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Summary

Rationale

An OWECS design solution was developed against the background of three objectives.
Firstly, improved understanding of the principles underlying the design of OWECS, gained during the course of the project, should be demonstrated by practical solutions. Application of promising innovations for large-scale utilisation, e.g. novel installation methods, consideration of operation and maintenance aspects, integrated design approach, etc., is more important than achievement of the absolute economic optimum.
Secondly, during the design process areas of poor understanding are identified and relevant solutions have to be developed.
Finally, the economic feasibility of large OWECS should be demonstrated.

With these particular intentions in mind it was decided to follow the novel, integrated OWECS design approach of Volume 1.

Feasibility study

During the first step of the feasibility study a broad inventory of all relevant aspects and concepts was made and pre-selections for the conceptual design were identified. Furthermore, a particular terminology appropriate to OWECS was established in order to promote a smooth communication.

The identification of six distinctly different reference sites in northern European waters was carried out in parallel with the investigation of sub-system concepts and of essentials features of overall dynamics and operation and maintenance (O&M) aspects.

Based upon a qualitative OWECS evaluation the following sub-system concepts were selected for the further development:

- two wind turbine concepts (geared - fixed speed, direct-drive - variable speed),
- rotor variants with diameters between 80 and 100 m and different rotor speeds,
- distinctly different combinations of support structure configuration, dynamic characteristics, installation procedure and site,
- base cases for grid connection and wind farm layout.

Conceptual design

The conceptual design phase was carried out mainly in parallel with work on sub-systems and development or extension of OWECS tools on cost modelling, O&M simulation, structural reliability considerations and overall dynamics.
Improved knowledge on particular OWEC aspects gained during this phase, i.e. combined wind and wave loading, extreme wave loads on gravity based support structures in shallow waters, led to the consideration of three support structure concepts rather than the initially considered two ones.

Particular innovations directly related to the integrated approach include:

- integrated development of support structure concepts and installation procedure,
- simultaneous optimisation of wind turbine (rotor speed, blade layout) and support structure (i.e. structure stiffness) with the main goal of reduction of aerodynamic fatigue loads,
- consideration of overall dynamics of OWEC in the support structure design,
- development of O&M strategies based on Monte-Carlo simulations,
- development of structural reliability analysis for an OWEC support structure.

Next, the novel cost model has been used to evaluate different OWECS assembled from the developed sub-system concepts for the six pre-selected sites with respect to the quantitative design objectives, i.e. minimum levelised production costs.
The economic performance together with some other criteria led to the selection of the final OWECS concept and the related site.

Structural design

During the structural design phase the selected concept has been further worked out and interactions between sub-systems have been fully considered.

This integration facilitated several achievements:

- improvement on reliability, availability, maintainability and serviceability of the wind turbine simultaneous to the development of the operation and maintenance solution,
- further significant cost reduction of the support structure and the installation procedure due to close cooperation between structural design and dynamic simulations of the wind and wave loading of the considered OWEC,
- balance of aerodynamic efficiency of the wind farm and cable costs of the grid connection,
- optimum placement of the OWEC transformer based on consideration of wind turbine, support structure and grid connection aspects.

Some innovative features of the final design solution are indicated in figure 1.

It is worth noting that neither during the structural design phase nor after the final evaluation of the design solution, major revisions of the design were required. The main reason for this was that the conceptual design had already been carefully examined with respect to technical feasibility and economic performance.

The structural design phase was concluded with a detailed economic analysis and parameter study on important cost drivers which confirmed the potential of the solution. An overview of some main data is provided by table 1.

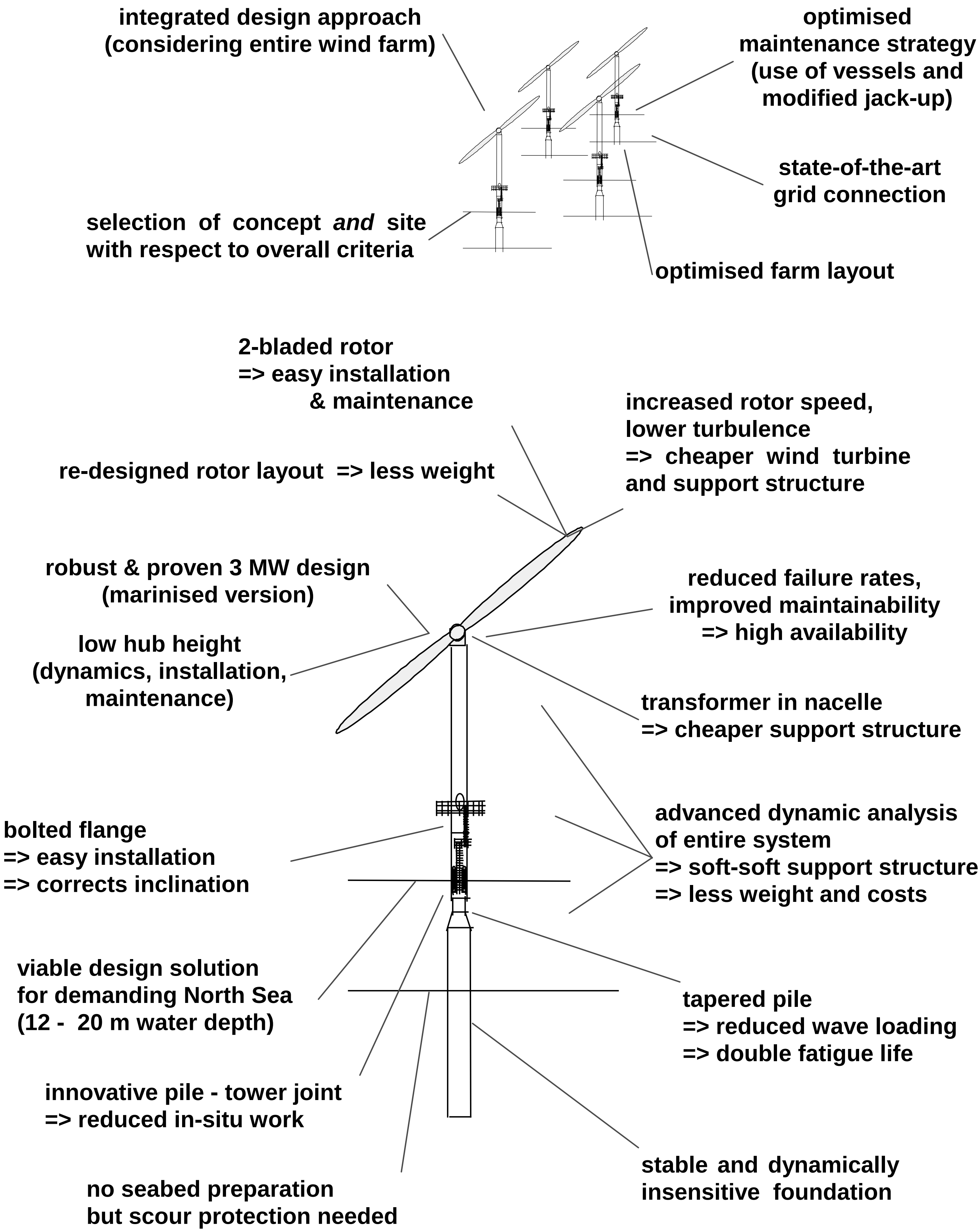

Figure 1: Innovative features of the OWECS design solution

Main design data	
Farm capacity	300 MW i.e. 100 times 3 MW
Wind turbine	WTS 80 M (3 MW - 80 m)
Support structure	soft-soft monopile
Offshore grid connection	AC submarine cables 24 / 150 kV
Array efficiency	93% (uniform spacing 10 *D*)
Transmission efficiency	96%
Availability	96.5%
Net annual energy yield	787 GWh/year
Site data	
Location	Dutch North Sea, near IJmuiden
Assumed annual wind speed (60 m)	8.4 m/s (A = 9.5 m/s, k = 2.2)
Distance from shore	11.4 - 18.6 km 15 km (from central cluster point)
Water depth	14 - 19 m (LAT)
Economic data	
Wind turbine cost	170 MECU
Support structure and installation costs	118 MECU
Offshore grid connection cost	77 MECU
Project management cost	2% of total capital cost
Total capital costs	372 MECU (1240 ECU/kW)
Operation and maintenance cost	9 M ECU / year
Decommissioning cost	10% of initial capital
Economic lifetime	20 years
Real interest rate	5%
Levelised Production Costs (LPC)	5.1 ECUct/kWh

Table 1: Main design and economic data of the design solution.

Table of Contents

1. Introduction

1.1 Overview on the JOULE III project Opti-OWECS

In the scope of the framework of the Non Nuclear Energy Programme JOULE III (Research and Technical Development) the European Commission supported the project ‘Structural and Economic Optimisation of Bottom-Mounted Offshore Wind Energy Converters’ (Opti-OWECS) under grant JOR3-CT95-0087 from January 1996 to December 1997.

Objectives of the Opti-OWECS project

The particular mission of the Opti-OWECS project was to extend the state-of-the-art, to determine required methods and to demonstrate practical solutions, which significantly reduced the electricity cost. This will facilitate the commercial exploitation of true offshore sites in a medium time scale of 5 to 10 years from now.

The specific objectives included:-

- A cost estimate and comparison of offshore wind energy converters of different sizes and different design concepts.
- An estimate of the cost per kWh of offshore wind energy at sites in different regions of the European Union.
- Development of methods for the simultaneous structural and economic optimisation of offshore wind energy converters with due considerations of the site characteristics.
- At least one typical design solution for a bottom-mounted offshore wind energy conversion system (OWECS).

Partnership and responsibilities

The project was an international cooperation of leading industrial engineers and researchers from the wind energy field, offshore technology and power management. The group of participants was as follows:-

- Institute for Wind Energy (IvW), Delft University of Technology (coordinator)

  Dutch research group active since more than 20 years in various fields of wind energy applications including major offshore wind energy research since 1992.

- Kvaerner Oil & Gas, Ltd. (KOGL)

  Major engineering and construction company, settled in the United Kingdom, with an established track record for implementing innovative concepts for offshore oil and gas developments.

- Kvaerner Turbin AB (KT)

  Swedish wind turbine manufacturer with expertise in the design of multi-megawatt machines (since the 1970s) and participant in another large study on offshore wind energy (1991).

- Renewable Energy Centre, University of Sunderland (US)

  British research group involved in techno-economic studies of renewable energy sources since 1978 among two major projects on wind energy costs.

- Workgroup Offshore Technology (WOT), Delft University of Technology

  Dutch research group with particular expertise in fluid loading of offshore structures and probabilistic methods, maintaining good relations with Shell Research Rijswijk.

- Energie Noord West (ENW) (sub-contractor)

  Dutch utility supplying 600,000 households in North-Holland and operating wind farms since more than 12 years among which the first Dutch offshore plant (Lely, 1994).

Kvaerner Oil & Gas, Ltd. and Kvaerner Turbin AB both form part of the international Kvaerner group which is organised in seven core business streams - KOGL being part of the Oil & Gas stream and KT being part of the Energy business.

