - In keeping with the overall approach in Germany, the regulatory framework is set by the BSH with strict requirements and little flexibility. This implies that the developers need to develop a decommissioning plan in keeping with the BSH standards, have this certified by a third party (whom the project owner contracts with directly), and then get formal approval by the BSH. This is a much more onerous approach than used in the UK and Denmark.

- Early guarantee provided
  - In Germany, the guarantee needs to be provided one day before the components are transported to site. This is relatively early compared to other jurisdictions.

4.7 Canada

4.7.1 Offshore wind

4.7.1.1 Federal

In Canada, offshore developments in navigable waters (broadly defined) are regulated primarily by the federal government as indicated in the Navigation Protection Act [42]. This states that: *"It is prohibited to construct, place, alter, repair, rebuild, remove or decommission a work in, on, over, under, through or across any navigable water that is listed in the schedule except in accordance with this Act or any other federal Act*." However, applicable provincial ministries will also come into play once the energy produced from any offshore energy production facility comes onshore.

Also relevant is the Fisheries Act [43] which governs any alteration of marine habitat. This states that: *"No person shall carry on any work, undertaking or activity that results in serious harm to fish that are part of a commercial, recreational or Aboriginal fishery, or to fish that support such a fishery"*. Serious harm to fish is defined by "*the death of fish or any permanent alteration to, or destruction of, fish habitat."*

4.7.1.2 Great Lakes

Governance of the Great Lakes is a complex web of binational, federal, state and provincial, local governmental, and tribal/First Nations activity. DNV GL understands that 10 U.S. federal agencies are involved in Great Lakes, and Canada has seven federal departments that work on Great Lakes issues. However, one large overarching international convention is the Boundary Waters Treaty [44]. This was signed in 1910 to "*prevent and resolve conflicts over shared waters"* and included the creation of the International Joint Commission (IJC) to oversee the shared water resources.

DNV GL does not believe there is specific guidance or policy on decommissioning for the Great Lakes at present.

4.7.1.3 Ontario

In Ontario, a Renewable Energy Approval (REA) must be obtained from the Ontario Ministry of the Environment and Climate Change (MOECC) depending on the Class of renewable energy project and certain conditions. Certain onshore and all offshore wind projects are subject to Ontario Regulation 359/09 ([45]) that entails decommissioning requirements; however, currently no offshore wind projects have been developed in Ontario and the REA technical guideline [46] indicates that the requirements for offshore wind under REA are to be considered following further scientific research.

DNV GL notes that onshore wind projects must prepare a Decommissioning Plan Report (DPR). The DPR must include a description of plans for the decommissioning of the wind project, including:

- Procedures for dismantling or demolishing the facility;
- Activities related to the restoration of any land and water negatively affected by the facility; and

- Procedures for managing excess materials and waste.

At the time of the REA submission, the DPR is required to consider all decommissioning activities, identify negative environmental effects that will or are likely to occur and propose potential mitigation measures. Since the DPR is completed prior to the construction and operation of the Project, the MOECC generally imposes a condition that requires the REA applicant to produce an updated and more comprehensive decommissioning plan six months prior to the start of decommissioning.

The REA technical guideline [46] stipulates that "*The MOECC also has the authority under section 132 of the Environmental Protection Act to require Financial Assurance on a project-specific basis, on any project issued an REA. Typically the ministry requires Financial Assurance against potential future environmental impacts and liability and against potential future waste disposal costs.''*

Financial assurance

Ontario already has in place a financial assurance guideline [47] which is authorized under Part XII of the Environmental Protection Act and allows Program Directors to require, as a condition of an order (only in a Director's Order), approval or by regulation, the provision of financial security by regulated parties. At present this guideline applies to Landfill Sites and Mobile PCB Destruction Facilities, yet DNV GL suggests it appears to offer good starting point to develop specific requirements and guideline for offshore wind farms.

The Guideline states that Financial Assurance, administered by the MOECC, can be required either to:

- Ensure compliance with environmental objectives;
- Ensure that requirements are achieved by a specified deadline; or
- Ensure that funds are available for future clean-up and remediation of landfills and other contaminated sites which require long-term care and monitoring.

Standard forms of Financial Assurance are recommended, including cash, irrevocable letters of credit, surety bonds and negotiable securities issued by or guaranteed by provincial or federal government. Other non-standard forms can be accepted if the proponent makes an acceptable compelling case that has to be reviewed by the Legal Services Branch, Business and Fiscal Planning Branch and the Economic Analysis Section.

Steps, procedures, concepts and information requirements to determine amounts of Financial Assurance to be provided to the MOECC for various types of orders, approvals, activities, sites and facilities are described in the Financial Assurance Guideline. Clear explanations of all sources of data and assumptions used in estimates and computations, include, but are not restricted to:

- A list of all compliance activities and conditions for which costs will be estimated;
- Unit or sized costs of different activities; estimation procedures and steps;
- References for all data sources;
- Worked examples of all computations (sample calculations);
- Estimation error ranges (i.e., +/- %) for each cost item; and
- Expected variations in recurring and capital costs over time.

All data and estimates provided in the Financial Assurance Proposal will be reviewed by the Program Director of the Business and Fiscal Planning Branch and the Environmental Assessment and Approvals Branch of the Ontario Ministry of Environment and Climate Change (MOECC).to ensure:

- Reasonableness;

- Completeness, in that all activities and associated costs have been included in the submission to address the conditions or terms of an order or approval;
- Appropriateness of financial parameters (inflation and discount rates); and
- Accuracy of computations.

4.7.1.4 Other provinces

Newfoundland and Nova Scotia have offshore oil & gas regulations ([48] & [49]), both of which state that:

"Every operator shall, at the time the operator applies for a development plan approval in respect of a production installation, submit to the Chief a concept safety analysis of the installation in accordance with subsection (5), that considers all components and all activities associated with each phase in the life of the production installation, including the construction, installation, operation and removal phases."

DNV GL could not identify any specific guidance or regulation relating to financial assurance or what would be defined as full removal.

4.8 United States

4.8.1 Offshore wind

4.8.1.1 Regulatory background

Decommissioning requirements for renewables energy in federal waters is defined by the Bureau of Ocean Energy Management (BOEM) within Title 30 of the Code of Federal Regulations, Part 585 – "Renewable Energy and Alternate Uses of Existing Facilities in the Outer Shelf" [50].

Within State Waters such as (the Great Lakes (the entirety of the US Great Lakes are State Waters) there are no specific regulations for offshore decommissioning, although some states have requirements to provide a decommissioning plan (including financial assurance) as part of the permitting process. The Ohio Power Siting Board Rules, which govern siting of power plants including onshore and offshore wind projects within Ohio include such a requirement but do not provide specific guidance on how decommissioning shall be completed [51]. State Waters also include the ocean zone inside 3 nautical miles, or 9 nautical miles for Texas and the Gulf Coast of Florida). New Jersey Offshore Wind Economic Development Act of 2010 requires offshore wind project developers to submit a decommissioning plan including provisions for providing financial assurance "as required by the applicable State and Federal government entities" as part of the application process for Offshore Renewable Energy Credits [52]. Regulations in Maryland have similar requirements, but specifically state that the decommissioning plan include interconnection facilities [53]. Rhode Island's Ocean Special Area Management Plan [54] describes decommissioning requirements for offshore renewable energy projects, but largely references federal requirements specified in the aforementioned section of the CFR. The Rivers and Harbors Act [55] governs the placement of fill material and structures, including utility lines in, over, or under Navigable Waters of the U.S. Section 404 of the Clean Water Act also applies in regard to the placement of fill material in in Waters of the U.S., including wetlands [56]. Neither appears to specify requirements in regards to decommissioning.

Given that state regulations for decommissioning of offshore wind projects are either limited in details or reference federal requirements, the following sections therefore focus on the process for federal level waters. For projects in the U.S. Great Lakes, decommissioning requirements will likely evolve with the industry and largely emulate best practices established for projects in U.S. federal waters where the first commercial-scale projects will likely emerge in North America.

4.8.1.2 Process

Prior to commencement of construction, a lease holder must submit a Constructions and Operations Plan (COP) which must include a discussion of general concepts and methodologies for decommissioning and site clearance procedures. In advance of decommissioning, a decommissioning application must be submitted for approval by BOEM. Following approval of the application, a decommissioning notice must also be submitted to BOEM at least 60 days before commencing decommissioning activities. Within 60 days of removal of a facility, cable, or pipeline, a written report must be submitted to BOEM verifying that the site has been decommissioned.

4.8.1.3 Definition of decommissioning

Decommissioning is defined within Title 30 of the Code of Federal Regulations, Part 585 which and states that:

Except as otherwise authorized by BOEM, within two years following termination of a lease or grant, a lessee must:

> *(1) Remove or decommission all facilities, projects, cables, pipelines, and obstructions (remove all facilities to a depth of 15 feet below the mudline, unless otherwise authorized by BOEM);*
>
> *(2) Clear the seafloor of all obstructions created by activities on the lease, including the project easement, or grant, as required by the BOEM.*

In the application, developers may request that certain facilities authorized in the lease or grant remain in place for other authorized activities, or request that certain facilities authorized in the lease or grant be converted to an artificial reef or otherwise "toppled" in place. BOEM may approve such requests on a case-by-case basis.

4.8.1.4 Financial assurance

Before BOEM will approve installation/construction of facilities, a decommissioning bond or other financial assurance must be provided. The amount of the financial assurance is determined by BOEM case-by-case, based on anticipated decommissioning costs associated with a conceptual decommissioning plan submitted with the COP. Financial assurance is in the form of a surety bond. In lieu of a surety bond, BOEM may authorize establishment of a lease-specific decommissioning account in a federally-insured institution. BOEM allows for financial assurance for decommissioning to be provided based on the number of facilities installed or being installed i.e. the size of the wind project and number of structures. BOEM must approve the schedule for providing the appropriate financial assurance coverage.

The costs of decommissioning may be re-evaluated (and the amount of financial assurance may be adjusted up or down by BOEM) during the period of the lease, but no specific reassessment period is prescribed.

The regulations list many ratings and requirements that financial assurance instruments must meet. Failing to comply with the approved decommissioning plan may result in civil or criminal penalties for the lease holder.

4.9 Other markets

4.9.1 Europe

4.9.1.1 Netherlands

Decommissioning regulations in the Netherlands to date have been set under the 'Wet Beheer Rijkswaterstaatwerken' (Water Control Act, part of the 'Waterwet'; the Water Act) [57], although these may be changed as part of the ongoing amendments to the offshore wind regulatory landscape in the Netherlands.

The existing regulation transposes IMO regulations and requires removal of the installation as to "*not hinder other use or disrupt the environment"*. In decommissioning plans reviewed by DNV GL, this is being applied at present to mean removal of the foundations (monopiles) up to 6 m below the seabed (however this may change by the time the decommissioning is actually required). Developers have to provide reasonable financial security, by bank guarantee before construction can commence. It is not clear how reasonableness is determined but it appears that the developer makes an estimate which is then considered by the competent authority as part of the general approval process.

Going forward, DNV GL understands that developers are pushing for the requirement for the upfront bank guarantee to be replaced with a fund that would accrue during the lifetime of the project. This is to reduce the financial burden on developers.

4.9.1.2 Belgium

A number of Ministries are involved in either setting legislation or reviewing impacts of offshore wind developments in Belgium. This includes Management Unit of the North Sea Mathematical Models (MUMM), who sit within the Natural Environment Ministry. MUMM review the developer's EIA and provide a recommendation to a Minister within the Social Affairs and Public Health department who grants the final consent. A lease concession is also provided by the Minister of Climate and Energy, while supporting legislation is laid by the Ministry of Economic Affairs.

Decommissioning requirements are therefore set within three Royal Decrees of 20 December 2000 (with amendment on 28 September 2008), 12 March 2002 and 7 September 2003 ([58], [59] & [60]). These requirements include typical conditions similar to other jurisdictions such as the following:

- The foundations have to be removed up to around 2 m under seabed unless local erosion dictates otherwise.
- All cables are to be removed/excavated if desirable from environmental perspective. This also includes any asphalt mats or related structures.
- Measures for removal of erosion protection will be set by the Minister after the lifetime of the wind farm.
- Turbines, met masts, and transformer stations are to be fully removed.

In terms of process, the Belgian approach is most akin to the German model, with the decommissioning plan needing to be checked and approved by a certification company (no further detail is provided) and a guidance committee checking and coordinating all activity with the Minister.

Financial assurance is provided through the reservation of funds during the lifetime of the offshore wind farm, through yearly deposits into a separate bank account. For example, for the 115MW C-power I offshore wind farm the total provision was set at €20 million (CND 27million) , to be placed in a separate bank account at a rate of €600,000 (CND 830,000) per year in operational years 3-10, and €1.53 million (CND 2.1million) in operational years 11-20.

4.9.1.3 Sweden

There are no specific regulations or guidelines relating to the decommissioning of offshore wind farms in Sweden. However, under the Swedish Environmental Code, it is the responsibility of the owner to take the precautions required to avoid or prevent harming the environment. Furthermore, the owner must secure a financial security guarantee for the cost of restoration measures:

> *"The validity of a permit, approval or exemption may be made subject to the requirement that the person who intends to pursue the activity must furnish a security for the costs of after-treatment and any other restoration measures that may be necessary as a result. The state, municipalities, county councils and associations of municipalities shall not be required to furnish a security."*

As a result, building permits for offshore wind projects will include a requirement for a financial guarantee to be taken, but it is understood that the type of security required varies across different counties. Permits may also stipulate that a decommissioning plan must be submitted and approved prior to decommissioning (for example the permit for Bockstigen wind farm indicates that this should occur within one year after the end of the project life).

While no offshore wind farms have been decommissioned to date, in September 2014 Swedish developer, Vattenfall, announced its plans to decommission the 10 MW Yttre Stengrund offshore wind farm (potentially becoming the first offshore wind farm to be decommissioned worldwide). It is understood that Vattenfall is currently in negotiations with the local municipal and county councils on the details of the decommissioning plan and at this stage it is not known what will be removed or left in place. It is Vattenfall's intention to decommission the project during summer 2015; however, the timing of this will depend on when the decommissioning plan receives approval. As per the building permit requirements, Vattenfall has established a decommissioning fund; however, DNV GL is not clear whether this is an operational fund or a reserve fund and understands that there remains uncertainty over the actual costs of the decommissioning and whether the funds are sufficient.

4.9.1.4 Norway

In Norway, regulations under The Energy Act [61] dictate that the holder of a permit is obliged to remove 'all electrical plants' over a certain voltage (1kV) and restore the area back to its original condition as far as it is reasonably possible. However, there are no clear regulations about what can be left in place. A decommissioning plan must be submitted to the Government for approval no later than one year prior to decommissioning. Conditions in the consent may vary but it is likely that there will be a requirement that the owner should present a plan for funding the decommissioning no later than the 12th year of operation. There are no strict rules on how this financial assurance would be defined.

4.9.1.5 Finland

The Act on the Exclusive Economic Zone of Finland, states that, in relation to an application for activities in the EEZ:

"…the recipient of the consent shall, to ensure safety of navigation, be obligated to remove, if possible, any disused installations and structures. The recipient of the consent shall also be obligated to inform the Ministry of Trade and Industry of the position, depth and dimensions of any installations and structures not entirely removed."

However, there are no specific national requirements for decommissioning structures in territorial waters, which are governed by coastal municipalities.

4.9.1.6 Ireland

In the Republic of Ireland, DNV GL understands that applicants for offshore wind leases (termed Foreshore Leases) are required by the Foreshore Acts to provide plans for the eventual decommissioning of the offshore wind project, although no further guidance on what a plan should contain is provided [62]. Furthermore, during the lease negotiations, the developer and Department for Environment, Communities and Local Government may agree on a bond or other suitable mechanism to ensure decommissioning costs are covered and will be subject to review at 5 year intervals to ensure that the funding level continues to be sufficient.

4.9.2 Asia

In Japan, no requirements for decommissioning are set precisely in any law, but wind energy developers are typically required to make a commitment of decommissioning when they apply for the building permit and local consents. DNV GL asked the Energy Ministry whether there was any specific framework for securing decommissioning costs but was told that there was not.

China does not have a formal decommissioning policy.

DNV GL understands that Korea started considering a decommissioning policy around 2 years ago, but the development of the offshore wind farms has been slower than expected with no decommissioning policy currently in place.

Taiwan does not have an offshore wind decommissioning policy at present, although the Government currently intends to develop a guideline next year.

4.10 Chapter summary

Decommissioning requirements around the world are broadly similar and stem from the United Nations Convention of the Law of the Sea (UNCLOS), which is transposed through the International Maritime Organisation (IMO) and subsequently into specific regulations within each jurisdiction.

The basic principles are that:

- Ideally, all installations or structures should be removed. In practice, however, there is some flexibility provided. This is usually on the basis of extreme cost, extreme safety risk or when removal will cause greater environmental damage than leaving in situ.
- Polluter pays, with regulators seeking to ensure that developers make adequate provision to meet decommissioning liabilities (reducing the risk of default/bankruptcy where the state would then need to step in to remediate the site to an acceptable level).

Beyond these basic principles, the specific approach varies somewhat between individual jurisdictions. DNV GL would, however, note the following key points:

- **Strong legislative backing and liabilities on developers**

  Given the high costs, long timescales, and high levels of uncertainty, regulators choose to place a broad liability on developers stating that regardless of the cost, they are responsible for paying for any cleanup. This is usually enshrined and supported by strong legislative provisions, such as making failure to comply a criminal offence and limiting the ability to transfer rights without approval by the relevant regulatory authority. Once in place, this broad requirement and strong legislative backing appears to allow regulators a degree of flexibility in the exact way in which they enforce these provisions.

- **Flexibility in provision of guarantees and appreciation of uncertainties**

  Most governments appear to be relatively flexible as to the way in which developers provide guarantees, with options usually accepted including cash, letters of credit, bonds, and accrual funds, with the exact decision approved on a case by case basis. Having said this, there are differences, for instance some countries appear to accept Parent Company Guarantees, while the UK does not. There is also flexibility in the approach to decommissioning with developers usually being asked to submit a decommissioning plan as part of the initial approval process, but with opportunities to revise and seek final approval closer to decommissioning. This appears sensible given the 20-year plus timescales expected before decommissioning and the high degree of uncertainty as to the actual decommissioning methods that will be used and the costs of such decommissioning.

- **Balance between ensuring protection while minimising burden on developers**

  Unlike O&G, hydrocarbon pollution risk is very low with offshore wind. This makes a proportional response very important, with governments having to balance the need to ensure adequate protection and enforcement of decommissioning requirements on developers, with the desire to minimise the cost burden on developers as much as is reasonable, taking into account the high upfront capital cost investment profile of the sector. Upfront bank guarantee appears to increase costs on developers, with developers in the Netherlands currently pushing for this provision to be amended to a through life accrual fund. In Denmark, developers only need to post the guarantee 12 years after first power to the grid.

- **Regulatory involvement reflects broader ideological and cultural approaches**

  The regulatory approach chosen in each jurisdiction appears to reflect a broader ideological relationship structure between regulator and developer. For instance, in Denmark, the regulator has a very active role, undertaking the initial decommissioning cost assessment on behalf of the developer, and assuming some of the risk of default, with developers only having to post guarantees after 12 years into the process. In Germany, the regulator issues design standards which include provisions for decommissioning, with the developer assessed against the standards by a third party reviewer. Guarantees need to be provided one day before transport of components to the installation site. In the UK, the regulator issues guidance, but works with developers on a case by case basis to approve the plan.

Table 4-1 to Table 4-4 summarise the involvement of the Regulatory Agency, the requirements for decommissioning plans, activities and the financial security for the UK, Germany, Denmark and USA.

Table 4-1 Regulatory Agency Involvement

Description	UK	Germany	Denmark	USA (Federal)
Lead regulatory agency	Department of Energy and Climate Change (DECC)	Federal Maritime and Hydrographic Agency (BSH)	Danish Energy Agency (DEA)	Bureau of Ocean Energy Management (BOEM)
Guidance material	DECC Guidance Note incorporating international obligations & UK Legislations	BSH issues standards, alongside some provisions in the Marine Spatial Plan	Decommissioning guidelines are part of the tender documents for each project.	Some guidance in Title 30 of the code of Federal Regulations, part 585.
Regulatory agency approach	Works with developers on a case-by-case basis	Sets standardized process to be considered on a case-by-case basis.	Rights and responsibilities generally written into the terms of the tender	Sets standard process
Pre-construction activities	Developer must assess impacts as part of the EIA and undertakes preliminary discussions with DECC.	Developer devises a decommissioning concept and plan which forms the basis of calculations of the appropriate level of security.	An obligation to return the site to its former state is part of the terms of the contract to build and operate the wind farm.	Construction plan must include discussion of decommissioning approach
Approval to proceed	Consent is granted usually with a condition that work cannot begin until a decommissioning programme has been submitted.	Permits to proceed with construction are contingent on approval from the BSH as well as the required security.	Determined by tender.	Application submitted to BOEM

Table 4-2 Decommissioning Plan

Description	UK	Germany	Denmark	USA (Federal)
Plan responsibility	Developer assesses impacts as part of the EIA, then submits a draft Decommissioning Programme.	Developer is responsible for the planning of decommissioning.	Developer responsible for plan including EIA	Developer prepares plan.
Approval authority	Plan formally approved by DECC Secretary of State (SoS) pre-construction.	Plan certified by a registered inspector and approved by BSH	DEA	Plan approved by BOEM
Plan Details	Developers must submit details of their proposed security and initial cost estimate within the decommissioning programme. Plan regularly reviewed (5 years).	Not defined. It is for the developer to devise an appropriate decommissioning 'concept' as part of the permit application process	Plan includes an EIA and an account of the removal of the offshore wind farm, assessment of the plan's environmental and safety related impact and time-schedule.	A discussion of general concepts and methodologies for decommissioning and site clearance procedures.
Approval	SoS may approve with modifications/subject to conditions, reject or require a new programme, OR, SoS may prepare a decommissioning report and recover the expenditure	Plan certified by an independent registered inspector and approved by BSH	Little detail available but assume DEA will have opportunity to approve or request modifications	Little information provided
Timeline	Construction cannot proceed until Decommissioning Programme has been submitted. Two years prior to decommissioning, final review and plan submitted.	One year prior to installation, decommissioning plan independently certified and approved by BSH. Six months prior, developer provides cost calculations. One day prior to transport, guarantee provided. In good time [1] before decommissioning plan review and approved. Following decommissioning, reports submitted to BSH.	Decommissioning plan presented no more than 11 years and 6 months after first power delivered to grid. No later than 12 years after first power, the approved guarantee must be provided. Decommissioning plan submitted two years before commissioning.	Pre-construction, concepts and methodologies discussed construction plan. Ahead of commissioning, an application to BOEM must be submitted. After approval of this application and at least 60 days ahead of decommissioning, BOEM must be informed. Within 60 days of completion, a report must be submitted to BOEM.
Other	Developer must consult with interested parties and stakeholders. DECC consults with other government departments	N/A	N/A	N/A

Table 4-3 Decommissioning Activities

Description	UK	Germany	Denmark	USA
Requirements	DECC guidance is that installations should be completely removed. Requirements determined on a case by case basis.	BSH require that all structures are removed. Planning is required that meets that objective. In practice, requirements defined case-by-case with a minimum requirement that decommissioning works "*ensure the remaining stumps are not exposed*"	The objectives of the decommissioning process are to minimize both the short and long term effects on the environment whilst making the sea safe for others to navigate.	Remove or decommission all facilities, projects, cables, pipelines, and obstructions (remove all facilities to a depth of 15 feet below the mud line, unless otherwise authorized by BOEM); Clear the seafloor of all obstructions created by activities on the lease
Foundations	Foundations cut below seabed to appropriate level. DECC recognizes that there may be circumstances where parts may be allowed to remain	In general, foundations cut to a depth determined on a case-by-case basis.	Structures and substructures – to be removed to the natural seabed level or to be partly left in situ.	Remove all facilities to a depth of 15 feet below the mud line, unless otherwise authorized by BOEM
Cables	Cables on case by case basis.	Cables must be removed unless removal will have greater environmental impact than abandonment.	Infield cables – to be either removed (in the event they have become unburied) or to be left safely in-situ, buried to below the natural seabed level or protected by rock-dump. Export cables – to be left safely in-situ, buried to below the natural seabed level or protected by rock-dump	See above
Timeline	Once commercial operation has ceased	Stated in the decommissioning plan. Commissioning can only be declared complete by the BSH	Stated in the decommissioning plan	Decommissioning must be completed within two years of the end of the seabed lease.
Post-decommissioning	Developer submits a report (generally within four months of decommissioning) showing the approved plan has been implemented.	Developer submits an independently certified report including evidence of completion of removal in line with plan and proper disposal.	Report submitted	A report verifying decommissioning must be submitted within 60 days of completion

Table 4-4 Financial Assurance

Description	UK	Germany	Denmark	USA
Financial instruments	Acceptable security agreed on case by case. DECC is relatively flexible in terms of acceptable security. SoS has powers to take remedial action and recover any expenditure.	Any directly enforceable guarantee from a licensed bank or insurer.	At least 100m DKK (CND $18m) is required in the form of a directly enforceable bank guarantee. The remainder, calculated on a case-by-case basis may be provided in the form of a parent-company guarantee. For rating purposes this liability is calculated on the basis of the estimated clean-up cost but may cover the full cost, should it exceed the estimate.	Surety bond or deposit into specific account (with BOEM authorisation)
Amount required	Case by case financial security provisions enacted. Statutory provision on developers to pay for clean-up. Developer is responsible for providing initial cost estimate in decommissioning programme	Determined on a case-by-case basis. Adequate to cover the expected cost.	Specified by the DEA in the tender documents. For the recent Horns Rev 3 tender, the cost was set at DKK400m (CND $73m).	Estimated costs calculated by BOEM on a case-by-case basis. Estimate based on concept described in the construction plan.
Timeline	Once wind farm reaches final investment decision, financial security provisions are enacted.	Certified evidence and calculations of estimated decommissioning costs a least six months before construction. Guarantee in place at least one day ahead of transport of goods to site	In the case of a parent company guarantee, documents supporting the financial capacity of the company must be provided every five years.	All bonds/assurances in place before approval of construction.
Ownership change	Approval needed for change in ownership.	Not defined	Written consent from DEA required.	Unclear
Other	Developer is liable for ensuring that there are sufficient funds available. The SoS does not need to wait until the shortfall is encountered but through the regular review process may ask developers to increase financial assurance.	N/A	N/A	N/A

5 TECHNOLOGY SELECTION AND DESCRIPTION

5.1 Chapter introduction

Having identified the main components of an offshore wind farm and the foundation technologies in use worldwide for offshore structures in Chapters 2 and 3, respectively, Chapter 5 focuses on the selection and description of the most likely technologies for the Great Lakes offshore wind projects.

Selection of suitable technologies is normally an iterative process, given that the type of foundation is just one of the drivers for the site selection and wind farm design. However for this Study, a simpler selection process is devised which is sufficient and appropriate for the current purposes.

The main sections in this chapter are:

- Section 5.2 – Processes of site finding and foundations selection:

  An outline is provided of the typical process of site selection for offshore wind farms and the typical stages in the selection. This section also describes the progressive detailing of the technology design process. The purpose of this section is to provide context for the reader to aid understanding of how the process applied for this study fits within the typical site selection and design process. This section then describes the site selection and technology selection processes that are applied for the current work, which is essentially a reduced version of the typical method. The process applied for the current work is devised to determine the different site types that may be selected in the Canadian Great Lakes and thereby identify the likely envelope of site conditions. From this, the potentially applicable foundation types are identified. In conjunction, this process also considers the range of appropriate turbine sizes that may be applicable in the Canadian Great Lakes.

- Section 5.4 - Application of selection process:

  The selection process is then applied whereby key characteristics of the Great Lakes are presented, different site-types are identified, the key criteria for the foundation types are outlined, and a screening process is applied to determine the specific foundation and turbine technologies to be carried forward for the decommissioning cost analysis presented in Chapter 0.

- Section 5.5 – Detailed description of selected technologies:

  The selected technologies are described in more detail, including the key features in the design and materials, the construction and installation methods, and the techniques and strategy options for decommissioning. Indicative weights and dimensions of the relevant components are tabulated. This section also provides a summary of the heavy lift vessels that would typically be used in construction and decommissioning and the implications for the Great Lakes where vessels availability can be restricted. Additionally, a subsection on cutting methods is included, given the importance of cutting to the decommissioning process.

Subsequently, in Chapter 6, the cost modelling of the decommissioning phase is presented and the results discussed.

Metric units are used as standard throughout. Where original data sources are non-metric, these are inserted alongside. Abbreviations and conversions between units are tabulated in the front matter of this document.

5.2 Processes of site finding and foundations selection

5.2.1 General process for site finding

The usual process during offshore wind energy development is to first identify suitable geographical zones and then select in more detail the location of the sites within the zones. At each level, the selection would be driven typically by ranking according to a set of technical and environmental parameters, to ensure the projects are practically and economically feasible, and acceptable for planning consent. Key factors will include water depth, seabed geology, wind resource and environmental factors (physical and biological), and human environmental factors (e.g. visual, shipping, fishing). In these circumstances, the methodical approach for site-finding is:

- Mapping and identification of spatial constraints (e.g. environmental features, built features, wind resource, transmission lines etc.);
- Removal of areas of constraint, defined as those which directly impact both the technical, commercial and social-environmental feasibility of an offshore wind development;
- Pragmatic weighting of the remaining area, outside the defined “hard” constraints, to identify suitable sites for wind farm development, taking into consideration the factors which impact the technical and commercial feasibility of wind farm development;
- Identification of the most promising sites, an iterative process; and
- Ranking, analysis and description of identified sites.

In many countries that have embarked on offshore wind development, the geographical zones made available for offshore wind projects are pre-selected by a government body, taking into account at a high level the main selection criteria and considering a range of competing interests. Typically each zone is allocated to an individual wind farm developer (or consortium) who may then have some flexibility within the zone to select the site area for the project.

In the case of the Canadian Great Lakes, no decisions have yet been made on the geographical locations of potential wind farms, and the full range of selection criteria are either not available or unknown. For the purposes of this decommissioning study, it is therefore appropriate to focus on defining site-types as described below rather than specific geographic locations.

5.2.2 General process for foundations selection

The “best” foundation type for an offshore wind project is a critical decision for both technical and commercial feasibility, and as a consequence a significant amount of engineering effort is employed during the early design stages to get this right. Not only must the foundation be matched to the site-specific conditions, it must also be well paired with the specific wind turbine model. In practice for the majority of cases the geometric footprint and member sizes of steel offshore wind foundations are primarily driven by turbine-specific factors such as: the turbine natural frequency window (determines footprint); extreme loading (determines pile embedment); and turbine fatigue loading (determines member wall thickness and diameter). Combining these turbine factors with the local geotechnical (seabed) and metocean (wave and current) conditions there is no substitute for a site-specific foundation design and type selection.

This site-specific approach to design is commonplace in European projects and the approach is summarized in Figure 5-1. With each iteration, more detailed location-specific data are acquired by the developer.

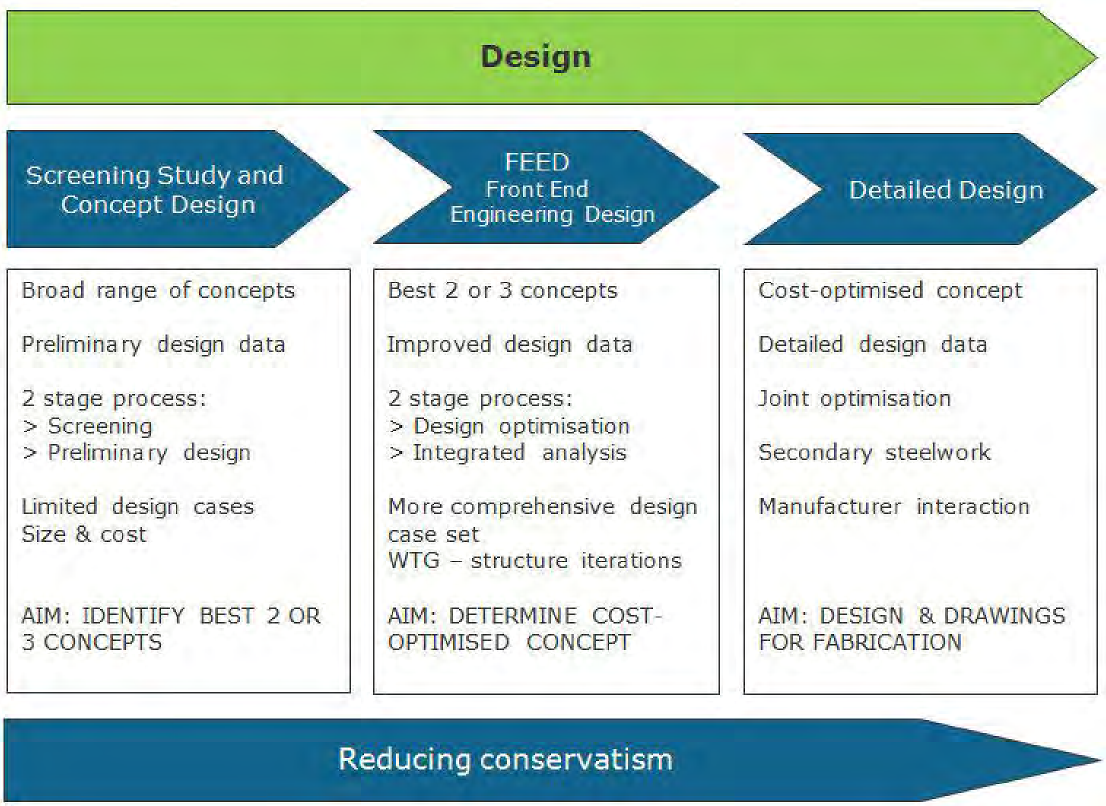


Figure 5-1 Progressive foundation design methodology

In the case of the Ontario Great Lakes study, where site types rather than geographical locations are being used, only the likelihood of different foundation types is determined through a screening process as described in the next section.

5.3 Technology selection processes for the Great Lakes

In this study, the purpose of the selection process is to determine first the potential site-types and then screen the major foundation types for their suitability for each site-type. The main purpose is to identify the full range of potential foundation technologies that may be deployed and therefore will ultimately need to be decommissioned. A reduced and modified version of the general processes described in the previous sections is therefore used for the selection process, as outlined below:

1. Mapping of the key characteristics of the Great Lakes, making use of readily available information and data. The most critical characteristics are:

   - Wind resource – to indicate viability of projects
   - Water depth
   - Seabed geology (bedrock and sediment)
   - Ice propensity
   - Ports locations
   - Territorial boundaries

   Brief qualitative descriptions of each are provided herein to explain the significance of each in the wind farm siting. Other relevant characteristics are briefly described.

2. Influence of site characteristics on foundation selection

3. Selection of site-types, grouping together combinations of the key characteristics. For example: shallow water / ice-free / shallow sediment on hard bedrock.

4. Selection of two turbine sizes, both to be of generic design.

5. Construction of a screening matrix, presenting for each site-type and turbine size a traffic-light rating system according to whether the foundation type is considered suitable, somewhat suitable or not suitable. Where appropriate, comments shall be provided to note other key influences on the suitability of specific technologies, such as ease of construction.

6. Selection and presentation of the five turbine foundation technologies most suitable for the Canadian Great Lakes based on the screening matrix. In addition, inclusion of one foundation technology for offshore substations is expected.

5.4 Application of selection process

5.4.1 Key characteristics of the Great Lakes

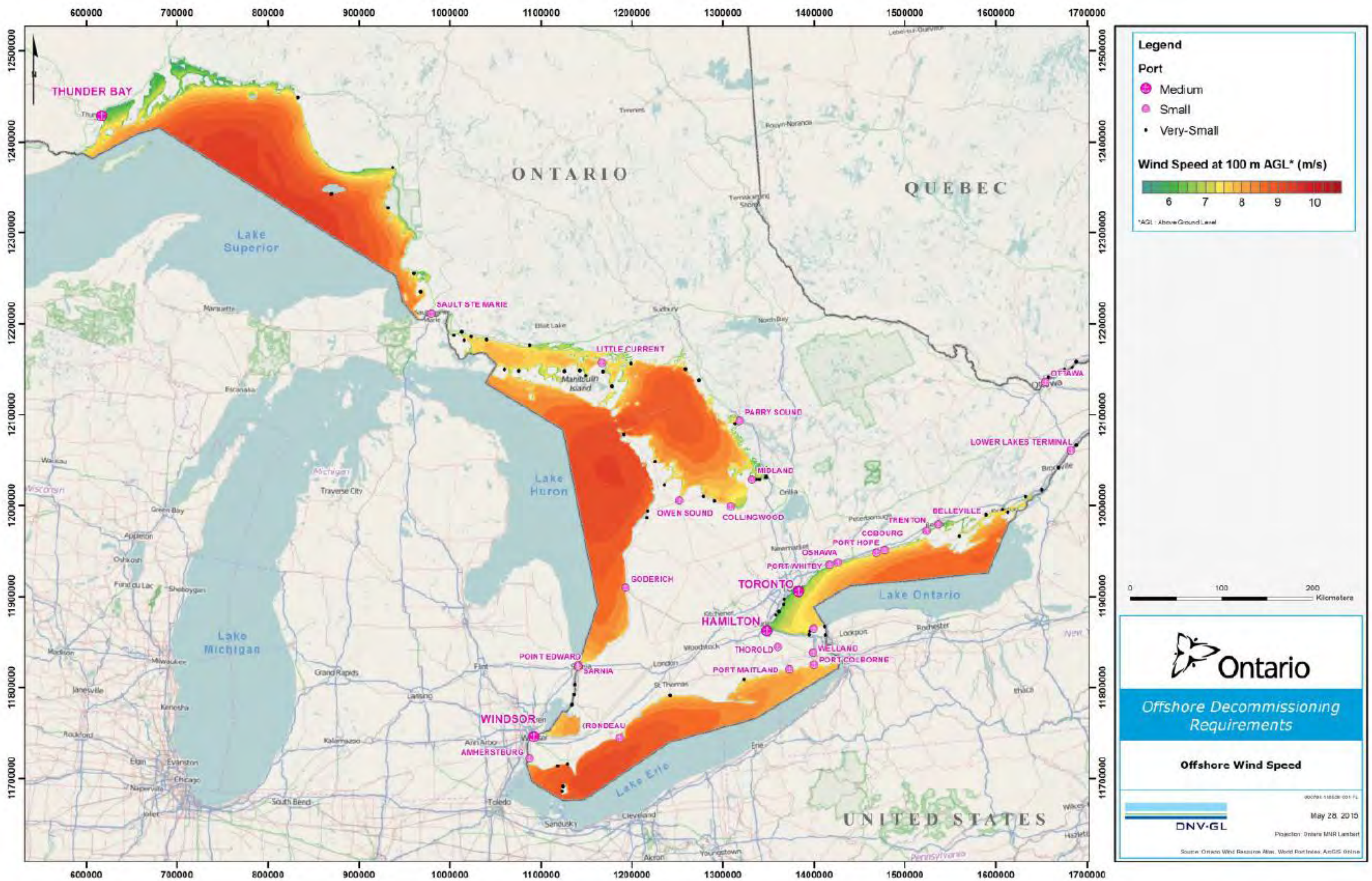
Figure 5-2 to Figure 5-12 present maps of the wind resource, water depth, geology and ice cover which will be the key characteristics determining the site selection. The maps also show the territorial boundaries of Ontario and the main ports.

5.4.1.1 Wind resource

The wind resource is the primary factor determining the potential energy yield from a wind farm and in turn is key to the income generated by the wind farm. With the energy carried in the wind being proportional to the cube of the wind speed, even small differences in wind speed are significant for the economic analysis of the cost of energy. For more complete assessment of the wind resource, detailed data would be required including the statistics of wind speed, wind direction, extreme values and turbulence intensity; and for energy yield assessment, details of the turbine interactions, performance and availability would also be required.

The mean long-term wind speed gives a general overview of the windiness, as in Figure 5-2 which presents the data from the Ontario Wind Resource Atlas [63]. The wind speeds are presented at 100 m height which is appropriate for the current sizes of offshore wind turbines.

Mean wind speeds of over 8 m/s are anticipated in all the Canadian Lakes with the strongest wind speeds in Lake Superior. Wind speeds of over 9 m/s are shown in Lake Superior, Lake Huron and western parts of Lake Erie. In general, stronger winds are located further from the lake shores, though winds of over 8.6 m/s are indicated at the northeastern shores of Lake Huron and along the western shores of Lake Erie.



Sources: Ontario Wind Resource Atlas **[63]**, World Port Index, ArcGIS Online

Figure 5-2 Wind resource – mean wind speed at 100 m

5.4.1.2 Water depth

The main influence of water depth is on the choice of foundation technology for the offshore structures. For a given type of (non-floating) foundation, the greater the water depth, the taller and heavier it will be, leading to more onerous manufacturing and installation requirements and greater cost. For floating foundations, the water depth has less importance though will still affect moorings and cable installation.

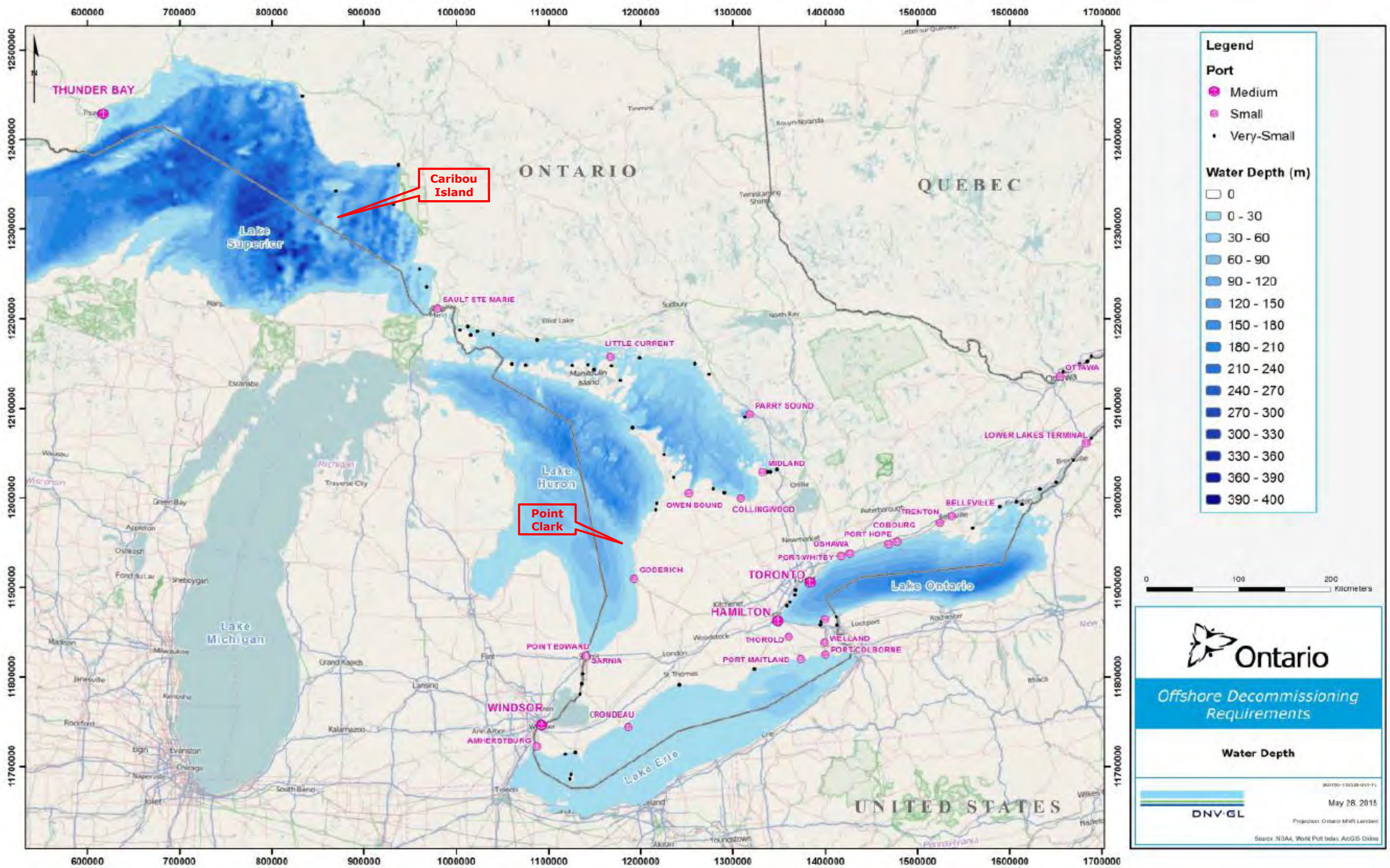
Figure 5-3 shows the water depths of the Canadian Great Lakes, clearly indicating the large differences between the lakes. In Figure 5-4, the same data are presented with colour bands separated at 30 m and 50 m depth. Table 5-1 gives the average and maximum depths of the four Canadian Great Lakes [64].

Table 5-1 Water depth – average and maximum

Area	Average depth	Maximum depth
Lake Superior	149 m	406 m
Lake Ontario	86 m	244 m
Lake Huron	59 m	281 m
Lake Erie	19 m	229 m

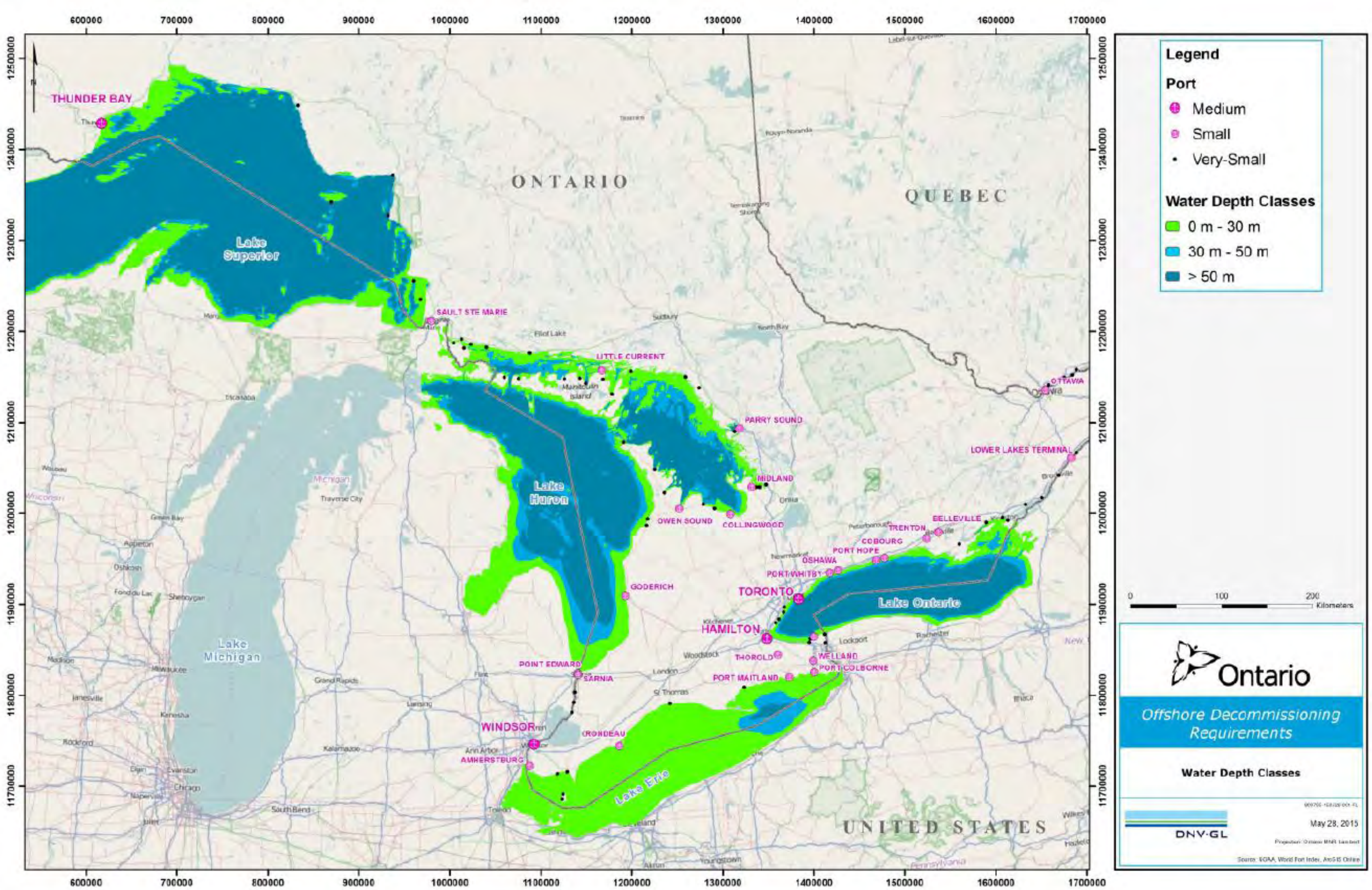
The majority of Lake Erie is less than 30 m deep with an average depth of 19 m and maximum 229 m localized in the eastern end. In contrast, the majority of Lakes Superior, Ontario and Huron are over 50 m deep. In general, the shallower waters are closer to the lake shores, though this is not always the case: there are patches of shallower water such as near Caribou Island in eastern Lake Superior or extending from Point Clark in eastern Lake Huron, indicated in the gradated water depth Figure 5-3. Conversely the rim of shallower water is relatively narrow at some shores, particularly the north eastern shore of Lake Superior.

Water depths in the Lakes vary little over time, with tidal effects being negligible and seasonal variations from precipitation melt and human extraction being managed within agreed limits of a few metres. The main variations are from storm surges caused primarily by sustained high winds, and from seiche oscillations (sometimes called “slosh”). Extreme variations relative to the managed levels are typically no more than ± 2 m [65].



Sources: NOAA Great Lakes Bathymetry program, World Port Index, ArcGIS Online

Figure 5-3 Water depth – gradated scale



Sources: NOAA Great Lakes Bathymetry program, World Port Index, ArcGIS Online

Figure 5-4 Water depth – with depth ranges

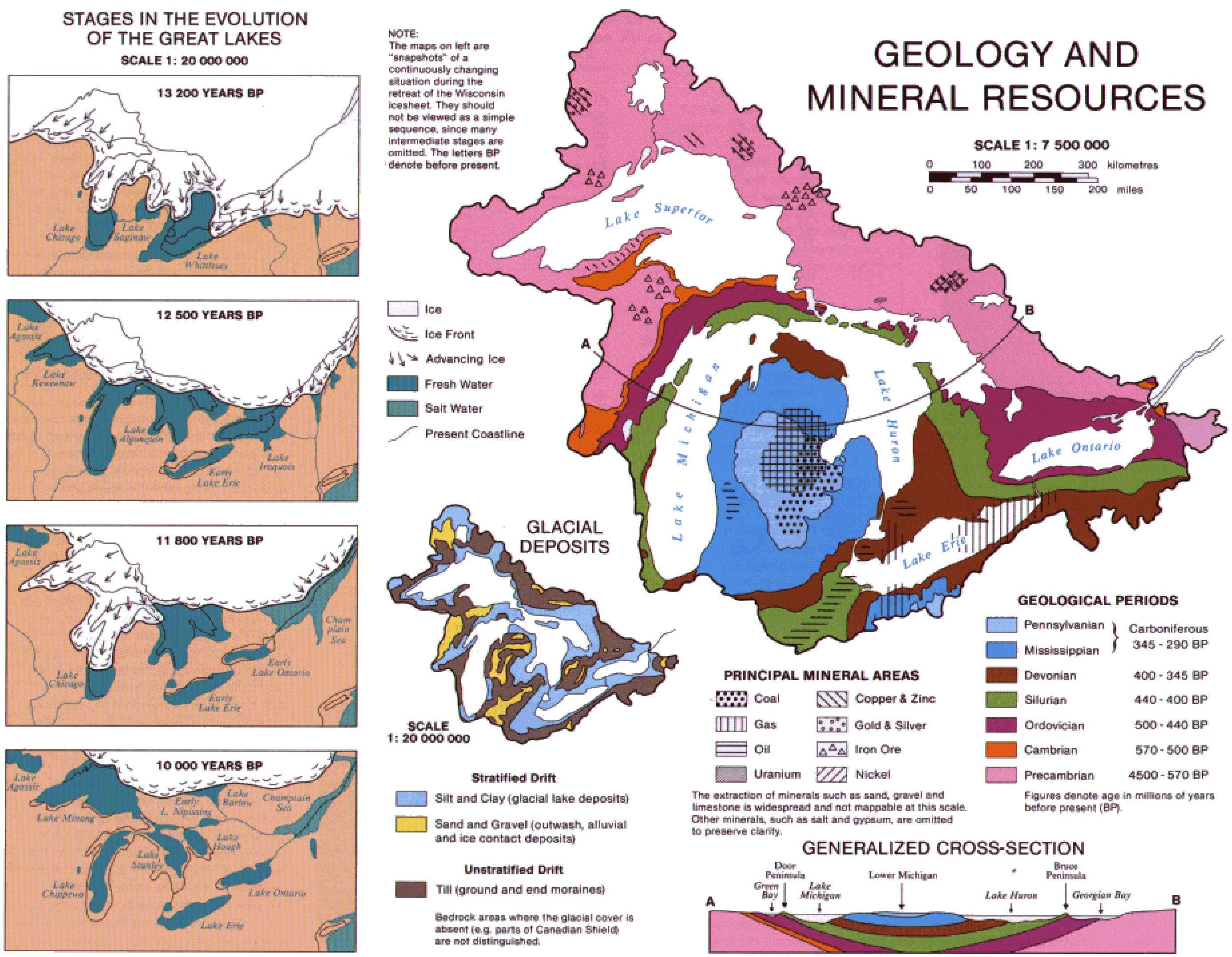
5.4.1.3 Geology

The lake-bed geology plays an important part in determining the optimum foundation, for example with very soft layers providing little mechanical support for foundations and jack-up vessels alike, and very hard rock preventing the driving of piles. The nature and thickness of the surface quaternary layers, and the nature and depth of the underlying bedrock are of key importance. Such information from the lake-beds may not be available in any detail and only limited information can be deduced from on-land geological studies, in particular the sedimentary layer in a basin.