The role of the partners is summarised in Table 1.1-1.

Partner	Role	Major scientific tasks
IvW	coordinator	- general expertise on (offshore) wind energy, - overall dynamics of OWEC, - wind turbine reliability, operation & maintenance, - design of grid connection and farm layout, - assistance in the cost analysis of OWECS, - aerodynamic rotor design,
KOGL	contractor	- general expertise on offshore technology, - design of support structure and installation procedure, - assistance in the cost analysis of OWECS
KT	contractor	- general expertise on wind turbine technology, - adaptation of wind turbine to offshore conditions
US	contractor	- concept and economic analysis of OWECS - development of cost models for OWECS, - estimate of costs of offshore wind energy at European sites
WOT	contractor	- general expertise on offshore technology, - structural reliability consideration, - assistance in the cost analysis of OWECS
ENW	sub-contractor (of IvW)	- general expertise as utility and as operator of (offshore) wind farms, - design of grid connection

Table 1.1-1: Distribution of responsibilities among the partners

1.2 Relation of this report to other work done within Opti-OWECS

The project continued the previous work in the scope of JOUR 0072 and makes use of recent developments in wind engineering and offshore technology. The study considered the most feasible and the most probable concepts for the near future i.e. horizontal axis wind turbines rated approx. 1 - 3 MW and erected on bottom-mounted support structures in the Baltic or the North Sea.

The work content of the project comprised three consecutive major tasks and a number of work packages (Figure 1.2-1):-

- Task 1 Identification

  The main cost drivers of offshore wind energy were identified and the base case concepts and the reference sites were selected.

- Task 2 Development

  The economic and structural optimisation and improved design methods were developed in three parallel tasks. A cost model for manufacturing, installation and operation and maintenance of offshore wind farms was compiled. Design concepts for all main sub-systems, i.e. wind turbine, support structure, grid connection and operation and maintenance aspects, were investigated and the best combination for a certain sites was selected. Also particular design methods for OWECS such as structural reliability considerations and overall dynamics of OWEC were new developed or extended.

- Task 3 Integration

  In the final phase the work of the former tasks was integrated and the relationships between them were fully considered. The achieved progress was demonstrated in a typical design solution for OWECS. Moreover, energy costs at different European sites or regions were estimated in a consistent manner.

The final reporting is organised in a more coherent way with a view to the subjects considered rather than in the sequence the work was carried out. Therefore the report available to the public is subdivided into six volumes:-

- Vol. 0 Executive Summary [1-1]
- Vol. 1 Integrated Design Methodology for OWECS [1-2]
- Vol. 2 Methods Assisting the Design of OWECS [1-3]
- Vol. 3 Comparison of Cost of Offshore Wind Energy at European Sites [1-4]
- Vol. 4 A Typical Design Solution for an OWECS
- Vol. 5 User Guide OWECS Cost Model [1-5]

All volumes are written in such a way that is possible to review and use the volumes separately.

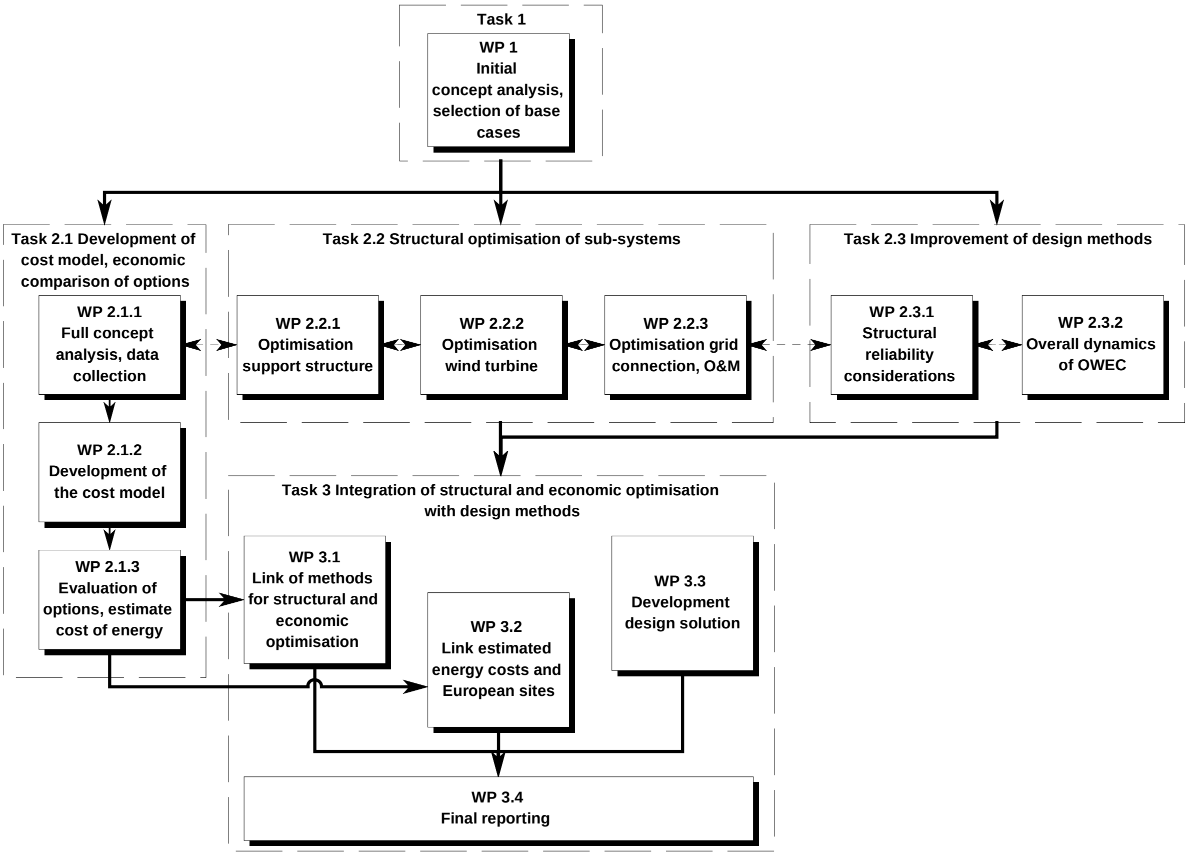

Figure 1.2-1: Opti-OWECS project organisation of tasks and work packages

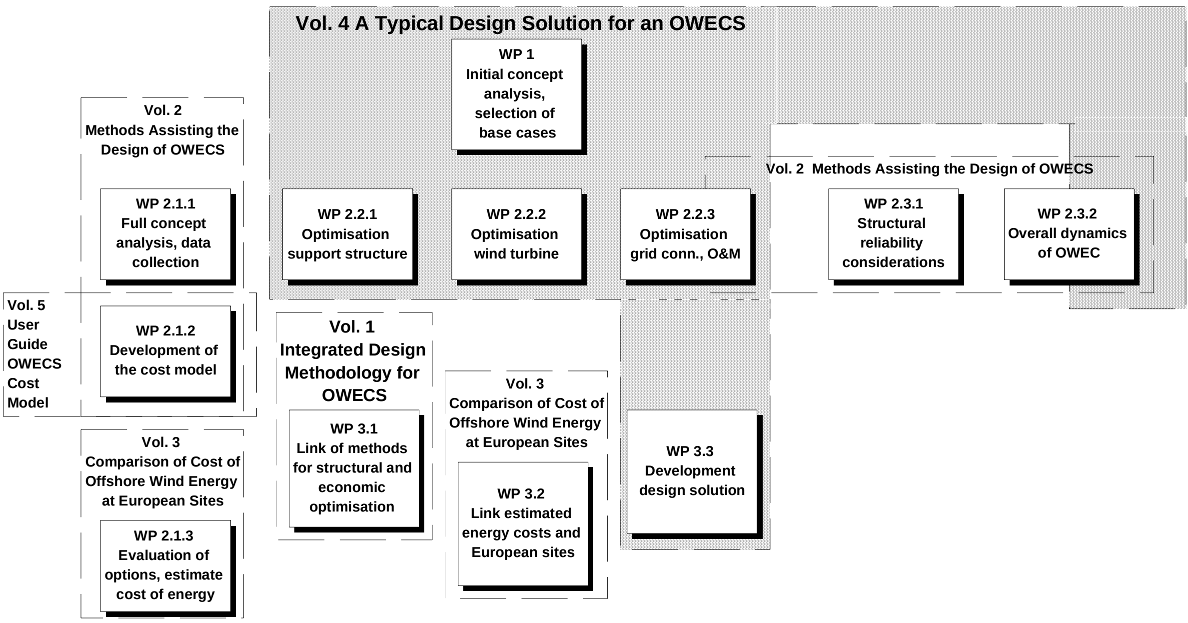

Figure 1.2-2: Interrelation between Opti-OWECS work packages and final report

As illustrated by Figure 1.2-2 the different reports cover all work packages. Since it should be possible to review and use the volumes separately, it was necessary to address some items in more than one report. However, in such a case the individual documents consider these issue from different points of view, e.g. development of cost model in Vol. 2, economic evaluation in Vol. 3 and user guide in Vol. 5.

This document ‘A Typical Design Solution for an OWECS’ is Volume 4 of the final report. Although this sub-report deals particularly with the work package 3.3 ‘Development design solution’ it is the result of the two-years work and includes the main results from work packages 1, 2.2.1, 2.2.2, 2.2.3 and 2.3.2. The report has been presented in a manner consistent with the OWECS design methodology given in Vol. 1.

1.3 Organisation of the report

This volume has been organised in the sequence of steps which would be followed when carrying out the design of an OWECS. This starts with setting of design objectives and criteria, described in chapter 2, before moving into the feasibility phase of the work, described in chapter 3. Here consideration is given to the preselection of the site, the alternative turbine, support structure, grid and farm layout and O&M options. The feasibility phase forms the basis for the concept phase which is described in chapter 4. Here each of the sub-systems are developed to the point that a single design option is identified. Much of the remainder of this volume deals with the development of the sub-system design. In chapter 5, the aspects of the wind turbine are addressed, whilst chapter 6 deals with the support structure. Chapter 7 and 8 address the grid connection, farm layout and O&M strategy. Issues which span beyond the boundaries of the individual OWEC sub-systems are dealt with in chapters 9 and 10. In chapter 9 the overall dynamics are addressed with the global economic assessment presented in chapter 10. Finally conclusions and recommendations are drawn in chapters 11 and 12.
Both appendices A and B provide comprehensive concept analyses of wind turbines. Whilst appendix A explains standard turbine features, which may be worth notice for someone from outside the wind energy community, appendix B focuses on future wind turbine concepts especially designed with due consideration of reliability and maintenance aspects paramount for offshore application.

It is opt to come to a detailed description of the work covered during Opti-OWECS. This implies that a lot of gained expertise on the design process of an offshore wind farm can be found in this volume. Furthermore it is possible to read some specific chapters, e.g. on the structural design, only; although it is the intention of this report to demonstrate the total design process. As a consequence the size of the report is rather large.

OWECS terminology

This report uses a certain terminology for OWECS which has been developed and successfully applied during the Opti-OWECS project (see appendix A of Vol.1 [1-2], [1-6]). In order to avoid misunderstandings the two essential conventions are mentioned here as well. Firstly, OWECS (offshore wind energy conversion system) or its synonym offshore wind farm describes the entire system, i.e. wind turbines, support structures, grid connection up to the public grid and infrastructure for operation and maintenance. Secondly, OWEC (offshore wind energy converter) is the term for a single unit of an offshore wind farm comprising support structure (i.e. tower and foundation) and the wind turbine (i.e. rotor and nacelle on top of the tower).

1.4 Contributions

This report comprises contributions from all project partners and has been edited by M.C. Ferguson of Kvaerner Oil & Gas, Ltd. The following people listed below in alphabetical order by institution have contributed to this volume.

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1.5 Acknowledgement

The data for the Dutch North Sea locations used in this study were obtained from the North European Storm Study database through Shell International Exploitation and Production B.V., whose co-operation is gratefully acknowledged.

The use of the FLaP code (Farm Layout Program) developed by the Faculty of Physics of the Carl von Ossietzky University of Oldenburg, Germany is kindly acknowledged.

1.6 List of abbreviations

CM	Corrective Maintenance
GBS	Gravity Based System
DNV	Det Norske Veritas
DIBt	Deutsches Institut für Bautechnik
DUT	Delft University of Technology
GL	Germanische Lloyd
HMSO	Her Majesty Shipbuilding Organisation
IEA	International Energy Agency
IvW	Institute for Wind Energy, Delft University of Technology
KOGL	Kvaerner Oil & Gas, Ltd.
KT	Kvaerner Turbin AB
MTBF	Mean Time Between Failures
MSL	mean sea level
NESS	North European Storm Study
O&M	Operation and Maintenance
PM	Preventive Maintenance
LAT	lowest astronomical tide
LPC	levelized production costs
Opti-OWECS	Structural and Economic Optimisation of Bottom-Mounted Offshore Wind Energy Converters
OWEC	offshore wind energy converter
OWECS	offshore wind energy converter system
RAMS	Reliability Availability Maintainability and Serviceability
RP	return period
SWL	still water level
US	University of Sunderland
WOT	Workgroup Offshore Technology, Delft University of Technology

2. Design Objectives and Criteria

Likewise to any design process also in case of an OWECS the project has to be identified and the objectives have to be stated prior to the beginning of the actual design work. In this chapter the conditions for the further design process (Chapter 3) are set.

2.1 Preliminary analysis

2.1.1 The fundamental concept of an OWECS

Due to high initial costs the utilization of offshore wind energy is not promising with single converter units but requires an entire offshore wind energy conversion system (OWECS).

The physical components of such an offshore wind farm are large number of (single) offshore wind energy converters (OWEC), the grid connection system and infrastructure facilities for operation and maintenance. An OWEC itself comprises the wind turbine and the support structure. Reference should be made to [2.1-1] for a precise definition of each of the subsystems. Further important aspects are the site with its particular environment and the operation & maintenance strategy (Figure 2.1-1).

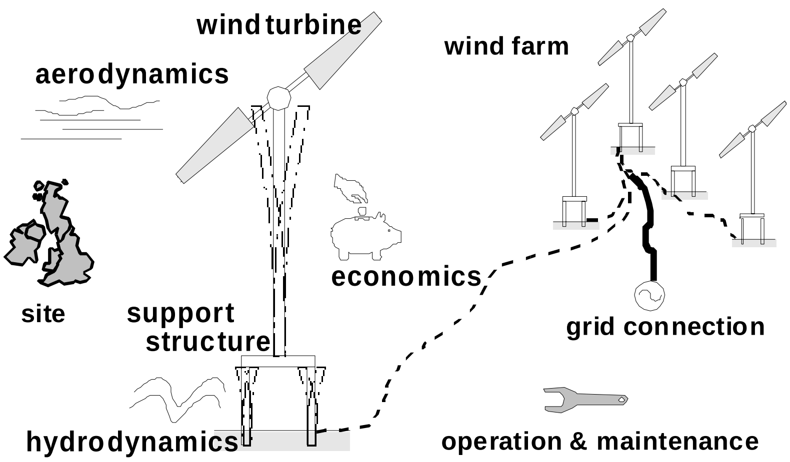


Figure 2.1-1: Components and aspects of an Offshore Wind Energy Conversion System (OWECS)

2.1.2 Technical economics

While wind itself is free of charge, the machines required to convert it into electricity and their maintenance are not. Thus, wind generated electricity is priced at a level intended to enable an investor in wind power plant to recover their initial costs, operate and maintain the machines and, hopefully, generate a return.

Land based wind turbines have developed to such a degree of sophistication that the electricity they produce at prime sites can be priced at a level competitive with conventional energy sources [2.1-2].
Siting a wind turbine offshore is intrinsically much more expensive due to the support structure and grid connection than land based construction, making the cost of electricity from offshore plant considerably higher than that from comparable onshore installations with same wind conditions. At the same time, offshore wind farms offer a number of attractive advantages over their land based colleagues, in particular (i) stronger, more reliable winds than onshore lowering the energy costs (partially), (ii) more space especially for large farms than onshore, (iii) the potentially lower conflict with other human interests who might be disturb the development.

2.1.3 Areas for attention during OWECS design

The major cost of an offshore wind energy converter system is the expense of the initial investment required to establish the project. This cost itself has three approximately equal components: the turbine machinery, the support structure and the electrical equipment/grid connection [2.1-3]. Parameters relating to the site itself influence the precise contribution each of these makes to the overall cost. The distance to shore is the most important, with the turbine becoming less dominant in expense the further the farm is from the shore. The annual mean wind speed has a small influence on the investment cost, but a strong impact on the energy cost. In contrast the average wave height at any location has a less significant influence on the costs.

Aside from the initial investment, the next largest expense confronting the owner of an OWECS is the cost of its operation and maintenance. Indeed, earlier studies have shown that operation and maintenance can account for as much as one-third of the cost of the electricity produced. Furthermore, there appears to be a strong linear relationship between the financial burden of O&M and the resulting electricity price, such that even relatively small changes in O&M costs could have a substantial influence on the economic viability of an OWECS project.

There are therefore, four technical areas in which a project to (economically) optimise OWECS design should focus, specifically, the support structure, the turbine design, the electrical equipment/grid connection and the operation and maintenance procedures.

Several studies have investigated the applicability of these existing technologies for OWECS. The culmination of this work has been the construction of a number of demonstration projects, which have essentially adapted existing components for OWECS use. In order to improve upon the successes of the demonstration projects, it is sensible to attempt to take a more integrated approach to OWECS design than has been possible to date [2.1-4]. Thus attention should be focused on the turbine, the support structure and the electrical equipment/grid connection together, taking full account of the complex interactions between them, and not only optimising them individually. Inevitably, to make such an integrated approach successful, account must be taken of the OWECS farm layout and the likely site parameters of the intended locations.

2.2 Objectives

2.2.1 General objectives for an OWECS

Only the OWECS as one entire system can provide a considerable amount of electric power in a reliable and cost-efficient way over the projected lifetime. Therefore four objectives for an optimum OWECS design can be stated which are related to the nature of such a system:

- Optimum distribution of investment and operation and maintenance (O&M) costs over the entire OWECS and its liftetime
  The economics of the entire plant have to be balanced with respect to the overall operational goal, which could be the achievement of the minimum price of energy, the delivery of a certain minimum amount of energy or a combination of both. Note, such a goal cannot be reached by optimization of single sub-systems alone.

- High reliability of OWECS as a whole and of essential sub-systems
  A failure of a major sub-system e.g. out-of-operation of all converter units due to a design mistake or power cut-off in the grid connection system, can result in a loss of production for several months or even a longer period. Such a failure together with unfavourably high repair costs might result in a hazard for the entire project and partial loss of the high initial investments.

- Adaptation to economy of scale and partial redundancy of single OWEC units
  A typical large offshore wind farm as regarded feasible within the next decade comprises between 40 to 100 offshore wind energy converters rated approx. 1 to 3 MW each. Thus wind turbines and especially support structures can be optimized with respect to the particular environmental and economic conditions of the site. Moreover consideration of a partial redundancy of the single OWEC units with respect to the production of the entire wind farm might be worthwhile, for instance within the operation and maintenance strategy or by the determination of a design probability of failure.

- Symbioses of experience from wind energy and offshore technology
  An optimal OWECS design is a challenge for any engineer whether he comes from wind energy or offshore technology since particular properties exist (see following sections) that do not allow the blind application of common design practices and require a joint solution of the problem.

2.2.2 Objectives of the particular OWECS design solution

- Demonstration of a design solution for a commercial, large-scale bottom-mounted OWECS to be build in medium time scale (5 - 10 years from now) in northern European waters
  The design should envisage a true offshore application as regarded typically for the longer term time scale rather than an inshore or nearshore solution.

- OWECS operational goal: lowest levelized energy costs
  In order to demonstrate the opportunities for the structural and economic optimisation a simple, economic operational goal is stated.

- Power delivery point on the shore line (no interaction with public grid and consumer),
  Non-consideration of existing infrastructure as public grid, harbours, construction sites, etc. in the vicinity of the site
  In order to avoid unnecessary complexity in this study some important constraints existing for a real project are removed.

- Application of the integrated OWECS design approach
  Although the design work has to be done in parallel to the development of the so-called 'integrated OWECS design approach' [2.2-1] the essential of this treatment should be followed as much as possible. However no one-to-one matching can be expected.

- Design process comprising: feasibility study, conceptual design and structural design but no design specification

2.3 Project constraints

The constraints for the design work are defined by those of the Opti-OWECS project itself (chapter 1).

Since it has been decided to build up specific OWECS knowledge during the design process and to demonstrate gained knowledge by design work a considerable amount of the project are available for the design solution.
The different design steps, 2 months feasibility study, 10 months conceptual and 10 months structural design are spread over the three phases of the project lasting two years.

The consortium has been selected in such a way that specialists of all required sub-system disciplines are present. Lack of experience in the important fields of system integration and OWECS project devlopment for a large-scale, true offshore application was inevitable simple due to the fact that there is no similar project concluded so far. So from the very beginning of the project particular emphasis has been put on the following:-

- distribution of specific knowledge related to sub-systems as well as OWECS within the consortium even without ‘actual’ need at that particular time,
- development of an OWECS terminology, definition of reference systems, conventions, standards, etc.
- careful consideration of interactions between sub-systems,
- interactive elements in the design process,
- investigation of governing design criteria rather than simply fixing of dimensions

2.4 Socio-economic conditions

The economic parameters are established in accordance with recent Danish studies [2.4-1] for large-scale exploitation of offshore wind energy to be an economic lifetime of 20 years and a rate of return of 5%. No subsidies are accounted for.
Further it is assumed that public acceptance and environmental constraints are fulfilled if a minimum distance from shore of 10 km and restricted areas are maintained. The OWECS has to be dismantled after the exploitation phase in accordance with international regulations.
No particular (inter-)national legal constraints have to be considered.