Figure 5-5 shows an overview of Great Lakes geology from the US Great Lakes Atlas [66]. The main graphic shows the types and ages of bedrock and includes a generalised cross section through Lakes Michigan and Huron.

The ancient rock of the Canadian Shield, shown in pink, comprises Precambrian igneous and metamorphic rocks, which are characterised by their high hardness. Some parts of the Shield became covered by layers of sedimentary rocks formed as deposits at the bottom of ancient seas, now present as a variety of sandstones, limestones and shales, with some pockets of gas and petroleum. In particular bowl-shaped layers of such sedimentary rock of different ages now make up the Michigan Basin, as indicated in the cross-section. Sedimentary bedrock is also found in the deep bowl of Lake Superior.

The Great Lakes region has been subjected to repeated glaciation, most recently around 12,000 years ago as shown on the left of Figure 5-5. Glacial action and sedimentation processes in the lakes have produced further sediments on top of the bedrock.



Source: US Great Lakes Atlas [66].

Figure 5-5 Great Lakes geology – overview

Figure 5-6 shows the bedrock in more detail, taken from the 2005 Geological Map of North America [67]. The full explanations of the colours and labels are rather complex, available at http://ngmdb.usgs.gov/gmna/. Just the key points are described here.

In Lake Superior the orange areas labelled Y3 in Figure 5-6 indicate the ancient sedimentary bedrock extending beneath the whole area of the lake. As a consequence of its age, this rock is expected be so hard as to make any piling into it impractical.

In Lakes Huron, Erie and Ontario, the blue colours in Figure 5-6 indicate sedimentary rock of different geological periods, and correspond to the layers of the Michigan Basin. However, the age alone does not determine the nature and strength of the material; they are also affected by the conditions at the time they were laid down. More detail will be available from direct investigations or deduced where the same strata are exposed on land. Experience of these kinds of rock indicates that the bedrock in these three lower lakes varies from strong carbonate (limestone) which will be too hard for piling, to weaker shale bedrock, which is more likely to be pileable. Interlayered and mixed structures are also possible.

Figure 5-7 presents the surficial map for the Great Lakes area [68], describing the distribution and characteristics of the sedimentary layers overlying the bedrock. In each of the lakes, the areas as defined in the legend (Figure 5-8) are one of the following:

- Lake mud (mL) fine grained, mixes of silt and clay
- Glacial & lake (fL) fine grained, mixes of silt and clay with local stones
- Lake sand (sL) coarse grained, sand and gravel
- Till blanket (Tb) consolidated glacial deposit

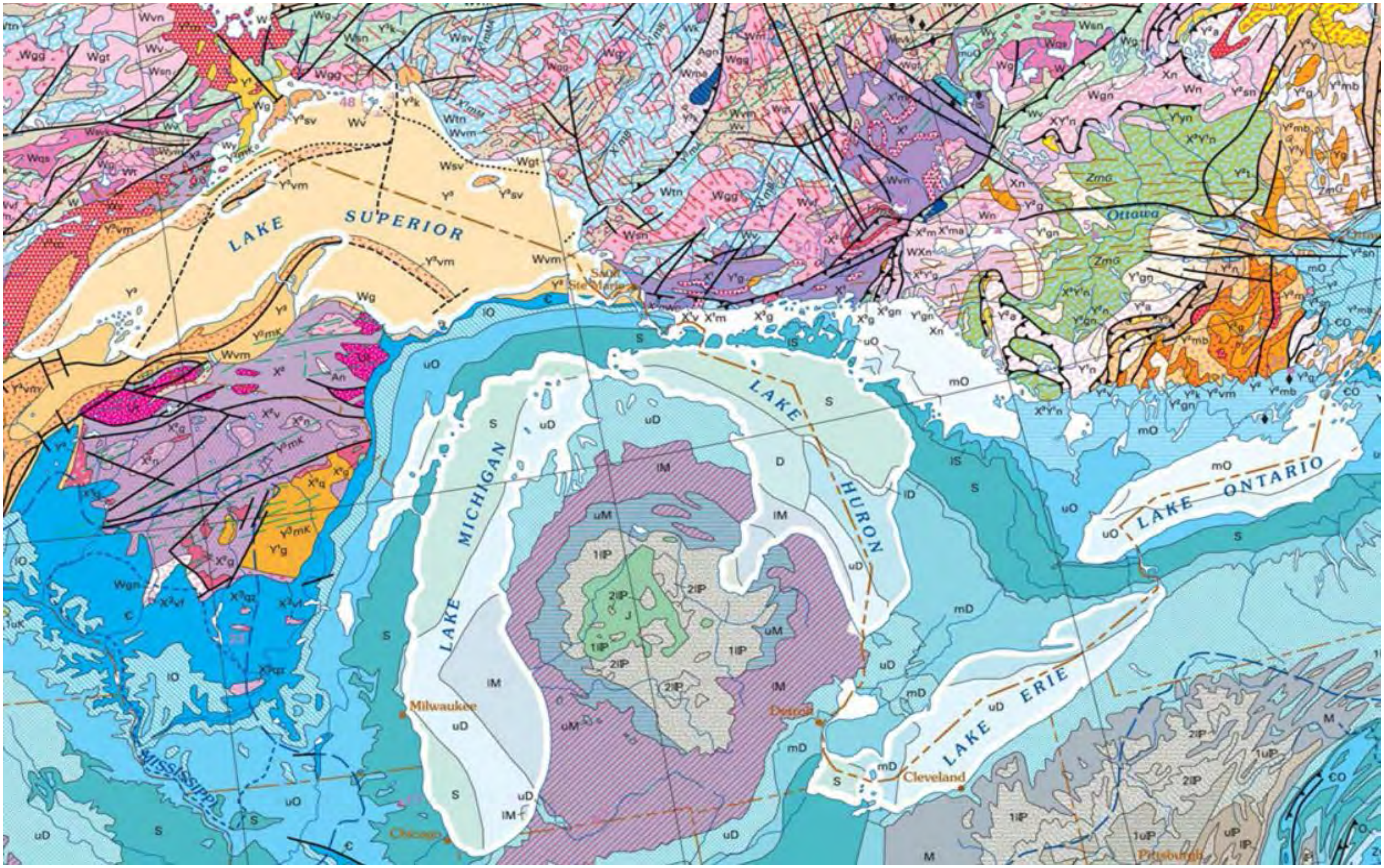
Experience indicates that there are likely to be wider areas of till extending underneath the areas of lake mud.

Material strengths of the layers are difficult to predict. However, tills are relatively stiff whilst still pileable; sediments of sand, silt and clay are usually softer than till and suitable for piles. Where there has been glaciation, there may be local paleo-channels – channels created in consolidated sediment during glacial melting and subsequently filled with softer sediment.

Figure 5-9 presents thickness data for the sediment layers over the bedrock, for Lakes Superior, Huron and most of Erie [69]. The figure also denotes the material as either till; coarse grained (i.e., sandy); or fine grained (i.e., clayey).

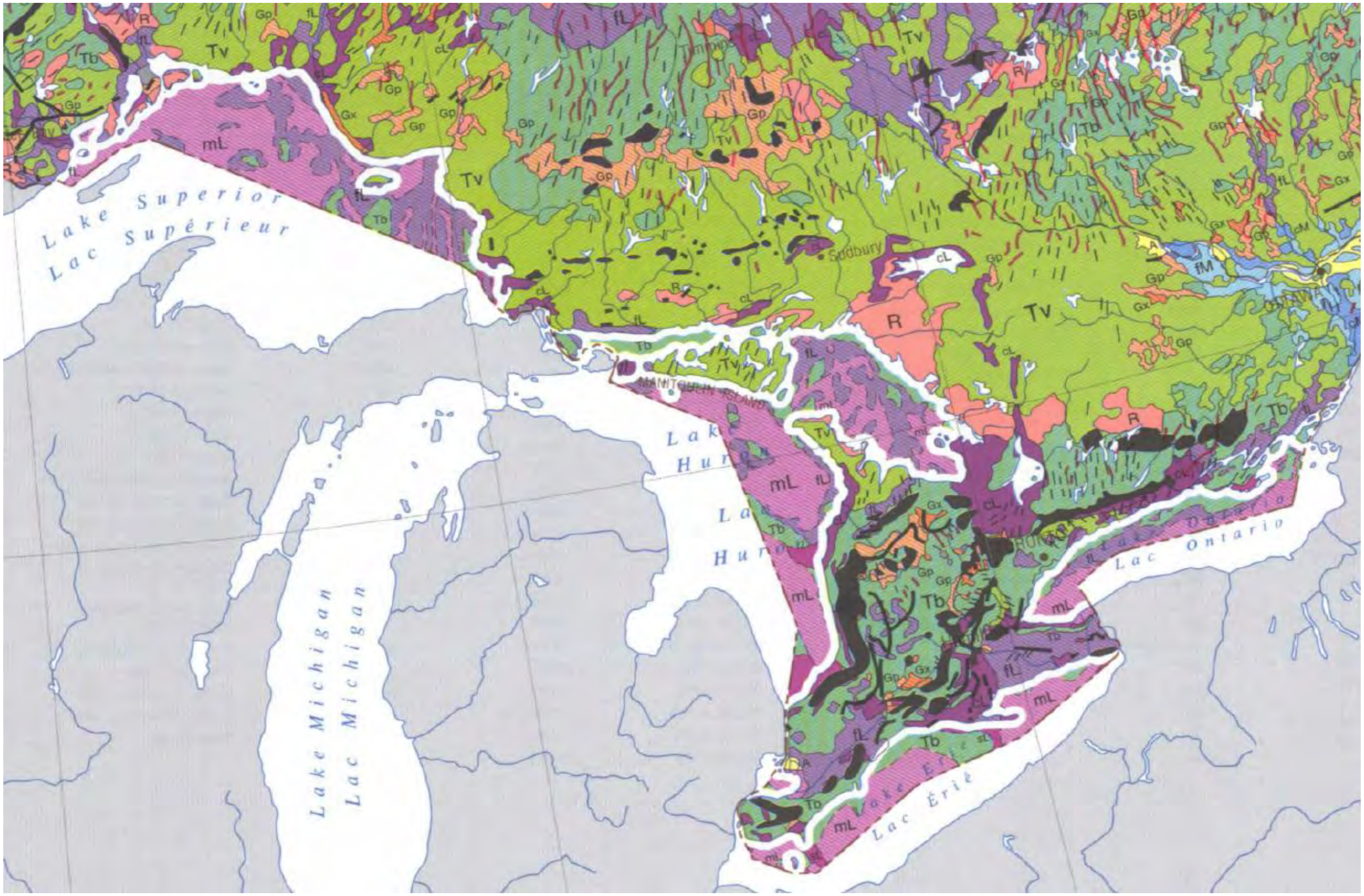
Sediments in the Canadian parts of Lake Superior tend to be thicker in the western areas than in the eastern areas, ranging overall from over 120 m (400 ft) in the west to less than 30 m (100 ft) in the vicinity of Caribou Island. In Lake Huron, sediment thicknesses are quite variable. In Lake Erie, they are generally fine sediments of more than 120 m thickness.

The implications of the geology on the foundations choice are discussed in more detail in a later section.



Source: 2005 USGS Geological Map of North America **[67]**.

Figure 5-6 Great Lakes geology – bedrock
For legend, see http://ngmdb.usgs.gov/gmna/

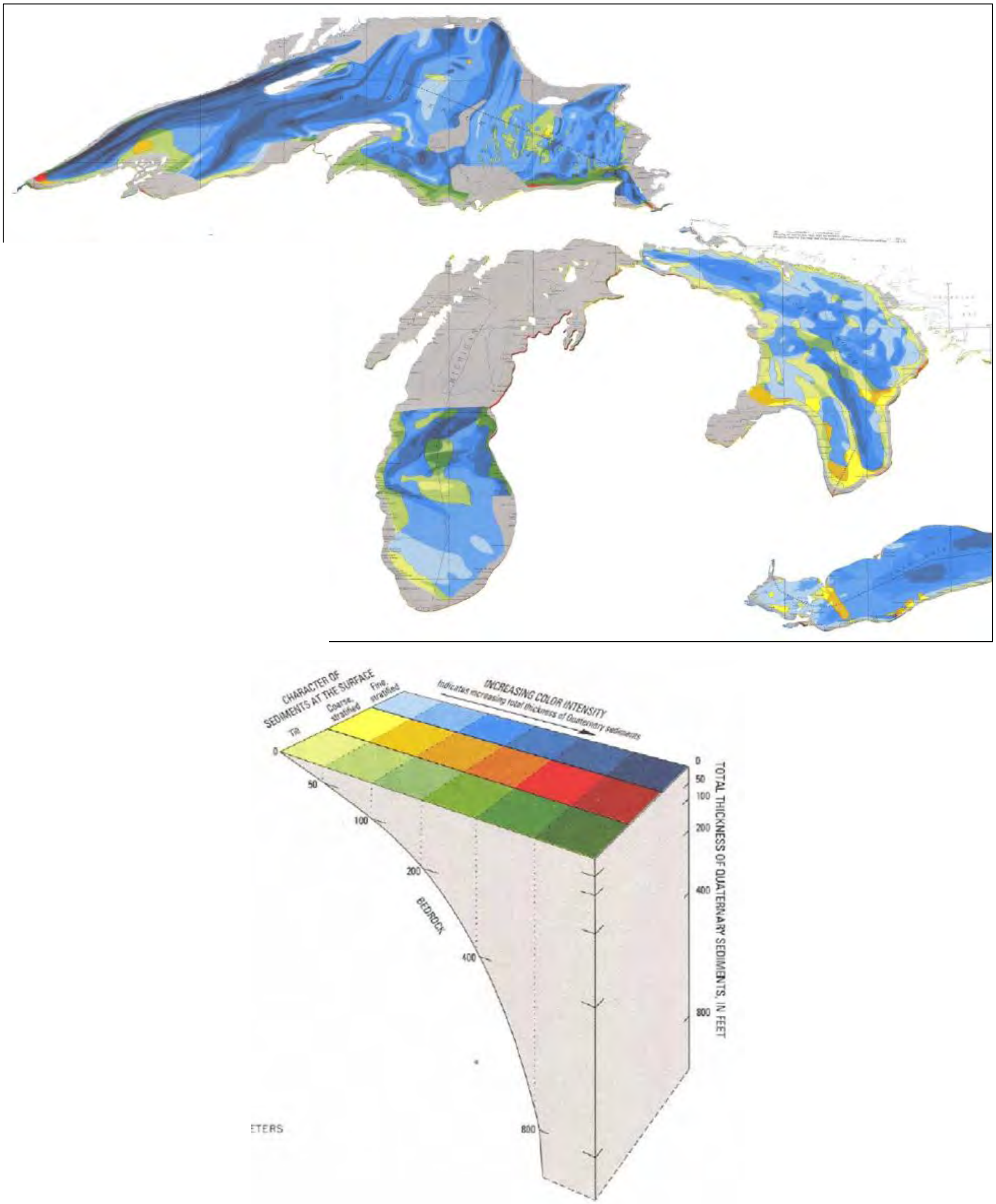


Source: Natural Resources Canada [68].

Figure 5-7 Great Lakes geology – surficial materials
See next page for legend.

Figure 5-8 Great Lakes geology – surficial materials - legend

See previous page for related map.



Source: US Geological Survey [67]

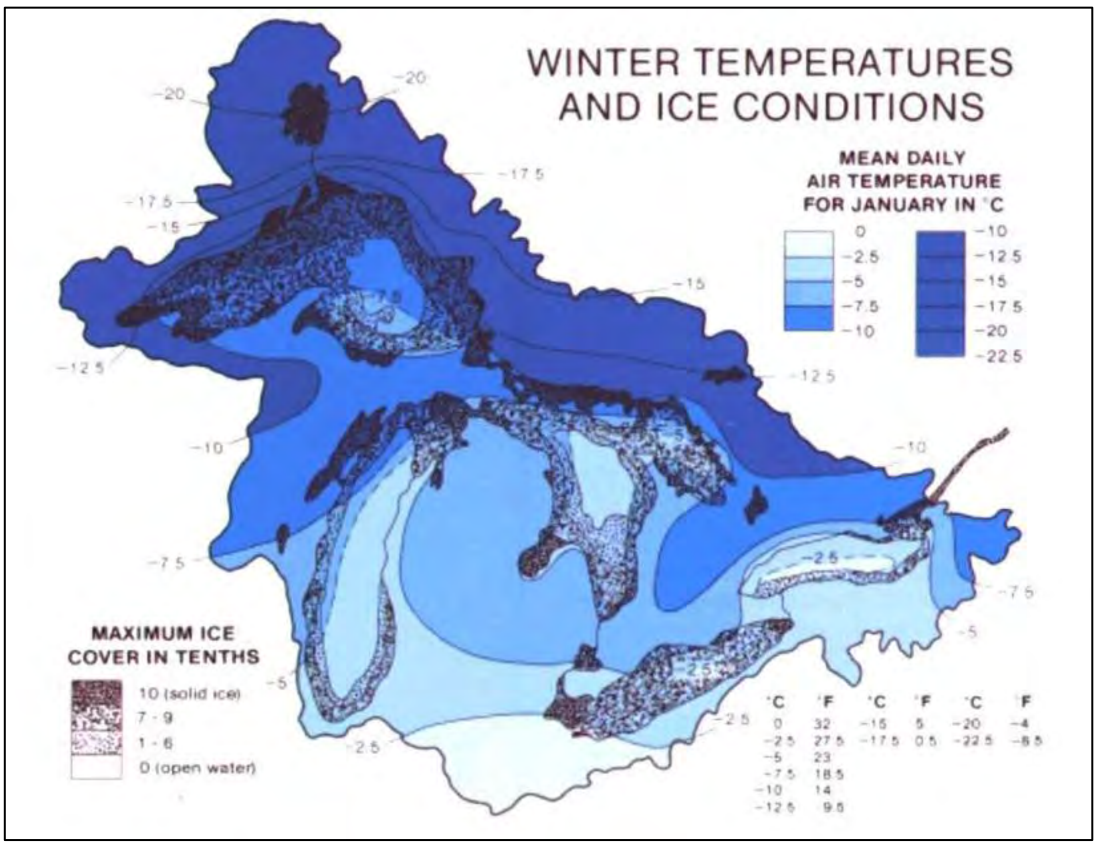
Figure 5-9 Great Lakes geology – quaternary sediment thickness and character, with key

5.4.1.4 Ice

Ice cover on the lake surface will influence the design of the foundations, in terms of withstanding the forces from dynamic pack ice and ice ridges, and from moving ice during melt and break-up. Ice cover will also affect access for vessels during installation and Operations & Maintenance (O&M) activities.

Icing on structures potentially influences the operation and efficiency of the turbines, though this is well-understood from the many onshore turbines experiencing icing conditions. In particular de-icing systems can be installed on blades and instruments to avoid ice accretion affecting their performance; and statistical analysis of energy yield will consider icing losses.

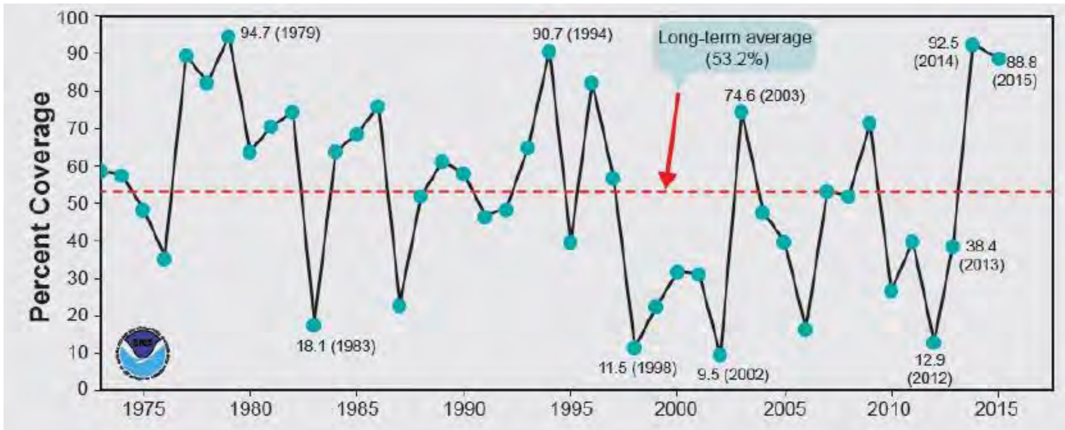
The average maximum ice cover of the Great Lakes varies between the lakes, depending in general on the water depth and the temperatures, as shown in Figure 5-10 from the US Great Lakes Atlas [66]. Lake Erie nearly always experiences 100% ice cover, whereas the deeper, upper lakes are often ice-free in the centre. Those areas which are deepest and have the longest wind fetch (the distance travelled by wind across open water) also have the shortest duration of ice cover. This is because wind frequently causes mixing of these waters so that any ice cover formed is melted or transported elsewhere.



Source: US Great Lakes Atlas [66].

Figure 5-10 Average maximum ice cover and winter temperatures

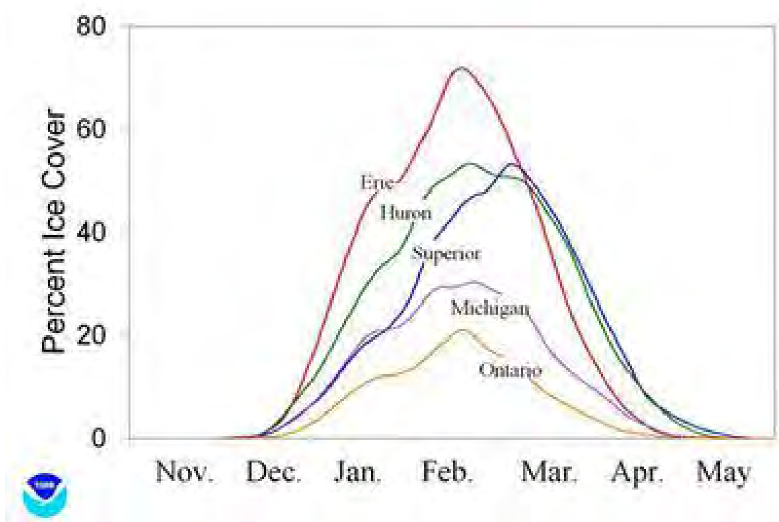
The Great Lakes Environmental Research Laboratory (GRERL) provides comprehensive statistics and research on ice cover. The extent of the ice cover varies considerably from year to year, as shown in Figure 5-11 [70] with a range over the last 40 years between 9.5% and 94.7%.



Source: NOAA GRERL Ice Brochure 2015 [70].

Figure 5-11 Great Lakes maximum ice coverage – annual variation 1973 - 2015

The ice season (Figure 5-12) follows a similar pattern in each of the Lakes, typically starting with ice onset in December, then growth of ice continuing through to February or March, then melt and break-up taking place until April or May. The commercial shipping season lasts around 42 weeks per year including 12 weeks when ice-breakers are required to keep ports and shipping lanes open as long as possible.



Source: NOAA in MRCC Climate Observer Nov.2012.

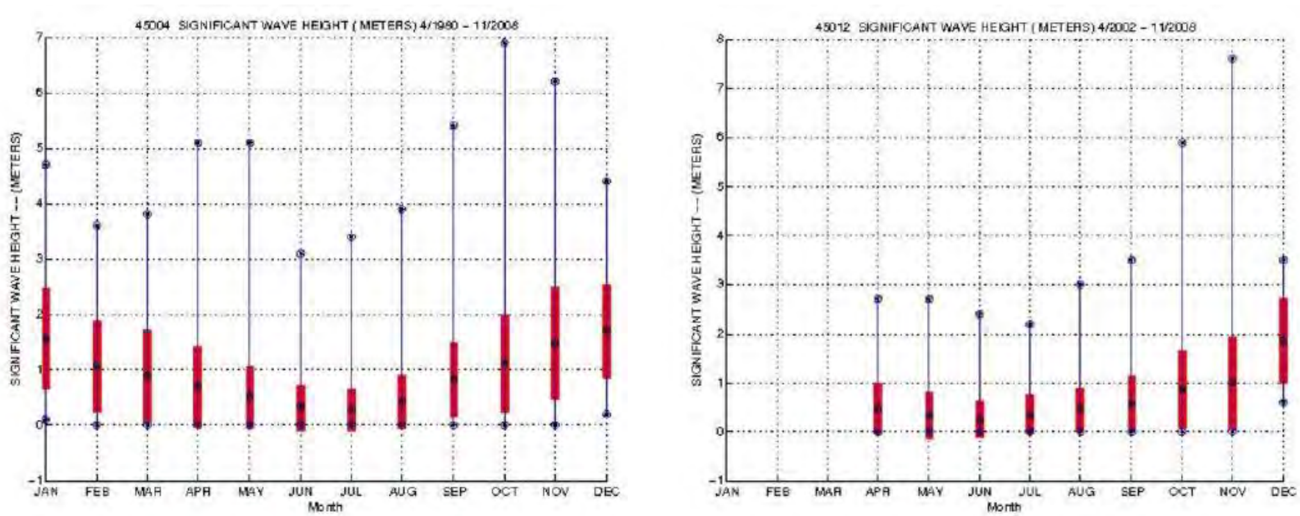
Figure 5-12 Great Lakes 30 year average ice season – monthly variation

The initial ice to form is fast ice attached to the shoreline with typical ice thicknesses of 0.3 to 0.6 m. Subsequent ice forming in open water (pack ice), can be of many types depending, for example, whether it has formed in calm or agitated conditions. The pack ice can be dynamic under the influence mainly of winds. This leads to the formation of ice ridges and ice rubble along the shore or further out which can be many metres high above the normal surface, and can also extend downwards to scour the lake bottom. To prevent ice jams from blocking the flow of rivers, ice booms are installed (for example at the head of the Niagara River) that help control the ice by forming an ice arch. Other ice damage, mainly during ice melt in the spring, can occur due to ice movement and thermal expansion of ice against shore structures.

5.4.1.5 Other characteristics

Water currents are relatively low magnitude throughout the Great Lakes, compared with locations experiencing tidal flows.

Waves in the Great Lakes are primarily wind-driven, the greatest wave heights occurring during storms and when the wind directions align with the longest fetches which are of the order of 300 to 400 km. Wave regimes will vary according to location with highest mean heights expected furthest from shore. Figure 5-13 shows mean significant wave heights (Hs) at buoys in open water in eastern Lake Superior and Lake Ontario, taken from the US National Data Buoy Center [71]. The annual mean wave heights are around 0.9 m Hs at the Lake Superior buoy, with summer mean values of around 0.6 m Hs at both locations. Maximum values of 6 to 8 m Hs are recorded in October and November. These compare with the wave regimes in the southern North Sea, where annual mean wave heights range from 0.8 m to 1.5 m Hs depending on the location and exposure.



a) Eastern Lake Superior b) Eastern Lake Ontario

Figure 5-13 Significant wave heights at NDBC buoys

Red = mean with 1 standard deviation; blue points = extremes

Fog occurs year-round throughout the Great Lakes basin, with typical frequencies in summer of 2 to 8 times per month quoted by Nav Canada aviation weather services [72]. The primary influence of fog may be to restrict vessel movements during marine operations.

Site selection will also be influenced by constraints from any marine nature reserves and from the requirements of other lake users such as shipping, fishing and radar which are all expected to affect quite small areas. Since this study does not aim to locate specific sites, it is assumed that these constraints will not rule out any site-types.

5.4.2 Influence of site characteristics on technology selection

The importance of wind speed, water depth, geology and ice on foundation and turbine selection is first described in general, and then in relation to the range of characteristics found of the Great Lakes.

5.4.2.1 Wind speeds

The wind speeds directly affect the energy production and therefore the revenue from the wind farm. The wind characteristics (e.g., extremes and turbulence) will also influence the wind turbine generator (WTG) type selection. Indirectly the wind speeds may affect the foundation selection by providing a driving force to consider locations further from shore and often in deeper water, or in areas with less favourable geology.

5.4.2.2 Water depth

For the purposes of this rough comparison, water depths are described as shallow (< 30 m), medium (30 – 50 m) and deep (> 50 m) as displayed in Figure 5-4. However in practice there is flexibility outside these bounds according to specific designs and conditions.

The effects of water depth on the technology selection for turbine support structures are largely through the changes in the stiffness and hence the fundamental frequency of the structure. This frequency needs to be designed to avoid the primary forcing frequencies created by the turbine rotation. The main factors affecting the stiffness and therefore feasibility of a structural design are:

- the length of the combination of tower and support structure, therefore influenced by the water depth;
- the geometry of the support structure, and therefore footprint; and
- the turbine size, and therefore mass.

In general, fixed bottom structures (monopiles, jackets, gravity base etc.) are suitable for water depths of up to around 50 m, though some increase may be possible.

With monopile (MP) foundations, an increase in water depth leads to reduction in the stiffness of the structure due to the increased pile length through the water. The main consequence is that MPs to date have (for 2 to 4 MW turbines) generally been restricted to shallow water depths, less than 30 m or possibly 40 m. However with the increase in projected turbine capacities and water depths in current and future European projects the industry is seeing the development of new extra large (XL) MPs allowing the depth range of MPs to be extended to approximately 50 m for 2 to 4 MW turbines and 40 m for 8 MW turbines. This has been driven by the advantages in fabrication simplicity with MPs and a resulting opportunity to reduce the cost of energy. This approach might yield MPs with diameters of 6-10 m and masses in excess of 1,000 metric tonnes; hence, local fabrication and installation capability should be carefully considered.

Jackets are inherently stiffer than MPs and water depth is less controlling in terms of design, although in very shallow water depths their high inherent stiffness might make meeting the turbines frequency window challenging without implementing modifications to turbine control systems. The main influence of water depth is the greater height and weight of jackets with greater water depths. Feasible depths are in the shallow (greater than approx. 20 m) and medium ranges.

Suction bucket monopods will have similar depth considerations to MPs in terms of stiffness, since they are very similar geometry above the mud-line. A certain water depth is needed for the process of installation and also leads to favourable, higher water pressure on the cap. Optimum depths of 15 to 30 m are assumed, extending to medium (30 to 50 m) for jacket type suction foundations.

Other multi-legged foundations will be best suited for medium water depths, of at least 20 m and up to 50 or 60 m depth [73].

Gravity base structures (GBS) are inherently much heavier than piled or bucket structures, and will have increasing dimensions and weight with deeper water. As a result more substantial manufacturing and installation capabilities are needed. Apart from these factors, selection of GBS foundations is relatively insensitive to water depth. It is assumed shallow and medium depths are optimum, with the extreme weight ruling out deeper waters.

Floating foundations are least affected by water depth, with the support structure design being independent of depth. A certain minimum depth is needed for towing and positioning, depending on the design. As mooring lines (and electric cables) require connection to the lake-bed, very deep waters are less favourable. In general, depths between around 50 m and 300 m are assumed optimum.

Table 5-2 summarises the likely depths for different foundation and turbine types.

Table 5-2 Approximate depth ranges for foundation and turbine types

Technology	3 – 4 MW turbine	6 – 8 MW turbine
MP (including XL)	0 – 50 m	0 – 40 m
Jacket	10 – 50 m	10 – 50 m
Suction monopod	15 – 30 m	20 – 50 m
Suction jacket	15 – 50 m	20 – 50 m
GBS	0 – 50 m	0 – 50 m
Floating	50 – 300 m	50 – 300 m

Comparing these depth ranges with the water depths in the Great Lakes, it is seen that the majority of locations suitable for fixed foundations are around the shores of the Lakes. The exception is Lake Erie which is less than 30 m deep over almost its entire area. On the grounds of depth alone, all of the fixed foundation types would be a possibility in Lake Erie.

In Lakes Superior, Huron and Ontario waters less than 50 m deep extend between 10 km and 20 km from the shore in many parts. More extensive areas less than 50 m deep are present in the centre and eastern end of Lake Superior near Caribou Island; in Georgian Bay and the eastern parts of Lake Huron; around underwater ridges in parts of Lake Huron such as extending from Point Clark; and at the eastern end of Lake Ontario.

Except for Lake Erie, extensive areas of the Lakes are much greater than 50 m deep and for wind farms to be built in these areas, floating foundations would need to be adopted.

5.4.2.3 Geology

The ground conditions in terms of the sedimentary layers and underlying bed-rock influence the selection of foundation technology through

- Providing the required support during turbine operation, plus
- Ease of installation.

For MPs and jacket piles the optimum ground conditions are similar, despite operating loads on MPs being dominated by lateral loading, and jacket piles by axial loading. Jacket piles are smaller diameter (1 to 2 m) than MPs (5 to 10 m). The optimum ground conditions are uniform consolidated clay or sand sediment layer for the full embedded depth of the piles, which may be 20 to 50 m below the mud-line depending on the turbine size and ground strength. These ground conditions are generally pileable, allowing piles to be readily installed by driving.

Ground conditions that are less optimal for piles, being more time consuming and costly, will be:

- Medium depth sediment layer, with hard underlying bedrock, requiring shorter piles or driving then drilling into bedrock;
- Shallow sediment layer, requiring drilling (and grouting) of piles into the bedrock;
- Non-uniform sediment containing boulders or rock layers, requiring installation by drive-drill-drive method;
- Softer sediment with low strength, requiring increased embedment, multiple piles or angled piles.

For suction bucket monopods, the ground needs to allow the installation of the bucket skirt to a depth of typically 10 – 15 m through the combination of its weight and suction, with smaller dimensions for suction bucket jackets. During turbine operation, the bucket is held in place primarily by friction of the soil with the internal and external surfaces of the skirt and also through the end resistance of the cap against the plug. The optimum geology is therefore uniform sedimentary material down to at least the skirt depth, of medium strength and low water permeability that allows suction to be maintained during installation. Skirt diameters and depths can be modified to some extent to suit soil conditions. Suction buckets would generally not be suitable in soft soils or where liquefaction is a risk.

GBS foundations are held in place by their weight with no embedment required. The foundation also needs have resistance to lateral sliding. GBS foundations are therefore best suited to level ground conditions that are either compacted sediment or rock with consistent strength. The ground needs strength with depth beneath the mud-line to avoid any risk of punch-through.

Floating foundations require secure mooring to the lake bed. Means are assumed available for all ground conditions.

Table 5-3 summarises the optimum geologies for each foundation type, and also notes implications of less optimum geologies.

Table 5-3 Optimum geologies for foundation types

Technology	Optimum geology	Acceptable geology
MP	Pileable to 50 m below mud-line: Uniform consolidated clay or sand sediments	Mixed hardness or less pileable soils.
Jacket	Pileable to 50 m below mud-line: Uniform consolidated clay or sand sediments	Mixed hardness or less pileable soils.
Suction monopod	Uniform medium strength soils to 15 m below mud-line	Some limited variation in soil composition.
Suction jacket	Uniform medium strength soils to 10 m below mud-line	Some limited variation in soil composition.
GBS	Level, consolidated sediment or rock.	Sloping or uneven profile, which can be levelled.
Floating		NB: Very insensitive, though not immune, to geology.

Comparing these criteria with the geology of the Great Lakes, it is seen that the sediment thicknesses across all four Canadian Lakes appear great enough in the majority of locations for even the longest piles not to reach the bedrock beneath. Furthermore with the repeated glaciation of the region, it is expected that the nature of the sediments is suitable for piled foundations and possibly for suction buckets; the sediments are mainly consolidated till and the variety of silts, sands and clays, though areas of local stones exist. However, any soft paleo-channels would need to be located and probably avoided.

In some locations, sediment thicknesses are less than 30 m (100 ft) and in a few locations there is less than 15 m (50 ft) thickness of sediment, shown as paler colours in Figure 5-9.

In Lake Superior the bed-rock is consistently very hard and not pileable, and in places the depth of overlying sediment may not be enough for piled foundations – such as some parts around Caribou Island. Such ground conditions may be more suitable for GBS foundations.

In Lake Huron, there are also some areas with relatively thin sediment, such as the band of consolidated glacial till extending in a north-west direction from Point Clark. As indicated, the detailed geotechnical data for the underlying sedimentary bed-rock is not known, though is expected to be pileable in at least some locations.

In Lake Erie, most of the area has fine sediments of more than 120 m thick with some shallower sediment layers in places, with sedimentary bed-rock beneath. Depending on the strength and uniformity of the sediments, they may be suitable for piling or for suction buckets.

In Lake Ontario, for which less geological information was found, the sediments are again glacial tills, lake mud and mixes of silt and clay with local stones; on top of sedimentary bed-rock. However, sediment thicknesses are unclear. More detail would be needed to confirm suitable foundation types.

5.4.2.4 Ice

In the presence of pack ice, fixed foundations require additional design to withstand the ice forces, typically in the form of angled deflectors. Foundation designs presenting larger cross sections will offer more resistance, and for this reason jackets may be less likely to be selected.

For floating foundations, pack ice may exert unacceptably high forces on the mooring and cable connections, and may also prevent the turbine being held at its required position and orientation. In the same way that data buoys are recalled during the ice season, it might be anticipated that floating turbines would be towed to shore when ice conditions set in, resulting in loss of revenue.

However, floating turbines look a more likely option for the deep, central lake areas of Lake Superior and Lake Huron which have some of the highest wind speeds and are also ice-free.

In general, ice in ports and around the turbines will restrict vessel movements. This is likely to affect the length of the construction season and affect access for O&M once the turbines are in operation. However alternative access methods should be possible over the ice using hovercraft or airboats; or road vehicles when the ice is strong enough; or by air using helicopters.

5.4.2.5 Remoteness

Remoteness will influence the siting and indirectly the foundation type in a number of ways:

- Distance from population, and therefore affecting grid connections, power demand, potential consent issues, and socio-economic benefit from employment
- Distance from ports, with implications for both construction and decommissioning phases.

In general, locations in Lake Superior and Lake Huron would be classed as remote; and locations in Lake Erie and Lake Ontario as either medium distance or near-shore.

5.4.2.6 Other factors

A large number of other factors may influence the technology selection. In some cases the influence is through their effect on the site selection. For example:

- If visibility is a key consenting issue, sites may be more likely at larger distances from shore which generally implies deeper waters.
- If wind speed is a dominant driving force, through the economics being strongly influenced by the magnitude of the power production, then sites may be more likely in the highest wind speed locations. Many of these are in the deeper water areas of Lake Superior and Huron which in turn will favour floating foundations.
- If the viability is strongly driven by proximity to onshore electric grid connections and population centres, then sites are more likely in Lake Erie and Lake Ontario, with the implications of their water depths and sedimentary geology for foundation types. Alternatively, offshore wind farms may be seen as providing a source of electric power for the expansion of more remote areas such as the northern shores of Lake Superior, with the implications of selecting foundations suitable for the very hard bedrock.
- If the requirement for local manufacturing dominates, then selection of the foundations will be influenced by the facilities and skills available such as the steel rolling mills, fabrication yards,

facilities for reinforced concrete, and quayside facilities for handing the components. Depending on the skills available, this could favour either steel foundations or concrete foundations.

- If installation vessels are a key issue, then this may influence the foundation choice. The 23 m width limitation of the St. Lawrence Seaway will prevent many of the specialised European offshore wind installation vessels from entering the Great Lakes. Installation methods will therefore have to rely on barges, vessels and jack-up platforms that are already within the Lakes or are capable of entering the Lakes, or on vessels constructed within the Lakes for the purpose. In these circumstances, it may be that foundations that can be towed into position are favoured.

5.4.3 Selection of site types

On the basis of the information presented in the previous sections and their degree of influence on foundation selection, the following site types are selected, Table 5-4.

Table 5-4 Site types selected

Site type	Water depth	Geology	Ice	Remote-ness	Typical lake
A1	Shallow	Thick (>50 m) uniform consolidated sediments	Ice	Medium	Erie
A2	Shallow	Non-uniform sediment with rock inclusions or multiple layers	Ice	Medium	Erie
A3	Shallow	Thick soft sediment	Ice	Medium	Erie
B1	Medium	Thick (>50 m) uniform consolidated sediments	Ice	Near shore	Ontario, Huron
B2	Medium	Non-uniform sediment with rock inclusions or multiple layers	Ice	Near shore or medium	Ontario, Huron
B3	Medium	Medium thickness (20 – 40 m) uniform consolidated sediments / pileable bedrock	Ice	Near shore or medium	Ontario, Huron
B4	Medium	Shallow (<10 m) sediment / pileable bedrock	Ice	Near shore or medium	Ontario, Huron
B5	Medium	Shallow sediment / hard bedrock	Ice	Remote	Superior
C1	Deep	Deep water (geology immaterial)	Ice	Remote	Superior, Huron
C2	Deep	Deep water (geology immaterial)	Ice-free	Remote	Superior, Huron

The main variation is in the geology: almost all combinations of nature and characteristic of bedrock and sedimentary layers are potentially present. It is not intended to identify particular locations given the relatively high level of the data used and the simplified range of characteristics considered. However, given the clear differences in geology an indication of the typical lake for each site type is noted.

Remoteness is also included in the site types. It is assumed that if the waters are consistently shallow, as in Lake Erie, the wind farm will be located away from the shore to benefit from higher wind speeds; however, where waters get rapidly deeper away from the shore as in the other three Lakes, the more likely combination leads to sites near shore with medium water depth. Remoteness also reflects distance from populations and ports.

5.4.4 Selection of turbine types

DNV GL proposes that two turbine types are selected for comparison in the decommissioning analysis, representing possible scenarios of technology choice.

A larger turbine in the 6 to 8 MW capacity range or more should be included to represent the latest generations of commercially available turbine sizes, now starting to be installed in numbers and becoming adopted as the "workhorse" offshore sizes in Europe.

However, a turbine in the 3 to 4 MW capacity range should also be included. This size is typical of the great majority of offshore wind turbines installed to date. In the five years prior to and including 2015 this has been the most popular size range, installed in the majority of the new offshore wind farms in Northern Europe. The design and installation of wind farms using these turbines is well understood.

Although attention is now turning to offshore turbines of larger capacity, it is anticipated that the 3 to 4 MW size might nevertheless be selected for the Great Lakes. This is envisaged because the large specialised offshore wind installation vessels will be unable to enter the Great Lakes system as a consequence of the width restrictions of the St. Lawrence Seaway. Alternative construction vessels will therefore have to be used as discussed in a later section, and the selection of a smaller turbine size may be a pragmatic part of the solution requiring lower lift weights and lower crane reach.

Table 5-5 lists representative dimensions of generic 4 MW and 8 MW turbines selected for this study. They are based on the Siemens SWT-3.6 and SWT-4.0 models and the new MHI Vestas V164-8.0 MW model, whilst taking into account that with more maturity, the 8 MW turbine diameter will be greater. Both are geared (not direct drive) and are the latest variants in their respective families.

Table 5-5 Turbine types selected – indicative parameters

Turbine type	Rotor diameter	Hub height above water level
4 MW	125 m	85 m
8 MW	175 m	110 m

5.4.5 Screening of foundation types

For each site type identified in Table 5-4, the foundation types are rated below in Table 5-6.

Table 5-6 Screening of foundation types

Site type	Turbine type, MW	Monopile	Jacket	Suction monopod	Suction jacket	Gravity base	Floating	Site type description and comments
A1	4	G	O	G	O	G	R	Shallow water; firm sediment: suitable for most
A1	8	G	G	G	G	G	R	Shallow water; firm sediment: suitable for most
A2	4	O	O	R	R	O	R	Shallow; non-uniform geology: depends on local geology
A2	8	O	O	R	R	O	R	Shallow; non-uniform geology: depends on local geology
A3	4	O	O	O	O	R	R	Shallow; soft sediment: depends how soft
A3	8	O	O	O	O	R	R	Shallow; soft sediment: depends how soft
B1	4	G	G	O	G	O	R	Medium water depth; firm sediment: suitable for most
B1	8	O	G	R	G	O	R	Medium water depth; firm sediment: suitable for most
B2	4	O	O	R	R	O	R	Medium; non-uniform geology: depends on local geology
B2	8	R	O	R	R	O	R	Medium; non-uniform geology: depends on local geology
B3	4	O	G	O	G	O	R	Medium; medium thickness sediment; pileable bedrock
B3	8	O	G	R	O	O	R	Medium; medium thickness sediment; pileable bedrock
B4	4	O	G	R	R	O	R	Medium; thin sediment; pileable bedrock: suits piles
B4	8	O	G	R	R	O	R	Medium; thin sediment; pileable bedrock: suits piles
B5	4	O	O	R	R	G	O	Medium; thin sediment; hard bedrock: suits GBS
B5	8	O	O	R	R	G	O	Medium; thin sediment; hard bedrock: suits GBS
C1	4	R	R	R	R	R	O	Deep water with ice: possibly suits floating
C1	8	R	R	R	R	R	O	Deep water with ice: possibly suits floating
C2	4	R	R	R	R	R	G	Deep water, ice-free: suits only floating
C2	8	R	R	R	R	R	G	Deep water, ice-free: suits only floating

Color code: Green = suitable; Orange = somewhat suitable; Red = not suitable

Some projections are made that technologies will be developed by the time the offshore wind farms are built, in particular the maturity of the 8 MW turbines and suction buckets. It should also be noted that without more data on the nature of the rock and sediment, in particular their hardness and softness, the suitability remains uncertain in many scenarios.

5.4.6 Selection of foundation technologies

On the basis of the indicated site conditions, none of the major foundation types for WTGs can be ruled out at this stage. For carrying forward to the next stages in this study, the five selected foundation technologies for WTGs are listed in Table 5-7 with their characteristics. A sixth technology is selected that focusses on offshore substations, assuming that jacket support structure will be used, as is currently very common.

Table 5-7 Foundation types selected with characteristics

	Site characteristics	Maturity	Manufacture	Installation	Environ-mental
Monopile	Pileable, consolidated sediment rather than hard rock Water depth limits on design Relatively small cross section to ice	Most established method for offshore WTGs Developments to increase pile sizes	Rolled and welded steel Well suited to batch or mass production Challenging for largest piles	Lift & upend piles Pile driving or drilling if required May be limited by hammer sizes Larger diameters heavy, > 1000 t	Piling noise
Jacket	Pileable, consolidated sediment rather than hard rock or mixed hardness Higher stiffness limits for use in shallows Larger cross section to ice than MP.	Established; synergies with O&G sector Developments to streamline design for manufacture but not yet established	Welded steel tubes and piles Joints welded or cast to increase fatigue life	Large footprint for transport Lift jacket Pile driving	Piling noise
Suction bucket (single or multiple)	Uniform sediment Water depth range Rocks/boulders high risk	Relatively new for WTGs: demonstration stage	Rolled and welded steel	Lift and controlled embedment	
Gravity base	Suitable for hard lake-bed Build ice deflection into design	Concept is established. Variety of potential designs	Reinforced concrete Large mass	Lift or float out Large mass	May require dredging or rock placement
Floating	Deep water (though can use in shallower depths) Requires essentially ice-free waters	Relatively new for WTGs: several designs at demonstration stage	Steel structures: mainly spars, tanks and cylinders plus moorings	Assemble at shore or sheltered waters Tow to site	Far from shore so less visible
Offshore substation with jacket	Pileable Relatively large cross section to ice	Established for offshore wind substations; strong synergies with O&G structures	Welded steel tubes and piles	Large footprint for transport and lift Pile driving Typically very heavy	Piling noise

The suction bucket monopods and suction bucket jackets are grouped together, since for decommissioning purposes the techniques are likely to be very similar.

Manufacturing is assumed possible in each case, as they are all either steel or concrete construction. The above considerations also assume that installation is possible in each case, though techniques may be different from those currently used in the Northern European offshore wind farms. Possibilities for installation techniques and any influence on the designs are considered in the following sections.

5.5 Detailed description of selected technologies

The selected technologies are described in more detail in this section, highlighting their likely design, materials and fabrication methods, their installation, and processes for decommissioning. The information expands on the overviews of the component technologies provided in Chapter 2 and includes consideration of ice conditions.

First, however, the likely influence of vessels capabilities is discussed as it is another key factor for offshore wind utilisation in the Great Lakes, particularly in relation to installation and decommissioning.

It should be noted that lift capacities of cranes are provided here in metric tonnes, abbreviated to "te" to avoid any confusion with long tons and short tons which are often found in US crane specifications. Following convention, vessel speeds are given in knots (kt). Abbreviations and conversions between units are tabulated at the beginning of this chapter.

5.5.1 Vessels in the Great Lakes

It can be assumed that installation and decommissioning activities will take place during the summer season when ice is not an issue for vessel movements or marine operations.

With the St. Lawrence Seaway restrictions of 23.7 m (78 ft) beam, 225.5 m (740 ft) length and 8.08 m (26 ft 6 in) draft, many existing construction vessels typically used for offshore wind activities will be prevented from entering the Great Lakes system. These restrictions apply from the seaward end of the St. Lawrence through to Lake Erie, thus incorporating the Welland Canal between Lakes Ontario and Erie. Furthermore for vessels operating within the Great Lakes system west of Lake Erie, there is a lock restriction of 33.5 m beam (110 ft), 365 m (1,198 ft) length and 7.6 m (25 ft) draft between Lakes Superior and Huron at Sault Ste Marie (the Soo).

Survey vessels and cable laying vessels of sufficient capacity are expected to be able to enter the Great Lakes system; the restrictions will mainly affect heavy lift vessels and platforms which tend to take advantage of greater beam to provide increased stability.

5.5.1.1 Heavy lift vessels used in Europe

For reference, Figure 5-14 shows some of the more capable heavy lift vessels currently used for installing offshore wind farms in Europe, together with their principle dimensions, maximum lift capacity and transit speed.

For turbine installation, in general, jack-up platforms or jack-up self-propelled vessels (also known as lift boats in North America) are needed, an example of which is shown in Figure 5-14a. This is because the precision needed when lifting the components generally requires a crane working from a static platform. Pile driving is also generally carried out from a jack-up platform or vessel (Figure 5-14b).

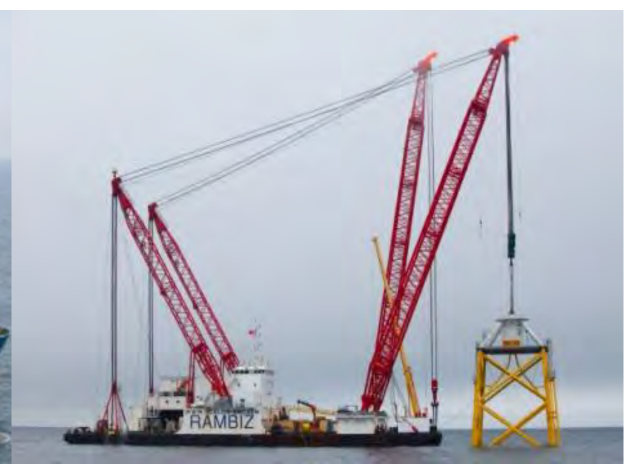
For foundations, the lifting precision is less critical and cranes working from floating vessels are sometimes used; however, sufficient stability from the vessel size and ballasting, and accurate positioning through dynamic positioning systems (DP) are employed. Figure 5-14c shows transition piece (TP) installation from a heavy lift construction vessel and Figure 5-14d shows jacket installation from a shearleg. Shearleg crane vessels are defined by the type of non-rotating crane that operates over the stern for stability. In general, they are suitable for use in inland waters and benign coastal waters. There are many sizes with a large range of lifting capacities. Smaller shearlegs are usually pontoons that are towed into position; larger shearlegs are usually self-propelled. For the offshore wind industry, "Rambiz" has been frequently used for the installation of jackets and offshore substations.