2.5 Technological conditions

The solution should be based on innovative design related to the offshore application, the OWECS as a whole and the applied integrated OWECS design approach. In contrast, the sub-system technology is restricted to state-of-the-art with respect to the ‘normal’ application in onshore wind energy and offshore technology, respectively.
Typical size of the single OWEC units should be about 3 MW or larger and the farm capacity should be at least 200 MW in order to make a step beyond other recent studies and actual plans on large offshore wind farms based on wind turbines in the so-called megawatt class.
The OWECS guidelines of Germanische Lloyd [2.5-1] are chosen as code of practice. In case of uncertainties guidance is taken from design practice and standard in offshore technology an wind energy application. If appropriate the OWECS should be considered according to type class S.
The design life time of the system solution is at least 20 years governed by the fixed life time of 20 years for the wind turbine. For other sub-systems, especially support structure and grid connection scheme, also longer periods might be interesting.

2.6 Geographical and site conditions

Only quite general geographical and site conditions are stated a priori. The solution should be located anywhere in northern Europe further than 10 km from shore and in a water depth of about 10 to approx. 30 m .
Global restrictions e.g. water depth, sea bottom slope, other users, restricted areas as marked in Admiralty Charts have to be considered in a similar way than done within JOUR 0072 [2.6-1]. However, local restrictions requiring site investigation offshore or of the affected onshore areas are not taken into account. This particularly apply to the properties of the public grid (see definition of the power delivery point) and the onshore infrastructure for marine operations and construction.

The convenient availability of suitable data required for innovative design methods e.g. structural reliability considerations, overall dynamics of OWECS are an important aspect in the selection of the sites to be considered. Therefore locations may be chosen from existing studies on offshore wind energy.

3. Feasibility Study

3.1 Introduction

After defining the design objectives and conditions in chapter 2 a feasibility study (figure 3.1-1) forms the next step in the design process. The results, a number of promising OWECS concepts and related to certain sites are further developed in the conceptual design in chapter 4.

The large number of options for sites and OWECS sub-systems is reduced by a so-called pre-selection (section 3.2 to 3.6) in order to limit the number of options to be evaluated on a system level (section 3.8). The pre-selection is based on sub-system considerations as interactions are mostly ignored for the time being. Likewise only the relevance and some essentials of the consideration of overall dynamics is investigated without connection to certain concepts (section 3.7).

In the entire feasibility study mainly qualitative evaluations are done which might be supported by calculations of the ‘back-of-the-envelope’ type. Instead of spending large efforts in the treatment of details here emphasis is put on producing OWECS concepts promising with respect to site and system considerations.

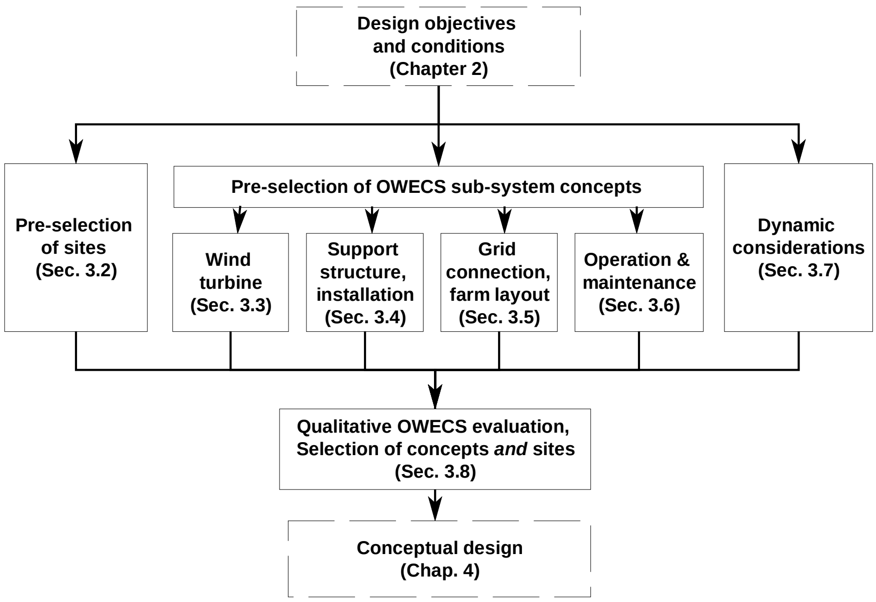


Figure 3.1-1: Flowchart of feasibility study and relation to chapters and sections of the report

3.2 Site pre-selection

3.2.1 Scope

The pre-selection of sites is intended to identify some promising or at least typical sites for future offshore wind farms. Inevitably, in an initial selection such as this, a completely rational decision process must give way to a degree of arbitrariness and pragmatism. Thus there is no suggestion that the sites proposed here constitute the best sites in Northern Europe for the construction of a certain or any other OWECS. The authors though do believe that the sites considered are good candidates for development.

Within Opti-OWECS no resources were available for collecting site data. Consequently, decisions as to which sites to investigate further have been driven as much by the availability of environmental information (e.g. from former studies on offshore wind energy) as by qualitative engineering criteria. A particular difficulty has been that more comprehensive site information is needed to undertake the detailed design of an OWECS (chapter 4 to 9) than is required for the site comparison with the detailed OWECS cost model [3.1-1] in section 4.7 of this report. As there is no point in comparing sites for which insufficient information is available to design an OWECS, the full availability of information must be checked from the outset.

As stated in the objectives for the OWECS design solution (section 2.2.2) the power delivery point is defined to be located on the shore line. Although this is an unrealistic assumption it was required since consideration of the onshore grid infrastructure for various Euroepan region was certainly beyond the scope of the study.

3.2.2 Selected sites

Six sites spread over northern European waters (figure 3.2-1) have been pre-selected as candidates for the proposed OWECS. Pertinent details are given in table 3.2-1. which have been obtained from various references and were partly corrected e.g. by consideration of [3.2-1], [3.2-2] to enable a consistent comparison.

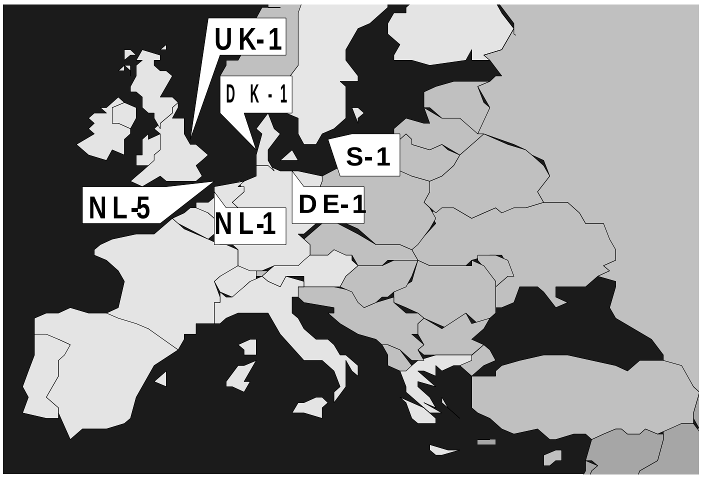


Figure 3.2-1: Location of the six selected sites

Quantity	UK-1 The Wash	NL-1 IJmui-den	NL-5 IJmui-den	DK-1 Horns Rev	DE-1 (i) Rostock	DE-1 (ii) Rostock	S-1 Blekinge
Annual mean wind speed at 60m (estimated)	8.2 m/s	9 m/s	9.5 m/s	9.2 m/s	7.8 m/s	7.8 m/s	8.4 m/s
Water depth	20 m	15 m	25 m	11 m	8 m	14 m	15 m
Distance from shore (to collection point)	30 km	8 km	50 km	20 km	5 km	10 km	7 km
Extreme mean wind speed at 60 m	41.5 m/s	41.5 m/s	41.5 m/s	43 m/s	40.5 m/s	40.5 m/s	43 m/s
Design wave height H_{max}	11 m	11.7 m	15.4 m	8.6 m	6.41 m	6.41 m	10.1 m
Surge	2.5 m	3 m	2.5 m	3 m	2.85 m	2.85 m	2 m
Tide amplitude	2.5 m	1 m	0.75 m	0.75 m	0 m	0 m	0 m
Design ice thickness	(no ice)	(no ice)	(no ice)	(no ice)	0.6m	0.6 m	0.6 m

Table 3.2-1: Assumed data of the sites pre-selected for OWECS development

British North Sea

The site selected in the British North sea (UK-1) is located in the Wash area. Preliminary data for the site conditions was taken from [3.2-3], [3.2-4]. This site has no particularly distinguishing features, but has a reasonable all round specification.

Similar locations to this have been identified in previous studies of UK offshore wind energy.

Dutch North Sea

The Dutch North Sea is unusual in that copious environmental information is available, thanks to the great interest that oil and gas companies have in the area. For this reason a ‘pre-pre-selection’ process was applied to narrow the possibilities down to the two proposed here (figure 3.2-2). This was important both because conditions vary considerably across the region and because its commercial importance means that man-made constructions, such as undersea pipelines, cables and oil rigs, considerably constrain the areas available for OWECS.

Two sites were selected, one fairly close to the shore (NL-1), and the other more distant (NL-5). The NL-5 site is very remote from the shore, but this substantial disadvantage may be offset by the very high wind speed it posses. By comparison, the NL-1 site is much more accessible and sheltered, but has a lower wind speed. In both cases data was obtained from a study internal to the project [3.2-5], and from published data [3.2-6].

Danish North Sea

The Danish North Sea generally has excellent wind speeds in regions relatively close to shore. While the waves in this region are fairly severe, there is at least no risk of the sea ice found at Baltic sites. The information shown is for the Horns Rev site, DK-1, and is taken from [3.2-7], [3.2-8].

German Baltic waters - Rostock area

Within German waters, the site selected (DE-1) is the Rostock area where a prototype OWECS project was abandoned in 1993. Representative data has been extracted from three sources [3.2-9], [3.2-10], [3.2-11]. This site has by far the poorest wind speed, but is very shallow and has close proximity to the shore. The required design for ice loading will not help the economics of OWECS here.
For the purpose of the later site comparison, the German site DE-1 was split into two ‘sub-sites’ DE-1(i) and DE-1(ii). This was because the environmental specifications available in the literature for the Rostock site covered a wide range of values. In essence DE-1(i) is at the onshore range of the reported values, with DE-1(ii) occupying the more offshore range of the spectrum.

Swedish Baltic

The site selected in the Swedish Baltic, S-1, is that originally identified in the Blekinge study [3.2-12]. It is much like the German site, but trades improved wind conditions due to a prevailing wind direction from the open sea.