For the most challenging sites in Europe with severe wave conditions and further from shore, the specialised self-propelled jack-up vessels have become most cost effective. However, for sites which are closer to shore and with relatively benign wave climates, construction using towed jack-up platforms and smaller capacity vessels is more frequent, with the selection being decided primarily by the lift capacity and lift reach of the crane.

a) Jack-up vessel "Sea Challenger" installing 6 MW WTGs. 39 m beam, 132.4 m length, 900 te crane, 12 kts transit speed

b) Jack-up vessel "Innovation" installing MPs and TPs. 42 m beam, 147.50 m length, 1500 te double boom crane, 12 kts transit speed

c) DP HLCV "Jumbo Javelin" installing TPs. 26.7 m beam, 144.21 m length, 2 x 900 te cranes, 17 kts transit speed



d) Shearleg crane vessel "Rambiz" installing jacket. 44 m beam, 85 m length, 3300 te dual crane, 6.1 kts transit speed

Figure 5-14 Example installation vessels used in European offshore wind projects

5.5.1.2 Heavy lift options for the Great Lakes

For the Great Lakes, the main options for heavy lifts are anticipated to be a combination of: existing vessels working within the Lakes system; vessels of sufficiently small beam that can be brought in from elsewhere; and adapted or new-build vessels constructed within the Great Lakes for the purpose. It is assumed that there are no restrictions to the use of vessels flagged outside North America, though transport of vessels based elsewhere will confer a cost especially if they do not make the journey under their own propulsion.

In addition, the most challenging combinations of lift weights and lift heights may need to be addressed by changing the designs rather than by using a more capable lift vessel – for example making more use of buoyancy to float out foundations rather than lifting them from the deck of a vessel; minimising the required lift radius to make maximum use of crane capacities; and breaking down components into pieces.

Fixed lift

In terms of jack-ups or lift-boats, existing vessels in the Great Lakes include some small platforms and options for constructing modular platforms. There are also some barges available with spud legs, suitable for work in shallow water: these legs extend to provide a steadier platform but do not raise the hull out of the water.

Figure 5-15 shows some examples of the type of jack-ups and spud-leg barges that are currently available in the Great Lakes and mid-America.

The larger McKeil jack-up ("Jack-up 600", Figure 5-15a) has a 28.4 x 11.5 m deck with maximum deck load when jacked of 235 te in water depths up to 21.3 m and less in deeper water.

Also shown are two types of platform that can be broken down into modular sections for transport by road and assembled to the size required, offered by Poseidon Barge and Combifloat (Flexifloat) (Figure 5-15c & d). The largest self-elevating pontoon in the Combifloat family can take a maximum deck load of 800 to 1000 te. Although these capacities are limited, designs to take heavier loads are quite possible, for example by linking together two platforms with a single load-spreading deck.

a) McKeil's "Jack-up 600", monohull with up to 6 legs

b) McKeil's "Jack-up 50", monohull with 4 legs

c) Poseidon portable sectional barge with spud-leg stabilisation, in use with a Manitowoc ringer mobile crane

d) Combifloat (Flexifloat) modular floating and self-elevating platform

Figure 5-15 Examples of spud-leg and jack-up platforms in the Great Lakes region

For construction operations, a mobile crane could work off such platforms. Figure 5-16 is a simplified graphic showing the main dimensions and terminology.

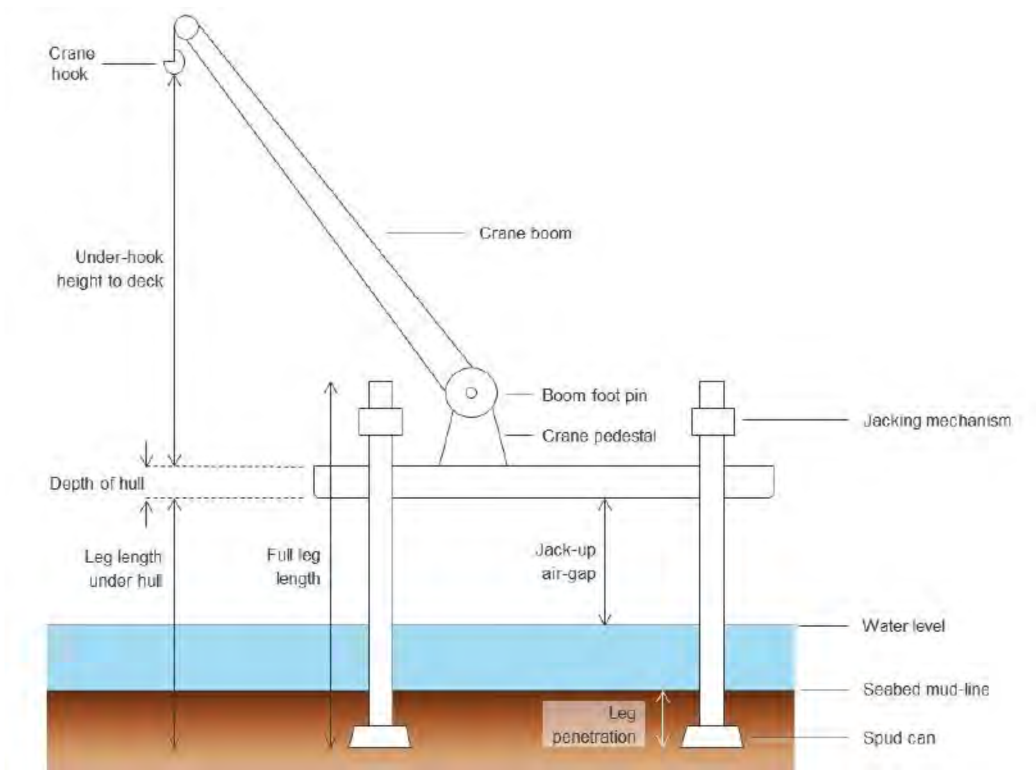


Figure 5-16 Main parameters of jack-up with crane

The key parameters would be:

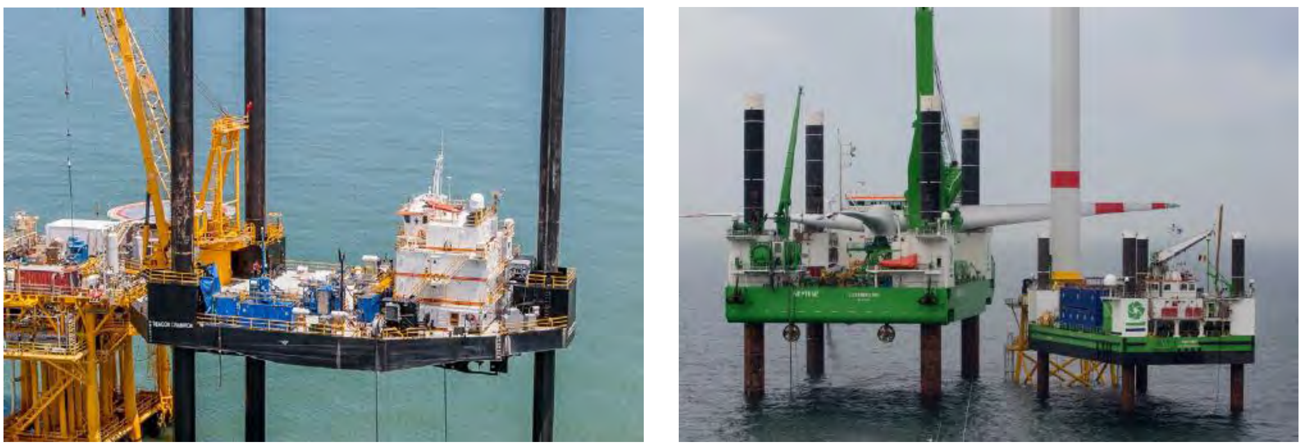
- Crane capacity: The combination of lift weight, lift height, and lift radius with allowance for the weight and dimensions of the lifting gear and also the additional height achievable from the height of the crane base above the water level. If lifting to or from a floating craft, a crane designed for dynamic lifting must be used which excludes cranes solely for onshore use. For dynamic lifts, a Dynamic Amplification Factor (DAF) must be included when determining the load capacity.
- Deck and jacking capacity: Capability to jack up with the weight of the crane, its support frame and counterweight. With a mobile crane, sufficient deck strength and load distribution are required. Once jacked up, capability to additionally take the weight of the lift load.
- Leg length: Capability to operate in the required water depth, with allowances for air gap between hull and water (depends on wave heights), and leg penetration into lake bed (which can be 10 m or more in soft soils). In transit mode, the height of the retracted legs above the deck (known as air draft) may limit access of a long-legged jack-up to some ports.
- Number of legs: Given the number of changes in position needed for offshore wind farm operations, having at least four legs is preferred to three legs. This lessens the risk of "punch through" or scouring instability. More legs may also be needed to share the load.

Other factors that may affect selection are:

- Spud cans to spread the load or protect the ends of the legs from damage when jacking up on rock;
- Water jetting to release legs;
- Wave limits for jacking operations;

- Speed of positioning (tugs, anchors, dynamic positioning); and
- Transit speed.

A very limited number of jack-ups or lift-boats operating outside the Great Lakes are of dimensions that allow transit in through the Seaway. The largest American lift-boats capable of entering the Lakes have lift capacities less than 200 te and would therefore have limited use. An example, shown in Figure 5-17a, is the "SeaCor Champion", a 230 ft Class (70 m leg length) three-legged lift-boat based in the Gulf of Mexico with a lift capacity of 181 te. Further afield the offshore wind industry in Europe uses towed or self-propelled jack-ups with four legs or more, which are less vulnerable to uncertain seabed conditions. Of the prevalent MSC Gusto designs, only the smallest examples of the towed marine construction jack-ups can pass into the Great Lakes, for example "Vagant" (Figure 5-17b).



a) "SeaCor Champion" – US liftboat. 28.8 m beam, 41.8 m length, 181 te crane. Seaway compliant.

b) "Vagant" (on right) during 5 MW installation, showing relative sizes. Vagant is Seaway compliant.

Figure 5-17 Seaway compliant jack-ups

Also Seaway compliant are "Sea Power" and sister "Sea Energy" (Figure 5-18), which are ship-shaped cargo vessels adapted in the early days of European offshore wind construction for use as leg-stabilised crane vessels. Sea Power's crane now has a maximum 600 te lift capacity, though like most cranes this is only achievable in rather limited configurations. Sea Energy no longer works in the offshore wind industry.

Figure 5-18 Sea Power leg-stabilized vessel

Another option to provide fixed lifting would be to fit spud legs or even jack-up legs to an existing or new-build barge or pontoon to provide a customised crane platform to meet the needs of offshore wind. With spud legs, the hull is not lifted out of the water unlike jack-ups. The spud legs are lowered into the sea-bed from the hull and provide some lateral stability. Such spud-leg or jack-up pontoons are relatively straight-forward to build and could be customised to create an even larger pontoon by connecting two or more together rigidly.

Floating heavy lift

Options for floating cranes on the Great Lakes are more extensive, the simplest being a land-based crane operated from a dumb (i.e., towed) barge, of which there are many. This is the most common type of vessel used to support marine construction projects in rivers, coastal and inland waters, sometimes with spud-legs to provide lateral stability. Active ballasting allows more stable operation. “Nunavut Spirit” (Figure 5-19) is one of the larger towed barges or pontoons operating within the Great Lakes and is of standard (400 ft) dimensions.

McKeil's "Nunavut Spirit", 32 m beam, 122 m (400 ft) length, spud legs for 30 m water depth.

Figure 5-19 Towed spud-leg barge operating within Great Lakes

Dedicated floating crane vessels in the Great Lakes system include vessels operated by the St. Lawrence Seaway commissions primarily for lifting dock gates, though with lift capacities of no more than 300 t.

Heavy lift cargo vessels capable of entering through the Seaway include a number which are self-loading as they have their own lift gear (which leads to them sometimes being referred to as "geared vessels"). Some, such as the "HHL Volga" shown in Figure 5-20a, are already used for delivering wind turbine components for onshore wind farms. Figure 5-20b shows "MV Fairlane" which has one of the greater crane capacities, with two 400 t cranes.

a) "HHL Volga" delivering wind turbine components in Great Lakes. Seaway compliant.

b) Jumbo Shipping's "MV Fairlane", Seaway compliant

Figure 5-20 Heavy lift cargo vessels, Seaway compliant

In summary, because the capacities of these existing vessels and platforms are quite limited, it is expected that a combination of imaginative techniques, adaptations and new-build vessels will be needed for installation of offshore wind projects. Moreover, bringing in capable vessels from afar for just the installation phase may not be the most prudent strategy for the whole life of the wind farm. When selecting installation vessels, it will be necessary to consider what will be available for through-life maintenance and for decommissioning.

It is outside the scope of this study to undertake a detailed review of vessels capabilities and ship-building capacity within the Great Lakes. Nevertheless in the following sections, consideration is given to the changes in installation and decommissioning methods to match the vessels options, rather than assuming methods used in Europe will directly translate into the Great Lakes.

From the perspective of decommissioning, however, the overall assumption must be that if offshore wind farms have been constructed in the Great Lakes then techniques and vessels will be in existence and will be in use for major change-outs of components during the life of the projects and will therefore be available for the end-of-life decommissioning.

5.5.2 Cutting techniques

The decommissioning of the majority of foundation types requires underwater cutting. Underwater cutting methods and equipment have been extensively developed in the last 20 years, largely to meet the requirements of Oil & Gas decommissioning. This has resulted in expertise and equipment being available on both sides of the Atlantic. The main techniques are abrasive water jet cutting and diamond wire cutting.

5.5.2.1 Ultra-high pressure (UHP) abrasive water jet cutting

UHP uses water at pressures of up to 3,000 bar fired through a nozzle to form a fine jet. With the entrainment of abrasive particles in the water flow, typically forms of garnet or flint, materials such as reinforcement in concrete and plate steel of thicknesses over 100 mm can be cut. The technique works above or below water.

UHP abrasive water jet cutting is used for pile removal in marine environments and manipulator tools are continually being developed for use with increasingly larger pipes and piles, and for applications using remotely operated underwater vehicles (ROV) rather than divers. Although the largest diameters catered for at present are less than 5 m, in principle the methods can be scaled up to the pile diameters and wall thicknesses required for offshore wind monopiles. Abrasive water jet is the established and preferred method for cutting underwater piles such as in oil rig decommissioning.

Cutting of the pile may be done externally or internally, depending largely on the ease of removing sea-bed material down to the level of the cut and the ease of access to the pile wall. In either case, the cutting will be underwater. The environment inside the pile is more sheltered.

a) External cutting frame

b) Cutting jet

c) External cutting track and ROV manipulator

d) Internal cutting manipulator

Source: Oil States.

Figure 5-21 Internal and external cutting using UHP abrasive water jet

External cutting would involve a circumferential cutting track carrying the cutting head on a tractor unit, as shown in Figure 5-21. Figure 5-21a shows a simple external frame, whereas Figure 5-21c shows an external track with an ROV manipulator that incorporates controlled buoyancy.

Internal cutting of piles often uses a “torpedo” manipulator with centralising arms and a rotating cutting head, as in Figure 5-21d. If internal cutting were used for the larger diameter of MPs, then an internal track with a tractor unit could be designed, or an expanded version of the torpedo-shaped manipulator devised. In either case, use of internal cutting may require internal steelwork to be removed to gain access.

Cutting times using UHP abrasive jet cutting depend largely on the circumference of the pile and on the wall thickness, though also on the energy (pressure) of the water jet. Cutting times of 18 to 30 hours are estimated for MPs of 6 to 10 m diameter and 100 to 120 mm wall thickness.

For offshore wind decommissioning, customised tooling would be developed, possibly adjustable to fit piles of different diameters. For cutting multiple MPs, two tracks or manipulators would be used so that whilst one was being used for cutting, the other would be setting up for the next unit.

5.5.2.2 Diamond wire cutting (DWC)

DWC uses a bespoke saddle and clamping to force a continuous abrasive wire onto the cut, as shown in Figure 5-22. It is necessarily an external cutting method. The photos show the rig on the left and the resulting cut on the right. In practice, the abrasive may be diamond or tungsten carbide.

Source: Proserv.

Figure 5-22 Diamond wire cutting

Wire cutting is a preferred method for cutting cables in conditions that are more challenging for divers as it can be set up from an ROV. It is also suitable for horizontal pipes where the cut is made near-vertically and there is ready access from the outside. However, diamond wire cutting is thought less suitable for the MP cuts as jamming of the wire is a potential risk when the cut is horizontal especially with greater diameters. For offshore wind decommissioning, diamond wire cutting might be selected for cutting the array cables at their exit from the MPs, using a bespoke rig to provide the support saddle and clamping arrangement.

The strategy for removing the foundations will centre on the number of cuts to be made. In general, it is most efficient to minimise the number of separate marine operations.

5.5.3 Wind turbine generator, 4 MW and 8 MW sizes

5.5.3.1 WTG design and materials

Figure 5-23 indicates the main parameters in the turbine design and Table 5-8 provides dimensions and masses of the key components for the two capacities of generic turbine selected. All masses are given in metric tonnes. Unlike tidal seas, no distinction needs to be made between low and high water for the level of detail in the current study.

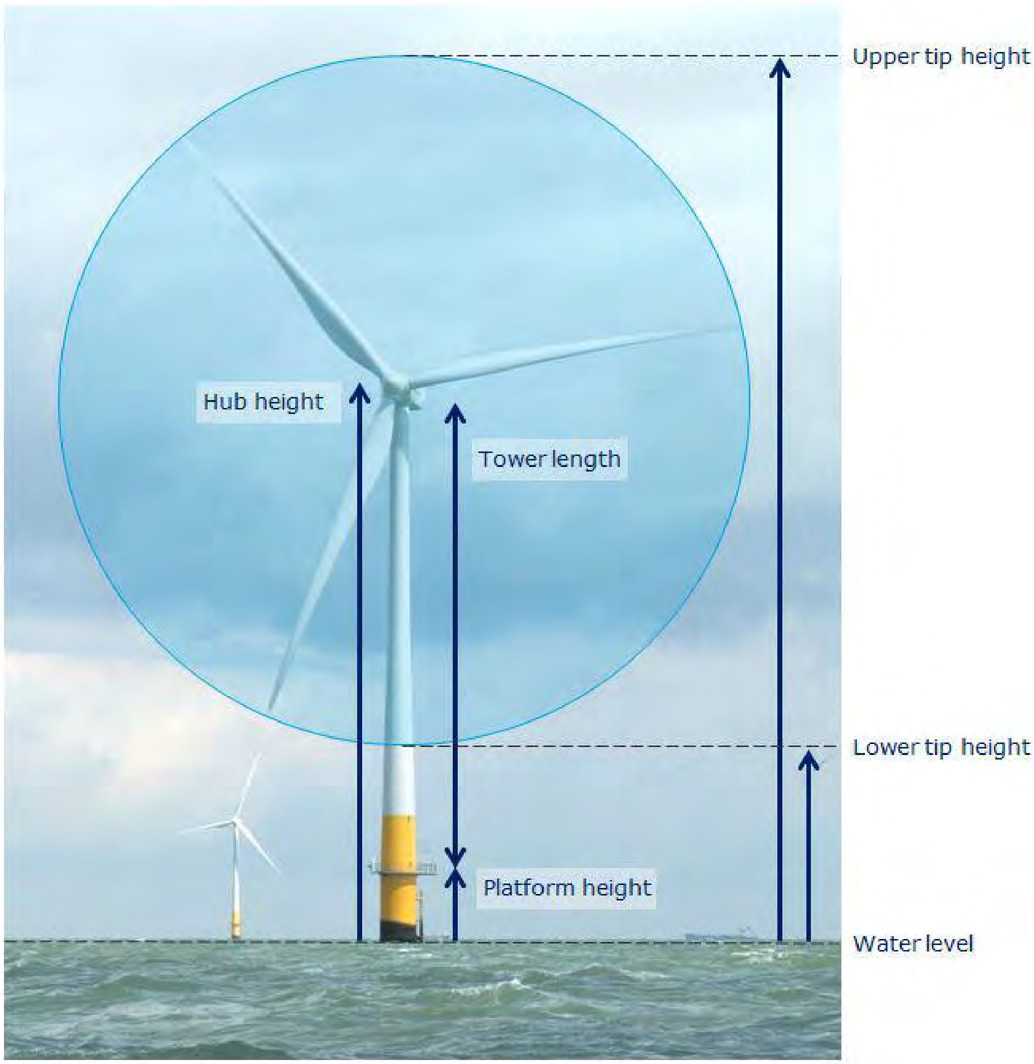


Figure 5-23 Main parameters of offshore turbine

Regarding the dimensions, the minimum hub heights for offshore wind turbines are determined by the rotor diameter and the requirement for clearance of the lower blade tip above the water surface, generally not less than 22 m. The heights of the external platform above the water level are influenced by the extreme wave heights and are expected to be 10 to 15 m in the Great Lakes. Depending on the design, the tower base may be level with the platform or may be higher. The rotor diameter selected may depend on availability from the turbine manufacturers and also on suitability for the wind conditions at the site. Likely values are presented in Table 5-8 below.

Table 5-8 Typical masses and dimensions for generic turbines

Component	4 MW turbine	8 MW turbine
Hub height above water level	85 m	110 m
Rotor diameter	125 m	175 m
Blade length	60 m	85 m
Nacelle dimensions (width x length x height)	5 x 13 x 5 m	8 x 20 x 8 m
Tower diameter at base	5 m	7 m
Tower length	70 m	95 m
Blade mass (each)	20 t	35 t
Rotor mass (3 blades + hub) = rotor star	90 t	155 t
Nacelle mass (excludes hub)	130 t	400 t
Nacelle mass (includes hub)	160 t	450 t
Tower mass, includes secondary steel	300 t	650 t

Regarding the masses, these can vary considerably according to the design of the components which in turn are a focus of development effort.

Turbine blades are hollow comprising shells of glass-reinforced epoxy (GRE) stiffened by layers of rigid foam. Longitudinal members (spars) of solid aligned GRE provide additional axial strength. In some blade designs, some critical areas may use carbon fibre in place of glass fibre for its greater stiffness to weight ratio. Layup of the glass fabric for the shells and load-bearing members is automated and the epoxy resin is typically vacuum-infused into the glass for a higher-quality result. At the blade roots, the aerofoil profile merges into a cylindrical section where integral root fixings provide for bolted connections with the turbine hub. Designs of the root fixings and aerofoil structure may vary between manufacturers. Construction may involve the adhesive bonding of two halves, or manufacture may be by resin-infusion in a single piece.

Layers of pigmented gel coat comprise the blade surface to seal and protect the blade from water ingress and ultraviolet degradation. Incorporated in the blade will be lightning protection, usually in the form of metal studs at the blade surface. Erosion protection is usually added in the form of strips along the leading edge.

Masses of blades are typically 20 t for a 4 MW turbine and 35 t for an 8 MW turbine. In general, developments in manufacturing techniques are leading to reductions in blade weights.

The main components atop the turbine tower are shown in Figure 5-24, in this case for a geared design.

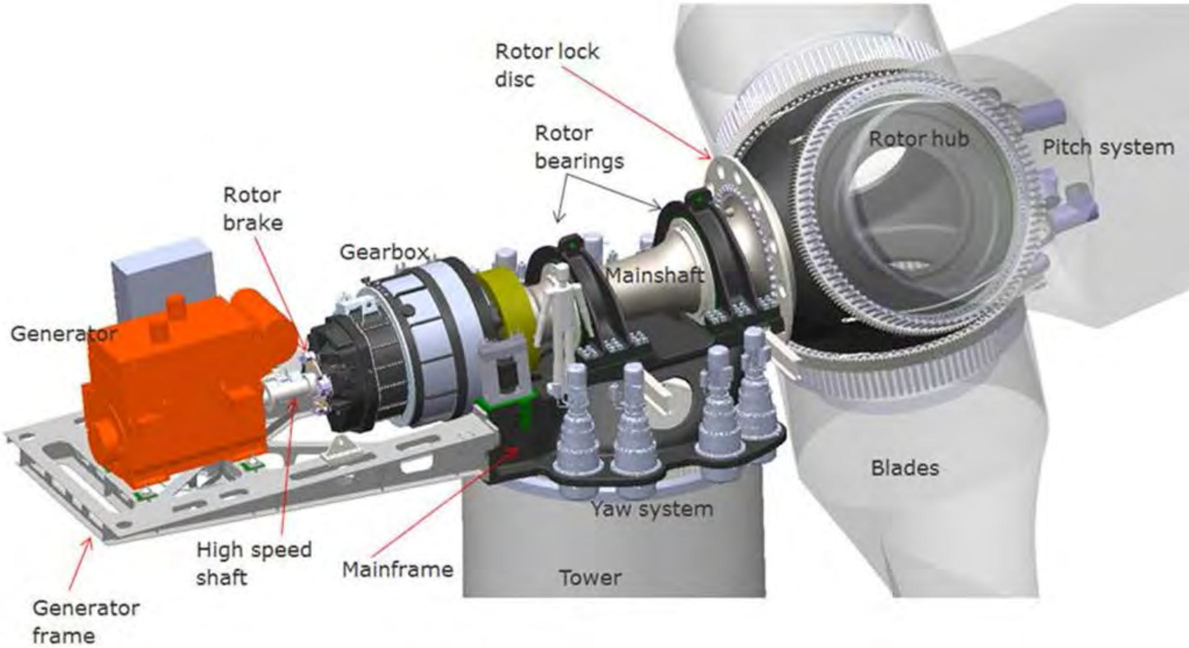


Figure 5-24 Wind turbine nacelle and rotor components

The blades are connected by bolted flanges to the hub, which in turn drives the rotation of the main shaft. In geared designs, the gearbox steps up the shaft speed into the electrical generator. In direct-drive designs, there is no gearbox and the generator is designed to suit, generally resulting in a heavier nacelle. The drive train includes bearings, lubrication systems and brakes, and the whole assembly is supported on a rigid bed plate. The yaw motors turn the nacelle about the tower top to face the rotor into the wind. Also in the nacelle will be the power electronics and usually the transformer; the control and monitoring systems, known as SCADA (Supervisory, Control and Data Acquisition) systems; and environmental control (temperature, humidity). Mounted externally on the back of the nacelle roof is likely to be a platform for helicopter hoisting operations – for emergencies, or possibly for maintenance access.

The hub is typically ductile cast iron; the gears, bearings and drive shafts are alloy steel; and the bedplate may be cast or fabricated steel. The generator and transformers contain copper windings typical of all electric machinery; in designs with a permanent magnet generator (PMG) rare-earth metals are present. The nacelle housing itself is typically aluminium alloy or glass-reinforced composite to minimise the weight.

The total weight of the complete nacelle can vary considerably according to the design and the manufacturer, though in general weights are being reduced. Weights can also vary according to which components are included. For the purposes of the generic turbines, the nacelle weight including hub is assumed to be 165 t for the 4 MW turbine and 450 t for the 8 MW turbine.

The tower is generally slightly tapering with a wider base than top and made of structural steel, painted inside and out for corrosion protection. The tower is fitted with internal platforms, ladders and a lift mechanism. The entire tower weight relevant for construction and decommissioning should generally include the internal steelwork, and is assumed to be 300 t for the 4 MW turbine and 650 t for the 8 MW turbine.

5.5.3.2 WTG construction and installation

The blades are generally manufactured at a separate facility from the rest of the turbine, and are delivered directly to the construction port usually by sea as such blade lengths are difficult for road transport.

The contents of the nacelle are assembled and tested in controlled conditions by the manufacturer, and delivered whole to the construction port. To aid installation the design includes lifting points. To allow individual components to be removed once the turbine is in service, many designs have a small crane fitted in the nacelle that can lower pieces down. If larger components need to be removed, access through the nacelle roof is possible by an external crane such as a crane jack-up.

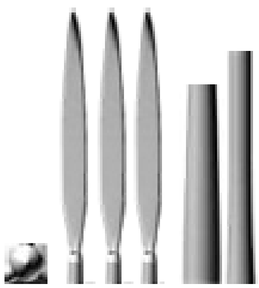
The tower is manufactured in two or more sections joined by bolted flanges. Each section is fabricated from cans of rolled and welded steel plate; once complete, corrosion resistant paint is applied inside and out. The base of the tower is bolted to the foundation, usually at the level of the external platform. The top of the tower has a bolted flange joint with the nacelle.

WTG installation at the project site can be carried out after varying degrees of pre-assembly, and the following main strategies have been used:

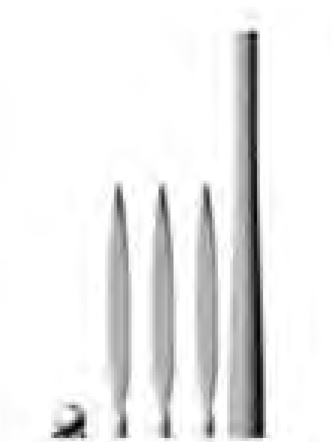
- Multiple lifts with the tower in two sections, then nacelle, then blades singly (Figure 5-25a) – current practice
- Tower as single piece, then nacelle, then blades singly (Figure 5-25b) – current, the most common
- Tower as single piece, then nacelle with two blades ("bunny ears"), then third blade (Figure 5-26)– previous practice
- Tower, then nacelle, then pre-assembled "rotor star" consisting of hub + blades (Figure 5-27) – current practice.
- Whole turbine pre-assembled as single lift (Figure 5-28) – done occasionally

Installation of the WTG requires precision lifting and is almost always done using a jack-up crane to provide a fixed lift; this enables tight positional tolerances to be achieved, avoids dynamic accelerations (knocks) damaging the components and for the safety of the technicians. In the illustrations, the exception is Figure 5-28 where a floating shearleg crane was used together with a temporary heave-compensating "soft landing" frame on the foundation, visible as the dark structure around the top of the yellow jacket.

Even with the use of fixed cranes, blade installation is very susceptible to winds, which naturally are greatest at hub height. To reduce the wind effects, blades are generally lifted in a horizontal orientation and with the use of special clamps, spreader beams and tugger wires as shown in Figure 5-25a.



a) Two-section tower "Seajacks Leviathan" – credit Seajacks

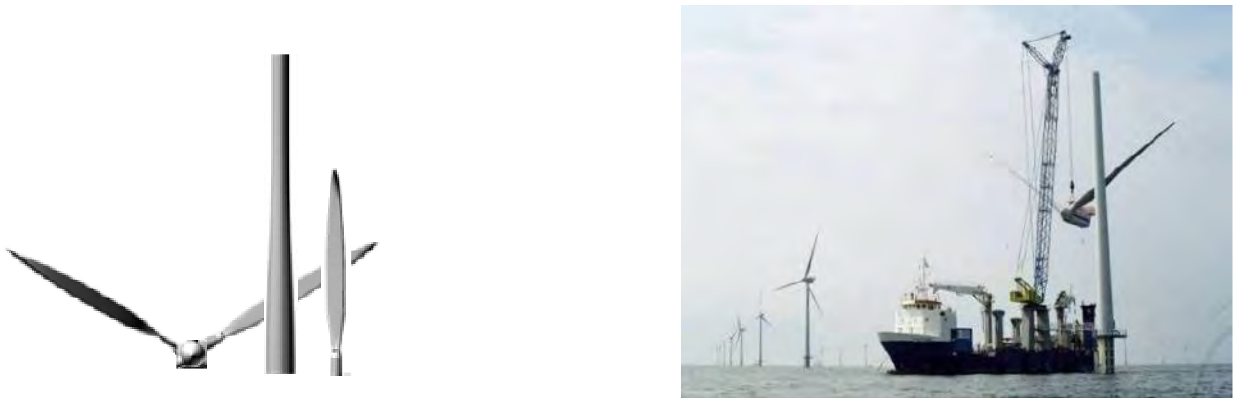


b) Single piece tower "Bold Tern" – credit Fred. Olsen Windcarrier

Figure 5-25 Illustrations of single blade lift

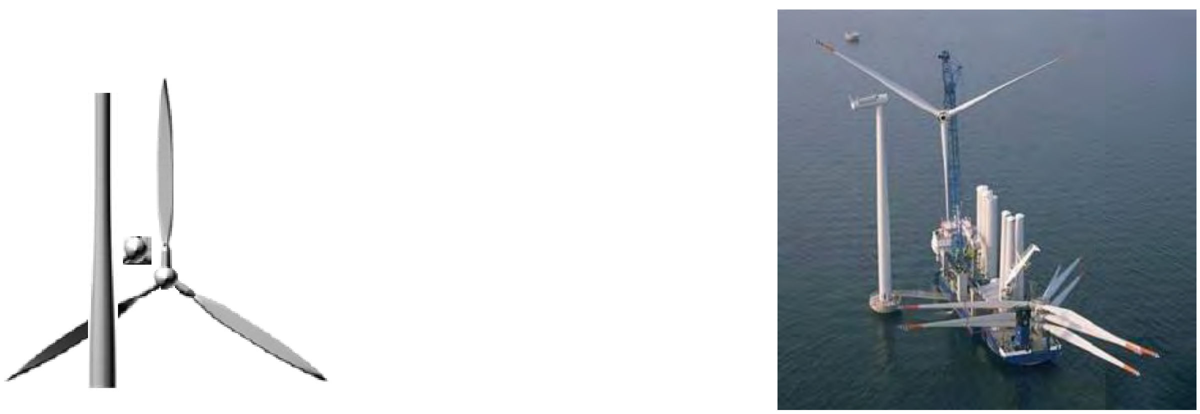
In general the philosophy has been to reduce the number of lifts offshore, which is one reason that full rotors (rotor stars) and "bunny ear" methods (see Figure 5-26and Figure 5-27) have been selected in the past. However the logistics of loading and transporting such bulky pre-assembled structures often outweighs the advantages of fewer lifts, and the most common method currently found in Europe is to install the tower, nacelle and each blade singly as shown in Figure 5-25b.

The WTG installation jack-up transports and installs the components of several turbines in a single trip from port. Bespoke modular blade racks and re-usable sea fastenings are employed to maximise the carrying capacity and minimise the time taken.



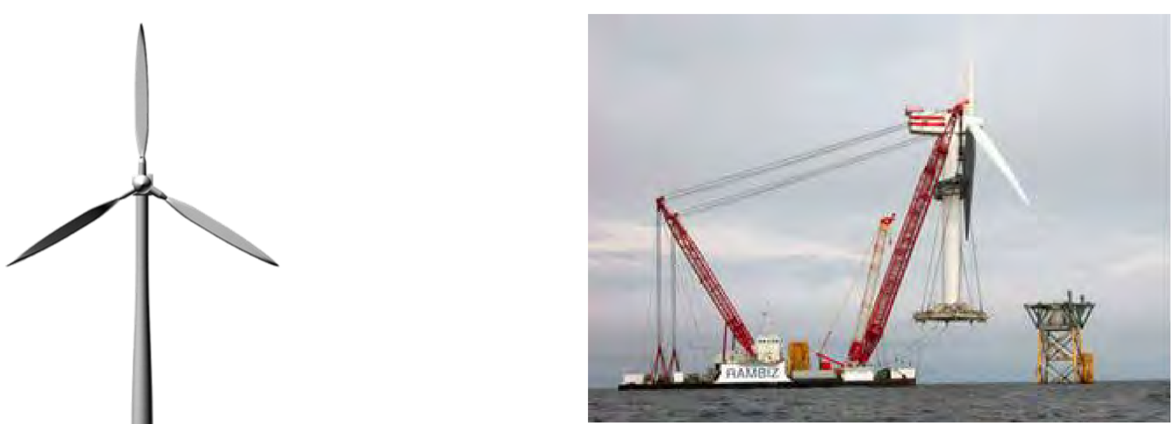
“Sea Energy” – credit A2SEA

Figure 5-26 Illustration of “bunny ears” installation



“Sea Power” – credit A2SEA

Figure 5-27 Illustration of a full rotor lift



“Rambiz” shearleg – credit Scaldis

Figure 5-28 Illustration of a full wind turbine installation

The ideal vessel for turbine installation thus has crane capability for the combination of hub-height lifts and weights, together with carrying capacity for the components of multiple turbines, and the leg length to jack up in the water depth at the project site. Crane capacities need to allow for the extra height and weight of lifting gear. Leg lengths need to allow for leg penetration into the sea-bed and provide a safe air-gap that takes seasonal wave heights into consideration.

The most challenging lifts, in terms of crane capability, are the lifts of the nacelle at hub height, assuming that the tower is removed in two sections if necessary:

- For the 85 m hub height of the 4 MW turbine (Table 5-8), this requires around 100 m under-hook height above the water after allowing for the lifting gear, and the 160 t nacelle probably requires a lift capacity of 200 t if the nacelle is lifted pre-assembled.
- For the 110 m hub height of the 8 MW turbine this requires around 130 m under-hook height and for the 450 t nacelle a lift capacity of at least 500 t, again at the required radius and assuming the nacelle is pre-assembled as is usual.

On the basis of this nacelle lift, A2SEA's "Sea Power" leg-stabilised vessel shown in Figure 5-27, or a self-propelled jack-up of similar size, has the capacity to install the 4 MW turbine in water depth up to 24 m, though not the 8 MW turbine.

a) Custom-built gantry to raise crane on jack-up. "Buzzard" (left) and "Vagant" (right) installing 5 MW rotor star.

b) Use of jack-up legs in shallow water to raise crane. "KS Titan" (subsequently called "Bull Rey") installing tower.

Figure 5-29 Some alternative methods for reaching hub height

Alternatively mobile cranes on jack-up platforms might be used, though may be particularly challenged by the hub height. Figure 5-29 shows two examples of attaining higher reach by either addition of a higher pedestal, or making use of the leg length if in relatively shallow water.

Another method is to use an even larger and more capable crane, with a sufficiently large platform to suit. As an example, Figure 5-30 shows the use of two onshore cranes including a 1600 t crane working at over 50 m radius to install the 171 m diameter rotor Samsung 7 MW prototype with 110 m hub height.

Figure 5-30 Installation of 7 MW turbine using onshore cranes

More radically, it is feasible that a modified strategy is adopted for the Great Lakes whereby the larger lifts are broken down into smaller lifts, such as adding the hub or even the drive train after installation of the rest of the nacelle, as is sometimes done when installing onshore wind turbines, and breaking down the tower into more sections if this becomes the largest lift.

5.5.3.3 WTG decommissioning

The decommissioning of wind turbines is essentially the reverse of installation and is expected to require similar cranes, vessels, and equipment. It is assumed that any life extension has already occurred and the turbines are being returned to shore for scrap. Although decommissioning activities are less sensitive to component damage than installation, operating limits still apply for the safety of personnel and legal use of equipment. For this reason and because there are unlikely to be offshore-capable cranes in the Great Lakes capable of lifting at height, fixed lifts are expected to again be required for handling of turbine components. Elsewhere, dismantling of WTGs using large offshore cranes may be a more economic option.

For decommissioning of the turbine, the main options range from removal in a single lift through to multiple lifts. It is envisaged that the standard five-lift strategy is used as far as possible, with the blades removed singly, then the complete nacelle including hub, and then the complete tower including internal steelwork.

For removal of the 4 MW turbine using the standard five lift strategy, the required minimum crane capacity of 200 t with hook height of 100 m can be achieved using:

- Either, a towed jack-up platform constructed within the Great Lakes, with a crawler crane on board capable of both height and weight required for the lift;
- Or a self-propelled jack-up or leg-stabilised vessel constructed within the Great Lakes, or possibly brought in through the Seaway (such as A2SEA's "Sea Power"), with integral crane of sufficient capacity.

Unless a crane vessel capable of dynamic positioning is used, tugs will also be needed to tow the crane platform to site. Once the anchor lines are in place, the jack-up barge uses winches for positioning.

The Terex Demag cc2800 crane fitted on "Sea Power" has nominal capacity of 600 t but when configured for an under-hook height of 90 m (above the crane tracks), it has a maximum lift of around 200 t at 15 m lift radius. Given the additional height provided by the crane support on the vessel and the height of the deck above water level, the 4 MW hub height should be achievable and the crane capability should be just sufficient for the 4 MW nacelle.

For the removal of the 8 MW turbine, a much more capable crane is needed to accomplish the five-lift strategy. To achieve the 500 t lift and 130 m hook height above the water for the nacelle, a heavy crawler crane operating off a large jack-up platform is likely to be used given the lack of access to the Great Lakes for specialised heavy lift jack-up vessels.

A large crawler crane such as a Liebherr LR11350-P1800 has maximum lift capacity 1,350 t. It can be configured to give a hook height of 118 m (above ground level) combined with a maximum lift of over 500 t at 34 m radius. Figure 5-31 shows such a crane lifting a 340 t nacelle lifted to 110 m during construction of a Senvion 5 MW wind turbine.

If mounted on a jack-up platform, the depth of the platform plus the air gap created by jacking up will extend the hook heights relative to the water level. In this configuration the total weight of the crane, its crawlers and counterweights is around 1,500 t, resulting in a total load borne by the supporting platform of over 2,000 t when a load of over 500 t is lifted.

Crawler cranes with greater capacity are also available such as the 3,000 t Liebherr LR 13000 crane. As an example this can be configured to give a hook height of 125 m combined with a lift of 1,000 t and reach of 23 m. Greater heights are possible trading off against lift capacity.

Liebherr LR 11350-P1800 lifting 340 t nacelle to 110 m – Credit Liebherr.

Figure 5-31 Example crawler crane for hub height lifts

It should be noted that if the dismantled turbine is being lifted by the fixed crane onto a floating transport vessel, this is classed as a dynamic lift and the crane capacity will be down-rated, typically by about 10%. Transfer to its own deck or to another jack-up will not incur this dynamic load factor. However, DNV GL does not believe that carrying out dynamic lifts with an onshore crane represents good practice, and would advise contractors to use jack-up feeder vessels when lifting with onshore cranes.

An alternative strategy for the 8 MW turbine, with more lifts, would enable a lower-capacity crane to be used. For example, separate removal of the hub reduces the 8 MW nacelle weight by about 50 t. Separate removal of major items from within the nacelle also reduces the maximum individual lift weight. Similarly the tower could be removed in two sections rather than in a single lift. Together, these modifications reduce the maximum single lift for the 8 MW turbine to an estimated 200 t, though a reach to the 130 m hub height is nevertheless required.

The overall decommissioning activities for the turbines will include:

- Pre-decommissioning: The season before, the condition of turbine components and in particular the integrity of lifting points is inspected. Compliance with regulations is implemented, and the decommissioning strategy developed. Tools and equipment are designed and contracted; method statements and risk assessments written; and vessels contracted. Onshore facilities are developed if necessary.
- Preparation: Immediately prior to dismantling, any moveable equipment is either removed or secured; any fluids or other hazardous materials are drained or otherwise made safe; the turbine rotor is oriented and electrically isolated as far as possible; and other actions carried out to make ready for dismantling (for example by easing bolts or cutting any that cannot be loosened). This work can be done by a small crew of technicians using a workboat.
- Turbine removal: Blades, nacelle, and tower are removed using a fixed crane; components are transported to shore and unloaded. If the blades are removed singly, the rotor may need to be turned between lifts to give the preferred horizontal blade orientation; this may require the use of a generator to energise the nacelle to power these movements. Transport may be on the crane vessel or on a separate vessel, barge or jack-up. A careful loading plan and design of sea-fastenings will optimise the use of the transport vessel and likewise the unloading plan at port will have to be drawn up. Fastenings can be more rudimentary than those for installation, given that the components will not be re-used.

5.5.4 Monopile WTG foundation

5.5.4.1 MP design and materials

Figure 5-32 illustrates the main components of a monopile (MP) foundation.

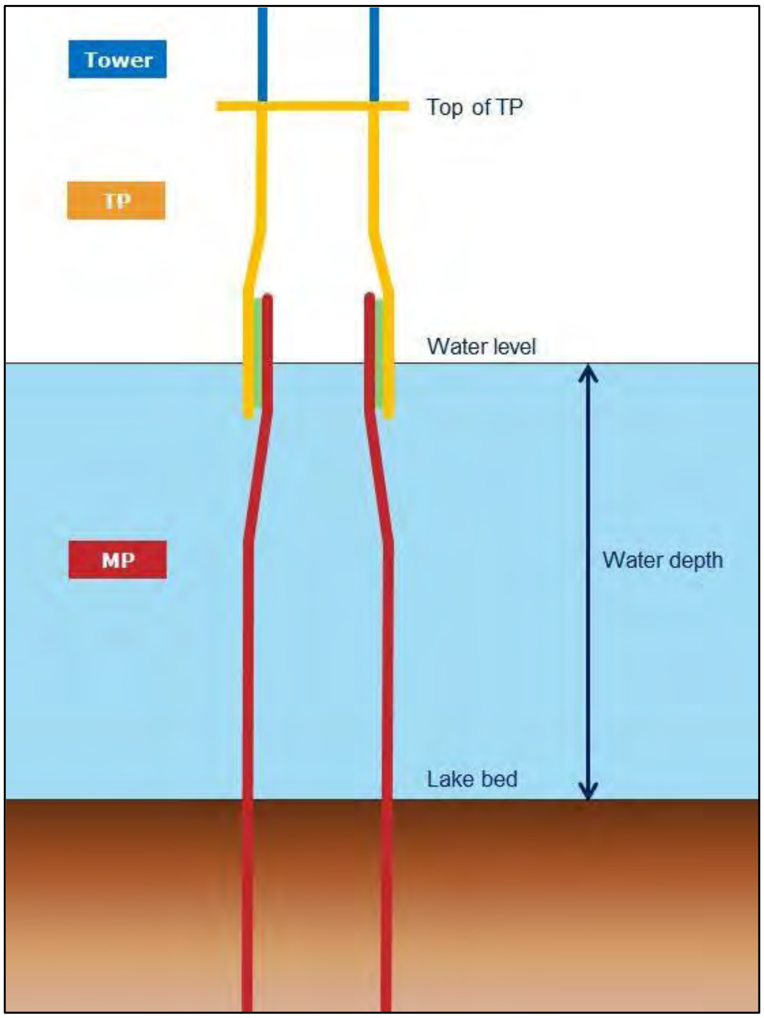


Figure 5-32 Standard configuration of monopile foundation

A typical MP foundation consists of a single pile embedded in the sea bed with the top of the MP usually above the water level. Attached to the MP is the transition piece (TP), shown in yellow. The turbine tower (shown in blue) is bolted to a flange at the top of the TP.

The primary purpose of the TP is to provide structural continuity carrying the loads between the tower and the MP. The TP also supports secondary steelwork comprising the main external platform, boat access ladders and landings, steel J-tubes or I-tubes (internal or external) taking the power cables from turbine to the sea-bed, frames of anodes for corrosion protection, and internal platforms. These are all seen in Figure 5-33, including external J-tubes on the left of each TP. On the right can be seen the access ladders.

In most designs, the turbine tower is bolted directly onto the top of the TP.

The detailed design and dimensions of the TP and MP are determined by consideration of the tower, TP and MP together, treated as a single entity. The main design drivers are the tower top mass of the turbine, the water depth and the strength of the sea-bed, combined with the static and dynamic forces from the wind, current and waves (mean and extremes), and the practicalities of installation.

TPs and MPs for Humber Gateway OWF – credit TAG.

Figure 5-33 Transition pieces and monopiles

In most offshore wind farms, the detailed design of the MP, and sometimes the TP, can be different for each turbine location or grouped in batches.

Table 5-9 provides typical dimensions and masses for MPs and their TPs for water depths of 25 m and 40 m.

The diameter of an MP is always constant throughout its embedded length, but often reduces gradually through the water column to a lower diameter at the top. Similarly the diameter of the TP may not be constant depending on the design.

Table 5-9 Estimated masses and dimensions for MP foundations

Water depth	Item	4 MW turbine	8 MW turbine
N/A	TP length	20 m	28 m
N/A	TP diameter	5 m	8 m
N/A	TP mass, including secondary steel	300 t	670 t
25 m	MP length overall	68 m	68 m
25 m	MP diameter, max	6 m	8 m
25 m	MP wall thickness, max	90 mm	120 mm
25 m	MP mass overall	650 t	1,200 t
40 m	MP length overall	83 m	83 m
40 m	MP diameter, max	6.5 m	10 m
40 m	MP wall thickness, max	90 mm	120 mm
40 m	MP mass overall	1,000 t	1,800 t

Typical TP dimensions for a 4 MW turbine are 5 m diameter and 20 m vertical length. For an 8 MW turbine the MP is around 8 m in diameter and 28 m in length. For a given offshore wind farm, the TPs are usually identical (with the exception of the J-tube arrangements), unless there are big differences in water depth or soil conditions that lead to large variations in the MP diameters.

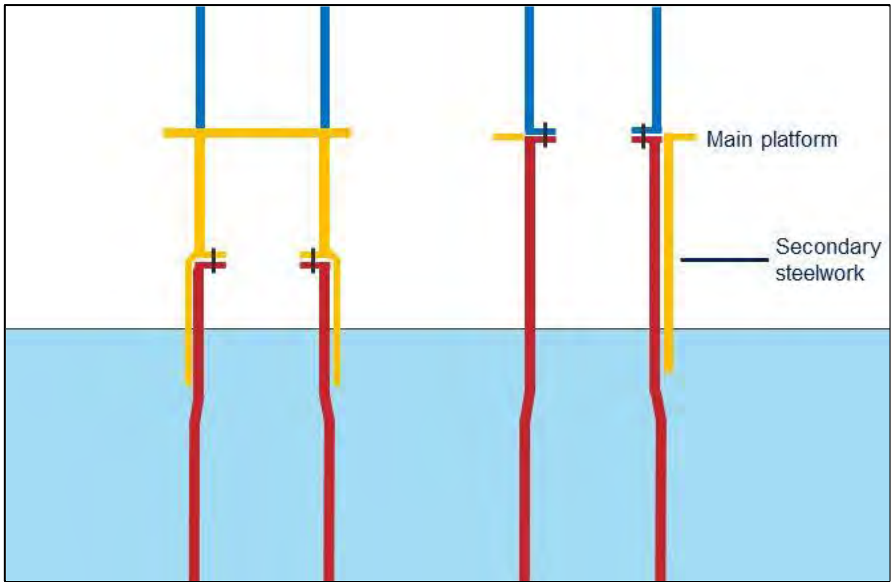
The MP diameters correspond to the diameters at mud-line level and for a particular turbine power rating are larger for greater water depths, primarily to provide the required stiffness. Typically sea-bed MP diameters are 6 to 6.5 m for 4 MW turbines, and 8 to 10 m for 8 MW turbines.

The depth of embedment of the MP below the mud-line is typically no more than 50 m and is assumed to be 40 m for the example cases. Thus after adding the length through the water column and the stick-up above the water level, total MP lengths are around 68 m and 83 m for the 25 m and 40 m water depths.

Wall thicknesses vary down the length with greatest thickness for MPs at the mud-line where the moments are highest, and for TPs in the splash zone where losses from corrosion are most likely. As a first approximation a diameter-to-wall thickness ratio of 100 at mud-line level is a reasonable estimate, indicating wall thicknesses of 60 to 100 mm.

The detail of the MP-TP connection can vary considerably, particularly with the recent introduction of bolted joints. The sketch in Figure 5-32 shows a traditional sleeved connection with the TP cemented in place by grout, shown green, which allows some adjustment for vertical misalignment. So that the load path does not rely entirely on the integrity of the metal to grout bond, the design of the joint may be given additional mechanical strength from either shear keys (e.g., raised metal ridges on the surfaces such as weld beads) or more often from the geometry itself through making the joint at a coned angle.

With tighter vertical precision now possible during piling, bolted joints are being developed and have started to be used. Figure 5-34 shows sketches of the two main variants.



a) Bolted MP–TP connection b) Direct bolted MP–tower connection

Figure 5-34 Bolted monopile connections

The bolted MP-TP shown in Figure 5-34a retains a TP skirt that extends down into the water and is used to support the secondary steelwork as in the standard design. To protect the joint from corrosion and to mechanically support the skirt, there may be seals or grout between the skirt and MP.

Foundations for Kentish Flats Extension - Credit Vattenfall.

Figure 5-35 Transport of direct bolted MP and secondary steelwork

In the design in Figure 5-34b, there is no TP with the tower bolting directly onto the top of the MP. The secondary steelwork is attached afterward installation of the MP, for example in the form of a cage as shown in Figure 5-35. The MP is longer than with other designs. Both types of bolted design have been used in recently installed offshore wind farms.

Design against ice is likely to require ice cones at the water level. These may be incorporated into the secondary steelwork attached to the TP, or in the case of the directly bolted MP-tower connection, the ice cones would be added afterward with the other secondary steelwork. Although speculative designs show both downward and upward angled cones, upward angled cones are thought more efficient in deflecting ice away especially in shallow waters and thick ice. Design against ice may also lead to greater wall thicknesses.

Materials. Monopiles, transition pieces and secondary steelwork are all made from structural steel. Corrosion protective coatings are applied to the TPs and steelwork, with extra attention in the splash zone, usually multiple layers of two-part epoxy resin and polyurethane paints augmented by metallic primers (e.g., zinc).

5.5.4.2 MP and TP construction and installation

MP and TP shells are constructed by rolling of sheet steel in axial lengths of 2 to 3 m (Figure 5-36).

These are welded longitudinally to form cans and then circumferentially to create the full length structure. Flanges and any secondary steelwork are then added. All welds require non-destructive inspection.

Developments in the fabrication facilities over the last five years has allowed the production of 10 m and 11 m diameter piles weighing up to 2,000 t to now be offered commercially, for example by SIF and EEW. One of the main limitations is the weight rather than the dimensions per se.

a) Pile rolling – credit SIF

b) Welded cans forming 7.5 m diameter MP – credit EEW

Addition of secondary steelwork to TP – credit EEW

Complete MP and TPs ready for installation – credit DEME-GeoSea

Figure 5-36 Manufacture of MPs and TPs

Manufacturing facilities are located so as to enable the completed foundations to be transported by sea to the construction port. Figure 5-37a shows loading of MPs and TPs using a crawler crane onto a towed barge. Figure 5-37b shows use of a heavy lift cargo vessel which can self-load using its own cranes. In this example eight MPs are transported by Jumbo's "Fairpartner".

a) Loading of MPs and TPs onto barge – credit TAG

b) Transport of MPs – credit Jumbo

Figure 5-37 Transport of MPs and TPs by sea

Installation of MPs is by driving if the seabed is sand or clay sedimentary layers. If the sedimentary layers contain rocks (such as the glacial boulder clays found in Northern Europe) or layers of harder material, then a combination of driving and drilling may be used, the "drive-drill-drive" method. If the sea-bed is too hard for driving, then the socket may be drilled and the pile grouted into place, as done in some of the offshore wind projects in the Baltic Sea such as Yttre Stengrund.

These MP installation techniques generally require the stability of a jack-up platform. However, if wave conditions are sufficiently benign, use of a floating vessel held on position by dynamic positioning or anchors may be possible.

MPs may be transported to the project site on board the installation vessel (Figure 5-38a & b), on a feeder vessel, or may be floated out after sealing the ends (Figure 5-38c & d). The MPs are then upended, using attachments to the top or trunnions on the sides of the pile, together with a pile upending frame from which they are transferred to the pile guide.

TPs may be installed from a floating or jack-up vessel. Figure 5-39 shows TP installation with a DP (dynamic positioned) floating heavy lift cargo vessel. It is then levelled and grouted (or bolted) into position.

a) MP transported on crane jack-up vessel

b) Upending of MP using manipulator

c) Towed MP showing seal – credit Dong

d) Upending floating MP

Figure 5-38 MP transport to site and upending

Credit - Jumbo Shipping

Figure 5-39 TP installation from heavy lift cargo vessel

After the MP foundation is in place and the array cables are laid, the cable ends are drawn up through their J-tubes into the cable hanger connections at the top of the TP, later to be connected to the turbine output cable.

Depending on the combination of sea-bed conditions, water depths and currents, the piles may require scour protection. In this case, a layer of gravel is laid on the sea-bed prior to driving the MP, and then further stones (known as rock armour) of larger size placed once the MP is in position. Given the very low current speeds in the Great Lakes it is unlikely that scour from currents will be an issue. However, if the cables cannot be readily buried, then protection for the cables by rock dumping or other means may be necessary to guard against disturbance by anchors or fishing.

The most challenging operations during installation are the lifts required to upend the MPs and hold them in the exact position for piling. If the full weight of the MP is taken by the crane, it will need to handle up to 1,000 t for the 4 MW turbine MP and 1,800 t for the 8 MW turbine MP when there is 40 m water depth: the lifting gear will add some weight, though the weight of the pile when immersed in water will be less. At the same time, the MP top will be at more than 40 m above the water level before piling commences and additional hook height, typically 20 m, will be needed to lift the pile hammer into place.

However, with the relatively benign conditions in the Great Lakes and limited heavy lift equipment available, it is likely that floating out of the MPs may well be adopted during installation. With careful design of the methods (such as design, positioning and removal of the sealing bungs), it should be possible to use the buoyancy of the sealed pile to support the weight of the pile during upending. If the water is too shallow for the pile to float vertically, the pile could be upended and manipulated using dual lifting points at each end of the pile. If such floating methods are used, the reach of the crane rather than its load capacity may become the key factor for the MP installation.

For TP installation, the 300 t weights (for the 4 MW unit) and 670 t (for 8 MW) with underhook heights of 25 m to 35 m above deck will also be challenging, but possible in the Great Lakes using a heavy lift cargo vessel such as Jumbo's Seaway-compliant "Fairlane" (Figure 5-20b) or a mobile crane mounted on a platform.

5.5.4.3 MP and TP decommissioning

Decommissioning plans and methods for MP foundations are the most commonly prepared and costed given the propensity of this type of offshore wind turbine foundation.

In general, the decommissioning assumption for MP foundations is that the MPs are removed by cutting below the mud-line level and taken to shore together with the TPs. The majority of the embedded MP is thus left in situ, on the grounds that removal would create excessive environmental disruption and the costs would be prohibitive. It is a standard assumption that this method will be acceptable provided the depth of the cut below the mud-line is sufficient to avoid exposure of the remaining piece or cause any future hazard to other sea users, in particular anchors and fishing gear. It is also assumed that the site is adequately monitored post-decommissioning.

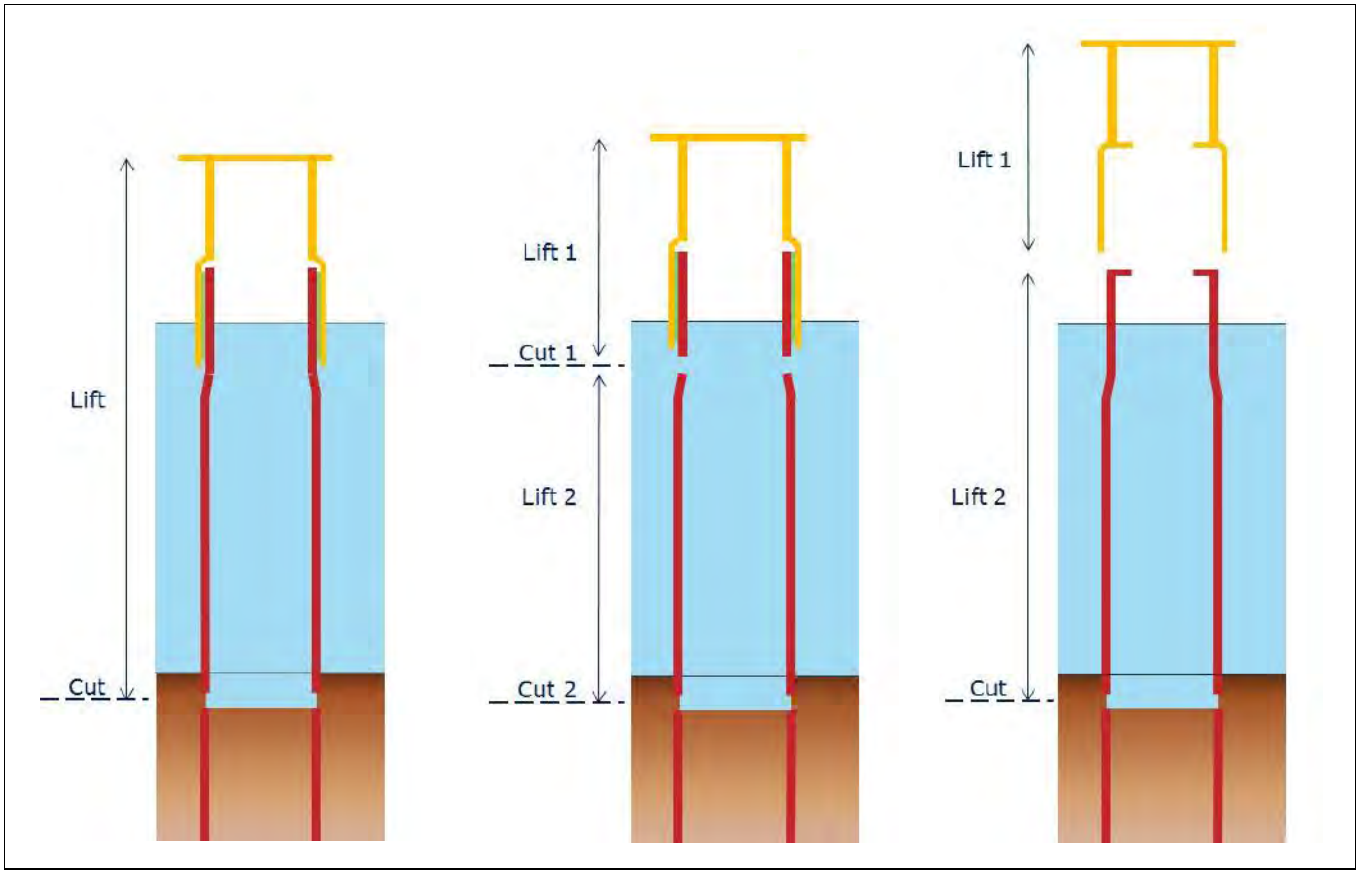
The exact depth below the mud-line is agreed with the regulatory authority and may be 1 to 5 m below the current mud-line, with the greater depths anticipated where the local mobility of the sea-bed could potentially uncover the pile stumps.

It is assumed that the removal of the turbine foundations is a separate operation from the removal of the WTGs. For offshore wind farms with numerous turbines, separate vessels are likely to be used for the WTG and foundations removal, working one behind the other to make the best use of the seasonal weather and the specialist capabilities of each vessel. It should be noted that for projects consisting of only a handful of units such as demonstration projects, it is likely to be more economical to use the same vessel for WTG and foundation removal.

For the foundations removal strategy, the main option is typically the number of lifts utilised, which is strongly related to the lift and reach capacity of the crane. In every case, the crane will need to be attached to the piece to be lifted for the duration of the cut. The crane vessel used can be a floating vessel (DP or anchored) or a jack-up.

Potential lift strategies

Figure 5-40 illustrates three possible lift strategies and Table 5-10 presents the approximate raw masses. The masses exclude lifting gear but include the secondary steel. Where piles are cut, the weights are obtained by scaling the mass in proportion to pile length. Where grouted, grout weights are assumed to be 20 t and 30 t for the two sizes.



a) Single lift, one-cut b) Two lifts, two-cut c) Two lifts, unbolt + cut

Figure 5-40 Main lifting strategies for MP & TP decommissioning

The sketches indicate cutting from the inside, requiring mud removal from inside the pile, though external cutting is also an option.

Figure 5-40a shows a single-lift strategy whereby the MP is cut at the sea-bed, and the MP & TP are lifted out together. The main advantage is that using a single cut reduces the overall cutting time and potentially the duration of the crane vessel hire. This is the most challenging strategy in terms of both the weight of this single piece, the crane reach, manipulation and transport. With 25 m water depth, the maximum raw weights for the lifts are around 600 t and 1,200 t for the 4 MW and 8 MW foundations respectively. With 40 m water depth they are 860 t and 1,680 t. Overall lengths of these single pieces range from around 40 m to 60 m.

Table 5-10 Approximate masses and axial lengths for MP removal

Water depth	Item	Cutting strategy	For 4 MW turbine		For 8 MW turbine	
			Mass	Length	Mass	Length
N/A	TP	Unbolt+cut, upper piece	300 t	20 m	670 t	28 m
25 m	MP overall		650 t	68 m	1,200 t	68 m
25 m	TP + MP (+ grout) above sea-bed cut	Single lift	610 t	40 m	1,230 t	44 m
25 m	TP + MP inside above upper cut	Two-cut, upper piece	420 t	20 m	880 t	28 m
25 m	MP from sea-bed cut to upper cut	Two-cut, lower piece	190 t	20 m	350 t	20 m
25 m	MP above sea-bed cut	Unbolt+cut, lower piece	290 t	30 m	530 t	30 m
40 m	MP overall		1,000 t	83 m	1,800 t	83 m
40 m	TP + MP + grout above sea-bed cut	Single lift	860 t	55 m	1,680 t	59 m
40 m	TP + MP inside above upper cut	Two-cut, upper piece	440 t	20 m	920 t	28 m
40 m	MP from sea-bed cut to upper cut	Two-cut, lower piece	420 t	35 m	760 t	35 m
40 m	MP above sea-bed cut	Unbolt+cut, lower piece	540 t	45 m	980 t	45 m

Figure 5-40b illustrates a two-lift, two-cut strategy whereby the first cut is made just below the TP skirt, enabling the TP and the grouted part of the MP to be removed as the first lift; then the remaining non-embedded part of the MP is removed as the second lift. With 40 m water depth, the weights (and lengths) of the two pieces are approximately equal, whereas with 25 m depth the first lift is considerable heavier than the second. Nevertheless, the maximum lift will always be less than that for the single lift strategy.

Figure 5-40c indicates a possibility for one type of bolted connection, whereby the TP is unbolted to form the first lift; then the non-embedded part of the MP is removed as the second lift after cutting. In this example, the joint design is assumed to allow unbolting and for the joint to be readily separated at the time of decommissioning; in practice, designs of bolted joints are relatively new and still under development, and there is uncertainty whether separation at the end of life can be assumed to be straightforward. The heaviest lift is likely to be the MP and will depend both on the water depth and the position of the top of the MP relative to the water level. With 40 m water depth, the second lift is considerably heavier and longer than the first lift, whereas with 25 m depth, the two lifts are quite similar.

A further possibility is to partly support the single piece by flotation, though the release of the piece at the finish of the cut would need to be carefully controlled to be safe. The piece could then be towed to shore.

Given the limited capacity of heavy lift vessels in the Great Lakes, it is probable that a two-lift strategy will be used for removal of the foundations. Either a heavy lift crane will be used, or more likely a pair of cranes to share the load and enable the longer length pieces to be manipulated from vertical to horizontal. If a single crane is used then a long piece can be pivoted using a kicker-post assembly on the transport vessel to lower it to horizontal. The lifting capacity of the cranes will need to allow for the weight and under-hook height of the lifting gear and potentially a heave compensation unit to guard against sudden load changes; a dynamic amplification factor (DAF) may be needed to take the motion into account.

To transport the removed foundation pieces to shore, options are:

- Self-loading onto the crane vessel if it has the deck capacity. As during installation, TPs are probably stowed upright and MPs manipulated to be horizontal especially if relatively long. The vessel uses its own crane to unload at port.
- On a second vessel such as a towed barge. Placement of the piece on deck would be subject to more restrictive operating limits than self-loading since two vessels are involved. Furthermore, a crane is needed at the port to unload the pieces.
- Flotation, by making the foundation piece itself buoyant and towing it to shore. This is more applicable to the MP piece. Buoyancy could be achieved using flotation bags inserted into the pile and inflated, or by external flotation chambers or bags. The process is more difficult than floating piles out from shore during installation which involves bungs being inserted on land, because for decommissioning the flotation mechanism needs to be applied offshore and with underwater working. The flotation can be applied either before or after cutting. A crane is needed at shore for unloading.

The overall decommissioning activities for a MP foundation will consist of:

- <u>Pre-decommissioning</u>: The season before, the MP and TP are inspected to check the condition of all parts of the foundation, internally and externally, above and below water. This includes assessing the integrity of lifting points and estimation of weight change from accretion, corrosion or equipment changes. Compliance with regulations and development of a decommissioning strategy is implemented—in particular how many lifts and whether piles are cut internally or externally. Tools and equipment are designed and contracted such as cutting head manipulators and sea fastenings; method statements and risk assessments are written; vessels are selected and contracted. Onshore facilities are developed if necessary.
- <u>Preparation</u>: Prior to any lifting, preparation includes removal of lake-bed material to give access to the cutting operation, by dredging or water jetting and lifting by entrainment with air ("air-lifting"); access may also require removal of steelwork. Preparation may also include bridging across TP and MP to avoid reliance on grout strength. If bolted joints are to be separated, bolts will be loosened or cut off and seals released. A lifting attachment may need to be added toward the base of the MP to enable manipulation during lifting. The final step is fitting of cutting equipment. Foundation preparation can take place from a smaller workboat, concurrently with lifting operations at another foundation.
- <u>Foundation removal</u>: The heavy lift crane(s) is attached prior to the start of pile cutting. The crane vessel repositions beside the foundation and lifting gear is attached. Cutting (or unbolting) then starts with the crane taking a small monitoring load whilst the cutting head tracks round. Once the cut is complete the piece is placed on the transport vessel. For the second cut, the cutting track is repositioned, the lifting gear attached to the lower piece and the process repeated. A careful loading plan and design of fastenings will optimise the use of the transport vessel. Fastenings can be more rudimentary than those used during installation, given that the components will not be re-used.
- <u>Post-decommissioning</u>: Sea-bed surveys are carried out immediately after the decommissioning operations to check there are no obstructions or dropped objects, and to confirm that the pile stumps are not protruding.

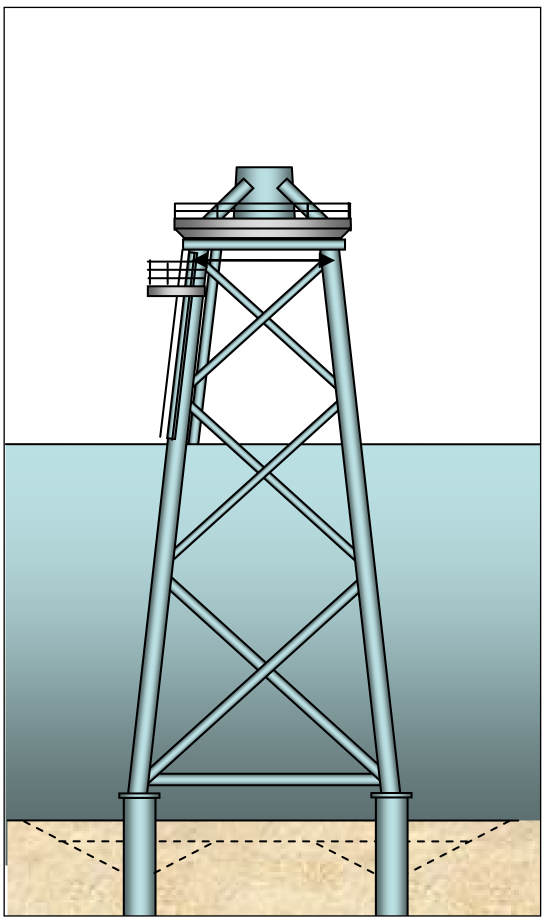
It is assumed that once the pile is cut off, the access hole around it will gradually back-fill without any further attention needed. If conditions make this unlikely, the hole can be filled with dredged material.

Once on the quayside, the components are reduced to the size of pieces that are required for recycling, using standard cutting techniques.

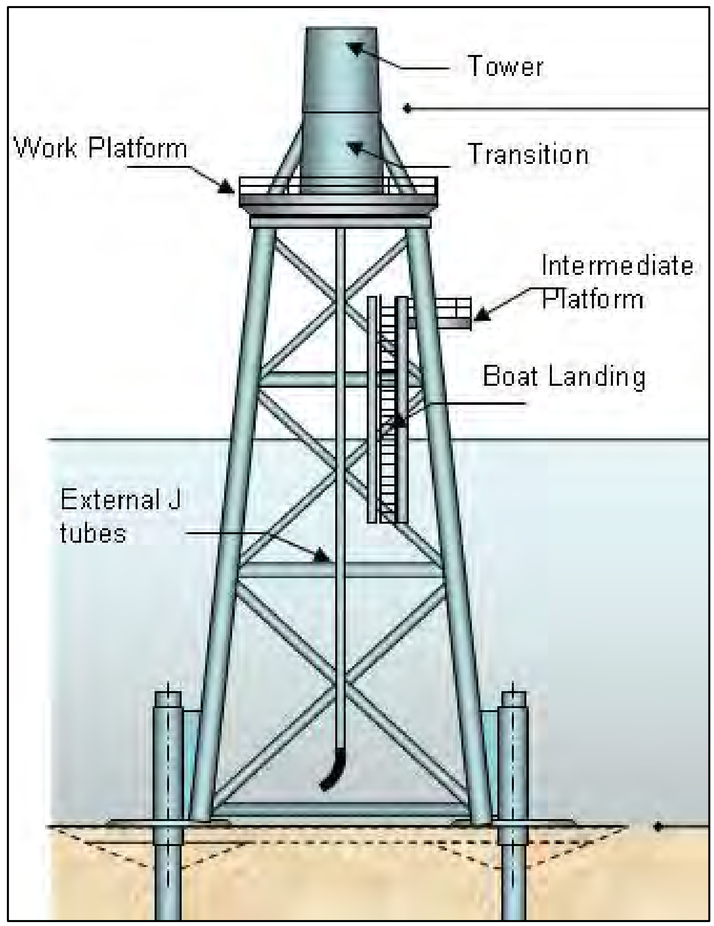
5.5.5 Jacket WTG foundation

5.5.5.1 Jacket design and materials

Figure 5-41 shows the main features of pre- and post-piled designs of jacket support structures. Figure 5-42 shows two recent examples of jacket structures used for turbine foundations in offshore wind projects.



a) Pre-piled jacket



b) Post-piled jacket

Figure 5-41 Standard configurations of jacket foundations

A typical jacket structure consists of three or four braced legs resting on the sea-bed and fixed in place by driven piles at each leg. The top of the jacket consists of a transition structure that incorporates the bolted flange connection with the base of the turbine tower, as shown in Figure 5-41b. The overall connection is designed to provide the required load transfer to the legs and resistance to the large overturning force.

a) Nordsee Ost jackets – credit RWE

b) Baltic 2 jackets, 3-legged – credit Blue Water Shipping

Figure 5-42 Examples of jackets for offshore wind turbines

The legs are inclined to provide a wide base that increases the resistance to overturning and increases the stiffness.

The jacket supports secondary steelwork consisting of the main external platform at the tower base, boat access ladders and intermediate platforms, conduits for the array cables (J-tubes or I-tubes) and anodes for corrosion protection.

The detailed design and dimensions of the jacket and transition structure are determined by consideration of the turbine tower and support structure together, treated as a single entity. The main design drivers will be the tower top mass of the turbine and the water depth, combined with the static and dynamic forces from the wind, current and waves (mean and extremes), and the practicalities of installation. Post-piled designs incorporate vertical pile sleeves as part of the jacket, through which the piles are driven once the jacket is in place. With pre-piled designs, the pin-piles are driven in place first with the aid of a template, leaving the top of the vertical pile sticking up from the sea-bed. Spigots at the foot of each jacket leg then stab into the piles and are grouted in place. Pre-piled jackets (rather than post-piled) are almost always selected for turbine foundations: the two step method better suits multiple installations as the pre-piling can be carried out using smaller vessels, well in advance of jacket installation, reducing programme risks. Furthermore the jackets have a lower maximum lift weight and overall footprint given the lack of sleeves.

Dimensions and weights

Individual brace and leg tubes are typically 0.5 to 1.5 m in diameter and 10 to 50 mm wall thickness, depending on the jacket size. For the assembled jackets, Table 5-11 provides jacket and pin-pile dimensions and weights estimated for supporting the two sizes of turbines in water depths of 25 m and 40 m, assuming a pre-piled design is utilised. The height of the platform is assumed to be around 15 m above water level.

Table 5-11 Estimated masses and dimensions of pre-piled jacket foundations

Water depth	Item	4 MW turbine	8 MW turbine
25 m	Jacket height overall	45 m	45 m
25 m	Jacket footprint at sea-bed	15 x 15 m	20 x 20 m
25 m	Pin-pile length / diameter	35 m / 1.8 m	45 m / 2.2 m
25 m	Jacket mass overall	400 - 500 t	700 – 800 t
25 m	Pin-pile mass, each	80 t	200 t
40 m	Jacket height overall	60 m	60 m
40 m	Jacket footprint at sea-bed	20 x 20 m	25 x 25 m
40 m	Pin-pile length / diameter	35 m / 1.8 m	45 m / 2.2 m
40 m	Jacket mass overall	500 – 600 t	800 – 900 t
40 m	Pin-pile mass, each	80 t	200 t

The complete jacket height is around 45 m from the bottom of the stab-ins to the interface flange with the topside for 25 m water depth; and around 60 m for 40 m water depth, assuming the platform is 15 m above water level. The footprint of the jacket base will range from about 15 m across for a 4 MW turbine in 25 m water to about 25 m across for an 8 MW turbine in 40 m water depth. Jacket weights, including the secondary steelwork but excluding the pin-piles, are estimated to range from 400 to 500 t to support 4 MW WTG in 25 m depth to 800 to 900 t for 8 MW in 40 m water depth.

The pin-piles are embedded by 30 to 40 m and are therefore typically 35 to 45 m long including the stick-up above the mud line. They generally have diameter of 1.5 to 2.5 m, wall thickness 25 to 100 mm and may weigh up to 200 t each.

Icing issues

Design against ice may be achieved by using greater wall thicknesses of the jacket members. Alternatively, or additionally, ice cones may be incorporated at the water line near the tops of the legs, as illustrated in the Baltic II jackets (Figure 5-42b).

Materials

Jackets, transition structures and secondary steelwork are all made from structural steel. Corrosion protective coatings are applied to the steelwork, with extra attention in the splash zone, usually multiple layers of epoxy resin and polyurethane paint augmented by metallic primers (e.g., zinc).

5.5.5.2 Jacket construction and installation

Jackets are fabricated from steel tubes that are welded from rolled steel sheet using standard processes and facilities. The tubes are then cut and prepared for welding into sections, sub-assemblies and then the complete jacket, such as shown in Figure 5-43.

Credit – EnBW, Baltic II OWF.

Figure 5-43 Fabrication of jacket

Manufacturing facilities are located to enable the completed jackets and pin-piles to be transported by sea to the construction port, usually on a towed barge (Figure 5-42).

Using the pre-piling route, the process of installation involves preparing the sea-bed, positioning a template to guide the relative location of the piles, driving of the pin-piles through the template leaving the pile tops sticking up from the sea-bed. In a second operation the jacket is lifted into place (Figure 5-44) and located into the protruding pile tops using stab-ins; the jacket is then grouted in place. Finally scour protection may be placed around the piles, in the form of rock pieces.

Figure 5-44a shows a shearleg crane lifting a jacket from a barge, and shows the stabs at the bottoms of the legs. Figure 5-44b shows a heavy lift jack-up being used to transport and install jackets. A second vessel may often carry the grouting equipment to free up the expensive crane vessel.

a) By floating shearleg crane – Ormonde OWF

b) By jack-up crane – Nordsee Ost OWF

Figure 5-44 Offshore turbine jacket installation by heavy lift vessels

If a number of jackets are installed, then the pre-piling and jacket placement are carried out as separate operations. The use of the template is a temporary means of maintaining the shape of the jacket base within required tolerances, leading to a lower jacket weight than for post-piling designs and providing economies with multiple installations.

Generally jackets for offshore wind foundations are installed as a single lift. However, in the case of the Block Island jackets, being installed during 2015 in US waters (Figure 5-45), they have been designed in two parts of similar weight.

a) Two-part jacket on transport barge - credit Deepwater Wind

b) “Weeks 533” floating crane lifting lower jacket section into place – credit Deepwater Wind

Figure 5-45 Block Island jacket installation

Each part is around 440 t thus minimizing the crane capacity required and installation being feasible by the “Weeks 533” (capacity 500 short ton = 454 t) crane barge which is one of the largest locally available. Such an approach may also be adopted in the Great Lakes to minimize the limiting lift, depending on heavy lift availability. It is likely that once in position, the two parts are fixed together by either grouting or welding. The heavy lift for installation can be supplied by a crane on a floating vessel for which the primary operating limit will be the wave heights. The stability of a jack-up is not essential, especially in relatively benign wave climates, though using a jack-up platform or vessel is another option.

A further possibility that could be adopted in the Great Lakes might be jacket installation by controlled flotation rather than using a heavy lift vessel. Figure 5-46 shows a large O&G jacket being launched into the water from a ballasted launch-barge. The jacket has temporary flotation attached with which to control its buoyancy and a heavy lift vessel is often used to upend it. In this case, the jacket was fixed by post-piling using multiple piles around each leg.

“Gina Krog”, Credit – Statoil.

Figure 5-46 O&G jacket installation by controlled flotation

5.5.5.3 Jacket decommissioning

There is considerable experience in the Oil & Gas industry of decommissioning jacket support structures, which can benefit the offshore wind sector, in particular cutting tools and also lifting and transporting the removed jackets.

In general, the decommissioning assumption for jacket foundations is that they are removed by cutting the pin-piles below the mud-line level and then the foundation is taken to shore together with any TPs. The majority of the embedded piles are thus left in-situ, on the grounds that removal would create excessive environmental disruption and the costs would be prohibitive. It is a standard assumption that this method will be acceptable provided the depth of the cuts below the mud-line is sufficient to avoid exposure of the remaining pile stumps or cause any future hazard to other sea users, in particular to anchors or to fishing gear. It is also assumed that the site is adequately monitored post-decommissioning.

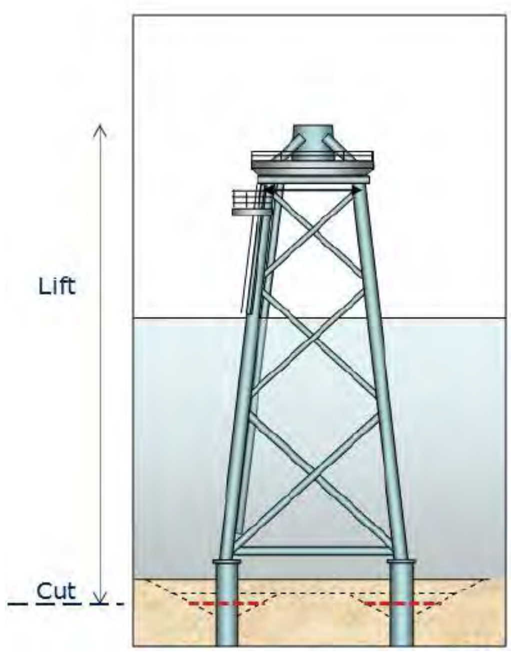
The exact depth below the mud-line will be agreed with the regulatory authority and may be 1 to 5 m, with the greater depths anticipated where the local mobility of the sea-bed could potentially uncover the pile stumps. Cutting of the pin-piles is likely to be by high pressure abrasive water jet, or possibly diamond wire as described earlier.

It is assumed that the removal of the turbine foundations will be a separate operation from the removal of the WTGs. For offshore wind farms with numerous turbines, separate vessels are likely to be used for the WTG and foundations removal, working one behind the other to make the best use of the seasonal weather and the specialist capabilities of each vessel. For projects consisting of only a handful of units such as demonstration projects, it is likely to be more economical to use the same vessel for WTG and foundation removal.

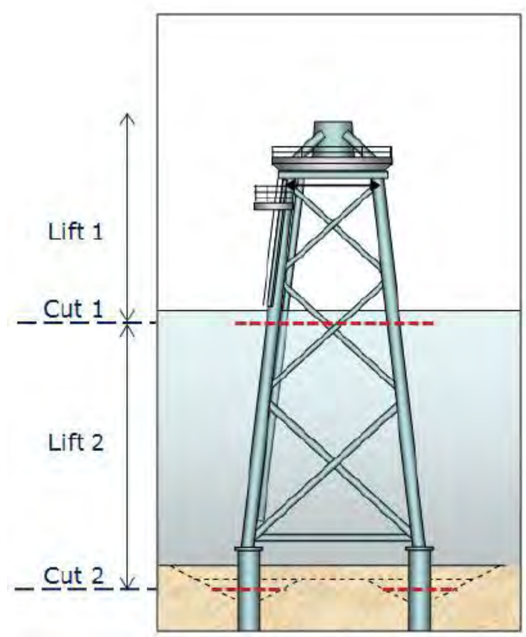
For the jacket removal strategy, the main option is typically the number of lifts utilized, which is strongly related to the design of the jacket and in turn to the lift and reach capacity of the crane, taking into consideration that the size of a jacket footprint leads to greater reach requirements compared with MPs.

Potential lift strategies

Because the pin-piles are assumed to stay in-situ, the structure to be removed is very similar size and weight to that during installation. Decommissioning is essentially the reverse of installation and will use similar lifting and handling equipment. Figure 5-47 shows the two main lift strategies and Table 5-12 summarizes the estimated key dimensions and raw maximum weights. Allowances for the lifting gear, uncertainties and potentially dynamic load factors will be needed in addition.



a) Single cut, single lift



b) Two cuts, two lifts

Figure 5-47 Main lifting strategies for WTG jacket decommissioning

Table 5-12 Approximate masses and dimensions for jacket removal

Water depth	Item	Strategy	4 MW turbine		8 MW turbine	
			Mass	Dimension	Mass	Dimension
25 m	Jacket, including pile tops and grout	Single lift or flotation	540 t	45 m height	900 t	45 m height
25 m	Jacket sections	Two lifts	270 t	25 m height	450 t	25 m height
25 m	Jacket footprint	N/A	N/A	15 x 15 m	N/A	20 x 20 m
25 m	Pin-pile diameter / wall thickness	N/A	N/A	1.8 m / 50 mm	N/A	2.2 m / 100 mm
40 m	Jacket, including pile tops and grout	Single lift or flotation	640 t	60 m height	1,000 t	60 m height
40 m	Jacket sections	Two lifts	320 t	35 m height	500 t	35 m height
40 m	Jacket footprint	N/A	N/A	20 x 20 m	N/A	25 x 25 m
40 m	Pin-pile diameter / wall thickness	N/A	N/A	1.8 m / 50 mm	N/A	2.2 m / 100 mm

These weights and dimensions of the decommissioned pieces are very similar to the original component weights given in Table 5-11, with the addition of the weights of the grout and the top part of the four pin-piles above the sea-bed cut – approximately 40 t and 100 t for the 4 MW and 8 MW sizes, respectively.

The main options for decommissioning are therefore:

- Single lift of complete jacket, after cutting of pin-piles (Figure 5-47a). The main advantages are that using a single set of cuts reduces the overall cutting time and preparation time compared with multiple lifts, and potentially the duration of the crane vessel hire. However this is the most challenging strategy in terms of the weight of this single piece, the crane reach (vertically and horizontally), manipulation and transport. With 25 m water depth, the maximum raw weights for the removed jacket including the pin-piles above the cuts are therefore around 540 t and 900 t for the 4 MW and 8 MW sizes respectively. With 40 m water depth, they are around 640 t and 1000 t for the two sizes.
- Two lifts, to provide two pieces of similar weight (Figure 5-47b). This may or may not be a pre-planned method:
  - If jacket is so designed (for example Block Island), though this is likely to require cutting operations to separate the joint.
  - Or by cutting through the structure at the appropriate height.

  The maximum raw lifts required are therefore halved, at 270 t and 450 t for 25 m water depth, and 320 t and 500 t for 40 m depth, in each case for the 4 MW and 8 MW sizes, respectively.

  A two-lift strategy requires additional marine operations but uses a smaller capacity crane which may be the deciding factor in the Great Lakes. However, for the 40 m water depth and possibly also the 25 m depth, the separation point will be below the water surface, probably requiring divers.
- Flotation, using controlled buoyancy by means of internal or external flotation bags or chambers to support the single piece during and after cutting the piles. The process would be more difficult than

using flotation during installation because for decommissioning the flotation mechanism would need to be applied offshore and probably with underwater working. The release of the piece at the finish of the cut would need to be carefully controlled to be safe especially as there will be uncertainty in the mass of the jacket at the time of decommissioning. If carefully controlled, a crane of only limited capacity would be required offshore, though a crane would probably be needed at shore to lift the piece out of the water.

To transport the removed jacket foundation pieces to shore, options are:

- Self-loading onto the crane vessel if it has the deck capacity. As with installation the jackets would probably be carried upright; alternatively (for example if there are height restrictions at port), the jacket could be pivoted and carried on its side. The vessel would use its own crane to unload at port.
- On a second vessel such as a towed barge. Placement of the piece or pieces on deck would be subject to more restrictive operating limits than self-loading because two vessels are involved. Furthermore, a crane would be needed at the port to unload the pieces. Given the dimensions of jackets, this option is most likely.
- Flotation, by making the jacket buoyant and towing it to shore. The buoyancy could be installed after release from the sea-bed with the jacket supported by a crane vessel; alternatively, as described above, the buoyancy could be applied as part of the release method. In either case, a crane would be needed at shore.

The overall decommissioning activities for a jacket foundation will consist of:

- Pre-decommissioning: The season before, the jacket will be inspected to check the condition of all parts of the foundation, internally and externally, above and below water. This includes assessing the integrity of lifting points and estimation of weight change from accretion, corrosion or equipment changes. Steps will be taken to comply with regulations and to develop a detailed decommissioning strategy—in particular how many lifts and whether piles are cut internally or externally. In practice external cutting is most likely unless provision is made in the design for internal access. Tools and equipment will be designed, manufactured and/or hired such as cutting head manipulators and sea fastenings; method statements and risk assessments will be written; vessels will be contracted. Onshore facilities are developed if necessary.
- Preparation: Prior to any lifting, preparation will include removal of lake-bed material to give access to the cutting operation, by dredging or water jetting, and possibly removal of some steelwork. Preparation may also include bridging across any grouted joints to avoid reliance on grout strength, and cutting of cables. If any bolted joints are to be separated, bolts will be loosened or cut off and seals released. A lifting attachment may need to be added toward the base of the jacket to enable manipulation during lifting. The final step is fitting of cutting equipment, repeated for each leg. Foundation preparation can take place from a smaller workboat, concurrently with lifting operations at another foundation.
- Foundation removal: The heavy lift crane(s) is attached prior to the start of any pile cutting. The crane vessel repositions beside the foundation and lifting gear is attached. Cutting then starts with the crane taking a small monitoring load whilst the cutting head tracks round. Once the cut is complete the piece is placed on the transport vessel. For any second cut, the cutting track is repositioned, the lifting gear attached to the lower piece and the process repeated. A careful loading plan and design of fastenings will optimise the use of the transport vessel. Fastenings can be more rudimentary than those used during installation, given that the components will not be re-used.

- Post-decommissioning: Sea-bed surveys are carried out immediately after the decommissioning operations to check that there are no obstructions or dropped objects, and that the pile stumps are not protruding.

It is assumed that once a pile is cut off, the hole created for access and any scour hole around it will gradually back-fill without any further attention needed. If conditions make this unlikely, the hole can be filled with dredged material.

Once on the quayside, the components are reduced to the size of pieces that are required for recycling, using standard cutting techniques.

5.5.6 Suction bucket WTG foundation

5.5.6.1 Suction bucket design and materials

The suction bucket concept, sometimes known as suction caisson, is relatively new to the offshore wind industry though has been an established technology in the Oil & Gas industry since the 1980s for securing platform legs and for removable anchors. However, these existing applications are primarily designed for vertical loading and they are less proven in applications with significant bending or dynamic loads as found in offshore wind.

The main versions for offshore wind purposes are:

- Mono-bucket, a single suction caisson supporting a single column, already in use for several offshore wind met masts. Figure 5-48 shows an example. Mono-buckets have been selected for the LEEDCo offshore wind farm in Lake Erie, for six 3 MW turbines.
- Suction bucket jacket (SBJ), with a suction caisson at each leg of a jacket such as the recently installed pilot at Borkum Riffgrund (Figure 5-49) currently undergoing load testing prior to installation of a 3.6 MW turbine.

For offshore wind applications, the dimensions and weights of suction bucket structures for different sizes and water depths can be only roughly estimated, given that detailed designs are still evolving. Table 5-13 presents estimates, based on data on the few offshore wind examples and to some extent on past studies by the DNV GL structural team. Required bucket dimensions strongly depend on the nature of the soils. For simplicity it is assumed here that bucket height and diameter are the same, though in practice the diameter can exceed the bucket height in many cases.

a) Met mast foundations on jack-up vessel b) Installation of mono-bucket foundation

Credit - Forewind

Figure 5-48 Suction bucket met mast foundations at Dogger Bank

a) Graphic of SBJ in place b) Installation of SBJ from jack-up vessel

Credit - DONG Energy

Figure 5-49 Pilot suction bucket jacket at Borkum Riffgrund

Table 5-13 Indicative masses and dimensions for suction bucket foundations

Water depth	Item	4 MW turbine	8 MW turbine
25 m	Mono-bucket dimensions	10 x 10 m	15 x 15 m
25 m	SBJ bucket dimensions (height x dia) Suction bucket jacket (SBJ) footprint	8 x 8 m 25 x 25 m	10 x 10 m 30 x 30 m
25 m	Foundation height overall	50 m	55 m
25 m	Foundation weight overall	750 t	900 t
40 m	Mono-bucket dimensions	15 x 15 m	20 x 20 m
40 m	SBJ bucket dimensions (height x dia) SBJ footprint	10 x 10 m 30 x 30 m	12 x 12 m 35 x 35 m
40 m	Foundation height overall	65 m	70 m
40 m	Foundation weight overall	900 t	1,100 t

Icing issues

Design against ice will be similar to that for MP and jacket foundations, namely ice cones at water level and greater wall thicknesses.

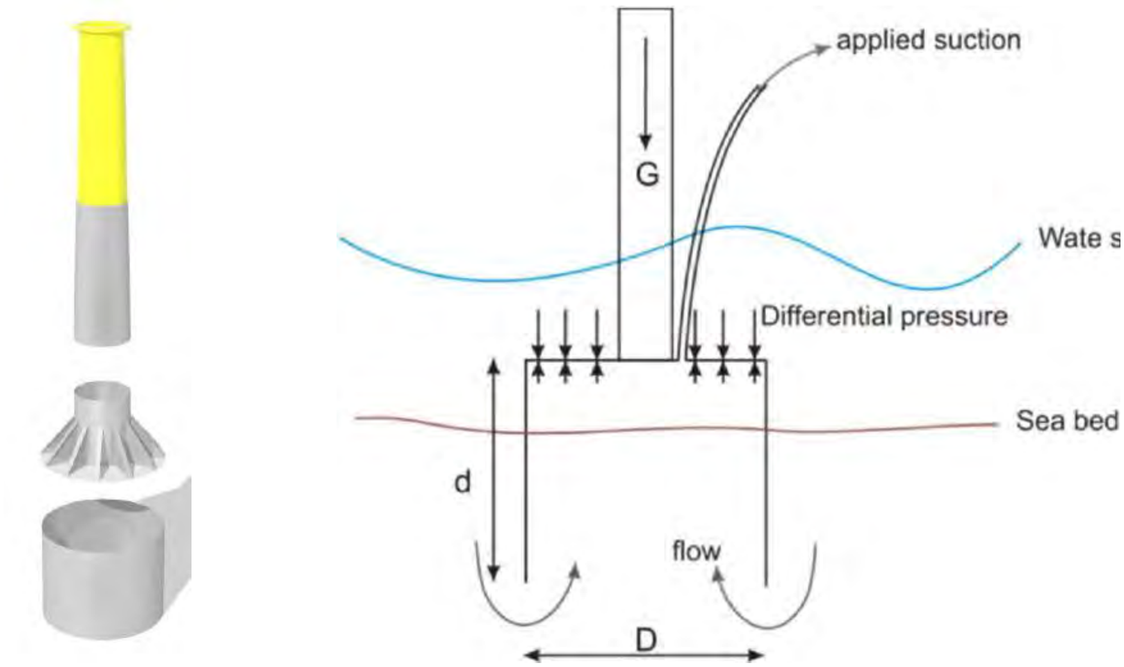
Materials

Suction bucket foundations are made from structural steel, both for the bucket and for the shaft or jacket above and the secondary steelwork. Stainless steel may be used for the injection lines for greater resistance to corrosion.

5.5.6.2 Suction bucket construction and installation

Suction bucket foundations are constructed from a combination of cast and rolled steel elements, assembled by standard welding techniques. The main components are the shaft, bucket lid and skirt, as shown in Figure 5-50a.

To install, the suction bucket structure is lowered to the sea-bed; then pumps reduce the pressure inside the bucket chamber (Figure 5-50b). The pressure difference and the deadweight cause the bucket(s) to sink into the sea-bed soils. There may be water jets inside the bucket to partially fluidise the internal soils and help the bucket to maintain verticality. Once in place, a thin layer of concrete grout may be injected between the sea-bed and the lid of the bucket to counter permeability of the soils.



a) Shaft, bucket lid and skirt b) Installation of suction bucket

Credit – Universal Foundation

Figure 5-50 Configuration and installation of suction bucket

During installation, usually temporary suction pumps are used that are attached directly to the top of the bucket whilst it is on deck. The pump unit for the Dogger Bank met mast foundation is visible on the right of Figure 5-48b.

The relatively large diameter of the bucket, compared with other foundation types, makes it more susceptible to wave effects whist it is lowered through the water surface though this can be mitigated using a heave-compensated crane. To date, jack-up crane vessels have been used to install suction buckets as shown in Figure 5-48a and Figure 5-49b.

In practice, both lifting and floating strategies have been used to lower the foundation into position. The examples in Figure 5-48 and Figure 5-49 show lifting from the deck of a jack-up. Figure 5-51 shows the foundation for the Horns Rev II met mast being towed and upended.

a) Floating out to site

b) Upending using heave-compensated crane

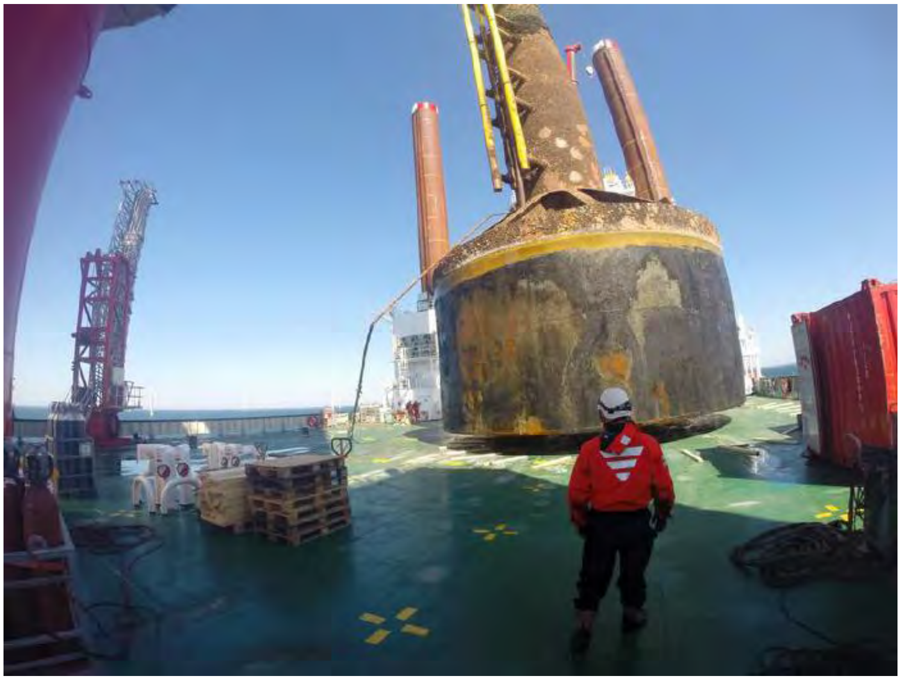
Credit – Universal Foundation

Figure 5-51 Floating installation of mono-bucket for Horns Rev II met mast

5.5.6.3 Suction bucket decommissioning

It is assumed that the suction bucket will be removed in its entirety by the reverse of the installation process. An overpressure is applied inside the bucket typically by means of internal pipework extending up to the platform thereby avoiding (or reducing) the need for divers. Throughout the process a crane is attached to the structure to lift it out once released.

In early 2015, the mono-bucket supporting the Horns Rev II met mast was decommissioned by this method after 6 years of service, apparently without incident (Figure 5-52). In the Oil & Gas industry, suction bucket anchors are routinely removed, though usually after some months rather than many years. As in the offshore wind industry, there is little or no experience in the Oil & Gas industry of decommissioning suction buckets used as support structures.



Credit – DBB Jackup

Figure 5-52 Lifting out of Horns Rev II met mast bucket foundation

It is assumed that the removal of the turbine foundations will be a separate operation from the removal of the WTGs. For offshore wind farms with numerous turbines, separate vessels are likely to be used for the WTG and foundations removal, working one behind the other to make the best use of the seasonal weather and the specialist capabilities of each vessel. It should be noted that for projects consisting of only a handful of units such as demonstration projects, it is likely to be more economical to use the same vessel for WTG and foundation removal.

For the foundations removal strategy, the main option is typically the number of lifts utilised, which is strongly related to the lift and reach capacity of the crane. In every case, the crane will need to be attached to the piece to be lifted for the duration of the removal operation.

Potential lift strategies

In the case of suction foundations, the whole foundation is likely to be removed as a single piece using the in-built injection lines, sometimes called retraction lines; alternatively, it could be removed in two or more pieces, by separately removing the upper part by cutting or otherwise separating the platform or TP, or by severing the pile or jacket part way up; and then removing the lower part together with the suction buckets. With suction bucket jackets, the jacket might be cut so as to allow each bucket to be removed separately. However, if the foundation is removed in multiple pieces, a method for providing injection to the buckets still needs to be provided.

The masses of the steelwork will be similar to installation, though with uncertainty from marine growth and corrosion. However, for each strategy, allowance needs to be made for the weight of sea-bed soils that may adhere to the sides of the bucket: loosening of the soils can reduce this inside the bucket using inbuilt water jets. If adhesion and friction are major problems on the external surface, they may not only cause extra weight but may result in the bucket not releasing. In this case, mass excavation water jetting might need to be used.

Once released, lifting the bucket through the water surface is particularly subject to wave limits as a result of its shape. There is a variable weight on the crane whilst the bucket is partially supported by the water and whilst any adhering soils may be detaching, so a heave compensating device in the lifting string is used.

The use of flotation rather than lifting the pieces fully out of the water reduces the required lifting capacity of the crane. To date steel flotation tanks have been used to remove Oil & Gas jackets, and glass reinforced polymer (GRP) tanks or air-bags have also been proposed. However, using flotation requires careful control of the imprecise weight and is subject to stringent wave limits. It also requires divers (or remotely operated underwater vehicles (ROVs)) to attach the lifting gear to the lower lifting points, with the accompanying operational limits, safety precautions and expense. In general, lifting out is preferred if the equipment is available and it is noted that the suction bucket at Horns Rev II was installed by flotation but decommissioned by lifting out.

For the Great Lakes projects, it is assumed that the foundation is removed in a single piece using integrated injection lines operable from the platform at the top of the foundation. Raw masses and dimensions are therefore as indicated in Table 5-14 at an estimated 750 t for foundation for a 4 MW turbine in 25 m water with total foundation height from bucket skirt to top of the platform of 50 m. The equivalent foundation mass is around 1,100 t for an 8 MW unit in 40 m depth with an overall foundation height of 70 m.

Table 5-14 Indicative masses and heights for suction bucket removal

Water depth	Technology	Strategy	4 MW turbine		8 MW turbine	
			Mass	Dimension	Mass	Dimension
25 m	Suction bucket foundation including shaft/jacket and platform	Single lift or/ flotation	750 t	50 m height	900 t	55 m height
40 m	Suction bucket foundation including shaft/jacket and platform	Single lift or/ flotation	900 t	65 m height	1,100 t	70 m height

If the foundation is lifted out of the water and placed upright on the vessel deck, then the crane needs an additional underhook height of around 10 m to allow for the lifting gear and heave compensation unit. Adding the extra lift capacity for lifting gear and allowances for large uncertainties requires a crane of at least 1,000 t lift capacity even for the smaller turbine size and water depth; and 1,500 t for the larger size and depth. Such combinations of lift and underhook height is unlikely to be available in the Great Lakes.