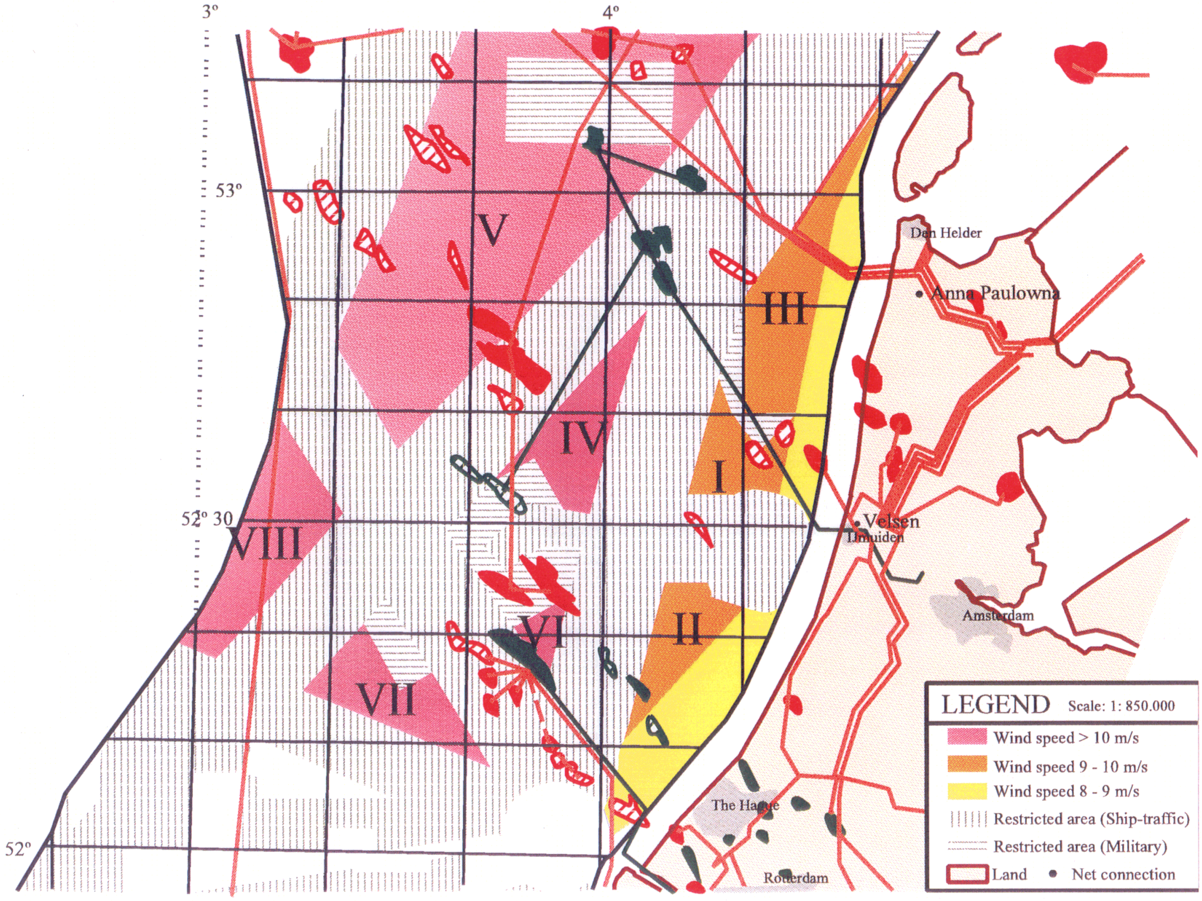


Figure 3.2-2: Possible sites for offshore wind farms in the Dutch North Sea [3.2-5]

3.3 Turbine pre-selection

Wind turbine concept analysis (Appendices A and B)

For the first generation of large offshore wind farms it is probable that the chosen wind turbine concept will be based upon a marinised onshore design. Therefore this section of the feasibility study deals with the pre-selection of such an onshore reference wind turbine. Standard design features of wind turbines are presented in a comprehensive concept analysis in appendix A which may be worth notice for someone from outside the wind energy community.
Eventually, wind turbines may/should be adopted more radically to offshore application as it is demonstrated by appendix B which focuses on future wind turbine concepts especially designed with due consideration of reliability and maintenance aspects paramount for offshore application.

Scope and available options for pre-selection of a reference wind turbine

In this report the Opti-OWECS project aims to demonstrate a typical design solution for a future generation of large offshore wind farms. By common consensus, such a design should employ large or even the largest practicable turbines.
Considering the current market situation then the upper limit is given by the largest machines of the so-called ‘megawatt class’ i.e. turbines rated 1.5 - 1.65 MW [3.3-1]. Wind turbines of this group have been proposed by different studies for large offshore wind farms [3.3-2], [3.3-3]. On the other hand simultaneous with the market introduction of the megawatt class the development of even larger so-called multi-megawatt turbines rated approximately 2 to 5 MW has been initiated by several manufacturers.
Exploitation of the huge offshore wind energy potential is an often stated rationale behind the development of (multi-)megawatt turbines. With respect to the medium time scale (5 - 10 years from now) of the Opti-OWECS project and the current rapid movement of the market towards large machine it was decided by the project consortium to state a wind turbine size of 3 MW or even larger as a pre-condition (section 2.2.2 and 2.5).

Multi-megawatt wind turbines proposed in literature e.g. by [3.3-4] are often based on desk-top studies, described only by their gross data and/or are no longer state-of-the-art. There is only one exception which has also shown one of the best track records of all actually built machines of this size, the Näsudden design line of Kvaerner Turbin which is therefore considered here further.

This design was produced by a continuation of the development of large scale wind turbines in Sweden that resulted in a first 2 MW turbine Näsudden I at the end of the 1970s. Based on this experience a next generation was build by a Swedish-German co-operation: the Näsudden II, placed on Gotland in the Baltic, and her sister machine Aeolus II located in Wilhelmshaven on the German North Sea coast.

Näsudden / Aeolus II wind turbine

The Näsudden/Aeolus II turbine is a two-bladed, pitch regulated machine on a concrete tower (table 3.3-1). The Swedish turbine has two constant rotor speeds while the German machine is a variable speed concept. Both turbines have shown high availability and met performance expectations since the start of operations in 1993.

Main data for Näsudden II / Aeolus II	
Rotor diameter	80 m
Rated power	3 MW
Number of blades	2
Blade material	CRP/GRP
Rotor speed	14/21 rpm / variable 10 - 21 rpm
Power control	Full span pitch
Hub height	78 m / 90 m
Hub design	Stiff
Drive train	Planetary gearbox + bevelled stage
Generator	Induction 2 speed / synchronous + inverter
Yaw system	Brakes + pinion
Tower	Concrete
Operating range	5 - 25 m/s
Tower head mass	160 t
Energy yield	7800 MWh at V_{ave}=7.6 m/s

Table 3.3-1: Data for the Näsudden II machine.

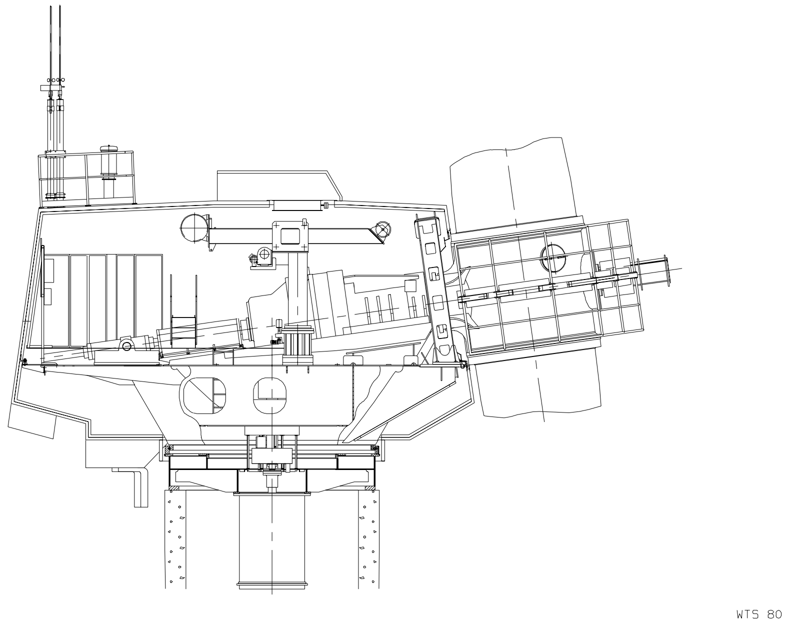


Figure 3.3-1: Nacelle of Näsudden II

Third generation of the Näsudden wind turbine

Mayor achievements of the Näsudden II were innovative technology, light-weight design e.g. for the rotor and high availability of the entire system. As a matter of fact however the price performance was poor in relation to the commercial turbines in the range of 250 to 500 kW. Therefore the development of a competitive 3 MW - 80 m diameter design based on Näsudden II has been started in the mid 1990s resulting in two machine concepts, the WTS 80 and WEC 3000.
While the former employs a geared drive train with an asynchronous generator whereas the latter sports a direct driven multipole generator. Both of the units share many features with the Näsudden II design, with significant differences being summarised in table 3.3-2.

Blade material	Wood epoxy
Yaw system	Soft / active
Operating wind speed range	4-25 m/s
Tower head mass	130 tonnes

Table 3.3-2 : Miscellaneous data for the WTS80 and WEC 3000 concepts

These designs were originally developed for onshore use, but provision has been made for their adaptation to the offshore environment. A number of modifications to the basic turbine designs that could help to achieve the required balance between extra investment costs and improved reliability have been selected for investigation by the manufacturer.

- adaptation to the more benign wind conditions offshore,
- increase in tip speed featuring more slender and lighter blades and a lighter drive train,
- protection against the harsh, corrosive nature of the sea,
- increase of the machine reliability,
- improvement of maintainability

Moreover, the possibility of undertaking more substantial modifications to the WTS 80 / WEC 3000 base cases as up-scaling to larger rotor diameters and / or higher rated power forms other promising options.

3.4 Support structure pre-selection

3.4.1 Introduction

Basic principle

There are three general approaches to the construction of WECS support structure, the over-riding objective being to avoid resonance of the structure with any likely periodic excitation force. For land based machines these are usually aerodynamic in origin, the lowest frequency driver being the rotation frequency with higher frequency excitation at the blade passing frequency equal to the number of blades times the rotation frequency.

Typical designs for the support structure from the early days of the industry, are of the so-called stiff-stiff variety whereby the support has an eigenfrequency above the rotation frequency of the rotor and the blade passing frequency. Recent years have seen the use of soft-stiff towers which have the lowest eigenfrequencies carefully pitched between the rotation frequency and the blade passing frequency, and have the advantage of reducing variable aerodynamic loads. Soft-soft support structures, with the lowest eigenfrequencies below the rotation frequency are also possible and come into wider use for large wind turbines.

OWEC support structures

Compared to land based machines, design of support structure for OWECS is complicated by the need to accommodate hydrodynamic as well as aerodynamic forces. Wave loading requires that soft-soft designs be designed with particular care. Difficulties in the accurate assessment of offshore foundation stiffness means that soft-stiff designs must also be considered carefully, since it would be quite possible for inaccuracies to push the natural frequency into either of the forbidden frequency zones. From a structural point of view, a stiff-stiff tower offers the benefits of a strong robust solution but may conflict with the wind turbine demands.