The minimum lift is reduced if the foundation is removed in several pieces though providing the injection line is less straightforward.

Floating decommissioning strategies are expected to be more feasible. The minimum underhook height then caters for just the elevation of the platform plus the lifting gear totalling around 20 m above the water level. Twin cranes of between 200 t and 400 t each are needed. These may be available from Jumbo's Fairlane (Figure 5-20), taking into account the considerable down-rating anticipated for this operation. Alternatively it may be achieved using mobile cranes on barges or jack-up platforms. The suction bucket design therefore needs to incorporate lifting points.

To transport the removed foundation pieces to shore, the options are:

- Self-loading onto the crane vessel if it has the deck capacity. The vessel uses its own crane to unload at port. This is only feasible if the lift capacity is available.
- On a second vessel such as a towed barge. Placement of the piece on the deck is subject to more restrictive operating limits than self-loading since two vessels are involved. This is only feasible if the lift capacity is available. An additional crane is needed at the port to unload the pieces.
- Flotation, by making the piece buoyant and towing it to shore. The process is more difficult than floating the structure out from shore during installation, because the flotation mechanism needs to be applied offshore (through air-bags and/or air-filled shaft) probably with underwater working; and because of the greater uncertainty in the weight.

The overall decommissioning activities for a suction bucket foundation are:

- <u>Pre-decommissioning</u>: The season before, the foundation is inspected to check the condition of all parts of the foundation, internally and externally, above and below water. This includes assessing the integrity of the lifting points and estimation of the weight change from accretion, corrosion or equipment changes. It includes checking and testing of the injection system and internal water jetting for the suction release. Compliance with regulations is implemented, and the decommissioning strategy developed. Tools and equipment are designed and contracted; method statements and risk assessments are written; and vessels contracted. Onshore facilities are developed if necessary.
- <u>Preparation</u>: Prior to removing the foundation, further sea-bed surveys are carried out and the injection mechanism checked. The cables are cut at the sea-bed. Flotation bags, lifting gear and/or tugging lines are put in place ready for crane attachment. Preparation may also include bridging across any grouted joints such as with a TP, or loosening bolts. Foundation preparation can take place from a smaller workboat, concurrently with removal operations at another foundation.
- <u>Foundation removal</u>: The crane is attached to the top of the piece via a lifting yoke with heave compensation unit and live load monitoring. If the piece is to be manipulated (for example to horizontal and/or for floating), lifting gear is also attached at lower positions. Discharge pumps first remove water from the foundation shaft. Then injection pumps are connected to the retraction line and pressure is applied into the bucket whilst simultaneously supporting the weight. The bucket gradually releases from the sea-bed and the foundation is lifted out.
- <u>Post-decommissioning</u>: Sea-bed surveys are carried out immediately after the decommissioning operations to check there are no obstructions or dropped objects.

It is assumed that the plug of material inside the bucket, and any scour protection outside the bucket will remain on the sea-bed. Post-decommissioning surveys confirm the status of the site.

Once on the quayside, the components are reduced to the size pieces require for recycling, using standard cutting techniques.

5.5.7 Gravity base WTG foundation

5.5.7.1 GBS design and materials

Figure 5-53 shows the typical base plus shaft design with closed chambers as assumed for this study. The ballast material is contained within the structure. The base may be conical or can be flatter as shown.

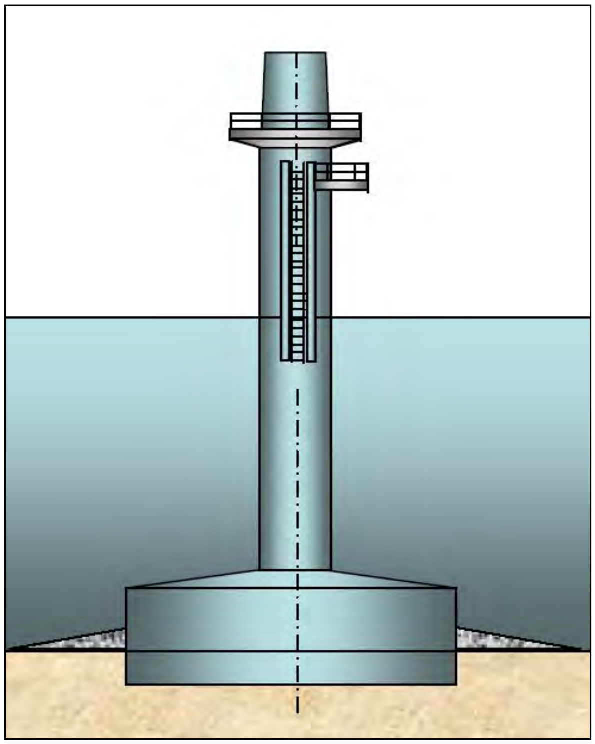
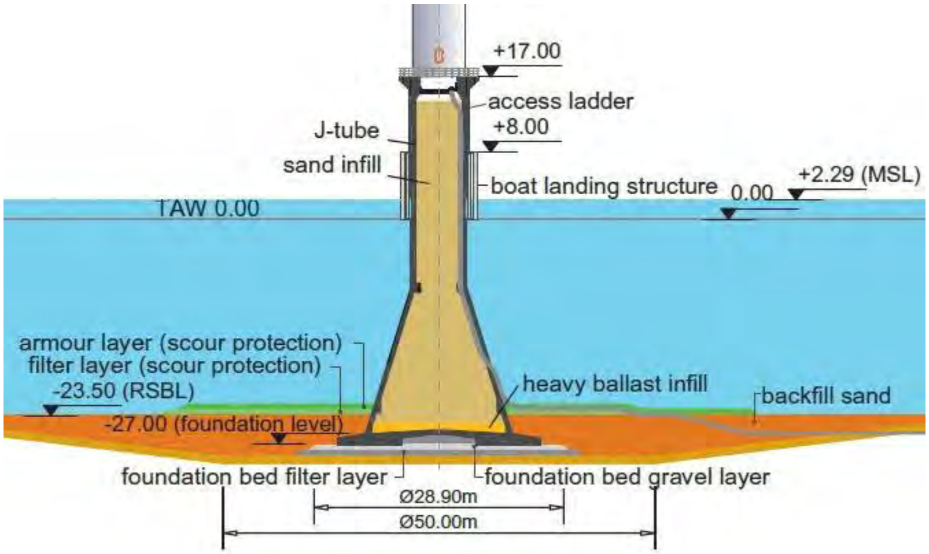


Figure 5-53 Concrete GBS foundation of base and shaft design

The foundations at Thornton Bank 1 offshore wind farm (OWF), completed in 2008, are an example of such internally ballasted GBS, pictured in Figure 5-54. These foundations support 5 MW turbines in around 30 m of water depth. In this design, the ballast is all contained within the conical structure and shaft, and the primary structure is reinforced concrete.

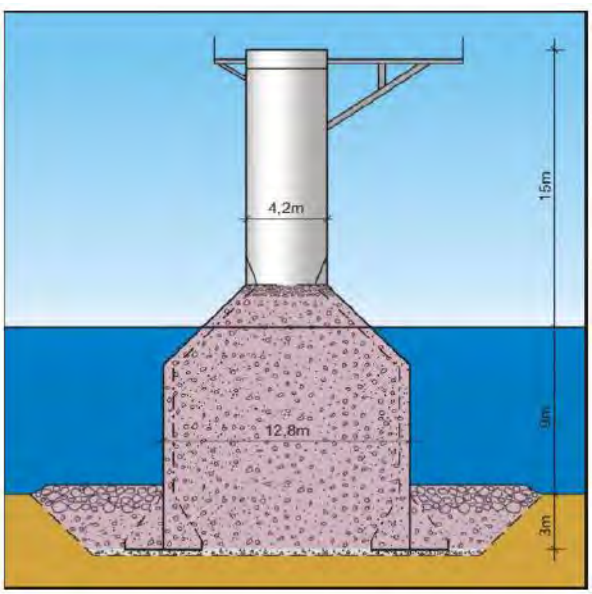
At the OWF, the foundations rest on level gravel beds with the base either level with or a few metres below the mud-line. There may be a skirt extending below the base to reduce scour. Once in position they are filled primarily with sand. Externally they are protected from scour by rock layers as seen in Figure 5-54a.



Credit – DEME.

Figure 5-54 Internally ballasted GBS at Thornton Bank OWF

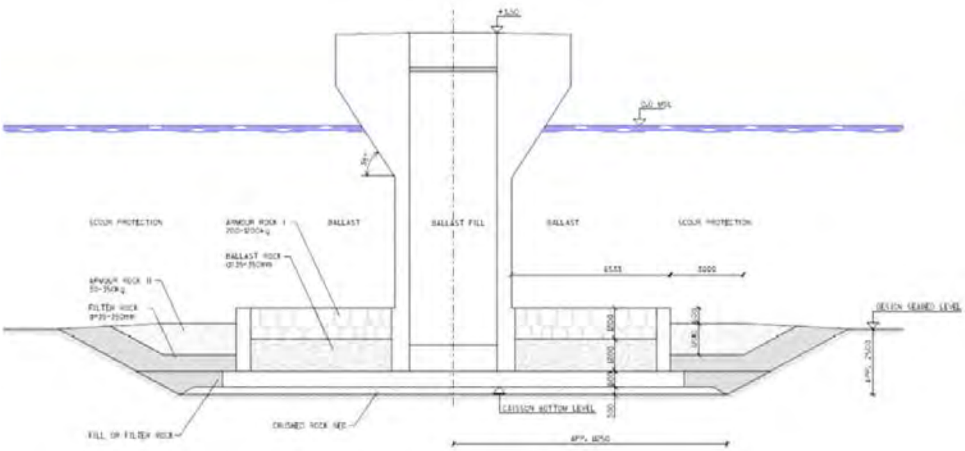
There are many variants of closed chamber gravity base foundations, and mostly they are constructed from reinforced concrete but also steel. An example of a steel GBS in use is the pilot turbine near Pori, Finland (Figure 5-55) designed for use in heavily iced waters.

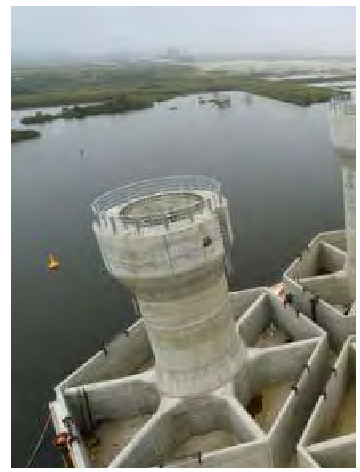


Credit – Eranti Engineering

Figure 5-55 Steel GBS at Pori 1 pilot turbine

GBS foundations with external ballasting are also in service mainly in the Baltic Sea and typically for turbines in shallower waters. Examples are the offshore wind farms at Lillgrund (built 2006) and Karehamn (2013). The design comprises a reinforced concrete hollow shaft encircled by a collar of open pockets, cast as a single structure (Figure 5-56). After installation, the shaft and external pockets are filled with ballast and topped with scour protection.





Credit – Vattenfall.

Figure 5-56 Externally ballasted GBS at Lillgrund OWF

It is assumed that the GBS designs used in the Great Lakes will take into account that the structures need to be completely removed during decommissioning. In particular, this requires:

- Ballast that can be readily removed (e.g., free-flowing sand)
- Lifting points that will be usable at end of life
- Not grouted under the base
- Mechanism to release the base suction (e.g., water jets)

For ease of ballast removal, closed designs are preferred. On this basis, indicative dimensions and dry (unballasted) weights are presented in Table 5-15. The strength of the soils is the major variable affecting the width of the base and therefore the unballasted weight.

Indicative weights of the unballasted GBS foundations range from around 2,000 t to 12,000 t depending on water depth and turbine size. Dimensions range from 45 m to 60 m tall and base widths are estimated from 20 m to 60 m for the different scenarios. If lake-bed soils are particularly soft, these weights and dimensions may be more as a greater area is needed to spread the load.

Icing issues

Designs against ice incorporate conical shapes at the water level to deflect the loads and the ice, as visible in Figure 5-55 and Figure 5-56.

Table 5-15 Indicative masses and dimensions for GBS foundations

Water depth	Item	4 MW turbine	8 MW turbine
25 m	GBS height overall	45 m	45 m
25 m	GBS width of base	20 - 30 m	40 - 50 m
25 m	GBS mass overall, excluding ballast	2,000 – 3,000 t	6,000 – 7,000 t
40 m	GBS height overall	60 m	60 m
40 m	GBS width of base	25 - 35 m	50 - 60 m
40 m	GBS mass overall, excluding ballast	2,500 – 3,500 t	8,000 – 12,000 t

Materials

GBS foundation structures are generally reinforced concrete, or sometimes structural steel. The ballast may be natural sand which may derive from the levelling operations, sometimes with a denser layer of heavy minerals at the base. External ballast is generally gravel, stones or rock, sometimes with denser materials such as the crushed iron ore used at Karehamn.

5.5.7.2 GBS construction and installation

Typically GBS designs are made in reinforced sections grouted together, with additional post-tensioning of the reinforcement whereby additional strength is provided by placing reinforcement bars in tension after construction.

Main options for construction are:

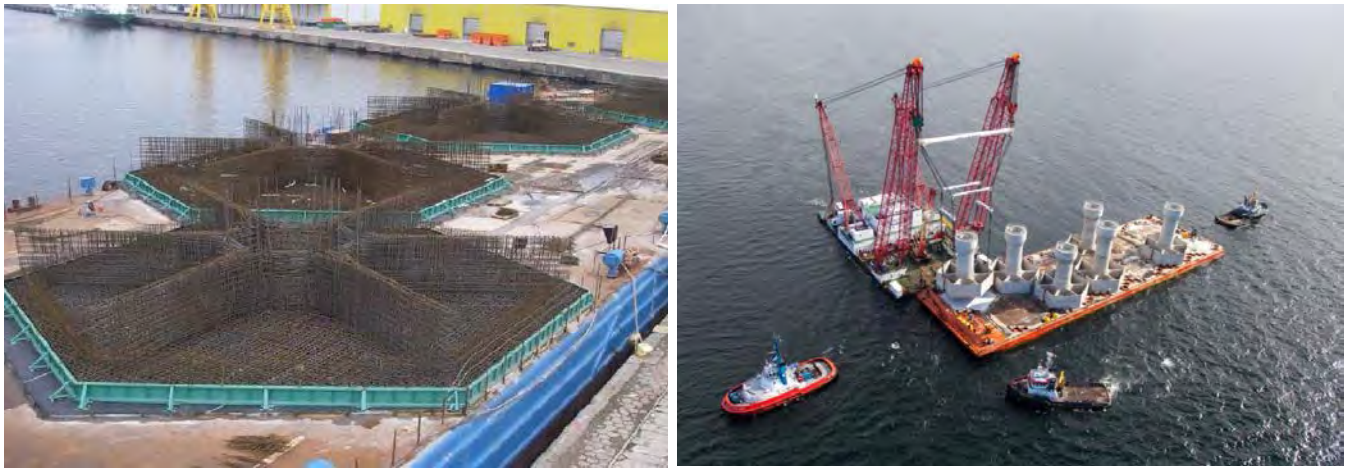
- Directly on the deck of the transportation vessel
- On quaysides, which need high load-bearing capacity
- In dry-dock, enabling the foundation to be floated out semi-submerged.

Main options for installation are:

- Barge transportation and heavy lift offshore.
- Transport using a semi-submersible barge or vessel followed by buoyancy-assisted lift from the submerged vessel offshore and lowering to the sea-bed. Offshore heavy lift vessels are required and the vessel ballasting and load transfer operations are complex and weather sensitive.
- Tow of semi-submerged foundation, then lower using crane vessel.
- Transport using floating crane carrying the foundation either in air or semi-submerged.

The secondary structures comprising the main platform, boat landings and corrosion protection are added either in port or offshore once the main structure is ballasted. The WTG is installed as the last operation.

Figure 5-57 shows examples of the barge construction and transportation method. Figure 5-57a shows the mesh of steel reinforcement prior to pouring the concrete. With several foundations on board, the barge is then towed to the site and the foundations lifted and lowered onto the pre-prepared bed (Figure 5-57b); another possibility is to use a semi-submersible vessel and float the GBS foundations off the back with the aid of a crane.



a) Reinforced concrete construction on barge, for Lillgrund OWF Credit - Hochtief

b) Installation by lift from barge at Karehamn OWF Credit - Scaldis

Figure 5-57 Construction and installation of GBS direct from barge

Figure 5-58 a) shows construction of conical GBS foundations on a quayside for Thornton Bank. Lifting points at the foundation base and a lifting yoke enable the completed foundations to be lifted using a heavy lift floating crane. The foundations were transported to the wind farm site semi-submerged using the floating crane with the assistance of tugs – Figure 5-58 b) – and then lowered into position.

a) Construction on strengthened quayside

b) Transport out to sea

Credit – DEME.

Figure 5-58 Construction and installation of conical GBS at Thornton Bank OWF

For the Great Lakes, where limited heavy lift capacity is available, floating options appear to be most likely for installation.

5.5.7.3 GBS decommissioning

In general, the decommissioning assumption for GBS foundations is that the entire main structure is removed and taken to shore. The gravel bed and scour protection are assumed to be left in-situ to minimise disruption to the marine habitat and on the basis that they are natural materials.

It is assumed that the removal of the turbine foundations is a separate operation from the removal of the WTGs. For offshore wind farms with numerous turbines, separate vessels are used for the WTG and foundations removal, working one behind the other to make best use of the seasonal weather and the specialist capabilities of each vessel.

To remove the GBS foundation, first the ballast is taken out. For decommissioning the remaining unballasted foundation, it is preferred to handle it as a single piece if possible, avoiding underwater cutting through large diameter constructions. Table 5-16 indicates raw dimensions and masses, excluding allowances for ballast residues and adhering material from the bed, for lifting gear, and for the dynamic forces during release of the base and when the pieces are lifted through the water surface.

Table 5-16 Indicative masses and dimensions for GBS removal

Water depth	Technology	Strategy	4 MW turbine		8 MW turbine	
			Mass	Dimension	Mass	Dimension
25 m	GBS foundation, excluding ballast	Single lift or/ flotation	3,000 t	45 m height 30 m base	7,000 t	45 m height 50 m base
40 m	GBS foundation, excluding ballast	Single lift or/ flotation	3,500 t	60 m height 35 m base	12,000 t	60 m height 60 m base

The main options for decommissioning and transporting the removed GBS foundations to shore are:

- Single lift of the foundation using a large crane and take to shore either on the deck of the crane vessel or on a towed barge. The crane will require lift capacity for the entire weight of the foundation, underhook height to manage the height of the foundation plus allowance for the lifting gear, and horizontal reach to allow for the base radius. These are challenging crane requirements especially for the 8 MW foundations.
- Single lift of the foundation and transport to shore held in air using the same crane. The full weight of the foundation is borne by the crane but the operation of loading onto a vessel is avoided.
- Single lift of the foundation so that it floats semi-submerged. Transport to shore by towing or supported by the same crane.
- Two lifts, to reduce the maximum lift required. However, with a two-lift strategy, the base of the foundation is kept intact and may be considerably more than half the mass. Such a two-lift strategy may be envisaged in the original design or may be devised afterwards which may affect its ease of application. For example
  - By separation of the upper section at a joint, if the GBS is so designed; or
  - By cutting through structure at the appropriate height. Reinforced concrete can be parted using high pressure water jets, sometimes called hydro-demolition, though it is time consuming.

For the Great Lakes, it is assumed that GBS foundations will be installed and decommissioned using floating techniques, and that the foundations will be designed with decommissioning in mind. Floating techniques require cranes for manipulating the foundations and tugs for manoeuvring. They also require sufficient depth of water to allow the structures to be towed inshore, and they may need to be grounded in sheltered water instead.

Overall decommissioning activities for a GBS foundation will comprise:

- Pre-decommissioning: The season before the GBS is inspected to check the condition of all parts of the foundation, internally and externally, above and below water. This includes assessing the integrity of the lifting points and estimation of any weight change. Steps will be taken to comply with regulations and to develop a detailed decommissioning strategy—in particular how many lifts and whether the structure will be floated to shore. Tools and equipment will be designed such as lifting gear, flotation methods and tools for underwater working. Method statements and risk assessments are written. Vessels are contracted. Onshore facilities are developed if necessary.
- Preparation: Prior to raising the foundation, preparation will include clearance of sediment and scour protection from around the base, and removal of the ballast, for example with water jets and air entrainment to fluidise and extract sand, and application of flotation methods. Lifting attachments are prepared.
- Foundation removal: The crane vessel is attached throughout the operations to release and raise the foundation and pump out the water. Depending on the strategy, the crane either lifts the foundation out of the water onto the transport vessel, or holds the foundation in the water whilst controlled buoyancy is achieved to manoeuvre the foundation to float semi-submerged.
- Post-decommissioning: Sea-bed surveys are carried out immediately after the decommissioning operations to check there are no obstructions or dropped objects, and to confirm the status of the site.

Once at shore, concrete components can be cut down using hydro-demolition cutting techniques and by mechanical crushing. However this results in a net cost, rather than yielding offsetting scrap value. Alternatively reinforced concrete structures can find another use, for example as breakwaters and other coastal structures.

5.5.8 Floating WTG foundation

Recent studies of floating offshore wind ([74], [75], and [76]) identify over 30 concepts under development with 5 demonstrated at full scale (i.e., over 1 MW turbine) in an offshore environment. The key requirement of each design is to provide a platform that has minimal sway to maintain verticality of the turbine, and restrains the rotation of the turbine to maintain its orientation into the wind.

Credit – NREL.
L-R: Spar buoy; semi-submersible platform; tension leg platform.

Figure 5-59 Types of floating wind support structure

The designs can be grouped into three main types, as illustrated in Figure 5-59:

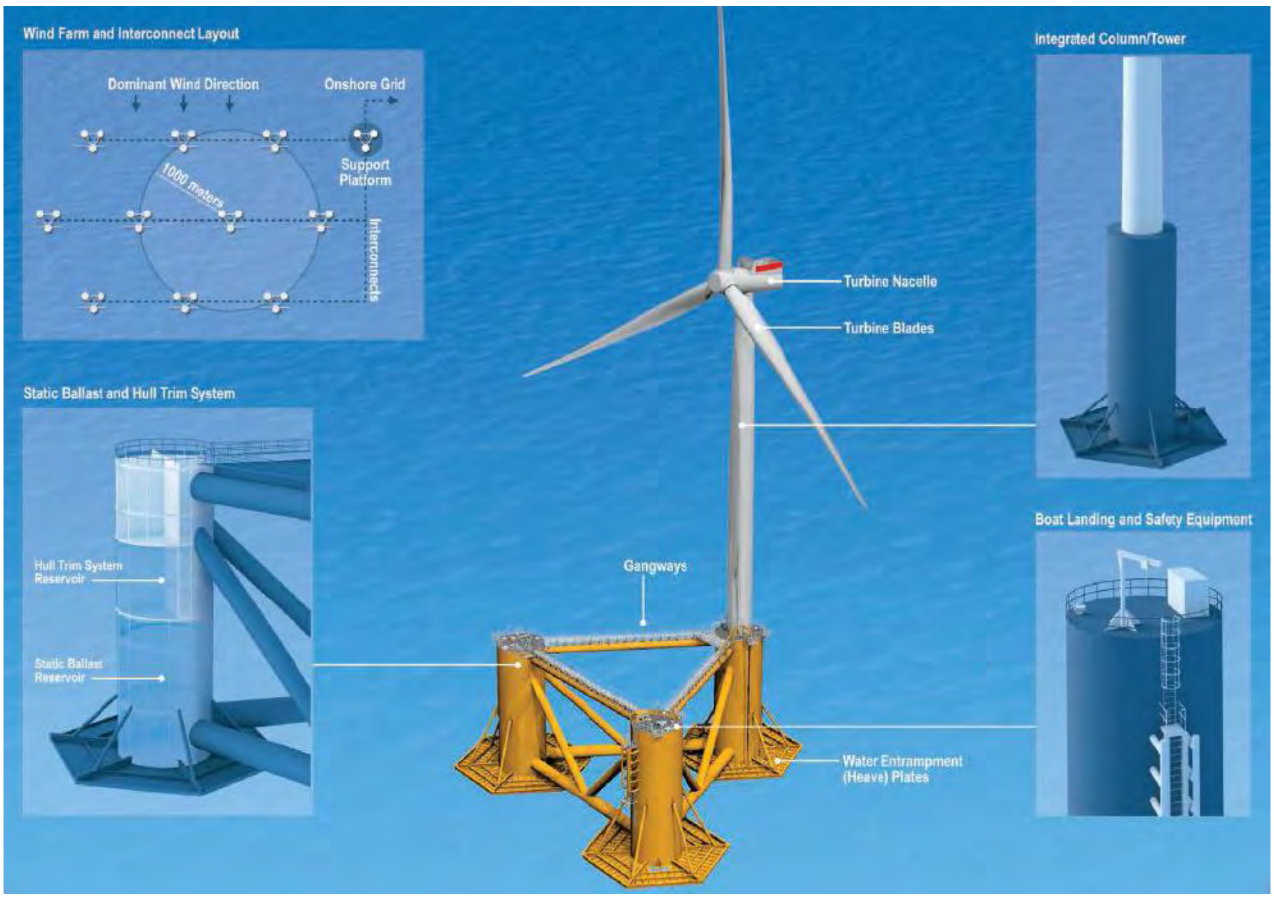
- Spar buoy: The structure is a simple ballasted vertical tube anchored by catenary mooring lines. Stability and verticality are provided by having the centre of gravity lower than the centre of buoyancy and a structure that is larger underwater and therefore less susceptible to wave motion. It is relatively straightforward to fabricate, though the large draft leads to restrictions in its deployment such as installation of the turbine onto the substructure whilst floating in sheltered deep waters.
- Semi-submersible platform: The platform comprises typically three chambers connected in a triangle, anchored by catenary mooring lines. It derives its stability from its size and from active and passive ballasting using pumped water to be semi-submerged during service. The low draft allows erection of the turbine at port and requires only tugs for installation.
- Tension leg platform (TLP): The platform is buoyant and semi-submerged, anchored with vertical tensioned mooring lines which provide stability. Although a lighter structure than the ballasted semi-submersible type, the installation process is more challenging and this type of floater is least well developed for offshore wind.

For application in the Great Lakes, the semi-submersible type has the major advantage of least demanding vessel requirements, flexibility of ports for construction and major maintenance (and decommissioning), and is one of the more advanced in terms of deployment experience. For the purposes of this MOECC study, a semi-submersible floating design is therefore used as the example, with particular reference to the

WindFloat designs by Principle Power, currently the subject of demonstration wind farms planned off the coasts of Oregon, US (WindFloat Pacific OWF) and Portugal (WindFloat Atlantic OWF).

5.5.8.1 Floating structure design and materials

Typical configuration of a semi-submersible floating structure (Figure 5-60) consists of three columns with static ballast tanks used to trim the structure down once at site and active ballast tanks to maintain dynamic stability. The columns are connected by cross members and heave plates at the base of each column assist in damping the motion from waves.



From WindFloat brochure by Principle Power.

Figure 5-60 Configuration of floating wind structure

The turbine tower is bolted to a flange and may be located atop one of the columns, as shown, or may be centrally located on the platform structure. The platform also supports secondary steelwork including boat landings, gangways, davit cranes, and possibly a heli-hoist or even a heli-landing facility. The design includes pipework and control systems for operating the ballasting systems, mooring points and connections for the power cables. The design also incorporates mechanisms for disconnecting and reconnecting the moorings and cable connections to allow the whole structure to be temporarily towed inshore. Indicative masses for semi-submersible floating foundations are given in Table 5-17, illustrating that the mass is not strongly dependent on the size of turbine.

Table 5-17 Indicative masses of semi-submersible floating foundations

Mass of foundation	4 MW turbine	8 MW turbine
	1,800 t	2,200 t

For floating structures of this type designed for 8 MW turbines, indicative minimum water depths (drafts) needed are around 20 m when ballasted for maximum stability and less than 10 m when the structures are more lightly ballasted during transit, or for the smaller structures for 4 MW size. The maximum draft in many ports in the Great Lakes is currently around 8 m; however, it is expected that facilities would be readily found or created to serve such floating wind structures.

The mooring systems consist of flexible chains or wires hanging from the floating structure to anchors on the lake-bed. The size and type of anchor strongly depends on the soil conditions. Where the material is firm sand or clay, embedment anchors or suction anchors are suitable. Where the material is harder so embedment is not reliably achieved, then piles may be used.

Icing issues

Design for Floating structures would be deployed in areas of the Great Lakes that are predominantly ice-free. As a precaution against lake ice, ice cones can be incorporated around the columns. If trapped in pack-ice, the structures can move with the ice and if necessary be disconnected from their moorings. Disconnection and towing to shore will already be part of the design for purposes of major maintenance. The process will involve disconnection from the power cables and then disconnection from the moorings using tugs which then tow the structure to shore. The connection points at site are designed as units that can be readily picked up for re-connection.

Materials

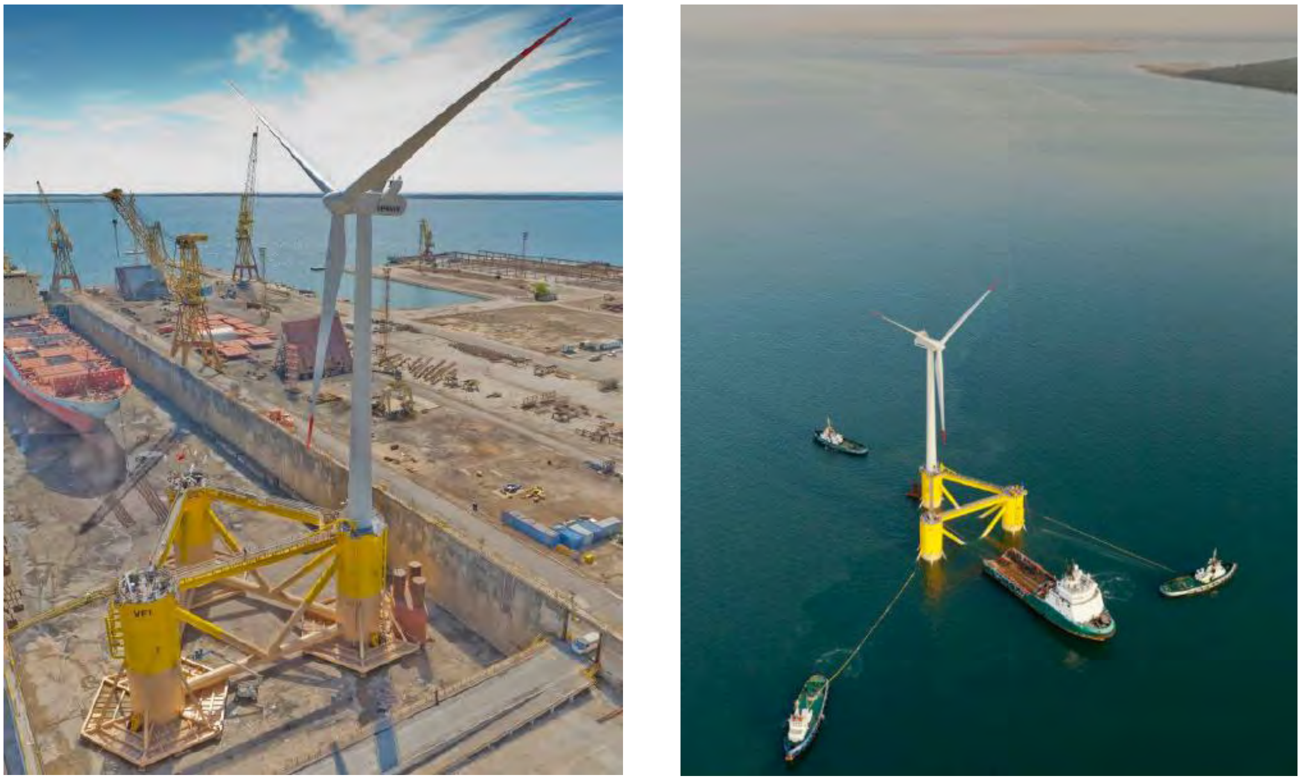
Floating wind support structures are made from structural steel, both for the columns, bracing and secondary steel. Stainless steel may be used for the water ballasting pipes for greater resistance to corrosion.

5.5.8.2 Floating structure construction and installation

Floating wind support structures are constructed primarily from rolled and welded steel tube and plate.

Figure 5-61 shows the construction and installation of the WindFloat I prototype in 2011 including a 2 MW turbine. In this case final assembly of the support structure is done in a dry dock ready for floating out. The turbine is also assembled onto the platform in dry dock using a land-based crane. The combined turbine and its support structure are then commissioned as far as possible whilst in port. In parallel the anchors and mooring lines are installed at the offshore site, and also the array and export power cables. Finally the turbine units are towed out to their locations using tugs and connected to the moorings and cables.

If a dry dock of sufficient size is not available, alternatives are to construct the turbine onto the platform using a land-based crane, with the platform floating at the quayside; or to construct the turbine onto the floating platform located inshore using a crane on a jack-up. In the latter cases, dynamic crane lifts are required, albeit onto a stabilised platform in sheltered water.



a) Assembly of platform and turbine in dry dock b) Tow out of complete assembly

Credit – Principle Power.

Figure 5-61 Construction and installation of WindFloat I

5.5.8.3 Floating structure decommissioning

Decommissioning of floating structures is the reverse of installation. The units are disconnected from the cables and mooring lines and towed to shore. Unlike other foundation types, the turbine is dismantled after the return to shore. The turbine is dismantled using a port-side crane, and then the structural steelwork is broken up for recycling.

At the offshore site, the mooring lines and anchors are removed as far as possible:

- Embedded anchors are removed by applying force in the appropriate direction
- Suction anchors are released by overpressure and lifted out
- Piled footings, by cutting just below sea-bed level (less straightforward)

The overall decommissioning activities for a semi-submersible floating foundation are:

- Pre-decommissioning: The foundation structure is inspected to check the conditions of all parts, in particular the towing and disconnection points, and static ballasting mechanism. Weight changes are estimated, for purposes of the ultimate lifting of the foundation out of the water and for dismantling operations. The anchoring points and cables are surveyed. Onshore facilities are developed if required.

- Preparation: As described earlier, the turbines are prepared for decommissioning by the draining and sealing of fluids, removal of loose equipment and electrical disconnection. The foundation is prepared by disconnecting the electrical cables and attaching towing lines.
- Removal and dismantling: Tugs connect to the towing lines, the static ballasting is adjusted for the towing configuration higher in the water, and the mooring lines are disconnected. The entire structure is towed to shore, either into dry-dock or shallow water. Turbine bolts are loosened and the turbine is dismantled in the reverse of installation using a shore-based crane. The support structure is then broken up for recycling.
- Post-decommissioning: Sea-bed surveys are carried out immediately after the decommissioning operations to check there are no obstructions or dropped objects.

5.5.9 Offshore substation with jacket foundation

The OWFs considered here are for 75 turbines of either 4 MW or 8 MW individual capacity. Thus the total wind farm capacities are either 300 MW or 600 MW. In practice a 300 MW OWF would be served by a single offshore substation (OSS) whereas a 600 MW OWF would usually have two offshore substations.

It is assumed that the offshore substations are supported by a jacket foundation, which is likely to be the case for the 25 m and 40 m water depths considered here.

5.5.9.1 OSS design and materials

An OSS consists of a jacket substructure secured with piles to the sea-bed and a topside with multiple decks housing the mechanical and electrical equipment. Figure 5-62 shows example configurations, for Westermost Rough OWF in the North Sea off the UK east coast and Anholt OWF in the Baltic Sea off the coast of Denmark.

a) Westermost Rough OSS – credit Dong Energy

b) Anholt OSS (visualisation) – credit Ramboll

Figure 5-62 Offshore substation jacket and topside

The jacket has typically four legs with skirt piles that are driven into the sea-bed after the jacket has been put in place. The jacket includes boat landings and J-tubes guiding the export and array cables to and from the sea-bed.

In the topside, the lowest deck is generally the cable deck where the cable hang-offs are located at the top of the J-tubes. Decks above contain the switch-gear and transformers; monitoring, metering and control equipment for the OSS and WTGs; emergency diesel generator and fuel; and craneage. Sensitive equipment is housed in protective environments with heating, ventilation, air conditioning and fire suppression systems. Other items are likely to be navigational aids; a workshop and stores; and facilities for technicians. Above the roof deck there may be a heli-hoist platform and a met mast.

OSS platforms are generally designed to be unmanned with only occasional visits for maintenance purposes. In some instances, the OSS may also be used by turbine technicians as a temporary marshalling point. The technician facilities are therefore unlikely to include any overnight accommodation other than emergency provision.

The dimensions and mass of the topside depend largely on the MW capacity of the OWF and also strategic decisions on the number of transformers and degree of redundancy. Typically there are two transformers, each taking half the OWF output in normal circumstances but capable of taking more should one transformer or export cable be out of service. The dimensions and mass of the jacket also depend on the depth of water.

Table 5-18 gives indicative dimensions and masses for the topside and jacket of an OSS of 300 MW capacity, for 25 m and 40 m water depth. The air gap is 15 m between the water level and the base of the topside. This is appropriate for negligible tidal variation and a relatively benign wave climate.

Table 5-18 Indicative masses and dimensions for OSS topside and jacket foundations

Water depth	Item	300 MW
N/A	OSS top height above water level	35 m
N/A	OSS topside dimensions (LxWxH)	25 x 25 x 20 m
N/A	OSS topside weight	1,500 – 2,000 t
25 m	OSS jacket base dimensions (LxWxH)	30 x 30 x 40 m
25 m	OSS jacket weight (excluding piles)	1,000 t
25 m	OSS jacket pin-pile weight, each	100 t
40 m	OSS jacket dimensions (LxWxH)	35 x 35 x 55 m
40 m	OSS jacket weight (excluding piles)	1,500 t
40 m	OSS jacket pin-pile weight, each	100 t

Icing issues

Design against ice is likely to require greater wall thicknesses of the jacket members and/or ice cones to deflect the ice.

Materials

The majority of the jacket and topside structures are structural steel. Decking may be steel or glass reinforced composite gratings. The electrical structures will contain considerable quantities of electrical grade copper.

5.5.9.2 OSS construction and installation

Topsides are assembled and commissioned on land as far as possible, to reduce the extent of offshore operations.

Jackets are fabricated from steel tubes that are welded from rolled steel sheet using standard processes and facilities. The tubes are then cut and prepared for welding into sections, sub-assemblies and then the complete jacket, such as shown in Figure 5-43.

Using the post-piling route, which is more appropriate for a single construction, the process of installation involves preparing and levelling the sea-bed. Mud-mats are then placed to provide a temporary support to the jacket prior to piling, in particular to spread the load to keep the jacket level and prevent it sinking into the sea-bed. After placing the jacket, the piles are driven through the pile sleeves and grouted in place; usually one pile, sometime two piles at each leg. Finally scour protection may be placed around the legs in the form of rock pieces (rock armour).

Figure 5-63 Transport of jacket and topside for offshore substation at Westermost Rough OWF

Figure 5-63 shows the jacket, piles and topside for the Westermost Rough offshore substation loaded on a 100 m by 33 m barge for transport from the manufacturer direct to the OWF site. This design is for an 18 m water depth and 210 MW wind farm capacity so is slightly smaller than the generic substation for the current study.

Installation of both jacket and topside require a crane of at least 2,000 t capacity, taking into account the extended lift radius for the square structures. Typically a large shearleg crane such as Rambiz (pictured in Figure 5-64) or a semi-submersible crane vessel is used. Piling driving equipment is also required.

The topside is designed with legs that stab into the tops of the jacket legs, just visible in Figure 5-64. They are then welded in place.

Credit - Scaldis

Figure 5-64 Installation of substation topside by Rambiz shearleg crane

For projects in the Great Lakes, crane vessels may not be available for 2,000 t lifts, thereby preventing the installation of the jacket and topside as single lifts. In this case, they may be designed as several smaller lifts: for example with the jacket as an upper and lower part, and the topside as a series of modules. One option is to install each of the transformers separately once the topside housing is already in place.

Alternatively, the topside could be installed without the need for heavy lift vessels for example by float-over. Float-over methods use a vessel that transports the topside in one piece, positions over the foundation substructure and lowers the topside onto the substructure. Typically the vessels used are either catamarans or dual barges which can therefore straddle the substructure For wide-based foundations, a relatively narrow transport vessel can be positioned within the legs of the foundation, provided the foundation is suitably designed. In each case the vessel lowers the topside by ballasting down, and then it sails out from underneath. The vessel needs to have sufficient stability and deck strength to carry the load, and leg mating units need to be specially designed. The operation relies on accurate anchoring in position.

SylWin Alpha converter - credit Overdick

Figure 5-65 Float-over installation of 15,000t HVDC converter topside

In the offshore wind sector, float-over installation has been used for HVDC converter platforms serving clusters of German offshore wind farms, such the 15,000t topside of SylWin Alpha installed in 2014 shown in Figure 5-65. The figure shows the pontoon being positioned between the legs of the foundation. The yellow topside overhangs the pontoon, to be lowered onto the legs. In this example, the topside was hydraulically jacked up once in position.

Should float-over be used for a smaller scale installation, as would be the case in the Great Lakes, then there would be a greater sensitivity to wave heights than for larger units.

5.5.9.3 OSS decommissioning

There is considerable experience in the Oil & Gas industry of decommissioning offshore platforms similar to an offshore substation. These can benefit the offshore wind industry, particularly in techniques for underwater cutting, and also methods for lifting and transporting the removed jackets and topsides.

In general the decommissioning assumption is that the topside is removed and taken to shore. Then the jacket foundation is removed by cutting the pin-piles below the mud-line level. The majority of the embedded piles are thus left in-situ, on the grounds that their removal would create excessive environmental disruption and the costs would be prohibitive. The piles are cut at a depth sufficient to avoid exposure of the remaining pile stumps or cause any future hazard to other sea users. The exact depth below the mud-line is agreed with the regulatory authorities prior to decommissioning and may be 1 to 5 m.

Cutting of the pin-piles is by high pressure abrasive water jet, or possibly diamond wire as described earlier. With skirt piles, the design may allow cutting access from the inside.

With only one or two offshore substations to be decommissioned, it will be more economical to use a single crane vessel for removing both the topside and jacket pieces. The number of lifts and the crane vessels used will be same as the installation process and depends on the design.

Table 5-19 indicates raw weights and dimensions of the pieces to be removed during decommissioning, including multiple lifts to give individual weights no more than 500 t. Allowances are made for the weights of pin-pile tops and grout, and that multiple lifts will not be equally divided.

Table 5-19 Approximate masses and dimensions for OSS topside and jacket removal

Water depth	Item	Strategy	Mass	Dimension
N/A	OSS topside	Single lift	2,000 t	25 x 25 x 25 m
25 m	OSS jacket, including pile tops and grout	Single lift or flotation	1,200 t	40 m height
25 m	OSS jacket sections	Three lifts	450 t	15 m height
25 m	OSS jacket footprint	N/A	N/A	30 x 30 m
25 m	OSS pin-pile diameter / wall thickness	N/A	N/A	1.8 m / 50 mm
40 m	OSS jacket, including pile tops and grout	Single lift or flotation	1,700 t	55 m height
40 m	OSS jacket sections	Four lifts	450 t	35 m height
40 m	OSS jacket footprint	N/A	N/A	35 x 35 m
40 m	OSS pin-pile diameter / wall thickness	N/A	N/A	1.8 m / 50 mm

Potential lift strategies for the topside are:

- Single lift: minimises the number of marine operations, but requires a high-capability crane, typically approaching 2,500 t once lifting gear and allowances for uncertainty and dynamic lifting are included.
- Multiple lifts: reducing the maximum lift required. Figure 5-66 shows an example from Oil & Gas decommissioning where the upper topside is lifted separately from the lower part. To reduce the maximum lift to under 500 t, at least five lifts would be needed, once allowances have been included, and possibly more.
- Non-lifting method, such as the reverse of float-over, depending on the original design.

Credit - Scaldis

Figure 5-66 Oil & Gas sector topside decommissioning in multiple lifts

Potential lift strategies for the jacket are:

- Single lift after pile-cutting at the sea-bed: the weight lifted is the jacket plus top part of the pin-piles and grout. For jackets in 25 m water depth, the raw lift is around 1,200 t; for 40 m it is around 1,700 t including the tops of the pin-piles and grout.
- Multiple lifts, with pile-cutting at sea-bed, plus underwater cutting part way up the jacket. To reduce the maximum lift to less than 500 t, the jacket in 25 m depth would need to be lifted in at least three pieces; and in 40 m depth the taller jacket would be lifted in at least four pieces.
- Flotation using controlled buoyancy. The flotation mechanism is applied offshore and probably requires underwater working. The release of the piece at the finish of the pile-cutting would need to be carefully controlled to be safe. A crane of limited capacity is required offshore.

To transport the removed pieces to shore, the options are:

- Self-loading onto the crane vessel, though it is unlikely to have the deck capacity.
- On towed barge or barges. This is the more likely option, given the sizes of the pieces. Dynamic lifting is involved to load the piece onto the floating barge so is more sensitive to wave heights.
- Flotation of the jacket by making it buoyant and towing it to shore.

The overall decommissioning activities for the OSS removal are:

- <u>Pre-decommissioning:</u> the season before, the jacket and topside are inspected to check the condition of all parts, internally and externally, above and below water. This includes assessing the integrity of lifting points and estimations of any weight change from accretion, corrosion or equipment changes. Steps are taken to comply with regulations and develop a decommissioning strategy, in cooperation with those responsible for decommissioning of the turbines and cabling. Tools are designed and vessels chartered; method statements and risk assessments are written.
- <u>Preparation</u>: The topside preparation involves de-energising electrical equipment; draining or sealing off fluids; removing or securing loose equipment; and strengthening lifting points if required. Cables

are disconnected and cut at the mud-line. Jacket preparation includes removal of soils from either inside or outside the piles to give access for cutting. Preparation is done as far as possible from a support vessel prior to arrival of the heavy lift vessel.

- Topside removal: Assuming the topside is to be lifted off, the crane is first attached, then stab-in joints are cut between topside and jacket. The topside is removed in one or more lifts with pieces placed on the transport barge and secured. At the disposal port the topside is dismantled completely with components re-used and materials recycled or safely disposed of as appropriate.
- Jacket removal: New lifting points are established at the top of the jacket and the crane is attached. Cuts are made and the jacket is removed in one or more pieces, placed on transport barge and secured. At the disposal port the structure is broken up for steel recycling.
- Post-decommissioning: Sea-bed surveys are carried immediately after the decommissioning operations to check for obstructions or dropped objects, and confirm none of the pile stumps are protruding.

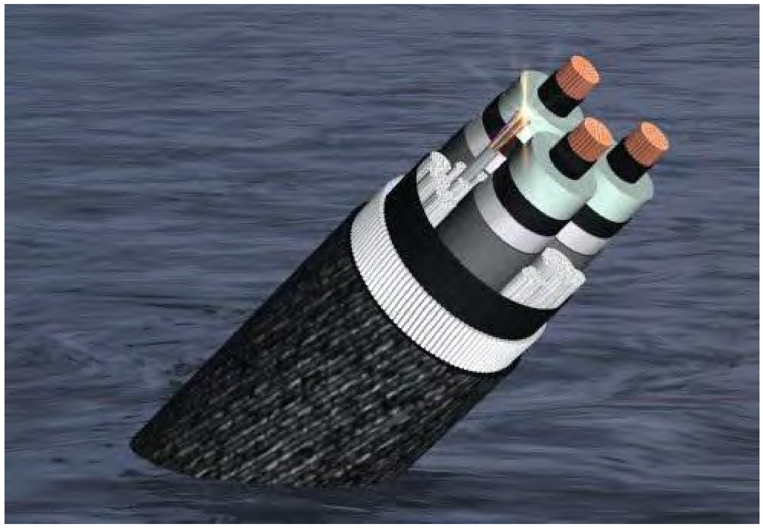
5.5.10 Cables

5.5.10.1 Cables design and materials

Array cables connect the turbines to the offshore substation usually in strings or loops. The array cables emerge from the foundation or J-tube near the level of the sea-bed and are buried between the turbines at a depth of 0.5 m to 2 m. The export cable connects the OSS to the shore. It often comprises two parallel cables buried some metres apart within the cable corridor, thus providing export capacity if one is damaged.

Sub-sea power cables typically contain three conductor cores, usually of electrical-grade copper though sometimes electrical-grade aluminium. The power capacity is determined by the conductor cross-section and different cable sizes may be used at different parts of the cable network as required.

Figure 5-67 presents an illustration of a cable cross section, showing the cores and their surrounding insulation (e.g. polypropylene); optic fibres that carry communication and monitoring signals; and an outer layer of protective galvanised steel armour wire.



Source: Nexans

Figure 5-67 Subsea power cable

Typical weights and dimensions of cables are given in Table 5-20. Array cable lengths assume typical spacing of the WTGs of 6 to 8 rotor diameters, allowing for extra length needed for installation and variations in route.

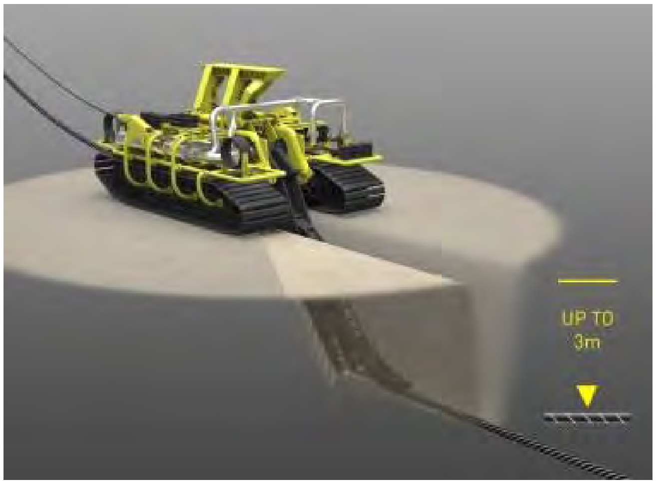
Table 5-20 Approximate masses and dimensions for sub-sea power cables

Array cable	Mass
Whole dry weight	15 – 30 t / km
Cable diameter	80 – 180 mm
Copper cross section, per core	95 – 400 mm^2
Length per array cable (4 MW WTGs)	800 – 1200 m
Length per array cable (8 MW WTGs)	1000 – 1600 m
Export cable	**Mass**
Whole dry weight	40 – 60 t / km
Copper cross section, per core	400 – 1000 mm^2

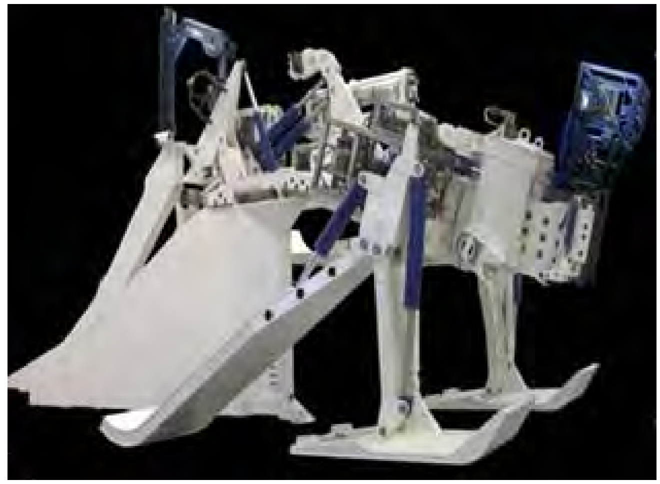
5.5.10.2 Cables construction and installation

To minimise defects and maximise electrical efficiency, cables are manufactured in continuous lengths as far as possible. At all times during transport and installation they are protected from internal damage by maintaining a minimum bend radius.

Cables are buried using remotely operated water jetting, ploughing, or by trench cutting depending on the hardness of the sea-bed material. Examples are given in Figure 5-68.



Source: Trenchformer by Boskalis
Tracked cable laying in jetting mode



Cable plough on sleds

Figure 5-68 Cable burial tools

The cable-burial tool on the sea-bed is remotely operated from a vessel. The burial may take place as a separate operation after the cable has been laid on the sea-bed, or it may be laid and buried simultaneously. The cable laying vessel needs to have the capacity to handle the cable and to carry the whole cable in its carousel which can weigh several thousand tonnes in the case of export cables. Figure 5-69 shows the "Stemat Spirit", a DP cable laying vessel capable of handling a carousel of over 4,000 t. Anchored cable laying barges are also used.

"Stemat Spirit" Source: VBMS.

Figure 5-69 Cable laying vessel

Where the export cable leaves shore, it may be drawn through a horizontal tube that has been drilled from the jointing point on land, under any coastal defences and to a point in shallow water.

After installation and burial of the cables, they may be given additional protection using dumped rocks or by laying flexible concrete mattresses (Figure 5-70). This may be needed if the burial depth is insufficient or if there is a risk of the cable becoming exposed through the scouring effect of currents. Additional cable protection may also be used where the power cable crosses an existing cable.

Source: IMCA.

Figure 5-70 Concrete mattresses for cable protection

5.5.10.3 Cables decommissioning

Options for cable decommissioning will range from complete removal of all cables and protection to leaving all in-situ. In practice partial removal may be optimum taking into account the practicalities, economics and environmental aspects. This might involve leaving cable protection in-situ together with any cable under the protection, but otherwise removing the cable. If cables are all left in-situ, then cable ends need to be cut and securely buried.

Assuming cables are to be removed, it is possible that they can be de-buried by physically pulling them out. However, after many years the sea-bed soils will consolidate to their original state and it is probable that a similar technique to their original burial will be used. The jetting, ploughing or trenching tool will be run alongside the cable to loosen the soil, allowing the cable to be pulled out. However, unlike installation, the bend radius of the cable does not need to be protected, nor does the cable need to be kept in a single piece – on the basis that the cable will not be re-used. The cable can therefore be cut into lengths on board the vessel and transported to shore in batches.

Figure 5-71 shows hydraulic cutters being used to cut such a cable.

Source: DNV GL.

Figure 5-71 Hydraulic cutting of power cables

The cable decommissioning vessel needs to be equipped for holding its position, for lifting the cable out, and for cutting and stowing the cable lengths, as well as launching and operating the remotely operated cable de-burial tool. However, a large vessel such as needed for export cable installation is not necessary. For decommissioning, the same vessel and equipment can be used for both array cable and export cable removal. Additional vessels and equipment may be needed if large amounts of cable protection (rocks or mattresses) need to be moved or removed.

Where possible, it is expected that remotely operated ROVs or WROVs will be used. However, divers are likely also to be needed, especially if the strategy requires many cable ends to be cut and buried. Depending on the site location, there may be restrictions arising from water depth (in the case of divers), water currents and poor visibility.

The overall decommissioning activities for array cable and export cables are:

- Pre-decommissioning. Assessments are made of cable burial depth, extent of protection and decisions are taken on the extent of cable removal. Regulations are complied with. Tools and equipment are designed and contracted; method statements and risk assessments are written; vessels are contracted.
- Preparation. The route is scanned to determine precise cable location and burial depth of cable. This is often carried out by the specialist cable vessel. Cable protection is removed or moved if required for access to the underlying cable, for example using crane-operated grabs. Cable ends are cut where it is to be left in place, such as either side of live cable crossings.
- Cable removal. Once the route is clear, the cable de-burial tool is run beside the cable route to release the cable. The cable is pulled out and cut to lengths on the vessel. The removed cable is

taken to shore in batches. Once on the quayside, the lengths of cable are stripped to separate out the materials for recycling and disposal.

- Post-decommissioning. The route is surveyed to check for remaining obstructions or dropped objects. If cable lengths are left in-situ, the ends are checked to avoid protrusions, and at intervals in the future repeat surveys are carried out to check no ends have become exposed.

5.6 Chapter summary

Table 5-21 summarises the characterisation of the potential sites and the technology selection and Table 5-22 summarises the installation and decommissioning of the selected technologies.

Table 5-21 Summary of site characterization and technology selection

Section	Description	Comments
Site finding process	The general process for offshore wind site finding involves • mapping of spatial constraints and resource; • weighting of areas outside the "hard" constraints; • iterative identification, ranking and selection of the most promising sites.	In the case of the Great Lakes, no decisions have yet been made on geographic locations and the full range of selection criteria are not available or unknown. Selection of specific locations is outside the scope of this study. Instead, the focus is on site-types and on suitability of different foundation types.
Characteristics of the Great Lakes	Publically available data are presented of • Wind resource – strongest in Lake Superior and generally greater away from lake shores; • Water depth – greatest in Lake Superior (mean 149 m) and least in Lake Erie (mean 19 m); • Seabed geology – bedrock very had in parts of Lake Superior and medium strength sedimentary rocks elsewhere, varying depths and strengths of overlying sediment; • Ice - the maximum ice cover varies greatly annually and between lakes. Parts of Lake Superior and Lake Huron are always ice-free.	Other characteristics are: • Water currents and tidal range are negligible throughout the Great Lakes • Wave heights are medium severity compared with European sites and least in summer On the basis of these physical characteristics, a full range of site-types are found in the Great Lakes. These cover • Shallow (<30 m) to deep (>50 m) • Pileable to non-pileable rock • With solid ice or ice-free • Range of remoteness (distance from ports and populations)
Turbine types	Two generic turbine types are selected for comparison in decommissioning analysis • 4 MW: 125 m rotor diameter, 85 m hub height • 8 MW: 175 m rotor diameter, 110 m hub height	4 MW is typical of machines installed to date; 8 MW represents the latest sizes. In view of restrictions in the size of vessels that can enter the Great Lakes, the 4 MW size may well be selected for offshore wind projects.
Foundation types	Monopiles: need pileable, consolidated sediment rather than hard rock; but suitable water depth is limited. Jackets: require pileable sea-bed; possible in deeper water than MPs. Gravity base: suitable for hard sea-bed Suction buckets: need uniform sediment. Floating: suitable for deeper ice-free water.	Monopiles, jackets and GBS are established technologies with MPs the most widely used for offshore wind. Suction buckets and floating structures are relatively new.

Table 5-22 Summary of installation and decommissioning

Components	Description	Comments
Vessels	The maximum size of vessels that can enter the Great Lakes through the Seaway is 23.7 m width, 225.5 m length, 8.08 m draft. Shipbuilding facilities are limited.	The specialised self-propelled jack-up crane vessels used in Europe for installing offshore WTGs will be unable to access the Great Lakes. Alternatives will be needed such as towed jack-up barges or modular jack-up platform with mobile cranes.
Cutting methods	Likely decommissioning methods are • High pressure abrasive water jet for pile-cutting • Diamond wire for cable cutting • Remotely operated vehicles (ROVs)	These subsea techniques are largely developed for O&G decommissioning.
Turbines	Turbines are installed in multiple lifts by cranes working from fixed platforms or jacked up vessels. The base of the turbine may be 15 m above water level. Decommissioning would essentially be the reverse.	Cranes operated from towed jack-up platforms would probably be used, rather than specialised self-propelled turbine installation vessels from Europe.
MP	MP installation is by driving or drilling the piles. The transition piece (TP) is grouted or bolted on top. Decommissioning is by cutting the pile at 1 – 2 m below the sea-bed level and lifting out.	MPs for larger WTGs can weigh up to 1000t. When decommissioning, the MP may be removed in several pieces. Transport and manipulation may be by floating in a controlled manner if a strong enough crane is not available.
Jackets	Jackets are fixed to the sea-bed by piles at each corner. Usually the piles are installed first (pre-piling). Decommissioning is by cutting the piles below the sea-bed level and lifting out.	The large footprint of jackets means transport would probably be on a towed barge. The jacket may be removed in two or more pieces to limit the maximum crane lift.
Suction bucket	Mono-buckets supporting a single column or suction bucket jackets both use suction caissons. Installation is by pumping water out of the caisson chamber causing it to sink into the sea-bed. Decommissioning is by over-pressuring the caisson.	Suction buckets rely on uniform sea-bed materials. Transport and manipulation may be by floating in a controlled manner as an alternative to lifting out of the water onto a vessel.
GBS	Typically made of reinforced concrete, GBS foundations are installed by lifting or floating into place, lowering to the sea-bed, and filling with ballast. Decommissioning is the reverse.	GBS weights, before ballasting, can be 3000t or more so quaysides and vessels need to be strong enough.
Floating structures	The turbine is installed on the floating platform, then towed out to the site and connected to mooring lines and power cables. Decommissioning is the reverse, with the turbines removed at shore.	Floating turbines have the advantage of not needing heavy lift cranes offshore.

6 COST ESTIMATES FOR DECOMMISSIONING

6.1 Chapter introduction

Having identified and described in Chapter 5 the most likely technologies for the Great Lakes offshore wind projects, Chapter 6 presents indicative estimates for the decommissioning costs of selected offshore technologies for different hypothetical scenarios. A separate section within the Chapter presents the disposal and potential revenue from materials recycling.

Chapter 6 includes description of the DNV GL Great Lakes Offshore Wind Decommissioning Cost Modelling Tool ("the Tool") provided as part of the work, together with guidance on its use. The Tool is designed for application to offshore wind projects within the Great Lakes and is focussed on OWFs of a particular capacity and number of turbines. However, having determined in Chapter 5 that no foundation type can be ruled out and given that the study does not involve identifying specific locations for the OWFs, the Tool provides the capability for analysing a range of variables within the feasible methodologies.

Typical results derived from the Tool are presented and discussed.

The current Chapter comprises sections on:

- Discussion of the scenarios to be modelled;
- Identification of the main categories of cost, including overheads and other costs not previously itemised in this study;
- Description of the marine operations and optimum logistics for decommissioning each of the different components;
- Consideration of the disposal of the removed components and possible recycling revenue from the main materials streams;
- Guide to using the Tool; and
- Guidance on input values to the Tool.

6.2 Selection of scenarios for modelling

In Chapter 5 of this Study, generic turbine sizes of 4 MW and 8 MW were selected and described. The 4 MW size represents the established technology in the offshore wind industry whereas the 8 MW size represents future technology that is just starting to be adopted in Europe.

In Chapter 5, the range of potential foundation types were also considered. It was concluded that none of the major foundation types for WTGs can be ruled out, on the basis of the range of different water depths and lake-bed conditions to be found in the Great Lakes. The cost modelling is therefore designed to encompass:

- Monopiles;
- Jackets;
- Suction buckets (single or multiple);
- Gravity base; and
- Floating.

For the current study it has been agreed with the MOECC to focus on the 4 MW turbine size during the modelling, on the basis that the decommissioning techniques can be more confidently determined. Furthermore, given the sizes and weights of the 8 MW turbines and their foundations, and the Great Lakes restrictions on vessel sizes and shipbuilding possibilities, it is anticipated that very different methods of construction and decommissioning will be adopted than those commonly used in Europe at present, as discussed in Chapter 5. Cost modelling specifically for these larger sizes is therefore considered too speculative to be meaningful at this stage.

For the 4 MW turbines, the main variations between the cost models arise from the methods of removing the WTG foundations, and whether multiple units are being removed or just one or two. The processes are therefore split into the following main strategies:

- Cut, Lift, Carry (multiple units) – e.g. MPs or jackets. Turbine is removed. Then pile(s) are cut and the foundation is lifted onto a vessel for transport.
- Lift, Float, Tow (multiple units) – e.g. GBS and suction foundations. Turbine is removed. Then foundation is released, raised to float in a controlled manner, and towed to shore.
- Detach and Tow (multiple units) – e.g. Floating wind. The already floating structure is detached from its connections and towed to shore. Turbine is removed at shore.
- Offshore sub-station (one or two) – cut, lift and carry. Topside is removed, then piles are cut and foundation is removed and transported to shore.

The cost modelling needs to give options to include or exclude the removal of array cables, export cables and offshore sub-stations. In practice, the inclusion of such electrical assets will depend on the following factors:

- Design of the offshore wind farm. Some OWFs may not have an OSS; others may have more than one.
- Requirements for decommissioning. In practice, it is possible that either array cables or export cables or both may be essentially left in-situ for economical or environmental reasons.

- Responsibilities for decommissioning. Part or all of the offshore electrical assets may be decommissioned as a separate operation, for example if they are the responsibility of a different body.

The scope of the cost modelling includes an optional analysis of the potential costs and revenue from the disposal of the materials brought to shore.

Finally the scenarios are all designed to encompass the full decommissioning phase, including pre- and post-decommissioning activities, engineering and project management work, and other overheads including the work required to obtain permits. However, the scope of the modelling does not include the decommissioning of the onshore assets of the OWF (comprising the onshore substation, cabling and operations case) on the basis that these are not part of the specifically marine obligations for decommissioning.

In line with standard practice the cost estimations are based on current prices and values, with no consideration of future inflation or price changes. To allow high and low cost scenarios to be explored, guidance is provided within this report and within the Tool on appropriate ranges of key costs and factors.

In the next section, the main cost categories are described in more detail, and in the Appendix guidance is provided on the use of the Tool and indicative ranges of input values.

6.3 Cost modelling of decommissioning activities

6.3.1 Identification of the main cost categories

A key feature of decommissioning an offshore wind farm is the optimisation of the marine operations, taking into account that multiple similar elements are being removed – in this case, 75 turbines and their foundations. The most efficient use needs to be made of specialised equipment such as cranes and vessels, requiring if possible, the operations to all take place within a single summer season to avoid the additional costs of remobilisation. Cost modelling of the decommissioning activities therefore requires consideration of the sequences of activities and the possibilities for parallel working. In practice this will mean that separate vessels and equipment are used for the turbine removal and for the foundations removal, with the foundations team following behind the turbine team. In each case, the removed components may be transported to the disposal port in batches to reduce the overall transit time.

Although the major expenditure is in the marine operations to remove the offshore structures, the overall cost of the decommissioning will also include preparatory work in the years and months before the marine activities, and some post-decommissioning activities. The costs will also include overheads for the engineering and management of the work.

In the following sections, the main phases of the operations are described, highlighting additional factors that may have a key influence on the costs and making reference to the selected Great Lakes scenarios. Note that descriptions of the technologies and decommissioning methods have already been provided in Chapter 5.

6.3.2 Pre-decommissioning work

Prior to starting decommissioning, reviews of the regulations and the EIA requirements are needed, consultations carried out with local and statutory bodies, and consents sought. Discussions will be held to ensure interfaces are addressed, such as with those decommissioning the on-shore facilities. Disposal facilities will be identified and developed if necessary in collaboration with specialist industrial recyclers.

The site lake-bed will be surveyed to identify and locate any obstructions such as wrecks, dropped objects and old cables; potentially unexploded ordnance (UXO) which may have moved since the last survey; and to provide information on the water depths and status of any sand waves. The location and burial depth of array cables and export cables will be determined.

The turbines and foundations will be inspected to check their condition and removal techniques developed if necessary, following the best practice at the time. Customised cutting equipment, tooling, lifting gear and transport fastenings will be designed and tested, and lifting points confirmed. Engineering analysis, method statements and risk assessments will be carried out.

The detailed logistics will be decided, vessels identified and chartered, contractors appointed and marine warranties[12] put in place. The operations base for the decommissioning will be set up, typically an expansion of the existing O&M facilities.

6.3.3 Turbines decommissioning

6.3.3.1 Turbine preparation

Immediately prior to dismantling the turbines, they are prepared by removing or making secure any moveable equipment, draining or making safe any fluids or other hazardous materials, orienting the turbine rotor, electrically isolating the turbine, and making it ready for dismantling (for example easing bolts or cutting any that cannot be loosened). Array cables are disconnected and cut at the exit point near the lake-bed.

This work can be done by a small crew of technicians using a workboat, thus allowing the specialised crane vessels to focus on the lift operations. As soon as the first turbine is prepared the turbine can be removed, whilst the turbine preparation team work on the next turbine.

The main weather limits are the wave heights affecting access to the turbines.

6.3.3.2 Turbine removal

As described in Chapter 5, the turbine will probably be dismantled by removing each blade individually, then the nacelle and then the tower in one or more sections depending on the crane capacity. A careful loading plan and design of fastenings enable the turbine components to be loaded efficiently on the transit vessel, with a single batch expected to be between 3 and 5 turbines. For 75 turbines, this translates to 15 to 25 batches.

It is assumed that dismantling the turbine requires the crane working from a fixed platform, provided by a jack-up vessel, jack-up platform or leg-stabilised pontoon (spud-leg pontoon). In the Great Lakes this is most likely to be a towed jack-up, requiring the use of a tug for positioning. The transit vessel to take the removed turbine components to shore may be either a separate transit barge or the components may be taken on board the crane vessel itself.

[12] Marine warranties are insurance contracts for specific offshore activities

The main sequence of marine operations for the turbine dismantling will be:

1. Position the crane vessel, jack up and pre-load (to ensure platform is secure)
2. Dismantle the turbine, load onto transit vessel
3. Prepare for transit (e.g. secure the crane), jack-down and transit to next turbine location
4. Repeat until the batch is complete. Then transit to the disposal port, unload and return to the site.

The main weather limits will be the wind speed at the turbine hub height affecting the crane operations and wave heights affecting jacking operations and vessel transits.

6.3.4 Foundations decommissioning

6.3.4.1 Cut, lift & carry

The piles (MP or jacket piles) will be cut using high pressure water jet and lifted out using a crane on either a jack-up or floating vessel. One or more cuts may be used, depending on the dimensions of the foundation and capacity of the crane. Preparation between multiple cuts will probably be done whilst the crane vessel is at the location. The removed components are taken to the disposal port on a separate barge or on board the crane vessel itself.

The main sequence of marine operations will be:

1. Foundation preparation. Remove lake-bed material and attach cutting equipment (either internal or external). Other preparation as required, to add lifting points and bridging welds between MP and grouted transition piece (TP).
2. Position crane vessel and attach crane
3. Cut pile(s) and lift foundation piece. Load onto transit vessel.
4. Repeat for multiple lifts of the same foundation.
5. Transit to next location
6. With a complete batch, transit to the disposal port, unload, return to the site

The main weather limits are wave heights affecting dynamic lifts and, to a lesser extent, transits.

6.3.4.2 Lift, float & tow

This method is likely to be used for fixed foundations that do not require cutting and can be made buoyant in a controlled manner, such as GBS foundations and suction bucket foundations. A variation could also be possible for MP foundations, if controlled buoyancy can be achieved, possibly as part of the original design and installation. The method assumes the foundations are towed individually to shore.

For such a method, the sequence of marine operations would be:

1. Position crane vessel and attach crane
2. Release foundation from lake-bed (remove ballast of GBS; water injection of suction bucket; cut pile)

3. Apply additional buoyancy (pump out water; air bags or buoyancy tanks)
4. Tow to shore, lift onto the quayside or lower into shallow water, return to the site

The main weather limits are wave heights affecting dynamic lifts and transits with towing.

6.3.4.3 Detach & tow

This method applies to floating turbines and it is assumed that the turbines are only removed after the structure is at shore. The method assumes the structures are towed individually to shore. The sequence of marine operations would be:

1. Detach electrical connections, ballast the floating structure down
2. Attach tug(s) to the floating structure
3. Detach from mooring lines and secure lines for retrieval
4. Tow the whole structure to shore, lower into shallow water, tugs return to the site
5. Decommissioning of anchors and dismantling of the turbine at shore occurs concurrently with removal of the next floating structure from the site.

The main weather limits are wave heights affecting transits particularly under tow.

6.3.5 Array cables decommissioning

Work on the array cables can be started as soon as the turbines are de-energised and disconnected, working in parallel with the turbine and foundations removal operations. It is assumed that the cables are already cut at sea-bed level at the turbines and OSS.

If the array cables are to be removed, it is assumed a single cable handling vessel is used for both removal of the cable and transport to shore. The de-burial is carried out using towed or tracked equipment operated remotely from the cable vessel.

If there are large amounts of rock or other cable protection to be addressed, an additional vessel may be used beforehand.

If both array cables and export cables are being decommissioned, it is assumed that the same vessels are used moving from one job to the other without remobilising.

The sequence of marine operations would be:

1. Detailed scan of array cable route
2. If required, move or remove cable protection (e.g. rock or concrete mattresses)
3. De-bury and pull out array cable using jetter or plough, cut cable into lengths on deck and stow
4. Proceed to next array cable
5. With a complete batch of cable lengths, transit to the disposal port, unload and return to the site.

In the case that the array cables are to be left in-situ, work will be required to cut and securely bury each of the cable ends (two per array cable), probably using divers.

The main weather limits are the wave heights for the vessels operations.

6.3.6 Offshore substation decommissioning

Work on the offshore sub-station(s) can be started as soon as all the turbines are de-energised. It is assumed that both the topside and jacket foundation are removed using the same heavy lift vessel, through a series of modular lifts. Depending on the capacity of the heavy lift vessel (HLV), a separate towed barge may be used to transport the removed components to the disposal port.

The sequence of marine operations would be:

1. Preparation, using a workboat or support vessel
   - Topside preparation (draining fluids, removing loose equipment, release joints with foundation)
   - Jacket foundation preparation (excavation of lake-bed, create lifting points)
2. OSS topside removal using heavy lift vessel
   - Transit of HLV to the site, anchor, deploy crane
   - Detach topside piece(s), lift, load onto the transit barge
   - Repeat if more than one topside piece
   - Transit of barge to the disposal port, unload and return to the site
3. OSS foundation removal
   - Attach crane and cutting equipment
   - Detach or cut foundation piece, lift and load onto the transit barge
   - Repeat if more than one foundation piece
   - Transit of barge to the disposal port, unload

For a second offshore sub-station the process is repeated using the same vessels.

The main weather limits are wave heights for the vessels operations.

6.3.7 Export cable decommissioning

Work on decommissioning the export cable can be started as soon as it is de-energised and disconnected from the offshore sub-station, and can be carried out in parallel with the decommissioning of the OSS.

If the export cables are to be removed, it is assumed a single cable handling vessel is used for both removal of the cable and transport to shore. The de-burial is carried out using towed or tracked equipment operated remotely from the cable vessel.

If there are large amounts of rock or other cable protection to be addressed, an additional vessel may be used beforehand.

If both array cables and export cables are being decommissioned, it is assumed that the same vessels are used moving from one job to the other without remobilising.

The sequence of marine operations would be:

1. Detailed scan of export cable route (one or more cables)

2. If required, move or remove cable protection (e.g. rock or concrete mattresses)
3. Cut the export cable at the OSS
4. De-bury and pull out the export cable, cut the cable into lengths on deck and stow
5. With a full load of cable, transit to the disposal port, unload and return to the site.
6. Continue de-burial and cable removal
7. Cut the cable at shore.

In the case that the export cables are to be left in-situ, work will be required to cut and securely bury the cable ends at the OSS probably using divers. Allowance may also be required for work to decommission export cable that is close to shore.

The main weather limits are wave heights for the vessels operations.

6.3.8 Post-decommissioning surveys

After the decommissioning operations are finished, the lake bed is surveyed to ensure that any pile ends are sufficiently buried, and that the site is clear of obstacles.

Monitoring will be carried out at intervals to ensure that buried objects have remained buried and to monitor back-filling of scour holes. The extent and frequency of monitoring and the provision required for any remedial work will depend on the risk, in particular the mobility of the lake bed.

6.3.9 Overheads

The main overheads, in addition to the marine operations will be:

- Pre-decommissioning reviews of regulations and consultations, permitting
- Pre-decommissioning surveys of the lake-bed and inspection of the OWF components
- Post-decommissioning surveys of the lake-bed
- Engineering and Project management, including inspections, design of new equipment, external consultants for Marine Warranty, documentation etc.
- Port fees, lease of quayside
- Insurance for the marine operations, which will depend on the number of vessels and duration of activities.

In the cost modelling described here, even at this high level, it is more appropriate to enter itemised values for the contributing overheads rather than entering them as a percentage of overall costs. This recognises that the overheads are primarily determined by the size of the OWF and scope of the decommissioning, whereas the overall costs are, in addition, strongly determined by outside factors influencing the marine operations. These outside factors relate to the local weather conditions and vessels capabilities – as illustrated in the example cases presented in Section 6.5. In other spheres an overall percentage may be more relevant.

6.3.10 Delays, contingencies and liabilities

Provision in the cost modelling is also needed to cover contingencies and future liabilities. These may typically be divided into:

- Cost contingency to cover unforeseen costs such as caused by equipment breakdowns.
- Future liabilities to cover work needed to address elements left in-situ, such as pile stumps that become exposed over time.

The modelling also needs to be clear whether the values used for durations of activities and costs are the most likely or "central" values, or whether they are deliberately biased towards being conservative. The Tool enables users to input high, low or central values to enable sensitivities to be explored.

6.3.11 Weather delays

Operations that are restricted by local weather conditions, such as wave heights or wind speeds, are first expressed in terms of an ideal duration (unrestricted by conditions) and then factors are applied to take into account statistically the periods when the conditions prevent work. These factors take into account both the operating limits such as the maximum wave height a vessel can work in, and the weather conditions at the site.

More description of the application of weather factors used in the Great Lakes cost modelling is provided in Section 13.3 of the User Guide in Appendix A.

Discussion of the limiting conditions for specific marine operations is included in Chapter 5 (Technology Selection and Description).

6.4 Disposal and recycling

6.4.1 Approach

Decommissioning costs are initially estimated up to delivery of the removed pieces on the quayside at a designated disposal port. In this section the disposal costs and residual value are considered. It is assumed that the residual value lies in the scrap value of the materials rather than in any re-use of the components.

As noted in the review of decommissioning regulations (Chapter 4), the potential revenues from the residual value are generally excluded from the cost estimates derived for the purpose of financial security. For example in the UK and US no allowance may be made for any income acting to offset the decommissioning costs. However, since the residual value can be substantial, it is prudent to include an estimate in the cost modelling.

The approach used in this study, and considered to be the most likely scenario in practice, is to assume that the recovered pieces are sold at the point of quayside delivery to experienced industrial recycling companies. These companies will bear the costs of disposal which will include breaking the components down to separate out the individual materials (e.g. cables, nacelles, topsides), cutting up the pieces to the required size for recycling, and transporting the scrap material away.

The recycling company will need to carry out this work with due consideration for health, safety and the environment. However, for OWF components the potential for pollution is relatively low in contrast to decommissioning of oil & gas facilities, and the cost of precautions is commensurate.

The price per tonne paid to the OWF owners by the recyclers therefore takes these disposal costs into account and will be considerably less than the top line commodity prices. It should also be taken into account that scrap values vary considerably from month to month.

6.4.2 Selection of disposal port

The requirements for the disposal port, where the removed components are brought ashore, are:

- Access for vessels involved (e.g. water depth, width, length, height clearance);
- Load capacity of quayside and laydown areas (for cranes, handling and storage);
- Area for laydown and storage;
- Distance from the offshore wind farm, which affects transit time and fuel use;
- Access to recyclers.

Given the volume of materials involved for a 75-turbine OWF, it is expected that the recyclers will set up specific facilities at the disposal port for the majority of the work. Closeness to a recycling company is therefore desirable though not essential.

Figure 6-1 shows the main ports in the Great Lakes, including US ports.

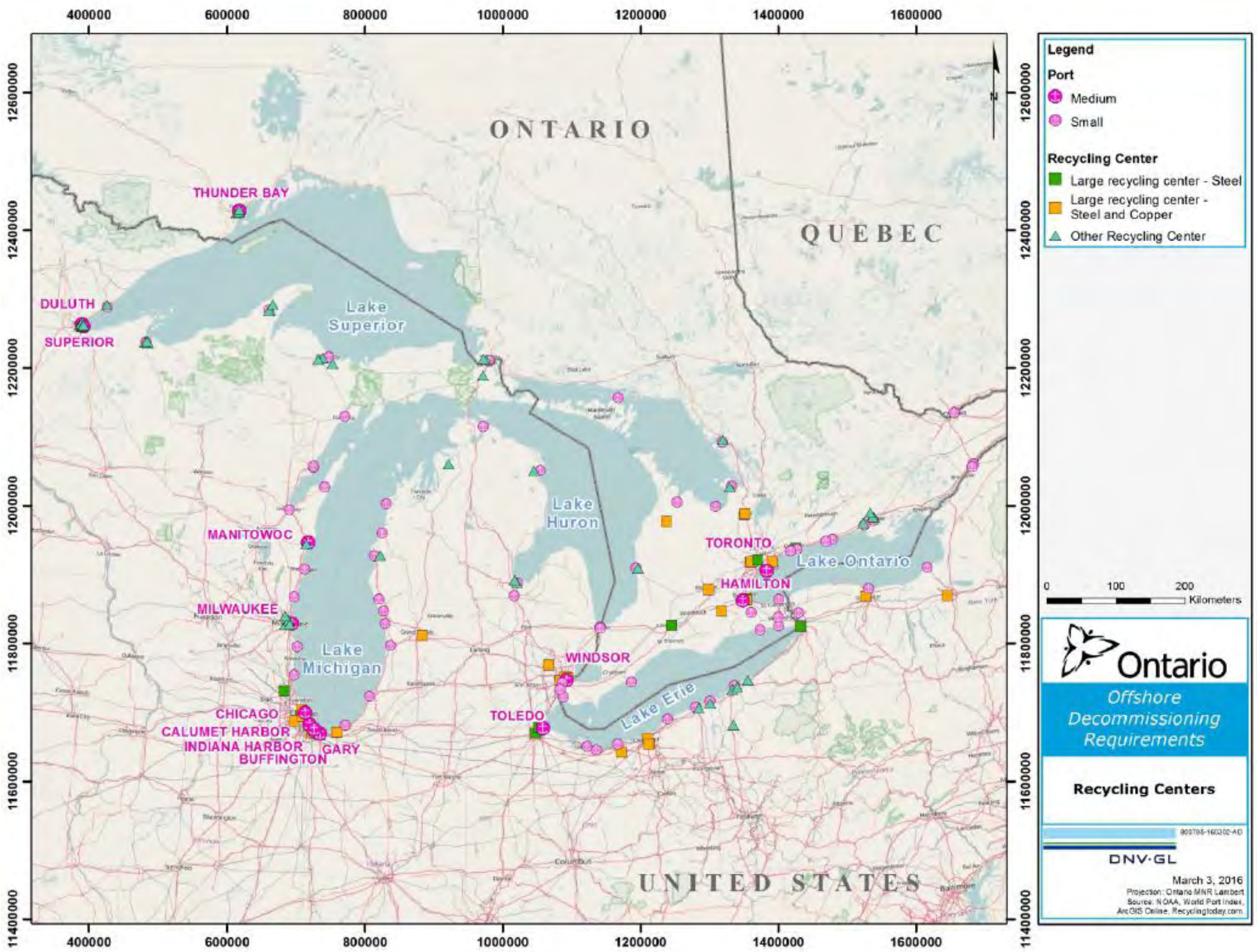


Figure 6-1 Ports and recycling companies of the Great Lakes region

There are "medium" sized ports in each of the lakes except Lake Huron and "small" ports around all. However, it must be remembered that a port may well have been expanded specifically for the construction of the OWF in question, for example one of the "small" ports, and if so, this expanded port is very likely to be available as the disposal port.

As described in the key, the map in Figure 6-1 also indicates sizable industrial recycling companies with green squares for those handling steel and orange squares for those that state they handle copper as well. The green triangles indicate smaller companies. The map is presented here only to indicate the distribution of companies; it is not intended to provide any detailed analysis of suitability. Such an analysis would be carried out through direct contact with the ports authorities and the recycling companies for each individual OWF.

As expected, there are larger recycling companies in the more industrial regions of southern Ontario near Lake Erie and Lake Ontario, and in the south of Lake Michigan. However, this does not preclude recycling facilities from being set up at the selected disposal port.

6.4.3 Steel

With the exception of concrete gravity base foundations, the majority of materials tonnage from the turbines and their foundations will be structural steel. Almost all of this structural steel will be recoverable, though the disposal costs will include provision for separating out the steel in grouted MP-TP connections and removing marine growth.

The price of scrap steel is widely monitored in the scrap industry. Figure 6-2 reproduces the Eurofer index [77] for the relevant grade over the last decade, presented here primarily to show the large variations that can occur.

Figure 6-2 Historic demolition grade steel price index

The index is approximately equivalent to Euros, with a current value of around €160 per tonne. However based on past quotes from recyclers, DNV GL expect that the net price given by a recycler taking quayside delivery is likely to be € 70 to € 80 per tonne of steel (CAD $100 to CAD $130 / t), or around 50% of the headline commodity price.

The guidance notes for the Tool include a table of indicative steel content for the generic 75- turbine OWF with the different scenarios.

6.4.4 Copper

Scrap electrical copper is highly valuable with a commodity price at over CAD $6,000 per tonne (January 2016).

For cables, it is expected that net prices paid by the recycler could be around CAD $2,000 per tonne of copper, with the recycler bearing the cost of stripping out the copper cores. The volume and hence mass of copper in cables can be calculated from the quoted cross-section of the cores, and is typically 5 to 10 t/km for array cables and 15 to 20 t/km for export cables.

For the copper in the WTGs, a rough estimate of 1.7 t copper per MW (6.8t for 4MW) and 80% recovery [78] can be used though will depend on the electrical design.

For the copper in the OSS, the revenue depends very much on the balance between the effort to extract the materials and the scrap value, though are expected to provide a relatively small net revenue.

6.4.5 Composites

The OWF owner's policy should be to re-use and recycle as much as possible, and most materials should yield some scrap value. However, the composites from the blades are difficult to recycle, especially as each blade is a combination of materials: mainly glass-reinforced polymer (GRP) composite; sometimes additional carbon fibre reinforced polymer (CFRP) composite; polymer foam or balsa wood stiffening; metal root fixings; and metal lightning protection. There may also be GRP composites content in the nacelle covers.

If recycled at all, composites are generally "down-cycled", the process of conversion into materials of lesser quality, though this is not yet happening on an industrial scale. However, given the greater priority being given in general to recycling and the volume of large articles now being made from composites, an increasing number of processes are being developed to handle composites. A pertinent example is the CompoCycle process in Germany [79] whereby wind turbine blades are shredded and crushed and the resultant used as a raw material in cement production. This process operates at a net cost and has been developed in response to changes in waste disposal legislation.

The most likely destination for decommissioned blades from a Great Lakes wind farm, at present, is assumed to be disposal in landfill which is generally charged as a cost per unit volume. Disposal costs for the blades will therefore need to encompass work to cut or crush them to size, transport to the landfill site and the landfill charge.

In the UK landfill fees are around £110 (CAD $206) per tonne including taxes but excluding transport, and are similarly high in other European countries as a result of European Directives. In the US and Canada, disposal costs are currently lower than in Europe, though may rise.

Including transport charges a net disposal cost for composites of around CAD $100 per tonne is estimated, based on current North American costs.

6.4.6 Concrete

For concrete gravity base foundations, the cost of disposal is likely to exceed any recovered value, and will depend whether they are disposed of whole, in sections or after cutting up and crushing.

Cutting and crushing methods and equipment are well established in the demolition business. Given the large size of the GBS foundations, the initial cuts will probably need to be done using portable cutting methods. Water jet methods can remove concrete whilst leaving the steel reinforcement untouched, or the technique can be used with abrasive entrainment to cut the re-bar as well. Precautions will be needed against the sudden release of stresses in tensioned re-bar. Once reduced to strips, the concrete can be fed into mobile crushers which separate out the steel re-bar and aggregate (comprising gravel and solidified cement).

As a very rough estimate, overall disposal costs for concrete are suggested in the range of CAD $20 to $50 per tonne.

6.4.7 Other materials

Steel, copper and composites are expected to be the major materials to be considered in most OWFs, with concrete for specific foundation designs. However, in some cases, aluminium rather than copper conductors are used in cables, particularly in export cables, with a content of around 6 to 10 t per km of cable.

Other metals will be present in the WTGs and OSS topsides in smaller quantities and will be recycled to realise relatively small revenues, after the costs of stripping them out are subtracted. Notable content will be permanent magnet generators, if present.

6.4.8 Recovery factors

For components which are made of a single material that is readily cut to the required size, or multi-material components that are easily separated, a high percentage of the recyclable material can be recovered. Examples are the steel foundations and the cable copper, for which typical recovery factors by weight of well over 90% may be typical.

Where components are more complex combinations of materials, the proportion recovered will be less. Examples are WTG nacelles and OSS topsides.

A table of typical ranges is provided in the User Guide in Appendix A.

6.5 Results from cost modelling

6.5.1 Cost modelling Tool

As one of the deliverables of the study, DNV GL provides a custom-built modelling tool - the DNV GL Great Lakes Offshore Wind Decommissioning Cost Modelling Tool (the "Tool"). Appendix A of this report provides a guide to the Tool, including a description of the model, guidance for its use and conditions for its use.

DNV GL has used the Tool to explore the potential cost ranges for different types and locations of OWF in the Great Lakes and to highlight the key variables.

All the modelling assumes a 75-turbine OWF using 4 MW generic turbines with the characteristics presented in Chapter 5. The modelling has been carried out for the main types of foundation, requiring the three main methodologies: Cut Lift Carry; Lift Float Tow; and Detach Tow. Vessels are selected that are thought likely to be available in the Great Lakes, as discussed in Chapter 5. In each case it is assumed that the scope of the decommissioning covers all the component phases.

The cost modelling exploration starts with a Base Case (case A), plus 11 variants exploring different factors in turn (cases B to J). The cost estimation is based on 2015 values, derived from DNV GL experience with marine operations.

6.5.2 Inputs used

6.5.2.1 Base Case (Case A)

The Base Case assumes WTGs with MP foundations in 25 m water depth, a single offshore substation and twin export cables extending the 20 km to shore. The disposal port is 20 km from the OWF. The main inputs for each phase of decommissioning are summarised in Table 6-1.

Table 6-1 Main inputs for Base Case

WTG phase	
Key characteristics	75 x 4 MW turbines
Jack-up platform, crane, barge, tug	CAD $120,000 / day
Logistics	Platform stays on site Barge transports 2 WTGs per cycle
Weather factor (see note below)	1.5
Foundations phase	
Key characteristics	75 x MP, 25 m water depth
Heavy lift cargo vessel	CAD $150,000 / day
Suction dredger	CAD $100,000 / day
Logistics	2 lifts per foundation, HLCV transports 3 foundations per cycle.
Weather factor	1.5
Array and export cables phase	
Key characteristics	80 km of array cable; 2x20 km export cable
DP cable removal vessel	CAD $150,000 / day
Cable protection removal vessel	CAD $30,000 / day
De-burial tool	CAD $20,000 / day
Weather factor	1.2
OSS phase	
Key characteristics	1 offshore substation, jacket foundation
Heavy lift shearleg, barge, tugs	CAD $180,000 / day
Logistics	5 topside lifts, 3 foundation lifts per OSS Transported to port separately
Weather factor	1.5
Overheads	
Itemised costs (excluding insurance)	CAD $11.3 million
Insurance	CAD $6,000 / day
Guard boat and workboat	CAD $3,000 / day & CAD $4,000 / day
Disposal revenue	
Net revenue for steel	CAD $115 / t
Net revenue for copper	CAD $2,000 / t
Net cost for composites disposal	CAD $100 / t

Note: The "weather factor" quoted here is a multiplying factor applied to the estimated duration of activities under ideal conditions to take into account the delays caused by operational weather limits being exceeded. The value depends on both the weather conditions and the sensitivity of the operation. For more information, see the User Guide to the Cost Modelling Tool in Appendix A and Section 6.3.10 on Delays and Contingencies and Section 6.3.11 on Weather Delays.

In the Base Case, the WTGs are removed using a combination of vessels comprising a jack-up platform with mobile crane on board, a transport barge and tugs. The platform stays on site whilst the barge ferries the components to port. A workboat is used beforehand for the turbine preparation and the cost of cable cutters is included for the duration of the preparation.

The foundations are removed in 2 pieces and transported in batches of 3 foundations using a heavy lift cargo vessel. A suction dredger is used beforehand to prepare the base of the foundations ready for the lake-bed cut. The number of lifts is decided on the basis that the lifting capacity of the crane is no more than 500 t, translating to net lifts of around 400 t maximum. The cost of the foundations phase includes cutting equipment and a dive boat working in tandem with the heavy lift vessel.

The array cable and export cables are removed using a single cable vessel capable of maintaining position using dynamic positioning (DP). Beforehand, cable protection is removed using a separate vessel. It is assumed that a limited amount of cable protection is present, such that the latter vessel can address 10 array cables or 5 km of export cable before returning to shore. The cable removal vessel works at a rate of approximately 1 day per array cable, and 1 day per km of export cable. The cost of the cable phases includes the cable de-burial tool.

The offshore substation is removed using a heavy lift shearleg crane vessel with transport barge and tugs, with a workboat for preparation work beforehand. The shearleg stays on site whilst the barge ferries the components to port. Based on the weights of the topside and foundation, the topside is removed in 5 lifts and the jacket foundation in 3 lifts, assuming appropriate design. The cost of the OSS phase includes cutting equipment and a dive boat for the duration of the phase.

Overheads for the overall decommissioning phase include CAD $11.3 million for pre- and post-decommissioning work, engineering, project management and port costs, with an additional CAD $6,000 per day for insurance. The cost recorded for the overhead phase includes a guard boat and a general purpose workboat for the duration of the marine decommissioning operations.

Disposal revenues are based on indicative component weights given in Chapter 5 with recovery factors of 95% for steel foundations and cable copper and lower amounts for nacelles, topsides and other more complex components.

For the Base Case, central values for vessel day-rates, durations of operations and scrap values are used. Central values of the weather factors are also used, taking into account the delays due to operational limits being exceeded (e.g. wind speeds and wave heights). More detail and indicative values are given in Appendix A.

6.5.2.2 Low and high cost (Cases B & C)

To explore the influence of vessels and equipment costs, Case B repeats the cost estimation using costs that are 30% lower than the Base Case. Case C uses costs that are 30% higher than the Base Case. This range of costs represents a possible variation in cost that could arise from market forces and also recognises the uncertainties in costs for vessels that are only expected to exist at the time of decommissioning.

Other variables are kept the same as the Base Case.

Table 6-2 includes a summary of the key inputs for each of the cases, highlighting the change in variable compared with the Base Case.

6.5.2.3 Shorter and longer duration of marine operations (Cases D & E)

To explore the influence of different time durations of marine operations, Case D repeats the cost estimation using durations that are half those of the Base Case. Case E uses durations that are twice those of the Base Case. These changes are achieved in the model by artificially re-setting the weather factor for each phase, though in practice changes in duration would come from a combination of the weather factor and the ideal duration of each step. The range of durations represents differences in operating limits of activities, differences in the wind and wave conditions at the OWF sites, the exact steps required, and the level of experience of the operators employed by the vessels.

Other variables are kept the same as the Base Case.

6.5.2.4 Distance to port (Cases F1 & F2)

To explore the influence of the distance to port, Case F1 repeats the cost estimation using a distance of 100 km from the OWF to the disposal port rather than the 20 km in the Base Case. Other variables are kept the same as the Base Case, including the length of the export cable. The scenario imagines that although the OWF is 20 km from shore, giving a total length of 40 km for the twin cable, the nearest suitable port for the disposal operations is much further away.

Case F2 assumes that the OWF is further from shore, and both the distance to port and the export cable length are greater than the Base Case. A port distance of 100 km is again used. The distance to shore is assumed to be 40 km giving a total length of 80 km for the twin cable. Other variables are kept the same as the Base Case.

6.5.2.5 Deeper water (Case G)

To explore the influence of the water depth, and therefore the dimensions and weight of the foundations, Case G repeats the cost estimation for a water depth of 40 m rather than the 25 m of the Base Case. The changes to the model inputs are:

- An increase in vessels costs to take into account the more capable vessels needed for working at the greater depth. The cost of the jack-up platform and its related vessels is increased to CAD $160,000 per day and the rates of the floating vessels working at the lake-floor are increased by 10%.
- MP foundations are removed in 3 pieces rather than 2 pieces for the Base Case with an associated increase in duration for the foundation removal phase. This is takes into account that the foundations are both longer and heavier.
- The OSS jacket foundation is removed in 4 pieces rather than 3.
- The mass of recycled steel is adjusted for both the foundations and the jacket weights, resulting in a greater weight of steel recovered.

Other variables are kept the same as in the Base Case.

6.5.2.6 Concrete GBS using Lift Float & Tow method (Case H)

For GBS turbine foundations rather than MPs, the Lift Float & Tow option is used in the model. The foundations are released and lifted in a single piece after a preparatory step using a suction dredger. The vessel combination selected for the main removal is a heavy lift shear leg crane vessel with tugs. The tugs tow the foundation to port once it is floating. The cost for the foundation phase includes a dive boat for the duration of the phase.

Other variables in the marine operations phases are kept the same as in the Base Case. In particular, the OSS is assumed unchanged, still with a jacket foundation.

In the disposal phase, the concrete disposal is assumed to be at a net cost, entered as CAD $30 / t. The amount of steel in the foundations is assumed to be only 50 t per foundation compared with 590 t for the MP.

6.5.2.7 Steel bucket (Case I)

For steel suction bucket foundations rather than MPs, again the Lift Float & Tow option is used in the model. The same inputs to the model as for the concrete GBS are used, with the exception of the disposal phase.

In the disposal phase, the suction bucket and the rest of the foundation structure are assumed to be steel that is recycled with a gross mass of 750 t per foundation and 95% recovery factor.

6.5.2.8 Floating (Cases J1 & J2)

For a floating wind farm (Cases J1 & J2) the Floating option is selected on the Main Inputs sheet thus disabling the WTG removal phase in the model, as described in the User Guide in Appendix A.

The vessels used are an offshore support vessel and two tugs that double as anchor handlers. The offshore support vessel (OSV) prepares the turbines and their support platforms for disconnection and transit, and stays on site to decommission the moorings once the structures have been detached. The tugs tow the structures to port.

An ideal duration of one day is assumed for the tug to position and detach one structure. A similar time is assumed for the preparation, occurring almost concurrently. To dismantle the WTGs once at shore, a cost of CAD $20,000 per day for a large mobile crane is input with one day required per WTG.

In the disposal phase, a gross steel weight of 1800 t per structure is assumed, with the WTG steel in addition.

In Case J1, the other variables in the cost model are kept the same as in the Base Case, thus assuming the OWF is 20 km from port. This enables direct comparison of the removal methodologies.

However, in practice floating OWFs in the Great Lakes are more likely to be further from shore and may be in locations that are more distant from suitable ports. In Case J2, the distance to port is changed to 100 km and the distance to shore is changed to 40 km, resulting in total length of the twin export cable of 80 km.

6.5.3 Summary of results

The results of the cost modelling are presented in Table 6-2 and graphically in Figure 6-3.

Table 6-2 presents the main inputs and results with the Base Case in the first main column.

The top half of the table summarises the main characteristics and inputs to the model. The main variations from the Base Case are indicated in the highlighted cells.

The bottom half of the table summarises the outputs from the models, listing the decommissioning costs for each phase, the overall duration and the number of seasons required. The overall costs are then presented as the Subtotal Cost of the individual phases, the Total Cost (including cost contingency and future liability) and the Total Cost after Revenue which incorporates any offset from materials revenue or net costs for disposal. Costs are expressed as overall values and on a "per turbine" basis.

6.5.3.1 Results for Base Case

For the Base Case, the Total Cost after Revenue is estimated at CAD $187.3 million, equivalent to CAD $2.49 million per WTG. Without the estimated recycling revenue of around CAD $11 million, the Total Cost is estimated at CAD $198.2 million or CAD $2.64 million per WTG, including the 10% cost contingency and CAD $1 million future liability. This cost represents a central estimate, neither conservative nor optimistic, as discussed in Section 6.3.10.

The overall duration for the decommissioning marine operations is estimated at 433 days (14½ months). It is judged that this would be spread over 2 seasons.

In Figure 6-3, the Subtotal Costs, as listed in Table 6-2, are broken down for the individual phases. Revenue (i.e. negative cost) from recycling is excluded largely since regulations generally do not allow such revenues to be considered for purposes of financial security.

In the Base Case, the foundations decommissioning phase has the highest cost at CAD $88.2 million, comprising 49% of the overall subtotal cost. This trend is repeated in all the cases apart from the floating foundations and reflects the combination of relatively expensive heavy lift vessels and their duration required for foundations removal. The turbine decommissioning phase has the second highest cost at CAD $37.3 million, comprising 21%.

Table 6-2 Great Lakes cost modelling - key inputs and results

Highlighted cells indicate variation compared with the Base Case; costs are in CAD million $ (CADM)

			A	B	C	D	E	F1	F2	G	H	I	J1	J2
			Cut Lift Carry	Cut Lift Carry	Cut Lift Carry	Cut Lift Carry	Cut Lift Carry	Cut Lift Carry	Cut Lift Carry	Cut Lift Carry	Lift Float Tow	Lift Float Tow	Detach Tow	Detach Tow
		Units	Base Case	Low cost vessels	High cost vessels	Short duration	Long duration	Far port	Far port, long cable	Deeper water	Concrete GBS	Steel bucket	Floating	Floating Far port, long cable
Inputs	No. turbine locations	#	75	75	75	75	75	75	75	75	75	75	75	75
	Fixed or floating?		Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Floating	Floating
	Water depth	m	25	25	25	25	25	25	25	40	25	25	N/A	N/A
	Distance from port	km	20	20	20	20	20	100	100	20	20	20	20	100
	Rates for vessels & equipment		Central	-30% cost	+30% cost	Central	Central	Central	Central	Central	Central	Central	Central	Central
	Durations for operations		Central	Central	Central	50% duration	200% duration	Central	Central	Central	Central	Central	Central	Central
	Foundation methodology		Cut lift carry	Cut lift carry	Cut lift carry	Cut lift carry	Cut lift carry	Cut lift carry	Cut lift carry	Cut lift carry	Lift float tow	Lift float tow	Detach tow	Detach tow
	Foundation lifts	#	2	2	2	2	2	2	2	3	1	1	1	1
	Array cable length	km	80	80	80	80	80	80	80	80	80	80	80	80
	Export cable length	km	40	40	40	40	40	40	80	40	40	40	40	80
	OSS no.	#	1	1	1	1	1	1	1	1	1	1	1	1
	OSS lifts per OSS	#	8	8	8	8	8	8	8	9	8	8	8	9
Outputs	WTG phase	CADM	37.3	26.1	48.5	18.7	73.4	37.7	37.7	49.3	37.3	37.3	NA	NA
	Foundation phase	CADM	88.2	61.8	114.7	44.9	173.4	92.2	92.2	124.6	106.6	106.6	21.4	22.7
	Array cable phase	CADM	16.8	11.8	21.9	9.0	32.5	19.2	19.2	18.3	16.8	16.8	16.8	19.2
	Export cable phase	CADM	10.6	7.4	13.7	5.5	20.7	11.9	23.6	11.5	10.6	10.6	10.6	23.6
	OSS phase	CADM	9.4	6.6	12.2	5.7	16.7	9.6	9.6	10.5	9.4	9.4	9.4	9.4
	Overheads	CADM	16.9	16.0	17.9	14.2	22.4	17.2	18.3	19.1	17.2	17.2	14.3	15.6
	Overall duration of marine ops	days	433	433	433	222	854	449	537	600	449	449	227	332
	No. seasons	#	2	2	2	1	4	2	3	3	2	2	1	2
	Subtotal cost	**CADM**	**179.3**	**129.7**	**228.9**	**98.0**	**339.1**	**187.8**	**200.7**	**233.4**	**197.9**	**197.9**	**72.5**	**90.6**
	Cost contingency & liability	CADM	18.9	14.0	23.9	10.8	34.9	19.8	21.1	24.3	20.8	20.8	8.3	10.1
	Total cost	**CADM**	**198.2**	**143.7**	**252.8**	**108.8**	**374.0**	**207.6**	**221.8**	**257.8**	**218.7**	**218.7**	**80.8**	**100.7**
	Total cost per WTG	CADM	2.64	1.92	3.37	1.45	4.99	2.77	2.96	3.44	2.92	2.92	1.08	1.34
	Less disposal revenue	CADM	-11.2	-11.2	-11.2	-11.2	-11.2	-11.2	-12.5	-13.3	-0.7	-12.5	-21.1	-22.4
	Total cost after revenue	**CADM**	**187.0**	**132.5**	**241.6**	**97.6**	**362.8**	**196.4**	**209.3**	**244.5**	**218.0**	**206.2**	**59.7**	**78.3**
	Cost per WTG after revenue	CADM	2.49	1.77	3.22	1.30	4.84	2.62	2.79	3.26	2.91	2.75	0.80	1.04
	% change on Base Case			-29%	29%	-48%	94%	5%	12%	31%	17%	10%	-68%	-58%

1. See description of Base Case model A for detail of inputs
2. Others are same as Base Case with variation in the highlighted area(s).
3. Overheads include cost of guard boat and one workboat for the overall duration.
4. Costs are in CADmillion (CADM).
5. Revenues (from recycling) are shown as negative costs in red.