Adopting an integrated design approach means that the support structure cannot be considered independently from the turbine. A soft-soft or possibly a soft-stiff support structure is preferable from the viewpoint of the turbine designer, as these provide the much needed aerodynamic damping for dynamic forces on the whole assembly.

With a stiff tower, the damping derives mainly from the foundation and support structure.

From the outset, some consideration must be given to the means by which the support structure and turbine will be installed at their offshore site. Here a wide range of possibilities are available including lifting from floating vessels and jack-ups - even floating-in the whole assembly.

OWEC support structure concepts

Bottom mounted support structure concepts for large OWEC developments fall into a number of generic types which can be broadly categorised by the nature of their foundation, their method of installation, their structural configuration and the material from which they are constructed. The options available for each of these are dealt with in the following sections.

3.4.2 Foundations

Options for offshore foundations are basically of three types:-

- Piled
- Gravity Based
- Skirted

Piled Foundations

Piled foundations make-up the most common form of offshore foundations. The standard method of installation is to drive the pile into the seabed using a steam or hydraulically driven hammer. The handling and driving of the pile generally requires the use of a crane which can be located on either a floating vessel or a jack-up. Where exceptionally stiff material is encountered e.g. very stiff clay or rock, then drilling equipment is required. This is best carried out from a specially equipped jack-up.

It is thought likely that the vibrations resulting from the piling operations would present a too great risk to component parts of the mechanical and instrument equipment housed in the nacelle and as a result piling would need to take place prior to placement of the nacelle.

The structure can be configured as a monopile or have piles that are driven through sleeve elements and are attached to the main structure by either a grouted or swaged connection. As such, the pile provides the means of transferring both lateral and axial (tensile as well as compressive) loads from the structure into the seabed.

Piles themselves are of simple tubular construction which is inexpensive to produce and provide a low cost fabrication option.

Gravity Foundations

The gravity foundation, unlike the piled foundation, is designed with the objective of avoiding tensile loads between the support structure and the seabed. This is achieved by providing sufficient deadloads to stabilise the structure under the overturning moments which result from wind and wave action.

Where the gravity loads from the support structure and nacelle are insufficient to maintain overall stability, additional ballast will be necessary. This may take the form of sand, concrete, rock or iron ore and can be either installed in the construction yard or alternatively placed following positioning of the main structure.

Depending on the superficial soils at the site, some form of seabed preparation may be necessary in order to avoid unacceptable inclination of the structure and to ensure the uniform loading of the seabed.

Skirted Foundations

Skirted foundations, also known as buckets, are similar in appearance to gravity foundations but are characterised by long skirts around their perimeter. Unlike a gravity foundation, the skirted variety is designed to transfer transient tensile loads and relies on undrained soil behaviour. Its application for wave load dominated structures can be significant owing to the transitory nature of the loading. Its suitability for large OWEC structures is however questionable owing to the sizeable static component of wind loading.

3.4.3 Installation

OWEC developments lend themselves to a variety of different methods of installation involving various forms of piecemeal installation through to placement of the complete unit including the nacelle and rotor as a single piece. Installation itself is either achieved by lifting or by floating in the component parts. The following sections address the options available for the OWEC support structures.

Lifting

Lifting of the OWEC is in principle the most straightforward method of installation and given access to a crane of sufficient capacity and reach it should be possible to install the OWEC units simply and efficiently. Lifting can be carried out from either a floating vessel or from a jack-up. Given the size and weight of the proposed OWEC a jack-up is an unlikely choice.

Although relatively light by offshore standards, the height of the support structure may be beyond the capability of many smaller in-shore crane vessels. The use of larger offshore vessels is likely to present draft limitation and have significant cost implications. Lifting the unit in several pieces offers possibilities yet the height of the final section combined with the awkwardness and delicacy of the rotor assembly again limits the vessels capable of the operation.

One of the major benefits of using a crane vessel is that it may have the capability and the necessary equipment needed to pile the structure to the seabed.

Floating

Floating the support structure into place offers the possibility of installing the complete support structure and avoiding the necessity of using a major crane. Alternatively, floating could be realistically considered for floating the tower over a piled foundation.

As a floating body the structure would need to be either constructed in a dock or lifted from a quay. It would need either inherent buoyancy or auxiliary buoyancy to float and have sufficient stability both for transportation and lowering.

3.4.4 Configuration

The support structure configuration can be categorised as two basic types i.e.:-

- monotower - a single element tower
- braced/lattice tower - a multi-element tower

Each has advantages, the monotower provides the benefits of simplicity whilst the braced/lattice tower offers a structurally efficient and more robust solution.

3.4.5 Materials

The candidate materials for the tower elements of the OWEC support structure are primarily steel and steel reinforced concrete. Steel offer the benefits of being some four times stiffer and stronger per unit mass than concrete and as such it offers the potential for appreciably lighter structures. It is this combination of stiff and light construction combined with steel's flexibility in the construction of braced structures that make steel the preferred material. Its reduced weight also reaps benefits with the structure being lifted more easily or requiring less buoyancy for floating.

The material to be adopted for the foundation is less clear. In the case of piled foundations, steel presents the obvious solution whilst for gravity foundations, steel or concrete may be appropriate with sand, rock or iron ore used for ballast material.

3.4.6 Concept Evaluation

From the preceding sections it can be concluded that potential support structures for the OWEC development can be identified from the following:-

The skirted foundation option is not included since it is unlikely to be viable owing to the appreciable static component on the wind loading.

Thus a total of eight potential support structure types are available. On the premise that the structure cannot be piled with the nacelle in-place and that it is impractical to lift the complete unit, then just two options can be realistically installed as a single unit. The remainder all rely on some form of piecemeal installation e.g. with the pile being installed prior to the tower.

Examples of support structure concepts are given in Figure 3.4-2 whilst Table 3.4-1 and Table 3.4-2 present an overview of advantages and disadvantages associated with the generic types.

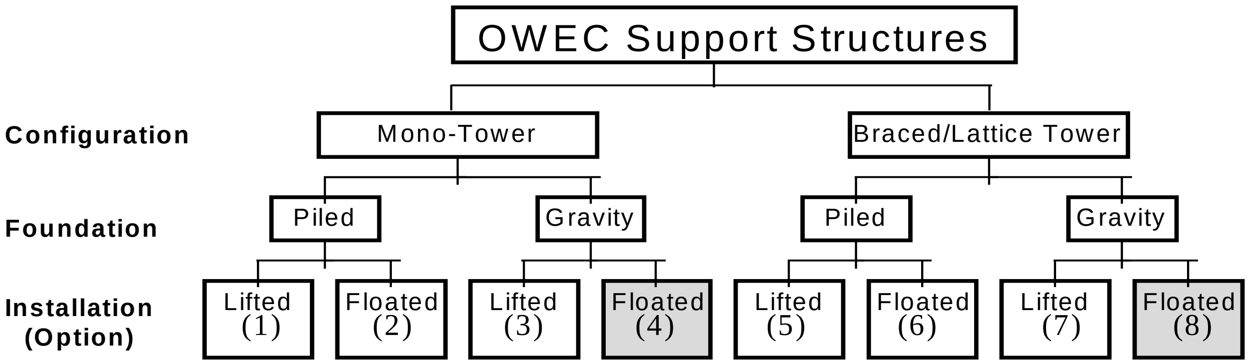


Figure 3.4-1 Support Structure Configuration Options (shaded option can be installed as an entire unit)

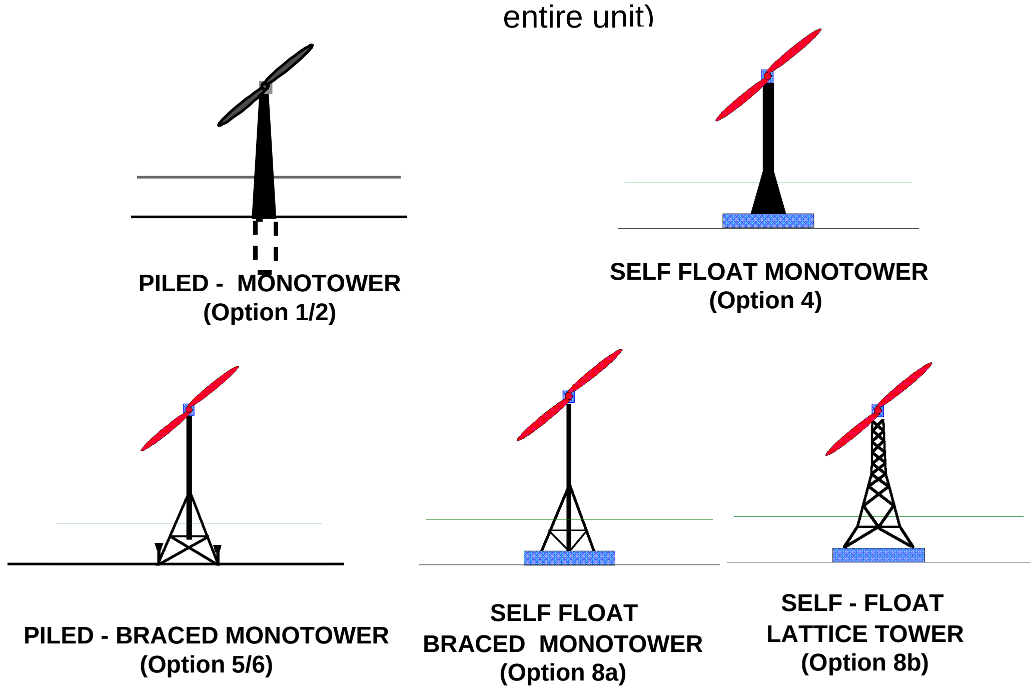


Figure 3.4-2 Examples Support Structure Concepts

Foundation Type	Design/Planning		Construction		Installation		Removal	
	Advantages	Disadvantages	Advantages	Disadvantages	Advantages	Disadvantages	Advantages	Disadvantages
Mono-Tower Piled (Monopile)	Simple structural configuration.	Relatively sensitive to scour	Minimal construction site investment required.		No seabed preparation required.	Requires piling equipment.		Piles cannot be completely removed.
	Flexible foundation response offers opportunities to tune the structure dynamic characteristics.	Performance may be sensitive to choice of soil parameters.	Tube rolling facilities are widely available.			Regions where boulders, very stiff clays, mudstones etc present will require drilling equipment		Piles require cutting at seabed using shaped charges or abrasive cutting.
	Suited to water depth of 3m to 20m.	Not suited to water depths in excess of 25m.	Construction is simple and thereby inexpensive and quick.			Field splice required between tower and pile. Adjustment to inclination of pile likely.		
		Poorly suited to very weak soils				Scour protection required in exposed locations.		
Mono-Tower Gravity Base		Not suitable for regions subject to seabed movement or excessive scour.		Large construction site investment required.	No piling required. Entire OWEC can be installled as single unit.	Seabed preparation required	Can be removed completely and possibly repositioned.	Removal of ballast material will be time consuming.
	Performance is relatively insensitive to choice of soil parameters.	Stiff foundation response limits the opportunities to tune the structure dynamic characteristics.		Desirable that construction site be close to wind farm.		Placement of ballast likely to be a slow offshore operation, sensitive to weather delays		Jetting may be required to lift the base.
		The base can be subject to substantial heave forces during the passage of the wave.		Appreciable space requirements at construction site.		Jack-up capacity/reach may be inadequate for lifting base.		
	Suited to water depth of 5m to 20m.	Not suited to water depths in excess of 25m.		Size of the base may vary according to the specific water depth requirement.				
		Poorly suited to very weak soils						

Table 3.4-1 Monotower Concepts - Pros & Cons

Foundation Type	Design/Planning		Construction		Installation		Removal	
	Advantages	Disadvantages	Advantages	Disadvantages	Advantages	Disadvantages	Advantages	Disadvantages
Braced/ Lattice Tower Piled		More complex structural configuration. Unsuitable for ice conditions.		More specialised fabrication methods required.	Minimum seabed preparation required.	Regions where boulders, very stiff clays, mudstones etc present will require drilling equipment		Piles cannot be completely removed.
		Very stiff foundation response limits the opportunities to tune the structure dynamic characteristics.		Desirable that construction site be close to wind farm.	Smaller piles are used thereby requiring a smaller pile hammer.	Multiple piles necessitate jack-up movements which is time consuming.		Piles require cutting at seabed using shaped charges or abrasive cutting.
	Suited to water depth upwards of 10m.	Not suited to water depth of less than 8m.		Appreciable space requirements at construction site.		Field splice required between tower/nacelle and substructure. Adjustment to inclination of substructure likely.		
Braced/ Lattice Tower Gravity Base		Not suitable for regions subject to seabed movement, excessive scour or ice conditions.		Large construction site investment required.	No piling required. Entire OWEC can be installled as single unit.	Seabed preparation required	Can be removed completely and possibly repositioned.	Removal of ballast material will be time consuming.
		More complex structural configuration.		Desirable that construction site be close to wind farm.		Placement of ballast likely to be a slow offshore operation, sensitive to weather delays		Jetting may be required to lift the base.
	Performance is relatively insensitive to choice of soil parameters.	Very stiff foundation response limits the opportunities to tune the structure dynamic characteristics.		Appreciable space requirements at construction site.		Jack-up capacity/reach may be inadequate for lifting base.		
	Suited to water depth upwards of 10m.	Not suited to water depth of less that 8m.		Size of the base may vary according to the specific water depth requirement.				
		The base can be subject to substantial heave forces during the passage of the wave.						
		Poorly suited to very weak soils						

ble 3.4-2 Braced/Lattice Tower Concepts - Pros & Cons

3.5 Grid Connection and Farm Layout Considerations

There are no principle differences in the grid connection and farm layout between an offshore and onshore wind farm. Of course, another wind climate is present offshore and the distance between the farm and grid feed-in point will normally be larger offshore, but the same methods and tools can be applied as used for onshore farms. Nonetheless, the different magnitude and distribution of the individual cost components of an OWECS in relation to an wind farm on land may lead to different optimum design solutions as for instance explained below for the wind turbine spacing.

3.5.1 Grid connection

Nowadays electronic components are available for a wide variety of applications and are modular. In this view no design restrictions are foreseen. For submarine power transmission cables to the shore, the fundamental choice lies between AC and DC. The difficulties of three phase cabling, and unavoidable capacative electrical losses count against AC installations, while DC equipment is hampered by the expense of converters (inverters and rectifiers). A decision between the two schemes can only be made by evaluating the total cost of each for any project (including cable laying costs). In general AC is preferable for distances to shore less than (very) roughly 60 km.

For power collection within the windfarm the selection should probably be AC, because voltage changes will undoubtly be required before transmission to the shore. The required transformers could be placed within the support structures, as long as adequate provision is made for their placement should it be necessary. Within large wind farms, arranged on a cluster basis, the power collection should usually be performed at two voltage levels, one within each cluster and then a higher voltage for transmission to shore.
From literature an option is found to use overhead lines inside the farm instead of cables. Although this option is economically attractive it is questionable that it seems feasible for large distances between the turbines. Furthermore ice formation on the lines and lightening may become problematic and the installation and O&M operations of the OWECS may be hindered. Finally larger hub heights are required which are less favoured with respect to the support structure costs. To investigate these aspects, further research is necessary which lies outside the scope of the project.

3.5.2 Farm layout

Here only some general remarks are given on farm layout since the complex influences of the design and site conditions can only be considered by computational models.
The geometric layout of the turbines in the farm may vary between a line, a rectangular or a square. The spacing between the individual turbines should be larger than the typical onshore distances of 3-4 rotor diameters perpendicular to the prevailing wind and 8-10 diameters parallel to it. This is because the wake of a turbine dissipates more slowly offshore than onshore and because space constraints are less significantly offshore.

Due important design driver for the layout of onshore wind farms the noise emission has offshore a significantly lower importance. In contrast, aspects of visual acceptance have to be considered also carefully for future offshore farms since these farms will generally be very large and thus visible from a considerable distance.

3.6 Operation & Maintenance Considerations

Operation and Maintenance aspects play an important role in the cost of electricity produced by an OWECS. In most of the studies that have been undertaken so far the yearly O&M costs are not related to certain parts of the structure, and are generally assessed to be something like 1.5 to 3% of the total investment costs (see also Volume 2). The longer economic life time of an offshore wind farm as generally assumed however implies that O&M costs may well add up to 30% of the total energy costs. Thus it is relevant to find ways to reduce the O&M part of the cost of offshore wind electricity and hence to improve its economics.

OWECS will in general have a considerably larger scale and will in general adopt wind turbines of a larger size than the current practice in operational onshore wind farms. Therefore OWECS will need special O&M consideration. There is however another evident and important difference with onshore wind farms. Not only is offshore installation of wind turbines more difficult and more expensive but offshore location also has a major impact on the accessibility. It may well be that the complete wind farm is unaccessible by boat or helicopter for a period of one or two months because of harsh weather conditions (wind and waves).

And even when weather permits access to the turbines the cost of offshore maintenance is far more higher than the equivalent job onshore. Lifting actions are performed relatively easy on land, but in an offshore environment special and therefore expensive and sometimes scarce equipment is needed. Moreover even straight forward service and minor maintenance activities need dedicated crew and means of transport and are thus far more expensive offshore than equivalent actions in an onshore wind farm.

Application of a kind of ‘touch and go’ philosophy, i.e. minimisation of the duration of in-situ operations as commonly followed in the offshore industry might be worthwhile. More generally, avoidance of any unproven design solution even for minor and/or apparently insignificant components is an important lesson to be learnt from the offshore technology. The latter should be particalurly considered serious for turbine concepts with a limited onshore track record (e.g. multi-megawatt machines).

Simple retention of the high reliability standard of the current generation of commercial onshore wind turbines with availability of 98% or sometimes even more, is insufficient for OWECS due to different reasons. The corrosive environment and probably stretched service intervals are an additional burden. Both limited access and limited availability of maintenance equipment may easily lead to a significant and thus unacceptable down time level. This makes it inevitable to assess the O&M demand of an offshore windfarm in conjunction with the other design parameters.

One of the aims of an integral O&M approach is evidently to keep the number of expensive maintenance visits to a minimum. Of course this must be evaluated in the light of the wish to limit the investment costs. Extensive use of monitoring equipment and remote resetting techniques in order to eliminate routine visits and avoid downtime due to predictable failures are foreseen. Such techniques may much reduce relatively simple maintenance visits, but there will still be unexpected failures in heavy components which will be difficult and expensive to repair, when not taken into account adequately in the design. Easy (and reduced) maintenance should therefore be a strategic design target for wind turbines placed offshore.

A minimum maintenance strategy adopted to a reduced maintenance design, coupled with remote monitoring and control is probably a good idea, but highlights a large number of obstacles which make it difficult assess. Particularly the lack of available detailed cost data of offshore maintenance is a problem. It may be possible to adapt O&M experience from other fields of offshore engineering but care must be taken. Costs at heavy offshore oil and drilling installations are not representative of those likely to be found at OWECS.

There is however a good general understanding of the maintenance procedures that are necessary for OWECS. When rational assumptions are made regarding the achievable reduction in failure rate of individual components, the nominal time to repair the failure as well as the cost of the replaced components, it is possible to model various maintenance strategies taking the offshore weather climate into consideration as well. Such rational assumptions can be extrapolated from current onshore experiences as well of the data furnished by manufacturers of large prototype wind turbines.

3.7 Dynamic Considerations during the Feasibility Study

3.7.1 Soft versus stiff - An important question already in the feasibility study

The right choice of the design values for the dynamic properties of an offshore wind energy converter (OWEC) are quite essential for a cost-effective and reliable design solution. In fact, the dynamic characteristics especially of the support structure has many consequences. In this section the different experience or design philosophies in wind turbine engineering and offshore technology are described and some general remarks on OWEC are given.

Wind turbine engineering

The exploitation of wind energy has undergone a rapid development in the last years. Technical reasons for its success are the improved economics due to series production, weight reduction and increase in plant capacity.
The two latter aspects have led to a ‘soft’ design philosophy for the rotor, the drive train and the tower. Consequently, at present common onshore designs are soft-stiff or even soft-soft[1] (Figure 3.7-1). Moreover, well-designed flexibility reaps benefits through reduced dynamic response [3.7-1].

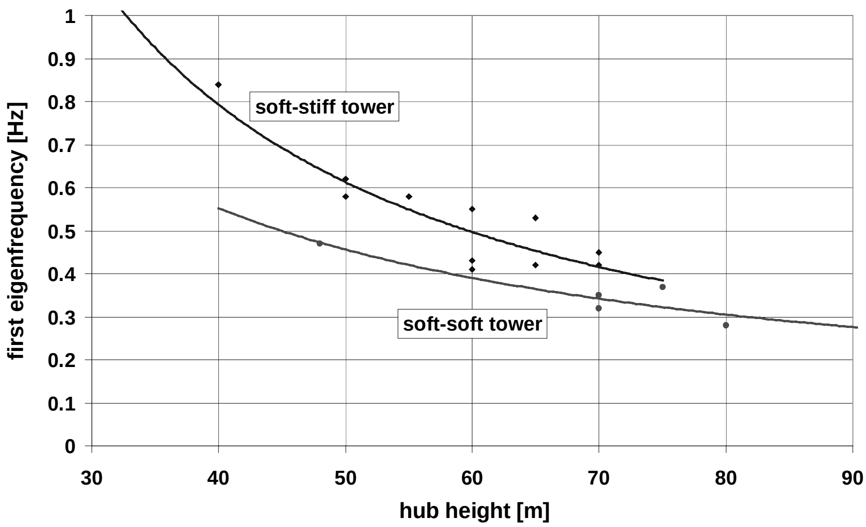


Figure 3.7-1: Stiffness of some tower of commercial wind turbines (500 kW - 1.5 MW) and extrapolated trends

Offshore technology

Fixed offshore structures are predominately designed ‘stiff’ since dynamic wave loading is strongly reduced for structural frequencies above approx. 0.4 Hz. The wave excitation range extends between f = 0.04 Hz and f = 0.5 to 1.0 Hz. From the over 7000 fixed offshore installations world-wide a relatively small number have eigenfrequencies below 0.3 Hz. Moreover, the applied platform concepts e.g. steel jacket and other design criteria as extreme loading or stability often lead to a stiff behaviour (Figure 3.7-2). Even for shallow water sites the overall costs are not simply driven by weight but also by the efforts for transportation, installation, maintenance, etc.