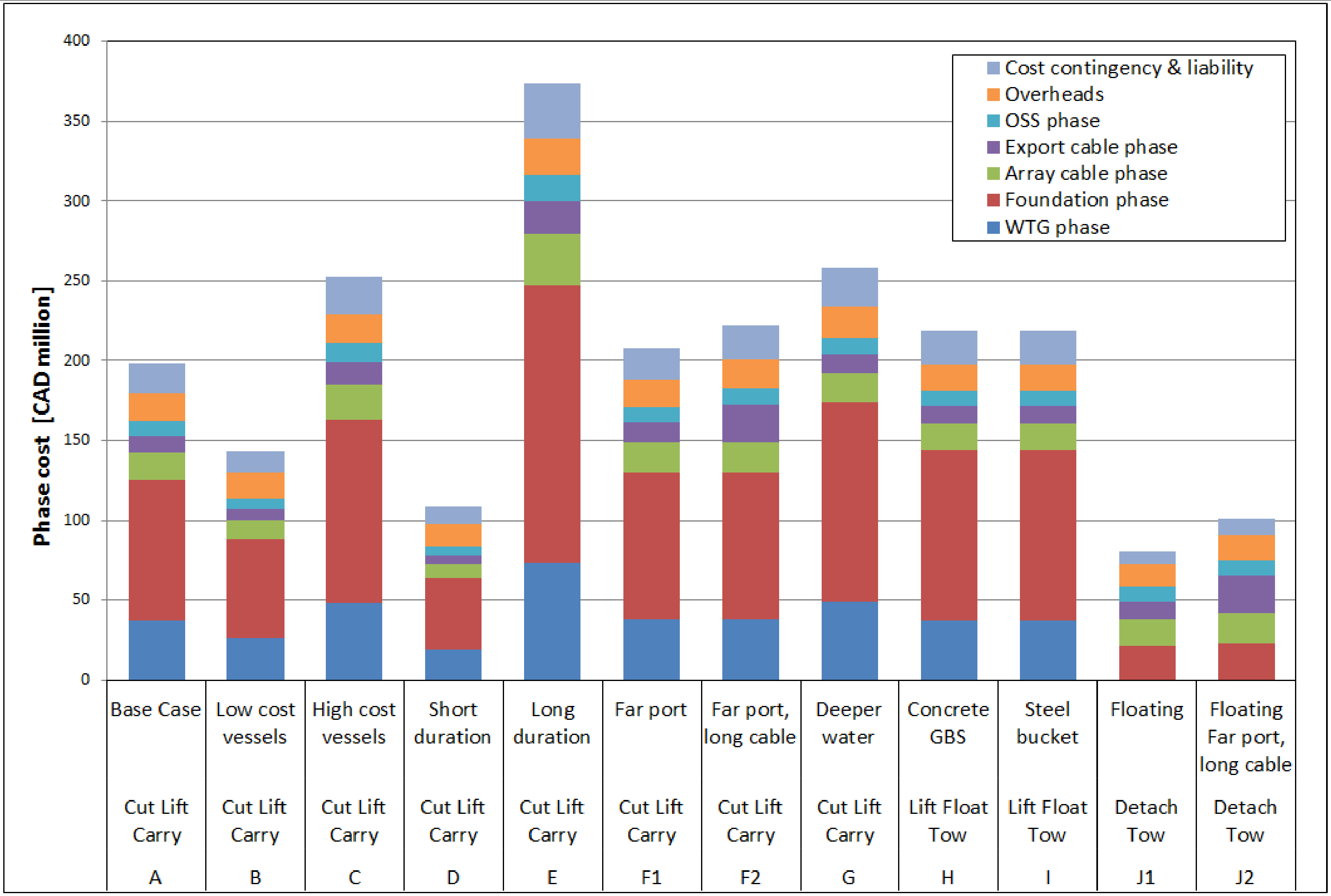


Figure 6-3 Great Lakes cost modelling - breakdown of decommissioning costs by phase

Costs presented exclude any offset from disposal revenue

6.5.3.2 Results for other Cases

Exploration of the vessels day-rates. The results of Cases B and C highlight the sensitivity of the overall cost to the expenditure on vessels chartering. A decrease in the vessels and equipment day-rates by 29% reduces the Total Cost after Revenue to an estimated CAD $132.5 million or CAD $1.77 million per WTG, a decrease of 29%. Similarly an increase of day-rates and equipment costs by 30% results in an overall increase of 29% in decommissioning costs, to CAD $241.6 million or CAD $3.22 million per WTG, again indicating an approximately linear relationship between vessels day-rate and overall decommissioning cost.

Exploration of the durations for the marine operations. The results in Cases D and E similarly highlight the sensitivity of the overall cost to the expenditure on vessels chartering. A halving of durations for the marine operations (Case D) results in an overall cost reduction of 48% to CAD $97.6 million, and an overall duration of 222 days (7½months) achieved in a single season. Doubling of durations results in an overall cost increase of 94% to CAD $362.8 million and an overall duration of 854 days (over 28 months) spread over 4 seasons.

Exploration of the distance to the disposal port. Cases F1 and F2 show that distance to port has a relatively small impact on overall cost, with an increase from 20 km to 100 km distance producing a 5% increase in overall cost (Case F1) to CAD $196.4 million Total Cost after Revenue. The reason for the relatively low increase is that the transit times comprise a relatively small proportion of the time of the vessels; by far the greatest time is spent in their preparations and performing lifting operations at site. If the export cable is also assumed to be longer, reflecting that the site is a greater distance from shore, then for an increase from 40 km to 80 km (Case F2) for the removed cable length, the cost of decommissioning the export cable approximately doubles and there is an increase in revenue from the recovered copper. Case F2 results in an estimated decommissioning cost that is 12% higher than the Base Case, at CAD $209.3 million Total Cost after Revenue.

Exploration of water depth. Increasing the depth of water at the site from 25 m to 40 m (Case G), results in an increase of 31% in the overall decommissioning cost to CAD $244.5 million or CAD $3.26 million per WTG compared with the Base Case, and an increase of overall duration to 600 days (3 seasons). These increased costs arise from the combination of more expensive vessels needed for all the phases, and that more lifts are needed to remove the WTG and OSS foundations because of their greater size and weight, which in turn leads to longer durations of the marine operations. Figure 6-3 clearly shows the large influence of depth on the cost of the foundations phase.

Exploration of foundation type. Considering the different types of foundation, the Lift Float Tow method adopted for the Concrete GBS (Case H) and Steel suction bucket (Case I) yields identical results, apart from the contribution from the disposal phase. The details of likely durations and methods are much less certain for these types of foundations, and it was not deemed appropriate to assign different inputs to the cost modelling of the marine operations. The change in cost compared with the Base Case lies as expected in a longer and more costly foundations decommissioning phase. The estimated total cost prior to considering disposal is CAD $218.7 million or CAD $2.9 million per WTG in each case and the estimated duration is 449 days (15 months). For the Steel Bucket type there is an offset of CAD $12.5 million revenue, largely from the steel recycling, giving a Total Cost after Revenue only 10% higher than the Base Case. However for the Concrete GBS, the disposal method of the concrete structure is very uncertain, and the input of CAD $30 per tonne disposal cost results in the disposal phase being almost cost-neutral, with the Total Cost after Revenue being 17% higher than the Base Case.

Floating support structures. Cases J1 and J2 illustrate the greatly reduced decommissioning costs for OWFs with floating structures, arising from the avoidance of any lifting or dismantling operations needed at site. In Case J1 where just the foundation type is changed, the Total Cost is 68% less than the Base Case, even with allowance made for dismantling of the WTG at shore. The overall duration is predicted to be less than one season at 227 days (7½ months). In Case J2, with longer export cable and further distance to port, the overall cost is still 58% less than the Base Case at CAD $78.6 million or CAD $1.1 million per WTG.

6.5.4 Discussion

The design of the cost model provides sufficient detail to allow all the main elements of the decommissioning costs to be captured. At the same time, it allows the strong dependence on the marine logistics to be explored with over 85% of the decommissioning costs directly related to vessels hire costs. By recognising the offshore wind farm technologies that may be present and the resulting decommissioning methodologies that will need to be employed, the Tool provides the means to derive guideline estimates of the full decommissioning costs.

The indicative parameters provided in the Study for the wind farm components, the vessels and the decommissioning methodologies are all based on DNV GL's strong experience in the current offshore wind industry. Even so, the parameters used in the modelling are largely generic, since the design and location of any Great Lakes offshore wind farms is as yet undecided, and the restricted options for suitable decommissioning vessels in the Great Lakes provide further sources of uncertainty in the cost estimates. The costs of vessels can also be strongly affected by the contractual arrangements and by market conditions.

Using realistic ranges to explore the main inputs to the model, the results emphasise the strong dependence of the decommissioning costs on the marine operations. In particular, they show the almost linear sensitivity to the combination of the daily charter rates for the vessels (in particular those used for the heavy lifts) together with the duration of their charter. In turn, the charter duration required depends on the combination of the operating limits of the marine activities and the severity of the local marine conditions. The marine operations with minimum overall cost may not necessarily involve using the lowest cost vessel; experience shows that a higher cost, more capable vessel may work out less costly overall if it can work more quickly and with fewer weather delays.

The indicative Base Case cost of around CAD $2.6 million per turbine for the 75-turbine OWF represents CAD $650,000 per MW for these 4 MW generic turbines, equivalent to Euro 435,000 per MW. This is of the same order of magnitude as the extensive and more detailed decommissioning studies carried out on specific European OWFs [80] which show costs of around Euro 300,000 to 500,000 per MW.

In the present Study, the method of releasing and floating foundations to shore, illustrated for GBS and suction bucket foundations, indicates a slightly higher overall cost than the cut, lift & carry method for the MP foundations. However, the floating method has inherently higher uncertainties as the technique is less established and its ease will be more dependent on the foundation design. In contrast, the decommissioning of floating structures is clearly very much lower than the fixed structures, with estimated costs of 30 to 40% of the Base Case largely since expensive heavy lift vessels are not required.

6.6 Future use of cost models

The decommissioning cost estimations described and presented in this Study are by necessity a balance between providing enough detail to be useful whilst accepting the embryonic nature of OWF development in the Great Lakes. The Tool has therefore been designed so that all the main cost elements are included, and to allow users to distinguish between the distinctly different types of foundation and methodologies of decommissioning that may be adopted – such as fixed or floating.

The cost estimations are based on current (2015) values. In line with standard practice, no consideration is given in these estimates of future changes from inflation or from market conditions. Such adjustments could be made subsequently, if required.

In the future, when decommissioning cost estimates are required for a specific offshore wind farm, then it becomes appropriate for more detailed cost modelling to be carried out:

- During the development of a specific offshore wind farm, the developer will require estimates of decommissioning costs as part of assessments of the financial viability, and it is likely that a cost estimate will be needed for financial security by those responsible for the sea-bed or lake-bed. At this stage the design and installation method of the OWF will be reasonably well known, as will the local site conditions. Decommissioning cost estimations will be possible with greater accuracy than in the present Study as methods and charter costs will be much more certain, and more detail in the model may be warranted such as applying separate weather factors against different operations.
- After construction of the OWF, detail can be added to the decommissioning cost model to take into account the actual elements installed such as the extent of cable protection found to be necessary. From the practical experience of installation, more precision should be possible when estimating durations required, such as the length of time to install a WTG or the influence of the ground conditions on the cable plough.
- As decommissioning operations approach, much more detailed analysis of decommissioning operations and costs will need to be carried out, first to identify the optimum methods and logistics with the vessels and equipment available at the time, and then to plan the decommissioning operations themselves. The most detailed analyses are likely to be carried out by the contractors who would perform the decommissioning operations.
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6.7 Chapter summary

Table 6-3 Summary of key points from decommissioning cost modelling

Section	Description	Comments
Scope of decommissioning	The cost of decommissioning depends partly on the scope, for example which components are included in the decommissioning costs. In some cases, the electrical transmission infrastructure (offshore substation and export cable) may be the responsibility of others.	It may be agreed to leave some components in place, in particular some or all array cables and scour protection. Disposal costs and recycling revenues may or may not be included in the total.

Section	Description	Comments
Scenarios modelled	Building on Chapter 5, the main scenarios cover 4 MW turbines and the five main WTG foundations types: Monopiles; Jackets; Suction buckets; Gravity base; and Floating.	Cost modelling is not carried out for 8 MW turbines as the methodologies are considered to be too speculative for the Great Lakes at this time.
Main cost categories	The main cost categories for decommissioning are: • Pre-decommissioning work to review and fulfill regulations and Environmental Impact Assessment (EIA) requirements, and engineering surveys and planning; • Marine operations to prepare and remove each of the components; • Post-decommissioning survey work after completion of the marine operations; • Overheads covering management costs, insurance, port fees etc.; and • Costs for materials disposal and potential revenues from recycling.	The overall cost estimate for the decommissioning phase needs to be comprehensive.
Foundation removal	For the scenarios in the Study, three strategies of foundation removal were devised: • Cut, Lift and Carry • Lift, Float and Tow • Detach and Tow	Foundations may be removed in batches, according to the carrying capacity of the vessel.
Marine operations	For decommissioning of multiple units, a number of specialist vessels work in parallel on different units for maximum efficiency.	Timings (durations) for each main step of the marine operations is estimated and delay factors applied to take into account when weather limits are exceeded.
Disposal and recycling	Decommissioning costs are estimated up to delivery of the removed pieces on the quayside. It is assumed any value lies in the recycling of the materials rather than re-use of components. The pieces are sold to an industrial recycling specialist who bears the costs of breaking down the components and transporting the scrap. The main revenues are from steel and copper. Disposal of concrete and composites are likely to incur costs.	Potential revenues from residual value are generally excluded from cost estimates derived for the purpose of financial security. However, it is prudent to include an estimate of the revenue as an internal guide, noting that scrap prices can vary considerably each month.
Cost modelling tool	A custom-built cost modelling tool for the Great Lakes is provided as one of the deliverables for this work, together with a User Guide as an appendix to this report.	The User Guide includes indicative ranges of values for the main inputs.
Cost modelling – Base Case	The cost modelling tool is used to model a Base Case and 11 variants. Each covers an offshore wind project of 75 turbines of 4 MW size with 1 offshore substation. All array cables and export cables are removed. The Base Case assumes MP foundations in 25 m water depth and 20 km to shore, using Cut Lift Carry method for MP removal. The overall estimated cost for the Base Case is CAD $198 million or CAD $2.6 million per WTG, including 10% cost contingency and CAD $1 million future liability, but excluding recycling revenue. The overall duration for the marine operations is 14.5 months over 2 seasons.	Methods and durations are used that are appropriate for the Great Lakes. For example, turbines are removed with a crane on a towed jack-up platform. WTG and OSS foundations are removed in multiple pieces. The decommissioning cost for the Base Case is a central (most likely) estimate. The cost is based on current (2015) values as is standard practice.
Cost modelling - variants	Scaling the vessels day-rates either up or down results in an approximately linear change in the overall decommissioning cost. Scaling the duration of vessels charters up or down similarly affects the overall cost. The distance to the disposal port has only a small effect on overall cost. In deeper water (40m) the greater weight and size of the	Over 85% of the decommissioning cost derives from vessels charters, and is therefore strongly dependent on the duration of the marine operations and the vessels day-rates.

Section	Description	Comments
	foundations gives a 31% cost increase with MP foundations. For GBS and suction bucket foundations, using Lift Float Tow, there is greater uncertainty but overall the decommissioning costs are higher. For floating turbines, the costs are less than half the Base Case, since vessels are less costly and marine operations are shorter.	
Future use of cost models	When cost estimates are required for a specific offshore wind power project, it becomes appropriate for more detailed cost modelling to be done. Further detail can be added once the project has been constructed, and then when the decommissioning phase is about to start.	

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APPENDIX A: USER GUIDE TO THE COST MODELLING TOOL

DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool
800785-UKBR-XLS-01-C

As part of the DNV GL Study on the Decommissioning of Offshore Wind Farms in the Great Lakes for the Ontario Ministry of Environment and Climate Change, a cost modelling tool (the "Tool") is supplied. The Tool is in the form of a single multi-worksheet Microsoft Excel® Workbook, with reference 800785-UKBR-XLS-01-C.

The Tool is provided under the terms of the contract for the Study, as given on Page ii of this report and in accordance with the Important Notice and Disclaimer within the Tool, reproduced below.

Important Notice and Disclaimer

This DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool (the "Tool") is created by DNV GL as one of the Deliverables under Agreement MOEOSS_00402760 with the Ontario Ministry of Environment and Climate Change ("the Ministry") dated 14 January 2015.

The Tool is designed to be specific to offshore wind farms that are located in the Great Lakes and that have a particular capacity and turbine size.

Any results obtained by the Ministry using the Tool are the sole responsibility of the Ministry.
DNV GL has no liability for the use of the Tool nor the cost estimates derived.

DNV GL does not warrant that use of the Tool will meet your requirements or be uninterrupted or error-free or that errors in the Tool will be corrected. DNV GL shall not be liable in any event for any modification you have made to the Tool.

This Tool was developed using the Suppliers Intellectual Property as that term is defined in the agreement referred to above. The Ministry and the Ontario Public Service acknowledge that the Tool is considered Intellectual Property of the Supplier.

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In this Appendix, each worksheet of the Tool is described and guidance is provided for its use.

This guidance should be read in conjunction with the body of the report, in particular:

- Chapter 5 which describes the characteristics of the Great Lakes, the technology of offshore wind farm components, and likely methods for their decommissioning; and
- Chapter 6 which describes the cost modelling factors and methods, and provides results from the implementation of the Tool for a series of hypothetical scenarios.

1. Introduction to the Cost Modelling Tool

The Tool is designed to enable the user to select the scope of the decommissioning work, to choose the marine logistics and to input key variables. A summary worksheet then compiles the overall decommissioning costs.

1.1. The workbook worksheets in the Tool

In summary, the worksheets in the Excel workbook are:

- Readme – Title page, Introduction to the Tool and its main assumptions. This sheet includes the Important Notice & Disclaimer.
- Main Inputs – To define the main project characteristics, select the scope of the cost estimations and the rates for vessels and equipment.
- Component Phases – To select the type of vessel and equipment for each phase of the decommissioning, and define operational steps. Here, durations of the marine cycles and vessel charter costs are calculated for each phase. The decommissioning phases are:
  - WTGs - Turbines
  - Foundations, with selection of methodologies
  - Array Cable
  - Export Cable
  - OSS - Offshore Substation(s)
- Overheads – To define the overhead cost items for the project, and if required, to select supporting vessels which will operate during the full duration of the marine decommissioning operations.
- Disposal – To define the weights of the major materials and the potential prices yielded per tonne. Here recycling revenues are calculated, taking into account disposal costs.
- Results Summary – Presents a compilation of the results from each decommissioning phase and the overall costs for project decommissioning.

1.2. Operation of the Tool

To open the Tool, the main Password is needed. Then, for general use, open with the "Read only" option.

The workbook is arranged so the user progresses from left to right through the different sheets. Similarly, each worksheet is set out to allow the user to progress in columns from left to right.

Input cells are highlighted in blue in all worksheets. Other cells displaying numeric values contain links and formulae and should not be overwritten.

1.3. Main assumptions

Marine logistics: A primary assumption is that the offshore wind farm has a sufficiently large number of turbines that the optimum logistics are to use a fleet of specialist vessels operating in parallel as far as possible, to make best use of each. This focus on the logistics of multiple similar units is characteristic of offshore wind farms, and would not be suitable for decommissioning of small numbers of turbines or other offshore structures.

In contrast, removal of the offshore substations is assumed to use a single heavy-lift vessel to dismantle and remove both the topside and foundations – which is optimum for single or very small numbers of units.

It is assumed that the marine operations are carried out on a 24/7 basis, only prevented when operational limits are exceeded. This is standard practice when using expensive specialist vessels.

Level of detail: The Tool does not require separate inputs for every single operational step, for every individual vessel or for each piece of equipment used. In general vessels that are working together in parallel (such as a barge and tug, or heavy lift vessel, transport barge and tug) are grouped together as a vessel combination (often referred to by mariners as a vessel "spread") with a collective day-rate and collective one-off cost for mobilisation and demobilisation.

The Tool provides the option for entering costs separately from the vessel combination, if required. Examples could be cutting equipment and cable de-burial tools which may in practice be hired and operated separately.

Day-rates used for the vessels are assumed to be inclusive, for example incorporating all staff (crew and technicians), accommodation, fuel, lifting gear, sea-fastenings etc. Users are warned against using "bare-boat" day-rates sometimes quoted by vessel operators.

Vessel speeds are assumed to be average speeds and needs to include allowance for decreased speed and manoeuvring at each end of the journey.

2. Usability

2.1. User inputs

By default the Tool is populated with indicative values and menus to choose the vessels and equipment to be used. Unit day-rates and costings are suggested for each.

These input cells, signified by pale blue shading, are always accessible for modification by the user.

When entering new values in the editable cells, users are recommended to overwrite the text in cells rather than dragging the contents from elsewhere.

In these guidance notes and in the wider reporting of this Study, information is provided by DNV GL on key influencing factors and on the circumstances when high and low values may be appropriate.

However, the ultimate responsibility for the use of the Tool and its results always lies with the user.

2.2. Access

The locked cells of the workbook can be accessed if required.

Locking of cells: For normal use of the Tool, only the blue input cells can be edited. Other cells are locked to prevent accidental overwriting of formulae.

If required, all the cells can be unlocked. To do this,

- Right click on the worksheet tab;
- Click on *Unprotect sheet*;
- Type *Password 2* and click *OK*.

- To re-lock the sheet, follow the same steps. The password needs to be typed twice for confirmation.

Each worksheet is locked and unlocked separately. If changes are made in the Read-only version, then the modified version must be saved with a different name.

Workbook lock: A lock is also applied to the Workbook.

To unlock the workbook,

- Go to menu *Review*;
- Click on *Protect Workbook*;
- Type *Password 2* and click *OK*.
- To re-lock the workbook, follow the same steps

It is strongly recommended that the Tool is used and stored with both locks applied.

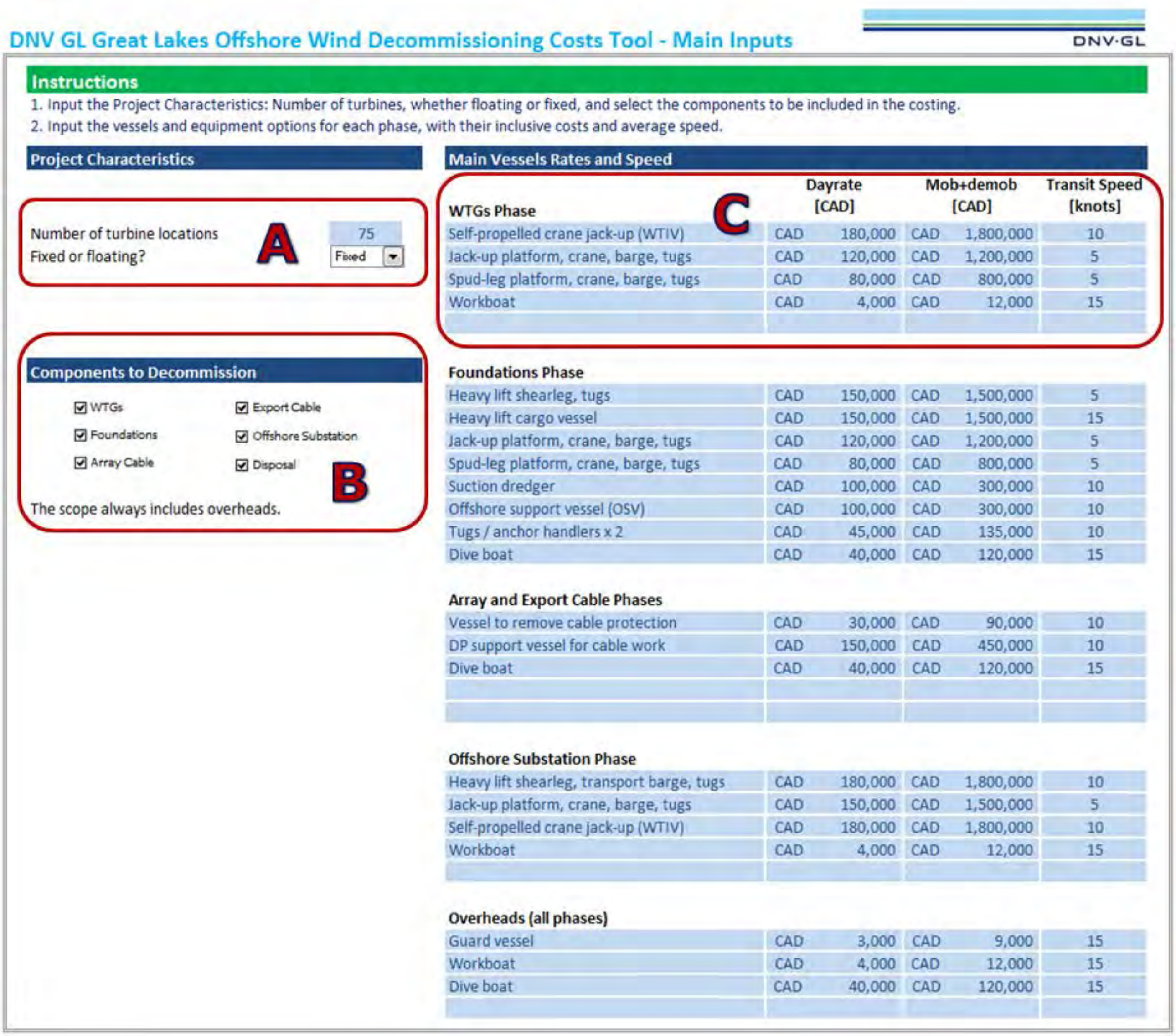
2.3. Printing and display

The Workbook has been designed for printing out the separate worksheets onto Letter format paper in Landscape orientation. When used onscreen, the sheets are displayed to be readable with minimal use of scroll and zoom.

3. Main Inputs worksheet - Instructions

The main inputs worksheet should be filled in first, defining the scope of the cost modelling and providing key project data and vessels that are then read through into the subsequent calculations.

The typical appearance is given in Figure A-1, with key areas outlined in red.



DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool - Main Inputs

DNV·GL

Instructions

1. Input the Project Characteristics: Number of turbines, whether floating or fixed, and select the components to be included in the costing.
2. Input the vessels and equipment options for each phase, with their inclusive costs and average speed.

Project Characteristics

A

Number of turbine locations	75
Fixed or floating?	Fixed

Components to Decommission

B

- ☑ WTGs
- ☑ Export Cable
- ☑ Foundations
- ☑ Offshore Substation
- ☑ Array Cable
- ☑ Disposal

The scope always includes overheads.

Main Vessels Rates and Speed

C

WTGs Phase		Dayrate [CAD]		Mob+demob [CAD]	Transit Speed [knots]
Self-propelled crane jack-up (WTIV)	CAD	180,000	CAD	1,800,000	10
Jack-up platform, crane, barge, tugs	CAD	120,000	CAD	1,200,000	5
Spud-leg platform, crane, barge, tugs	CAD	80,000	CAD	800,000	5
Workboat	CAD	4,000	CAD	12,000	15
Foundations Phase					
Heavy lift shearleg, tugs	CAD	150,000	CAD	1,500,000	5
Heavy lift cargo vessel	CAD	150,000	CAD	1,500,000	15
Jack-up platform, crane, barge, tugs	CAD	120,000	CAD	1,200,000	5
Spud-leg platform, crane, barge, tugs	CAD	80,000	CAD	800,000	5
Suction dredger	CAD	100,000	CAD	300,000	10
Offshore support vessel (OSV)	CAD	100,000	CAD	300,000	10
Tugs / anchor handlers x 2	CAD	45,000	CAD	135,000	10
Dive boat	CAD	40,000	CAD	120,000	15
Array and Export Cable Phases					
Vessel to remove cable protection	CAD	30,000	CAD	90,000	10
DP support vessel for cable work	CAD	150,000	CAD	450,000	10
Dive boat	CAD	40,000	CAD	120,000	15
Offshore Substation Phase					
Heavy lift shearleg, transport barge, tugs	CAD	180,000	CAD	1,800,000	10
Jack-up platform, crane, barge, tugs	CAD	150,000	CAD	1,500,000	5
Self-propelled crane jack-up (WTIV)	CAD	180,000	CAD	1,800,000	10
Workboat	CAD	4,000	CAD	12,000	15
Overheads (all phases)					
Guard vessel	CAD	3,000	CAD	9,000	15
Workboat	CAD	4,000	CAD	12,000	15
Dive boat	CAD	40,000	CAD	120,000	15

Figure A-1 Cost Model – Main inputs worksheet

Instructions:

1. **Input number of turbine locations (Area A)**. This value is used in the logistics of the WTG and foundation phases.
2. **Select fixed or floating** (Area A). If “Floating”, then the WTGs phase becomes hidden in the model on the basis that turbine removal will not be part of the marine operations. If required the cost of WTG removal onshore is added elsewhere in the model.
3. **Select which phases are to be included in the cost estimate**, using the tick-boxes (Area B). Un-ticked phases become hidden and are not included in the overall costing. Note that:
    a. If cables are not to be removed, there will still be some cost for making the ends secure.
    b. The Overheads worksheet is always visible and should be filled in on a case-by-case basis.
4. **Input vessels options for each phase.** Enter their inclusive day-rates, the combined fixed cost for mobilisation & demobilisation, and their average speed. These lists become the drop-down menus for each phase. Area C gives an example of the selection list for the WTG decommissioning phase. It is recommended to use a single line to represent the combination of vessels and equipment working together for the same duration, such as lift vessel, the mobile crane on board, its related transport barge and their tugs. The average speed is used to estimate the transit time to port and should take into account time for manoeuvring at each end. Note that:
    a. The cost model is populated with indicative vessels costs. As discussed later, these can vary widely and have a strong influence on the overall decommissioning costs, so the user should endeavour to obtain the best estimates.
    b. The overheads vessel list is for vessels that will be employed for the entire duration of the marine operations, such as the guard boat.
    c. **Warning:** To replace or edit the vessels descriptions and rates, users should overwrite the blue cells. Users should not drag contents between cells.

4. Component worksheets – Features in common

The worksheets covering the Component phases (WTGs, Foundations, Array Cables, Export Cable and OSS), the inputs and modelling methods are similar. Examples here are taken from the WTG sheet but are similar in the others.

The main features in common are:

- **Selected vessel**. Click on the blue box to show dropdown of vessels or vessel combinations related to that phase, read from the Main Inputs sheet. (e.g. Figure A-2)
- **Maximum seasonal duration.** Enter number of days relevant for that phase. Guidance on values: For example turbine dismantling may be restricted to the least windy conditions and is often a shorter season than foundations and cable dismantling. In the Great Lakes there will be ice restrictions at ports and at site that prevent vessels operating in winter. This input is used primarily to determine the number of times the vessels combination needs to be mobilised and demobilised, which adds to their charter cost.

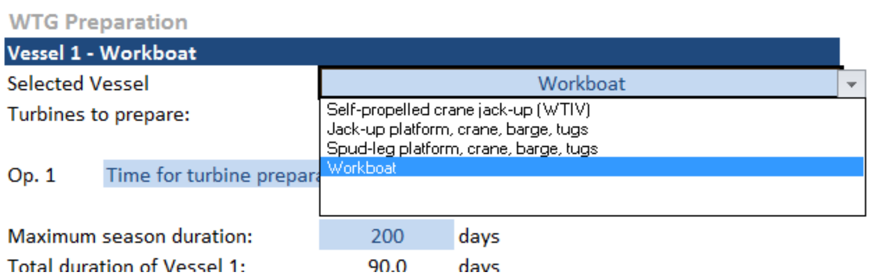


Figure A-2 Selected Vessel dropdown

For marine operations performed in cycles (e.g. Figure A-3), where removed components are taken to shore in batches, there are inputs for:

- **Units per cycle** for example the components of how many turbines or foundations will fit on the vessel to make a batch. This applies only if the same vessel is used for the removal operations at the site and for the transport to the disposal port.
- **Vessel stays on site?**

  If **"No"**, then the time for transits to port is added to the cycle times at site.

  If **"Yes"**, then the dismantling operations at site continue whilst another vessel makes the transit to port. In this case, the "units per cycle" is set to the total number (75) since allowance is not needed for multiple transits to the disposal port.
- **Distance to port.** This is entered in km and, from the average vessel speed, is used to calculate transit time to port.
- **Operation steps.** The description and ideal time duration for each step in the cycle of operations at site is entered, and defined as either "Site" or "Transit". A Transit step refers to time within the offshore site to move from one location to another. It is intended that the steps encompass overall activities rather than precise detail which is not warranted in a generic model. For example, the

dismantling of the turbine is treated as a single step rather than considering the timing each crane operation. Similarly timings are recorded in days rather than hours.

- **Weather factor.** A single multiplier factor is input for the set of marine operations, to take into account the delays when the operational limits are exceeded. These are derived ideally from statistical knowledge of the site conditions together with the operational limits for the activities and equipment.

Foundation cut, lift & load

Vessel 2 - Heavy lift cargo vessel					
Selected Vessel		Heavy lift cargo vessel			
Foundations per cycle (Vessel capacity)				3	
Vessel stays on site?	No		Distance to Port	20	km
Op. 1	Position vessel(s), prepare		Site	0.5	days/unit
Op. 2	Separate/cut, lift & load piece1		Site	1.0	days/unit
Op. 3	Separate/cut, lift & load piece2		Site	1.5	days/unit
Op. 4	Transit to next unit		Transit	0.1	days
Weather Factor (applied to the cycle duration)				1.5	

Figure A-3 Cyclic work at site – inputs for operational steps

From these inputs, the Tool calculates and displays the number of cycles, the duration of each cycle in days (including weather delays), and the overall duration that the vessel is required. Also displayed is the number of seasons needed.

The white calculation cells in the lower part of Figure A-4 provide an example.

Foundation cut, lift & load

Vessel 2 - Heavy lift cargo vessel					
Selected Vessel		Heavy lift cargo vessel			
Foundations per cycle (Vessel capacity)				3	
Vessel stays on site?	No		Distance to Port	20	km
Op. 1	Position vessel(s), prepare		Site	0.5	days/unit
Op. 2	Separate/cut, lift & load piece1		Site	1.0	days/unit
Op. 3	Separate/cut, lift & load piece2		Site	1.5	days/unit
Op. 4	Transit to next unit		Transit	0.1	days
Weather Factor (applied to the cycle duration)				1.5	

Maximum season duration:	270	days
Number of cycles required:	25.0	
Transit to site time (one-way):	0.03	days
Duration per cycle (excl. transit to site):	13.8	days
Total duration of Vessel 2:	346.5	days
Seasons required:	2	
Total Cost of Vessel 2:	**CAD**	**54,975,225**

Figure A-4 Cyclic work at site – inputs and outputs

In this example, the heavy lift cargo vessel does not stay on site and the vessel capacity has been set as 3; this means it returns to the disposal port after each cycle of three foundations. Operations 1 to 3 describe the steps to remove each foundation, comprising positioning of the heavy lift vessel beside the location and removal of the foundation in 2 pieces with the pieces loaded onto the same vessel. Operation 4 is the time to transit from one unit location to the next and it is marked as "Transit"; this means that this duration is not counted for the last unit of each cycle when the vessel will be travelling to port rather than to the next location. For "n" locations per cycle there will be "(n-1)" transits between locations.

The duration per cycle is calculated by summing the time to perform the series of operations for each location, including the required number of in-site transits, and multiplying by the weather factor. The number of cycles required is calculated from the number of units input in the Main Inputs sheet and the number of units per cycle. The total duration for all the cycles is obtained from the number of cycles, duration per cycle at site, and the transit times between site and the port.

This total duration is compared with the stated length of the season to derive the number of seasons needed.

At the bottom of the area is the total cost of the vessel combination calculated from the duration required, its day-rate and costs for mobilisation & demobilisation, taking into account any remobilisation costs if it is used for more than one season.

If the vessel combination is defined as staying at site (as in the example settings for the WTG phase), then the calculation includes only one transit to and from the port. In this case it calculates in-site transits between every pair of locations. This scenario assumes that the heavy lift vessel is loading the removed components onto a barge or other transport vessel which is working in parallel. It also assumes that the operations of the heavy lift vessel determine the overall time needed by the group of vessels, rather than the transport barge. The heavy lift vessel can be assumed to have enough deck capacity to store a small number of removed components, thus avoiding operations being held up whilst the transport barge is making the return trip to port; alternatively the vessels combination can include two barges so that there is always one at site.

The **Other Costs** area is to input costs specific to this phase and not already included in the main vessel combinations. The example in Figure A-5 includes a dive boat for the duration of the phase and some specialist equipment that might be hired separately from the main vessels.

Other Phase Related Costs					
	Duration [days]	Daily Cost	Fixed Cost	Qty.	Total Cost [CAD]
Dive boat	90	CAD 40,000	CAD 120,000	1	CAD 3,720,000
Cable cutters	90	CAD 10,000	CAD 200,000	1	CAD 1,100,000
Other cost 3					CAD -
Total Other Phase Related Costs:					**CAD 4,820,000**

Figure A-5 Other costs related to the phase - inputs

For each component worksheet, the overall cost and duration in days (including weather factor) is summarised with green highlighting at the bottom. This information is carried through to the Results Summary worksheet.

5. WTGs worksheet – Instructions

The WTGs worksheet is used to define the marine operations associated with removing the turbines from their foundations, as described in Section 6.3.3.

The typical appearance is given in Figure A-6 with the different areas outlined in red.

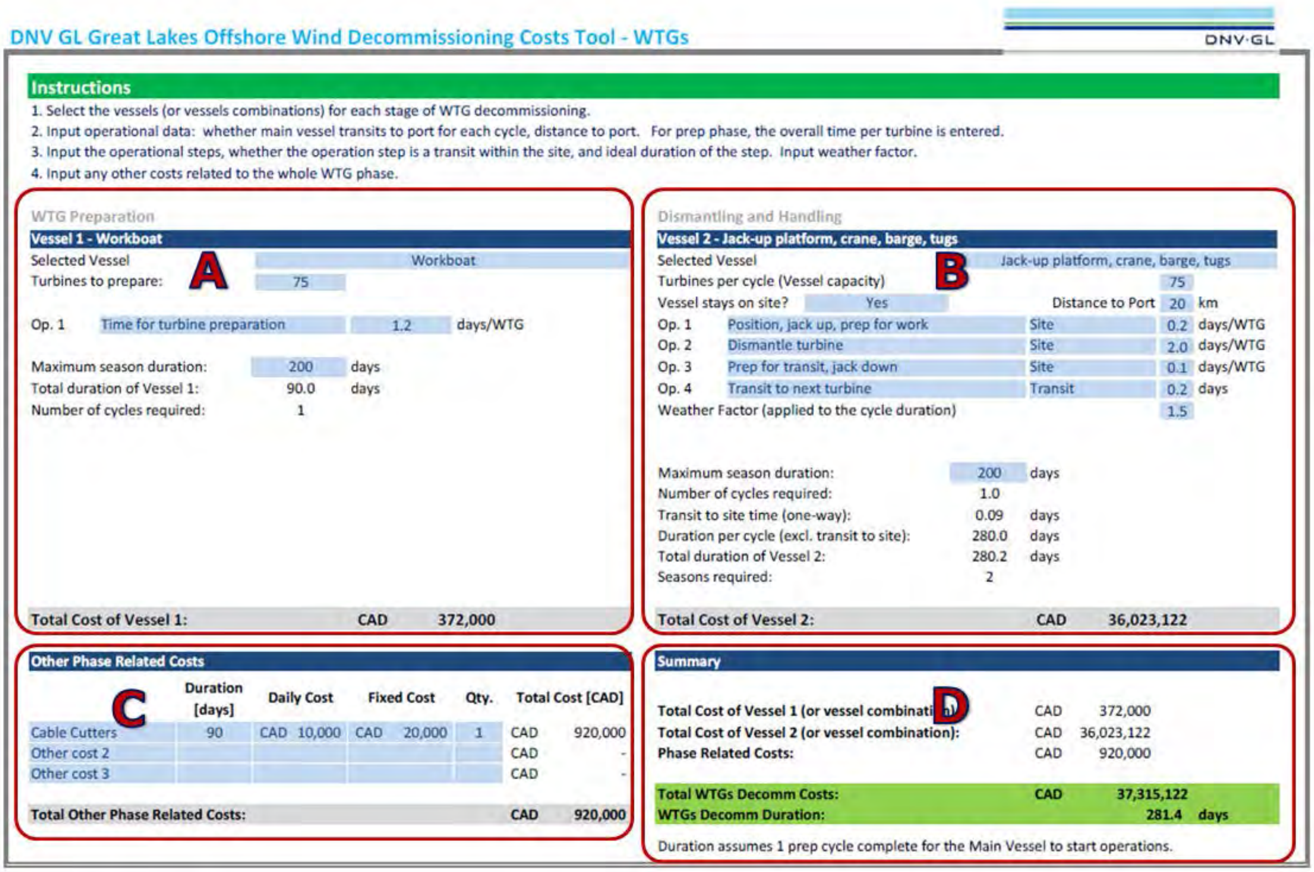


Figure A-6 Cost Model – WTGs worksheet

Instructions

1. **Select the vessels combinations for each stage of the WTG removal**. To do this, click the blue box to show the dropdown menu reading from the Main Inputs sheet. In Figure A-6, a workboat is selected for the WTG preparation stage (Area A). For the WTG dismantling stage (Area B), the vessel combination comprising jack-up platform, mobile crane, transport barge and tugs is selected.
2. **Input turbines per cycle.** This is typically the number of units that are transported to port in each batch, representing the carrying capacity of the vessel. The example here assumes a relatively small barge with capacity for the components of just two turbines.
3. **Input operational data for the WTG preparation stage** (Area A). Enter an overall time required per WTG, including any transits of the workboat.
4. **Input operational data for WTG dismantling stage** (Area B). In the example here, it is assumed a mobile crane on a jack-up platform is used, staying on site whilst a separate barge transports the removed components to shore in batches of two units. Transits of the platform between locations will take longer than if a specialised WTIV (self-propelled crane jack-up) is used.
5. **Input weather factor and seasonal duration**
6. **Input other costs** (Area C). In this example a dive boat and cable cutters are added, working concurrently with the turbine preparation work.

The cycle analysis, charter costs for the required vessels, and the overall costs and durations for the phase are presented at the bottom of the worksheet.

See Section 13 of this Appendix for general guidance on setting up the inputs for the Tool.

6. Foundations worksheet – Instructions

The Foundations worksheet is used to define the marine operations associated with the removal of the foundations, as described in Section 6.3.4 of the main report, and after the turbines have been removed using a different vessel.

6.1. Selection of methodology

The Tool provides three different methodologies as described in Section 6.3.4.

- Cut, Lift & Carry (e.g. MP or jacket foundations)
- Lift, Float & Tow (e.g. GBS or suction bucket)
- Detach & Tow (e.g. floating support structures)

Figure A-7 and Figure A-8 show the configuration of the sheet for the Cut, Lift & Carry methodology.

Figure A-7 Cost Model – Foundations sheet, selection of Decommissioning Methodology

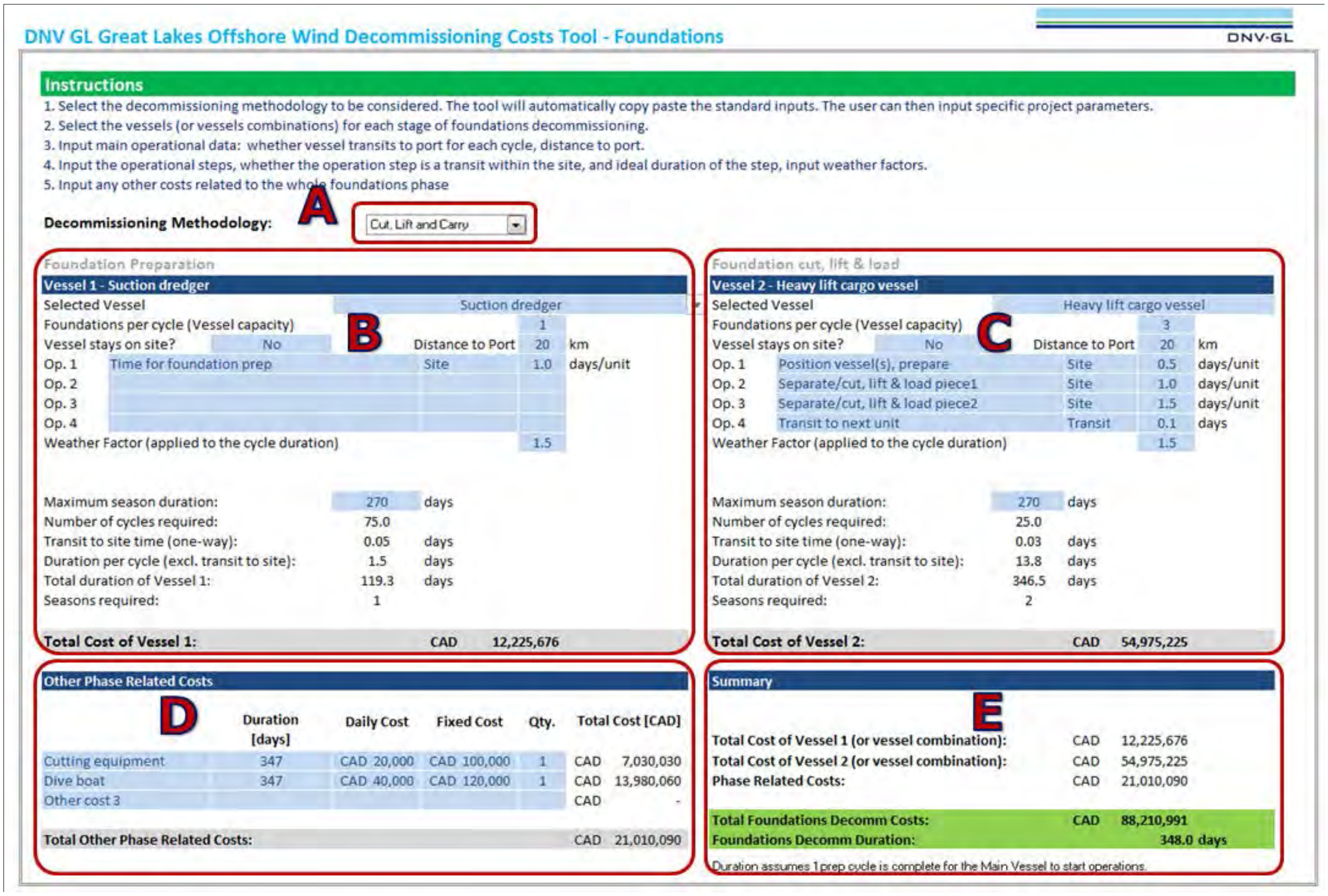
Instruction

Select the decommissioning methodology (Area A). As soon as the methodology is selected, the worksheet is populated by the appropriate interface, which is slightly different for each. Once selected, the blue boxes can be edited as before.

Warning: If the methodology is switched after editing the inputs, the edits will be lost. To preserve these inputs, users are recommended to save the workbook with a unique name prior to changing to another methodology.

6.2. Cut, Lift & Carry methodology

The Cut, Lift & Carry methodology, previously described in Section 6.3.4.1, is modelled using the worksheet presented in Figure A-8.


DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool - Foundations

DNV·GL

Instructions

1. Select the decommissioning methodology to be considered. The tool will automatically copy paste the standard inputs. The user can then input specific project parameters.
2. Select the vessels (or vessels combinations) for each stage of foundations decommissioning.
3. Input main operational data: whether vessel transits to port for each cycle, distance to port.
4. Input the operational steps, whether the operation step is a transit within the site, and ideal duration of the step, input weather factors.
5. Input any other costs related to the whole foundations phase

Decommissioning Methodology: A Cut, Lift and Carry

Foundation Preparation

Vessel 1 - Suction dredger	B			
Selected Vessel	Suction dredger			
Foundations per cycle (Vessel capacity)			1	
Vessel stays on site?	No	Distance to Port	20	km
Op. 1	Time for foundation prep	Site	1.0	days/unit
Op. 2				
Op. 3				
Op. 4				
Weather Factor (applied to the cycle duration)			1.5	
Maximum season duration:	270	days		
Number of cycles required:	75.0			
Transit to site time (one-way):	0.05	days		
Duration per cycle (excl. transit to site):	1.5	days		
Total duration of Vessel 1:	119.3	days		
Seasons required:	1			
Total Cost of Vessel 1:		CAD	12,225,676	

Foundation cut, lift & load

Vessel 2 - Heavy lift cargo vessel	C			
Selected Vessel	Heavy lift cargo vessel			
Foundations per cycle (Vessel capacity)			3	
Vessel stays on site?	No	Distance to Port	20	km
Op. 1	Position vessel(s), prepare	Site	0.5	days/unit
Op. 2	Separate/cut, lift & load piece1	Site	1.0	days/unit
Op. 3	Separate/cut, lift & load piece2	Site	1.5	days/unit
Op. 4	Transit to next unit	Transit	0.1	days
Weather Factor (applied to the cycle duration)			1.5	
Maximum season duration:	270	days		
Number of cycles required:	25.0			
Transit to site time (one-way):	0.03	days		
Duration per cycle (excl. transit to site):	13.8	days		
Total duration of Vessel 2:	346.5	days		
Seasons required:	2			
Total Cost of Vessel 2:		CAD	54,975,225	

Other Phase Related Costs D	Duration [days]	Daily Cost	Fixed Cost	Qty.	Total Cost [CAD]	
Cutting equipment	347	CAD 20,000	CAD 100,000	1	CAD	7,030,030
Dive boat	347	CAD 40,000	CAD 120,000	1	CAD	13,980,060
Other cost 3					CAD	-
Total Other Phase Related Costs:					CAD	21,010,090

Summary E		
Total Cost of Vessel 1 (or vessel combination):	CAD	12,225,676
Total Cost of Vessel 2 (or vessel combination):	CAD	54,975,225
Phase Related Costs:	CAD	21,010,090
Total Foundations Decomm Costs:	CAD	88,210,991
Foundations Decomm Duration:		348.0 days

Duration assumes 1 prep cycle is complete for the Main Vessel to start operations.

Figure A-8 Cost Model – Foundations worksheet for Cut, Lift & Carry methodology

Instructions

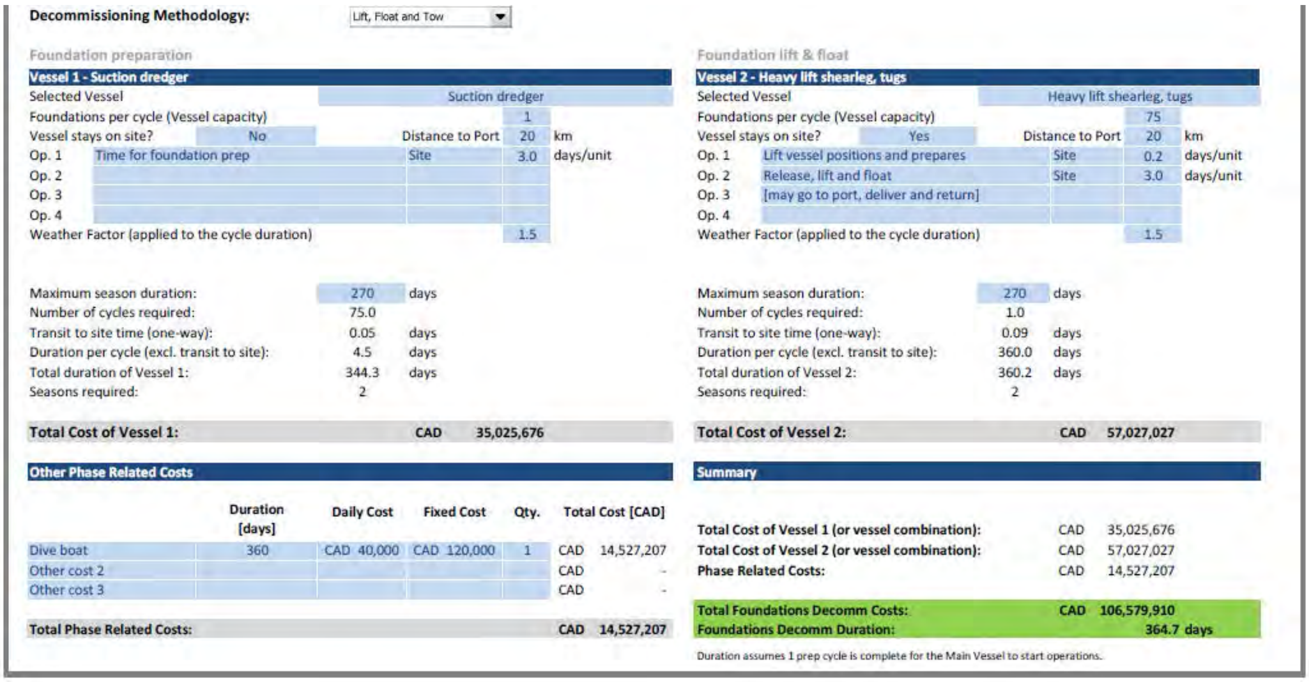
1. **Select the vessels and vessel combinations** for the preparation and removal stages of the foundations removal using the dropdown menus at the top of Areas B and C. In the example, a suction dredger is selected for preparatory seabed removal at the piles, and a heavy lift cargo vessel for the cutting, lifting and transport of the removed foundations.
2. **Input operational data for the preparation stage** (Area B). Select whether the vessel stays on site throughout or returns to port after each cycle. Enter number of units per cycle. Enter time for preparation of each unit and, if relevant, time to transit between units.
3. **Input operational data for the foundation removal stage** (Area C). Select whether the vessel stays on site or returns to port after each cycle. If foundations are removed in two pieces, separate steps can be created for each as shown. Durations should allow for any cutting time. Enter number of units per cycle. In the example, the vessel can carry the pieces of 5 foundations in each cycle.
4. **Input weather factors and seasonal duration.**
5. **Input other costs** (Area D). In this example a cost for the cutting equipment is included.

The estimate of duration assumes the foundations preparation work and removal work take place at the same time on different units, with the removal vessel starting work after one cycle of the preparation vessel.

See Section 13 of this Appendix for general guidance on setting up the inputs for the Tool.

6.3. Lift, Float & Tow methodology

The Lift, Float & Tow methodology previously described in Section 6.3.4.2 is modelled using the worksheet presented in Figure A-9. By default the method assumes that the foundations are removed and towed back to shore individually.



Decommissioning Methodology: Lift, Float and Tow

Foundation preparation

Vessel 1 - Suction dredger				
Selected Vessel	Suction dredger			
Foundations per cycle (Vessel capacity)			1	
Vessel stays on site?	No	Distance to Port	20	km
Op. 1	Time for foundation prep	Site	3.0	days/unit
Op. 2				
Op. 3				
Op. 4				
Weather Factor (applied to the cycle duration)			1.5	

Maximum season duration:	270	days
Number of cycles required:	75.0	
Transit to site time (one-way):	0.05	days
Duration per cycle (excl. transit to site):	4.5	days
Total duration of Vessel 1:	344.3	days
Seasons required:	2	
Total Cost of Vessel 1:	**CAD**	**35,025,676**

Foundation lift & float

Vessel 2 - Heavy lift shearleg, tugs				
Selected Vessel	Heavy lift shearleg, tugs			
Foundations per cycle (Vessel capacity)			75	
Vessel stays on site?	Yes	Distance to Port	20	km
Op. 1	Lift vessel positions and prepares	Site	0.2	days/unit
Op. 2	Release, lift and float	Site	3.0	days/unit
Op. 3	[may go to port, deliver and return]			
Op. 4				
Weather Factor (applied to the cycle duration)			1.5	

Maximum season duration:	270	days
Number of cycles required:	1.0	
Transit to site time (one-way):	0.09	days
Duration per cycle (excl. transit to site):	360.0	days
Total duration of Vessel 2:	360.2	days
Seasons required:	2	
Total Cost of Vessel 2:	**CAD**	**57,027,027**

Other Phase Related Costs

	Duration [days]	Daily Cost	Fixed Cost	Qty.	Total Cost [CAD]
Dive boat	360	CAD 40,000	CAD 120,000	1	CAD 14,527,207
Other cost 2					CAD -
Other cost 3					CAD -
Total Phase Related Costs:					**CAD 14,527,207**

Summary

Total Cost of Vessel 1 (or vessel combination):	CAD	35,025,676
Total Cost of Vessel 2 (or vessel combination):	CAD	57,027,027
Phase Related Costs:	CAD	14,527,207
Total Foundations Decomm Costs:	**CAD**	**106,579,910**
Foundations Decomm Duration:		**364.7 days**

Duration assumes 1 prep cycle is complete for the Main Vessel to start operations.

Figure A-9 Cost Model – Foundations worksheet for Lift, Float & Tow methodology

Instructions

1. **Select the vessels and vessel combinations** for the preparation and removal stages using the dropdown menus. In the example, a suction dredger is selected for preparatory seabed removal around suction foundations. In the case of GBS foundations, the phase would require vessels and equipment for ballast removal. For the controlled lifting and towing of the removed foundation, a shearleg floating crane with tugs is selected.
2. **Input operational data for the preparation stage**. Select whether the vessel stays on site throughout or returns to port in between. Enter time for preparation of each unit and, if relevant, time to transit between units.
3. **Input operational data for the foundation removal stage.** The number of units per cycle is therefore set to one.
4. **Input weather factors and seasonal duration.**
5. **Input other costs**.

The estimate of duration assumes the foundations preparation work and removal work take place at the same time on different units, with the removal vessel starting work after one cycle of the preparation vessel.

See Section 13 of this Appendix for general guidance on setting up the inputs for the Tool.

6.4. Detach & Tow methodology

The Detach & Tow methodology previously described in Section 6.3.4.3 is modelled using the worksheet presented in Figure A-10.

When the turbines are defined as "Floating" in the Main Inputs sheet, it is the only Foundations worksheet accessible.

Decommissioning Methodology: Detach and Tow

At-site preparation and moorings work

Vessel 1 - Offshore support vessel (OSV)					
Selected Vessel		Offshore support vessel (OSV)			
Foundations per cycle (Vessel capacity)				1	
Vessel stays on site?	Yes		Distance to Port	50	km
Op. 1	Prepare turbine for transit		Site	0.5	days/unit
Op. 2	Disconnect, ballast down		Site	0.5	days/unit
Op. 3	[Decomm moorings concurrently]				
Op. 4					
Weather Factor (applied to the cycle duration)				1.5	

Maximum season duration:	270	days
Number of cycles required:	75.0	
Transit to site time (one-way):	0.11	days
Duration per cycle (excl. transit to site):	1.5	days
Total duration of Vessel 1:	112.7	days
Seasons required:	1	
Total Cost of Vessel 1 + Spread:	CAD	5,786,261

Detach and Tow

Vessel 2 - Tugs / anchor handlers x 2					
Selected Vessel		Tugs / anchor handlers x 2			
Foundations per cycle (Vessel capacity)				1	
Vessel stays on site?	No		Distance to Port	50	km
Op. 1	Tugs position and prepare		Site	0.5	days/unit
Op. 2	Attach tow, detach moorings		Site	0.5	days/unit
Op. 3	[Go to port, deliver & return]				
Op. 4					
Weather Factor (applied to the cycle duration)				1.5	

Maximum season duration:	270	days
Number of cycles required:	75.0	
Transit to site time (one-way):	0.11	days
Duration per cycle (excl. transit to site):	1.5	days
Total duration of Vessel 2:	129.4	days
Seasons required:	1	
Total Cost of Vessel 2 + Spread:	CAD	5,957,635

Other Phase Related Costs

	Duration [days]	Daily Cost	Fixed Cost	Qty.	Total Cost [CAD]
Moorings decomm	75	CAD 50,000	CAD 150,000	1	CAD 3,900,000
Dismantle WTGs at shore	75	CAD 20,000	CAD 60,000	1	CAD 1,560,000
Other cost 3					CAD -
Total Phase Related Costs:					CAD 5,460,000

Summary

Total Cost of Vessel 1 (incl. spread):	CAD	5,786,261
Total Cost of Vessel 2 (incl. spread):	CAD	5,957,635
Phase Related Costs:	CAD	5,460,000
Total Foundations Decomm Costs:	CAD	17,203,896
Foundations Decomm Duration:		130.9 days

Duration assumes 1 prep cycle is complete for the Main Vessel to start operations.

Figure A-10 Cost Model – Foundations worksheet for Detach & Tow methodology

Instructions

1. **Select the vessels and vessel combinations** for the preparation stage and the main removal stage using the dropdown menu. In the example, an offshore support vessel (OSV) is used for the preparation work and a set of tugs for the main removal and tow to port.
2. **Input operational data for the preparation stage**. Select whether the vessel stays on site throughout or returns to port. Enter time for preparation of each unit and, if relevant, time to transit between units. In the example the vessel stays on site.
3. **Input operational data for the foundation removal stage**. The structures are taken to port individually therefore the number of units per cycle is set to one.
4. **Input weather factors and seasonal duration**.
5. **Input other costs**. The example includes costs for a vessel to decommission the moorings (assumed to happen concurrently) and costs to remove the WTGs from their structures once inshore.

The estimate of duration assumes the preparation work and removal work take place at the same time on different units, with the removal vessel starting work after one cycle of the preparation vessel.

See Section 13 of Appendix A for general guidance on setting up the inputs for the Tool.

7. Array Cables worksheet - Instructions

The Array Cables worksheet is used to define the marine operations associated with decommissioning the array cables, as described in Section 6.3.5. The worksheet is presented in Figure A-11.

If the array cables are to be removed, the Tool allows for an initial operation to address cable protection, followed by a second operation to remove the cable.

If the array cables are left in-situ, the costs for making secure the ends of every cable are entered in this worksheet for transparency in the Results Summary.

DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool - Array Cables

DNV·GL

Instructions

1. Input the number of array cables. It is assumed similar time is taken for each.
2. Select the vessels (or vessels combinations) for each stage. EG for removal of cable protection (if required) and for cable deburial.
3. Input main operational data: whether vessel transits to port for each cycle, distance to port.
4. Input the operational steps, whether the operation step is a transit within the site, and ideal duration of the step. Input weather factors.
5. Input any other costs related to the array cable decommissioning phase

Number of Array Cables: 75

Seabed Preparation

Vessel 1 - Vessel to remove cable protection				
Selected Vessel	Vessel to remove cable protection			
Array cables per cycle (Vessel capacity)	10			
Vessel stays on site?	No	Distance to Port	20	km
Op. 1	Remove cable protection (1 section)	Site	0.4	days/unit
Op. 2	Transit to next cable section	Site	0.1	days/unit
Op. 3				
Op. 4				
Weather Factor (applied to the cycle duration)			1.2	

Maximum season duration:	270	days
Number of cycles required:	7.5	
Transit to site time (one-way):	0.05	days
Duration per cycle (excl. transit to site)	6.0	days
Total duration of Vessel 1:	45.7	days
Seasons required:	1	

Total Cost of Vessel 1: CAD 1,461,622

Deburial, Cut and Recovery

Vessel 2 - DP support vessel for cable work				
Selected Vessel	DP support vessel for cable work			
Array cables per cycle (Vessel capacity)	2			
Vessel stays on site?	No	Distance to Port	20	km
Op. 1	Preparation and positioning	Site	0.1	days/unit
Op. 2	Survey one cable	Site	0.3	days/unit
Op. 3	Debury & remove one cable	Site	0.5	days/unit
Op. 4	Transit to next cable	Transit	0.1	days
Weather Factor (applied to the cycle duration)			1.2	

Maximum season duration:	270	days
Number of cycles required:	37.5	
Transit to site time (one-way):	0.05	days
Duration per cycle (excl. transit to site):	2.2	days
Total duration of Vessel 2:	87.4	days
Seasons required:	1	

Total Cost of Vessel 2: CAD 13,563,514

Other Phase Related Costs

	Duration [days]	Daily Cost	Fixed Cost	Qty.	Total Cost [CAD]
Cable deburial tool	87	CAD 20,000	CAD 60,000	1	CAD 1,808,468
Other cost 2					CAD -
Other cost 3					CAD -
Total Other Phase Related Costs:					**CAD 1,808,468**

Summary

Total Cost of Vessel 1 (or vessel combination):	CAD	1,461,622
Total Cost of Vessel 2 (or vessel combination):	CAD	13,563,514
Phase Related Costs:	CAD	1,808,468
Total Array Cable Decomm Costs:	**CAD**	**16,833,604**
Array Cable Decomm Duration:		**133.1 days**

Duration assumes cable deburial starts as soon as any preparation stage is complete.

Figure A-11 Cost Model – Array Cables worksheet

Instructions

1. **Input the number of Array Cables.** It is assumed that they are of similar length. In the example there are 75 cables. For the 4 MW turbines in the example, they are typically 1 km apart, which results in average array cable lengths of just over 1 km. A total array cable length of 80 km is entered elsewhere in the model when estimating scrap values.
2. **Select the vessels and vessel combinations** for the initial work and for the cable removal stages, using the dropdown menus. Note that the same list of vessels in the Main Inputs sheet is used for both Array Cable and Export Cable operations.
3. **Input operational data for the initial stage (if required).** Select whether the vessel stays on site, or returns to port after each cycle (e.g. to dump removed materials). Enter the average number of array cables that are addressed in each cycle and the time required to address each. If no initial stage is required, delete the default inputs.
4. **Input operational data for the array cable removal.** Enter whether the vessel stays on site or returns to port after each cycle. Enter the number of array cables removed per cycle. Insert the operational steps. In the example the cable removal vessel returns to port with each cycle of 2 cables (about 2 km); and also performs the survey work.
5. **Input weather factor and seasonal duration.**
6. **Input other costs.** In the example, the cable de-burial tool costs are entered here.

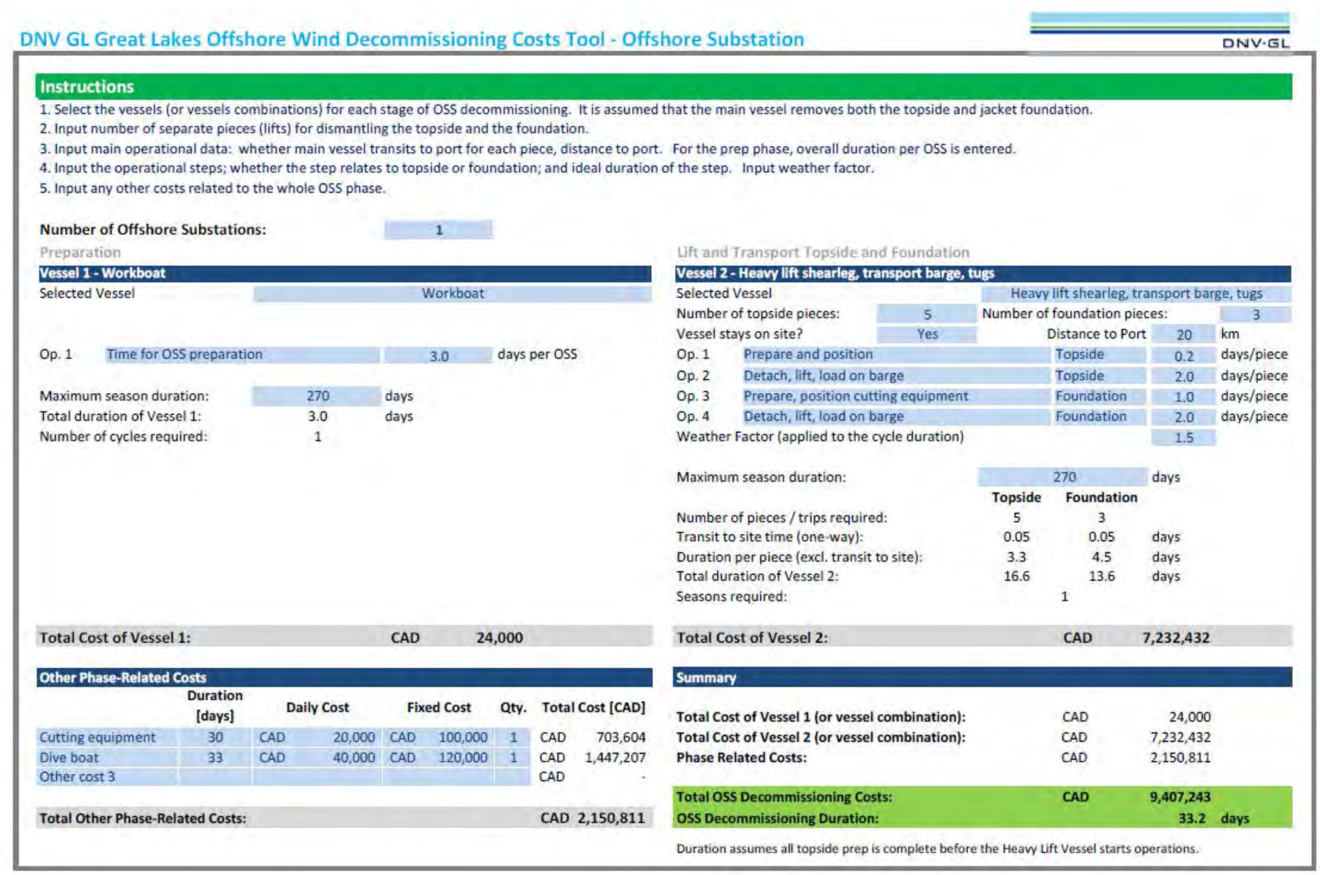
The overall duration of the array cables phase assumes that cable de-burial starts as soon as any preparation stage is complete.

See Section 13 of Appendix A for general guidance on setting up the inputs for the Tool.

8. OSS worksheet – Instructions

The OSS worksheet is used to define the marine operations associated with the removal of the offshore substation or substations, as described in Section 6.3.6. The worksheet is presented in Figure A-12.

It is assumed that the main removal vessel is employed for both the topside and its jacket foundation, using a series of modular lifts to reduce the maximum crane capacity needed. A separate stage for preparation of the OSS is incorporated in the model.


DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool - Offshore Substation

DNV·GL

Instructions

1. Select the vessels (or vessels combinations) for each stage of OSS decommissioning. It is assumed that the main vessel removes both the topside and jacket foundation.
2. Input number of separate pieces (lifts) for dismantling the topside and the foundation.
3. Input main operational data: whether main vessel transits to port for each piece, distance to port. For the prep phase, overall duration per OSS is entered.
4. Input the operational steps; whether the step relates to topside or foundation; and ideal duration of the step. Input weather factor.
5. Input any other costs related to the whole OSS phase.

Number of Offshore Substations: 1

Preparation

Vessel 1 - Workboat

Selected Vessel	Workboat		
Op. 1	Time for OSS preparation	3.0	days per OSS
Maximum season duration:	270	days	
Total duration of Vessel 1:	3.0	days	
Number of cycles required:	1		
Total Cost of Vessel 1:		CAD	**24,000**

Lift and Transport Topside and Foundation

Vessel 2 - Heavy lift shearleg, transport barge, tugs

Selected Vessel	Heavy lift shearleg, transport barge, tugs			
Number of topside pieces:	5	Number of foundation pieces:	3	
Vessel stays on site?	Yes	Distance to Port	20	km
Op. 1	Prepare and position	Topside	0.2	days/piece
Op. 2	Detach, lift, load on barge	Topside	2.0	days/piece
Op. 3	Prepare, position cutting equipment	Foundation	1.0	days/piece
Op. 4	Detach, lift, load on barge	Foundation	2.0	days/piece
Weather Factor (applied to the cycle duration)			1.5	

Maximum season duration:	270		days
	Topside	**Foundation**	
Number of pieces / trips required:	5	3	
Transit to site time (one-way):	0.05	0.05	days
Duration per piece (excl. transit to site):	3.3	4.5	days
Total duration of Vessel 2:	16.6	13.6	days
Seasons required:	1		
Total Cost of Vessel 2:	CAD	**7,232,432**	

Other Phase-Related Costs

	Duration [days]	Daily Cost		Fixed Cost		Qty.	Total Cost [CAD]	
Cutting equipment	30	CAD	20,000	CAD	100,000	1	CAD	703,604
Dive boat	33	CAD	40,000	CAD	120,000	1	CAD	1,447,207
Other cost 3							CAD	-
Total Other Phase-Related Costs:							CAD	**2,150,811**

Summary

Total Cost of Vessel 1 (or vessel combination):	CAD	24,000	
Total Cost of Vessel 2 (or vessel combination):	CAD	7,232,432	
Phase Related Costs:	CAD	2,150,811	
Total OSS Decommissioning Costs:	**CAD**	**9,407,243**	
OSS Decommissioning Duration:		**33.2**	**days**

Duration assumes all topside prep is complete before the Heavy Lift Vessel starts operations.

Figure A-12 Cost Model – OSS worksheet

Instructions

1. **Input number of offshore substations**.
2. **Select the vessels and vessel combinations** for the preparation work and for the main removal stages, using the dropdown menus. In the example a workboat is used for the preparation; and for the removal a vessel combination comprising a shearleg crane, transport barge and tugs.
3. **Input operational data for the preparation stage**. Enter an overall time required per OSS, including any transits.
4. **Input the number of topside pieces (or modules) and foundation pieces**. This determines the number of lifts of each.
5. **Input operational data for the removal stage**. Operations are categorised as either topside or foundation, allowing the durations to be estimated separately. Select whether the vessel stays on site; if not, it makes one transit to port per lift.
6. **Input weather factors and seasonal duration**.
7. **Input other costs**. These may include cutting equipment if not included in the vessel cost. In the example a dive vessel is included here for the duration of the OSS phase.

The duration for the OSS removal operations assumes that the preparation is complete before the heavy lift vessel starts operations.

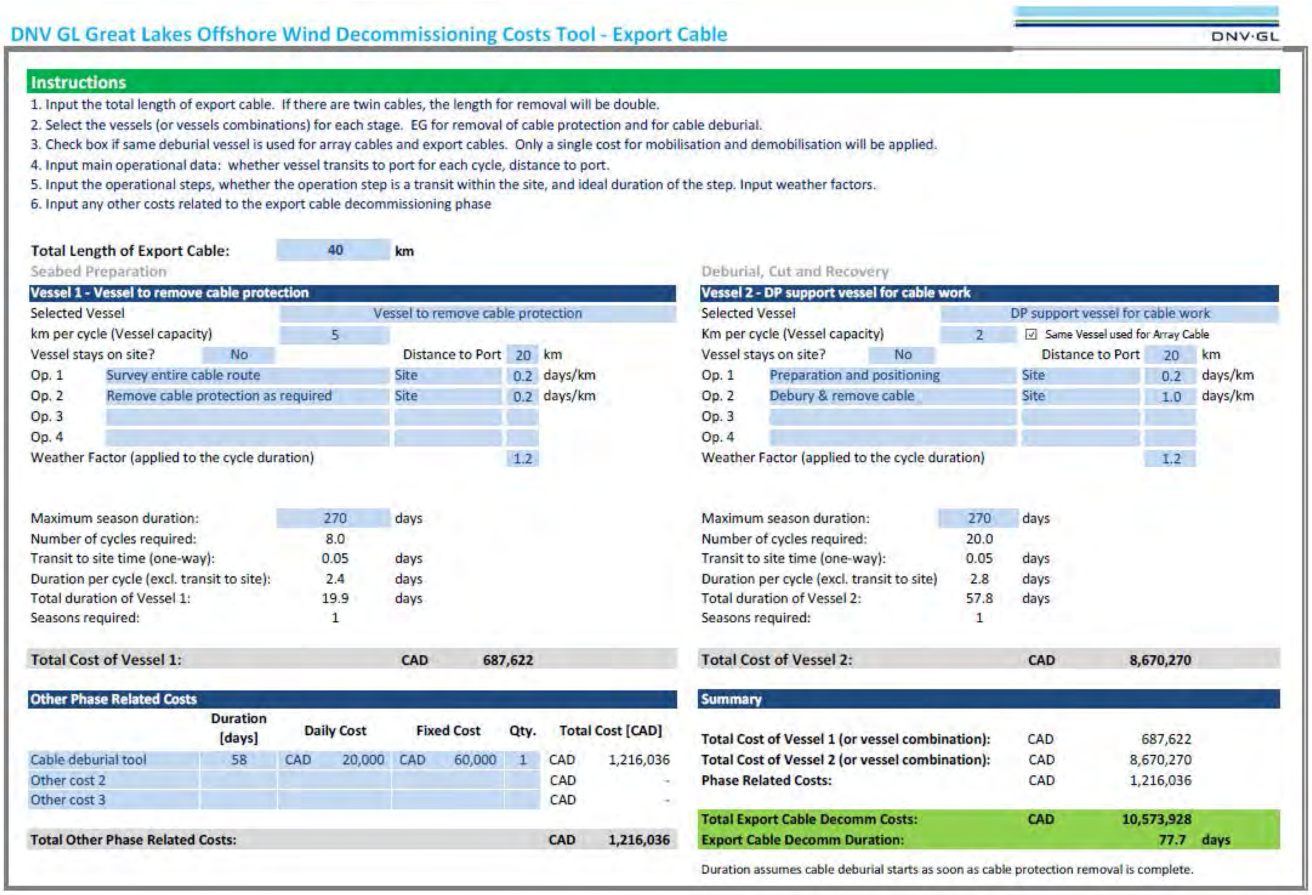
See Section 13 of this Appendix for general guidance on setting up the inputs for the Tool.

9. Export Cables worksheet - Instructions

The Export Cable worksheet is used to define the marine operations associated with decommissioning the export cable, as described in Section 6.3.7. The worksheet is presented in Figure A-13.

If the export cable is to be removed, the model allows for an initial operation to address cable protection and/or to survey the route followed by a second operation to remove the cable.

Even if the export cable is left in-situ, there will be minor decommissioning costs for addressing the two ends of the cable.



DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool - Export Cable

DNV·GL

Instructions

1. Input the total length of export cable. If there are twin cables, the length for removal will be double.
2. Select the vessels (or vessels combinations) for each stage. EG for removal of cable protection and for cable deburial.
3. Check box if same deburial vessel is used for array cables and export cables. Only a single cost for mobilisation and demobilisation will be applied.
4. Input main operational data: whether vessel transits to port for each cycle, distance to port.
5. Input the operational steps, whether the operation step is a transit within the site, and ideal duration of the step. Input weather factors.
6. Input any other costs related to the export cable decommissioning phase

Total Length of Export Cable: 40 km

Seabed Preparation

Vessel 1 - Vessel to remove cable protection			
Selected Vessel	Vessel to remove cable protection		
km per cycle (Vessel capacity)	5		
Vessel stays on site?	No	Distance to Port	20 km
Op. 1	Survey entire cable route	Site	0.2 days/km
Op. 2	Remove cable protection as required	Site	0.2 days/km
Op. 3			
Op. 4			
Weather Factor (applied to the cycle duration)			1.2

Maximum season duration:	270	days
Number of cycles required:	8.0	
Transit to site time (one-way):	0.05	days
Duration per cycle (excl. transit to site):	2.4	days
Total duration of Vessel 1:	19.9	days
Seasons required:	1	

Total Cost of Vessel 1: CAD 687,622

Deburial, Cut and Recovery

Vessel 2 - DP support vessel for cable work			
Selected Vessel	DP support vessel for cable work		
Km per cycle (Vessel capacity)	2	☑ Same Vessel used for Array Cable	
Vessel stays on site?	No	Distance to Port	20 km
Op. 1	Preparation and positioning	Site	0.2 days/km
Op. 2	Debury & remove cable	Site	1.0 days/km
Op. 3			
Op. 4			
Weather Factor (applied to the cycle duration)			1.2

Maximum season duration:	270	days
Number of cycles required:	20.0	
Transit to site time (one-way):	0.05	days
Duration per cycle (excl. transit to site)	2.8	days
Total duration of Vessel 2:	57.8	days
Seasons required:	1	

Total Cost of Vessel 2: CAD 8,670,270

Other Phase Related Costs

	Duration [days]	Daily Cost	Fixed Cost	Qty.	Total Cost [CAD]
Cable deburial tool	58	CAD 20,000	CAD 60,000	1	CAD 1,216,036
Other cost 2					CAD -
Other cost 3					CAD -
Total Other Phase Related Costs:					**CAD 1,216,036**

Summary

Total Cost of Vessel 1 (or vessel combination):	CAD	687,622
Total Cost of Vessel 2 (or vessel combination):	CAD	8,670,270
Phase Related Costs:	CAD	1,216,036
Total Export Cable Decomm Costs:	**CAD**	**10,573,928**
Export Cable Decomm Duration:		**77.7 days**

Duration assumes cable deburial starts as soon as cable protection removal is complete.

Figure A-13 Cost Model – Export Cable worksheet

Instructions

1. **Input total length of export cable**. If there are twin cables, then this length will be double the distance to shore.
2. **Select the vessels and vessel combinations** for the initial work and for the cable removal stages, using the dropdown menus. Note that the same list of vessels in the Main Inputs worksheet is used for both Array Cable and Export Cable operations.
3. **Is same vessel used for array cable**? If the box is checked, then the fixed cost of mobilizing and demobilizing the removal vessel will not be counted twice.
4. **Input operational data for the initial stage (if required).** Select whether the vessel stays on site, or returns to port after each cycle. Enter the length of cable that is addressed in each cycle and the time required to address each. If no initial stage is required, delete the default inputs.
5. **Input operational data for the export cable removal.** Enter whether the vessel stays on site or returns to port after each cycle. Enter the length of cable removed per cycle. In the example the cable removal vessel returns to port with each cycle of 2 km.
6. **Input weather factor and seasonal duration.**
7. **Input other costs.** In the example the cable de-burial tool is entered here.

The estimated duration of the export cable phase assumes that cable de-burial starts as soon as any preparation stage is complete.

See Section 13 of this Appendix for general guidance on setting up the inputs for the Tool.

10. Overheads worksheet – Instructions

The Overheads worksheet captures the additional costs that are not specific to particular phases during the main marine operations as shown in Figure A-14. It is therefore used to incorporate the costs of vessels that are not phase-specific, and the Pre- and Post-Decommissioning activities, as well as the engineering and project management aspects.

DNV GL Great Lakes Offshore Wind Decommissioning Costs Tool - Overheads

DNV·GL

Instructions

1. Input the Overheads estimated for the whole decommissioning phase and their fixed cost per item. Most will depend on project size.
2. Select the vessels required throughout the marine operations. EG guard vessel

Overheads

Itemised Overheads		
Item		**Fixed [CAD]**
Pre-decommissioning EIA and regulations review	CAD	700,000
Pre-decommissioning surveys and inspections	CAD	200,000
Post-decommissioning surveys and monitoring	CAD	400,000
Engineering and project management	CAD	6,000,000
Berthing, pilotage, provisions at operations base	CAD	4,000,000
Insurance (depends on duration and no. activites)	CAD	2,596,344
Other	CAD	-
Total Itemised Overheads:	**CAD**	**13,896,344**

Support Vessel during all operations

Vessel 1 - Guard vessel			
Selected Vessel		Guard vessel	
Total duration of all activities:	433	days	
Total Cost of Vessel 1:		**CAD**	**1,307,172**

Vessel 2 - Workboat			
Selected Vessel		Workboat	
Total duration of all activities:	433	days	
Total Cost of Vessel 2:		**CAD**	**1,742,896**

Vessel 3 -			
Selected Vessel			
Total duration of all activities:	0	days	
Total Cost of Vessel 3:		**CAD**	-

Summary		
Total Itemised Overheads Cost:	CAD	13,896,344
Total Vessels Cost:	CAD	3,050,068
Total Overhead Costs:	**CAD**	**16,946,412**

Figure A-14 Cost Model – Overheads worksheet

Instructions

1. **Input itemised overhead costs**. Enter text description and fixed cost. Note that the costs for the majority of items will depend on the size and scope of the OWF but are not calculated as a percentage of project capital cost (as further described in Section 6.3.9. Note that the sheet is pre-set with a formula for the Insurance item, linked to the number of days of the overall marine operations. However, the multiplier used in the formula (i.e., insurance cost per day) is also dependent on the scope of the activities. Alternatively a single value can be input.
2. **Select vessels** that are used throughout the marine operations using the dropdown menu. Examples are guard vessels or general purpose workboats. The required charter duration is picked up by the model from the Results Summary.

Note that inputs for cost contingency and for future liabilities are provided in the Results Summary worksheet and should not be entered here.

11. Disposal worksheet - Instructions

The Disposal worksheet estimates the revenue or costs derived from the major materials streams (e.g., steel, copper and composites), as described in Section 6.4. The elements of the worksheet are presented in Figure A-15 and Figure A-16.

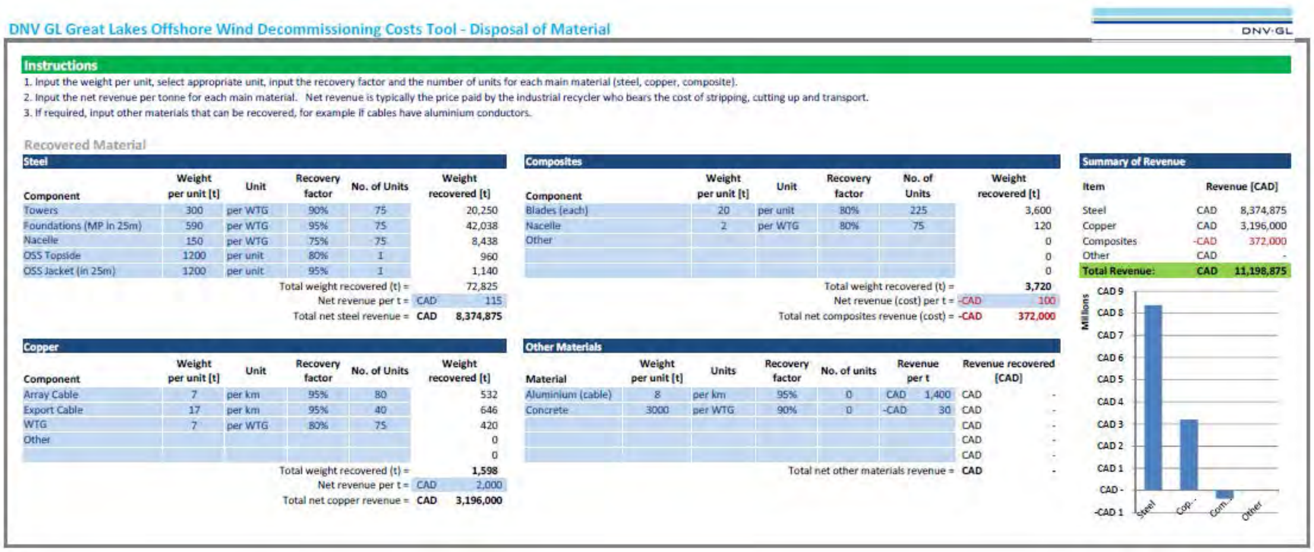


Figure A-15 Cost Model – Disposal worksheet inputs

Instructions

1. For each of the major materials streams (e.g., steel, copper, composites), input separate lines for each source:

   - **Input gross weight per unit.**
   - **Select appropriate unit:** WTG or km. For blades, select "unit"
   - **Input % recovery factor.**
   - **Input number of units.**

   The recovered weights estimated for each line are summed.

   - **Input the net revenue realized per tonne**. This is assumed to be the price given by the recycling company who bear the cost of cutting up and transporting. For the composites this is likely to be a fee rather than a revenue so is entered as negative, appearing in red.

2. In the "Other materials" area, each line can record a different material.

On the right side of the worksheet, the total materials revenue is tabulated and presented graphically. Figure A-16 provides an example.

Summary of Revenue		
Item	**Revenue [CAD]**	
Steel	CAD	6,918,750
Copper	CAD	7,000,000
Composites	-CAD	552,000
Other	CAD	-
Total Revenue:	**CAD**	**13,366,750**

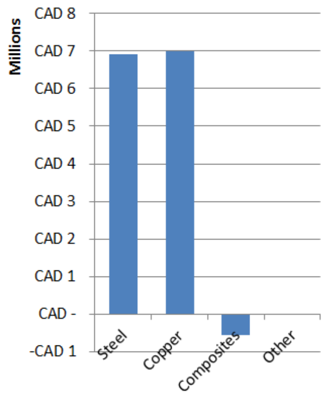


Figure A-16 Cost Model – Disposal worksheet summary of revenues

12. Results summary worksheet

The Results Summary worksheet in the Tool collects the time durations and main costs from the separate worksheets, as shown in Figure A-17. Note that access is available so that all cells can be copied if required.

Enlargements of the Costs Summary and Durations Summary are presented in Figure A-18 and Figure A-19 respectively.

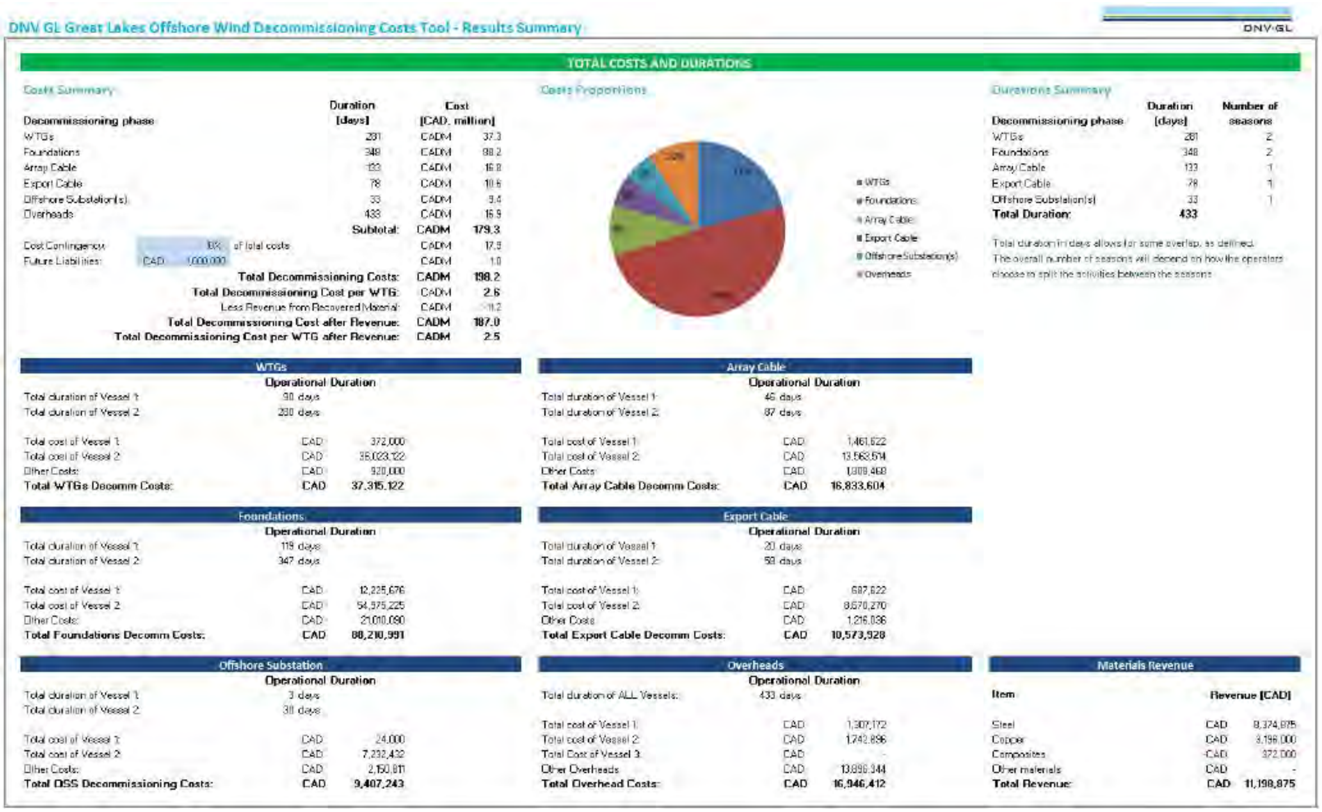


Figure A-17 Cost Model – Results Summary worksheet

12.1. Costs summary

In the Costs Summary table at the top left of the worksheet, users can input additional factors as shown in Figure A-18.

- **Input a % cost contingency**
- **Input an allowance for future liabilities**.

Results are then given excluding and including offset from materials revenue, and quoted as an overall figure or expressed per WTG location.

The pie chart in the centre of the worksheet presents the make-up of the “Subtotal” listed in the Costs Summary, before addition of the contingencies.

Costs Summary

Decommissioning phase			Duration [days]	Cost [CAD, million]	
WTGs			281	CADM	37.3
Foundations			348	CADM	88.2
Array Cable			133	CADM	16.8
Export Cable			78	CADM	10.6
Offshore Substation(s)			33	CADM	9.4
Overheads			433	CADM	16.9
			Subtotal:	**CADM**	**179.3**
Cost Contingency:	10%	of total costs		CADM	17.9
Future Liabilities:	CAD 1,000,000			CADM	1.0
			Total Decommissioning Costs:	**CADM**	**198.2**
			Total Decommissioning Cost per WTG:	CADM	**2.6**
			Less Revenue from Recovered Material:	CADM	-11.2
			Total Decommissioning Cost after Revenue:	**CADM**	**187.0**
			Total Decommissioning Cost per WTG after Revenue:	**CADM**	**2.5**

Figure A-18 Cost Model – Costs Summary

12.2. Durations summary

The phase durations and number of seasons in the Durations Summary as shown in Figure A-19 are copied through from the individual worksheets.

Durations Summary

Decommissioning phase	Duration [days]	Number of seasons
WTGs	281	2
Foundations	348	2
Array Cable	133	1
Export Cable	78	1
Offshore Substation(s)	33	1
Total Duration:	**433**	

Total duration in days allows for some overlap, as defined.
The overall number of seasons will depend on how the operators choose to split the activities between the seasons.

Figure A-19 Cost Model – Durations Summary

To estimate the overall duration for the marine operations, the overlap between different activities must be taken into account.

The Tool assumes that there are two groups of marine operations taking place one after the other.

- The first group is the almost concurrent decommissioning of the WTGs, Foundations and Array Cables.

- The second group is the almost concurrent decommissioning of the Offshore Substations and Export Cable, which cannot start until the last WTG has been de-energised.

To estimate the total duration of all the operations, the longest phase in Groups 1 and 2 are added together and an extra 7 days added to allow for operations not being completely concurrent. In the example, the longest durations are 348 days and 78 days. Thus 348 + 78 + 7 = 433 days overall.

The user is reminded that the number of seasons is used in the Tool primarily to determine the costs of the main vessels, and in particular the mobilisation and demobilisation costs. They are therefore presented only for each phase individually. The overall number of seasons for the decommissioning operations will depend on how the operators choose to split the activities between the seasons. For example, the removal of the offshore sub-station is one of the last operations and may be postponed until the following season to ensure the best weather.

13. Guideline values for Great Lakes

This section provides tables of key values for cost modelling of Great Lakes projects. Ranges are given with explanation of the circumstances when high or low values would be relevant. More information is provided in the relevant sections in Chapter 6.

13.1. Vessel costs

Vessel costs entered in the model are required to be all-inclusive, to capture costs of operation (e.g. fuel), equipment (e.g., lifting gear, fastenings, pumps, ROVs) and staffing for 24 hour per day / 7 day per week working schedule (e.g. crew, technicians plus accommodation).

Since the ideal fleet of vessels does not currently exist in the Great Lakes, assumptions are made for the use of existing vessels and for vessels that have been modified or newly built for the installation and servicing of the OWFs. Even so, the size restrictions in the Great Lakes will make it very unlikely that vessels of the capability found in Europe will be present. In particular, the maximum crane capacity of heavy lift vessels is assumed to be much smaller for both floating vessels and jack-ups. This large uncertainty in vessel availability leads to large uncertainties in their possible costs. Nevertheless Table A-1 provides indicative costs for vessels and vessel combinations that might be available, based on 2015 rates.

Table A-1 Indicative vessel costs

Vessel combinations	Day-rate [CAD $]	Combined mob/demob [CAD $]	Average speed [knots]
Self-propelled crane jack-up (WTIV)	120,000 - 240,000	1.2 – 2.4 million	6 - 10
Jack-up platform, mobile crane, transport barge, tugs	60,000 – 180,000	0.6 – 1.8 million	3 - 6
Spud-leg platform, mobile crane, transport barge, tugs	60,000 – 100,000	0.6 – 1.0 million	3 - 6
Heavy lift shearleg, tugs	110,000 – 190,000	1.1 – 1.9 million	3 - 6
Heavy lift cargo vessel	110,000 – 190,000	1.1 – 1.9 million	12 - 16
Suction dredger	80,000 – 120,000	0.2 – 0.4 million	8 – 12
Barge, tug	30,000 – 40,000	0.1 – 0.2 million	3 - 6
Offshore support vessel (OSV)	80,000 – 120,000	0.1 – 0.2 million	8 – 12
DP support vessel for cable removal	120,000 – 180,000	0.3 – 0.5 million	8 - 12
Dive boat	30,000 – 50,000	0.1 – 0.2 million	12 - 16
Workboat	3,000 – 5,000	9,000 – 15,000	12 - 16
Guard boat	2,000 – 4,000	6,000 – 12,000	12 – 16
Cable de-burial	15,000 – 25,000	45,000 – 75,000	N/A
Pile cutting equipment	10,000 – 20,000	40,000 – 80,000	N/A

Notes: List is for vessels possible in the Great Lakes. Very big vessels are excluded.
Cost ranges encompass possible size and capability of vessel.
Costs are all inclusive of fuel, crew and staffing, equipment. Assumes 24/7 working schedule.
Costs refer to 2015 rates.
Average speed includes allowance for lower speed at ends of transit.

13.2. Operation timings

Ideal timings are very dependent on the capabilities of the vessels and equipment, and the experience of the operators as shown in Table A-2. When all-encompassing durations are input, time must be allowed for preparatory work as well as the main activity. For example:

- For vessel activities, time is required for vessels to be positioned (using DP or anchors), for jack-ups to lower (or raise) legs and carry out pre-load checks, and for cranes and equipment to be made ready or stowed.
- For lifting operations, time is needed to attach and detach the lifting gear, and to load and fasten the piece for transport.

With more specialist vessels that are designed for repetitive operations, time spent on these associated activities will be reduced. However, for the Great Lakes such specialisation is only likely if a large and mature offshore wind industry has been created. The indicative timings assume some level of maturity as a consequence of the installation experience, but without the benefits of the scale of European offshore wind.

Table A-2 Indicative operational timings

Operation	Ideal timing per unit [days]
Turbine dismantling	2 – 4 days
Foundation removal (MP)	1 – 3 days
Foundation removal (jacket)	1 – 4 days
Foundation removal (GBS)	1 – 4 days
Foundation removal (suction bucket)	1 – 4 days
Floating structure removal	0.5 – 2 days
Cable de-burial	0.5 – 4 days / km (0.25 – 2 km / day)
Offshore substation topside removal	2 – 8 days
Offshore substation jacket removal	2 – 8 days

Notes:
Timings refer to 4MW size turbines and their foundations
Assumes conditions are within operational limits, i.e. excludes any weather factor
Includes multiple steps and directly associated activities
Excludes transit times to port
Ranges encompass capability of vessels and equipment, and sizes of components

13.3. Weather factors

Weather factors arise from the combination of the operational limits of the activity, and the local statistics of the wind speeds, wave heights or other controlling conditions. Only very approximate indicative values are possible in this Study.

Although local statistics for the Great Lakes are not known for this Study, it is expected that wind speeds, wave heights, ice cover and fog will be the main controlling conditions. Water currents and tides are negligible.

Summarising the review of Great Lakes conditions in Chapter 5, Section 5.3:

- Mean wave heights in the Great Lakes appear to be around 0.5 m Hs in summer and less than 1.0 m Hs year-round, compared with annual mean values in the southern North Sea of 0.8 to 1.5 m Hs. In each case local values depend on location and exposure.
- Expected mean hub height wind speeds may be 8 to 10 m/s depending on location.
- Ice cover is very variable in terms of location, duration and extent each year, with a commercial shipping season lasting around 42 weeks per year.
- Fog may be present 4 to 8 times per month. In some locations, the highest incidence is in summer.

In the Tool, weather factors are a multiplying factor applied to each phase as a whole, making allowance for the delays when weather conditions prevent work as shown in Table A-3. It should include consideration of the length of time window needed as well as the probability the limits are exceeded.

Table A-3 Indicative weather factors

Operation	Main controlling conditions	Main operational limit	Estimated weather factor
Lifts at height (turbine dismantling)	Wind speed	8 – 12 m/s	1.3 – 1.6
Jacking up (WTIVs, jack-up barges)	Wave height	1 – 2 m Hs	1.2 – 2.5
Dynamic lifting (floating crane or transport vessel)	Wave height	1 – 2 m Hs	1.2 – 2.5
Vessel movements (shearlegs, towing)	Wave height	1.0 – 1.5 m Hs	1.5 – 2.5
Cable removal	Wave height	1.2 – 2.0 m Hs	1.2 – 2.0
Technician transfer onto structures (workboats)	Wave height	1.2 – 1.5 m Hs	1.5 – 2.0

Notes: Factors are estimates for Great Lakes conditions.
Assumes operations are undertaken in ice-free season.
The lower the operational limit, the higher the weather factor to be applied.

13.4. Seasonal duration

As described in Section 4 of this Appendix, the seasonal durations are used in the Tool primarily to determine whether a particular vessels combination incurs remobilisation costs due to working in more than one season. The maximum seasonal duration in the Great Lakes is likely to be controlled by ice-free access to ports typically at least 9 months (270 days). The ice-free season will vary considerably with location of the port and the OWF within the Great Lakes system.

Operational limits will restrict the season further as shown in Table A-4.

Table A-4 Indicative seasonal durations

Determining factor	Seasonal duration
Ice-free	250 - 300 days
Seasonal (6 – 9 months)	180 – 270 days
Summer (5 – 7 months)	150 – 210 days

For operations that are sensitive to wind speeds, such as dismantling of WTGs, seasonal durations of 5 - 7 months (150 - 210 days) are more suitable.

Similarly operations that are sensitive to wave heights may also have a restricted seasonal duration. Examples would be the use of shearleg floating cranes, which could also be restricted to 5 - 7 months.

13.5. Component weights

Typical masses of the main OWF components were presented in Chapter 5, Section 4, and are shown in Table A-5 for the 4 MW generic units for the two modelled water depths of 25 m and 40 m. Ranges of weight for array cables and export cable are also given.

Table A-5 Indicative masses for 4 MW units

Component	25 m water depth	40 m water depth
Blade	20 t	20t
Nacelle (including hub)	130 t	130 t
Tower	300 t	300 t
TP	300 t	300 t
MP above seabed cut	290 t	540 t
Jacket	540 t	640 t
Suction bucket	750 t	900 t
GBS (excluding ballast)	3,000 t	3,500 t
Floating support structure	1,800 t	1,800 t
OSS topside	2,000 t	2,000 t
OSS jacket	1,200 t	1,700 t
Array cable, whole dry weight	15 – 30 t / km	
Array cable, copper content	5 – 10 t / km	
Export cable whole dry weight	40 – 60 t / km	
Export cable, copper content	15 – 20 t / km	

When estimating the crane capacities needed, allowances need to be added as described in Chapter 5. When estimating revenue from recycled materials, recovery factors will be applied as described in this Appendix, Section 13.6.

13.6. Recovery factors

Descriptions of the materials that can be extracted and sold for recycling were given in Section 6.4, and instructions for setting up the Disposal worksheet in Section 11 of this Appendix.

Indicative recovery factors are provided in Table A-6, showing the weight than can be sold for revenue as a percentage of the total component weight. Values will vary according to the complexity and combination of materials present.

Table A-6 Indicative recovery factors for the main OWF materials

Component	Recovery factor [%]
Steel in MPs, jackets, suction buckets, TPs	90 – 97 %
Steel in towers	85 – 90 %
Steel in OSS topsides	75 – 85 %
Copper (or aluminium) in cables	90 – 97 %
GRP composite in blades	70 – 90 %
Concrete in GBS	80 – 95 %

13.7. Overheads

Typical items to be listed in the overheads section were outlined in Section 6.3.9. As noted, the structure of the Tool also includes costs of vessels that are used throughout the marine operations such as a guard boat.

Indicative cost ranges for a 75-turbine offshore wind farm are given in Table A-7, assuming that the scope of decommissioning covers all of the components.

Costs are estimated at 2015 prices.

Table A-7 Indicative overhead costs for a 75-turbine OWF

Overhead item	Cost range [CAD $]
Pre-decommissioning EIA and regulations review	500,000 – 900,000
Pre-decommissioning surveys and inspections	160,000 – 240,000
Post-decommissioning surveys and monitoring	360,000 – 440,000
Engineering and project management	5 – 7 million
Berthing, pilotage, provisions at operations base	3 – 5 million
Insurance (depends on durations and scope of activities)	4,000 – 10,000 per day

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