[1] Three design solutions exist for wind turbine tower depending on the ratio between the fundamental eigenfrequency f_o and the rotor frequency f_R and the blade passing frequency $f_b = N_b \cdot f_R$, respectively: soft-soft i.e. $f_o < f_R$, soft-stiff i.e. $f_R < f_o < f_b$ and stiff-stiff i.e. $f_b < f_o$. In order to limit dynamic response the fundamental eigenfrequency f_o should have a minimum distance of e.g. $\pm$ 5 - 10 % to the excitation frequencies f_R, f_b and their low integer multiples.

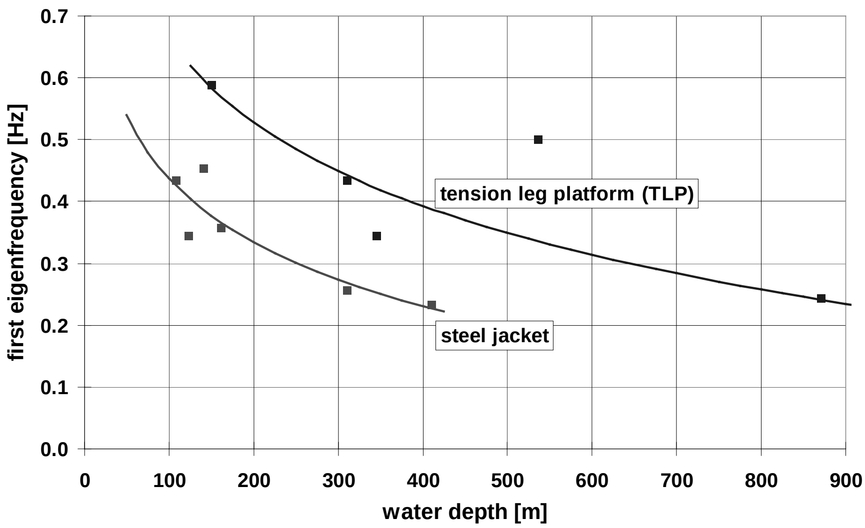


Figure 3.7-2: Stiffness of offshore platforms in deeper water and extrapolated trends

Offshore wind energy application

For offshore wind energy two principal solutions exist either to follow directly the experience of the parent technologies by erecting a ‘soft’ wind turbine tower on a ‘stiff’ foundation platform or to build up a new understanding by linking the two backgrounds. The former has been applied successfully at the two Danish demonstration offshore wind farms. While the latter is most promising and maybe even required for the future large-scale utilisation (in deeper waters).

All three options for the stiffness of OWEC support structures have their pro and cons. Stiff-stiff characteristics provides a robust solution with respect to hydrodynamic loading as well as foundation uncertainty but conflicts with the wind turbine demands and suffers high fatigue loads with origin in the tower top. Soft-stiff concepts are often a good compromise between offshore and wind energy technology as long as the inborn uncertainty of the soil does not alter the first natural frequency too much. Finally, soft-soft structures are interesting for large OWEC from an economic view point but are inherently prone to hydrodynamic fatigue and to foundation properties; so, they require carefully dynamic analysis and may not be viable in demanding environments.

Up to now no design lines for offshore wind energy have been established. Apart from the variety of different support structure concepts, also for the wind turbine many options e.g. variation of turbine size, rotor speed, hub height, 2- or 3-bladed rotor, control system, etc. exist.

3.7.2 Relation between aerodynamic damping and support structure concepts

As an example of the particular importance of various interactions of OWEC sub-systems here the aerodynamic damping of the support structure is considered. In addition, this effect is an indication for the magnitude of the dynamic rotor - tower coupling.

The aerodynamic forces on the rotor blades also depend on the motion due to flexibility in the tower and/or blades. Normally, the flexibility adds (aerodynamic)

damping to the support structure. Note: in case of stall the damping can become negative which in certain circumstances can lead to instability.
Significant aerodynamic damping occurs only for the flapwise i.e. out-of-plane motion of the blades, the tower fore/aft modes and to a lesser extent for the tilt and yaw movement of the nacelle. The damping effect on the support structure is of particular importance for OWEC since dynamic response on wave excitation, mostly more or less collinear with the wind direction and thus the rotor orientation, can be aerodynamically damped. Moreover, depending on the OWEC design the aerodynamic damping can account for several times the structural damping.
From aero-elastic stability analysis it is well-known that the aerodynamic tower damping is inversely proportional to both the fundamental tower eigenfrequency and the modal tower mass [3.7-2]. Therefore from a dynamic point of view, considering only the rotor-tower interaction and an onshore wind energy converter, softer and lighter support structures are in favour. For instance for a braced tower (tripod) and a gravity based monotower with the same fundamental eigenfrequency the former will provide more damping due to a lower modal mass.

3.7.3 Comparison of the onshore and offshore wind loading

Fatigue loading

For the same wind speed distribution the dynamic loading due to the offshore wind climate is considerably less than onshore since turbulence intensity and wind shear are reduced. Table 3.7-1 gives a comparison of some parameters relevant for design calculations.

In principle the lower turbulence level offshore offers a welcome opportunity for a lighter and thus more economic design certainly under consideration of the high number of OWEC units (about hundred or more) within a large-scale offshore wind farm. However, one has to keep in mind an opposing effect, the more severe wind speed distribution offshore. Even under the assumption of a Rayleigh distribution the frequency of the wind speeds at post-rated, high loaded conditions is significantly increased (Figure 3.7-3). Taken also the generally larger Weibull shape factor (Table 3.7-1) into account this effect is even more pronounced.

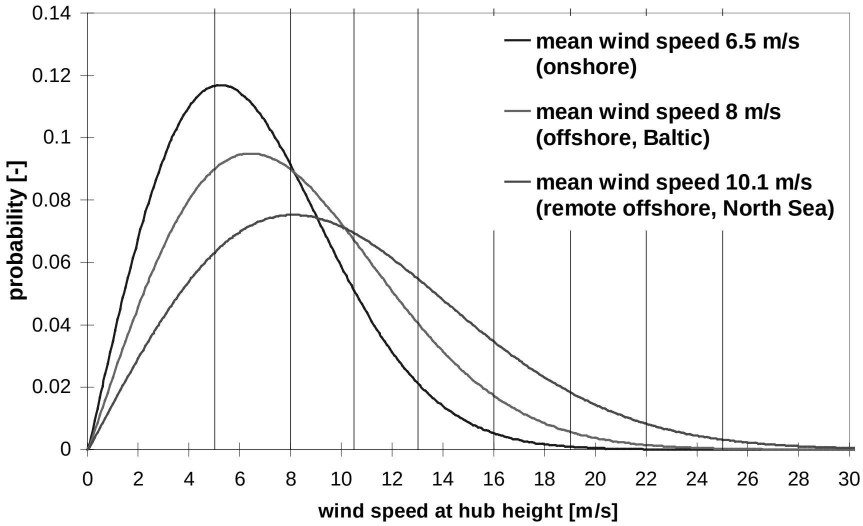


Figure 3.7-3: Rayleigh distribution of wind speed at some typical onshore and offshore sites (hub height 60 m)

Wind farm effects

Within wind farms the dynamic loading increases significantly due to the wakes generated by turbines located upstream. Especially the partial wake operation, when the swept area of a turbine is only partly affected by a wake, results in high load fluctuations. Measurements at the first Danish offshore wind farm Vindeby [3.7-4] indicate that the relative increase in turbulence due to wind turbine wakes is considerable higher offshore and remains longer downstream due to the lower ambient turbulence. Within a recent EU JOULE project design guidelines for dynamic loads in onshore wind farms have been developed [3.7-9]. Complex influences as machine type (pitch or stall regulated), machine component and material considered, wind farm spacing, etc. are implemented in an engineering method that models the wake effects by an equivalent increase of the ambient turbulence.

		onshore	offshore
turbulence intensity I_T	measurements	typically 14 % - 15 % (roughness z = 0.01 - 0.03 m) [3.7-3]	theory: 8 % neutral conditions (z = 0.001m) Vindeby: 6 - 10 %, 8% for higher wind speeds [3.7-4] West Sole: 8 - 10%, 8% for higher wind speeds [3.7-5]
	GL design guidelines [3.7-6, 3.7-7]	17 %	12 %
wind shear exponent α	GL design guidelines	0.16	0.11
Weibull shape factor k	Dutch site data (1 h mean) [3.7-8]	$k \approx 1.75$	$k \approx 2.2$
	GL design guidelines	Rayleigh k = 2 identical between standards	

Table 3.7-1: Comparison of the onshore and offshore wind climate as relevant for a fatigue analysis

Extreme wind conditions

Although the extreme mean wind speed is higher offshore the extreme wind gust and the extreme change in wind direction are less severe (Table 3.7-2.) again due to the lower turbulence. For instance the GL standards specify a gust increase of only 20 % offshore whilst 40 % is used for land based systems. Moreover, a reduced partial safety factor for loads γ_F of 1.35 offshore instead of 1.5 onshore is given by the GL standards. The rationale behind this difference is the reduced damage to the environment by a major failure of an OWEC and the fact that the simultaneous consideration of a high safety factor on aerodynamic as well as hydrodynamic loads would be over-conservative.

extreme condition		onshore	offshore
extreme mean wind speed $\bar{v}_E$	typical Dutch site data [3.7-8]	≈27.5 m/s	≈38.5 m/s
	design guidelines [GL, 3.7-7, 3.7-8]	30 m/s (Class IV) - 50 m/s (Class I) identical between GL standards	
extreme 5 s gust v_E [GL]		$1.4\ \bar{v}_E$	$1.2\ \bar{v}_E$
extreme operating gust [GL]		identical between standards	
extreme change in wind direction at 15 m/s [GL]		115^o (Class IV) - 145^o (Class I)	35^o (all classes)
partial safety factors for loads [GL]	aerodynamic force	$\gamma_F = 1.5$	$\gamma_F = 1.35$
	other forces	identical between standards	

Table 3.7-2: Comparison of the onshore and offshore wind climate as relevant for extreme conditions (strength analysis)

3.7.4 Design conditions for different OWEC components

Different investigations establish that the rotor and the electro-mechanical conversion system of an OWEC are not considerable affected by wave excitation transmitted by the support structure [3.7-10, 3.7-2] (Section 9.3-4). Nonetheless the different wind conditions, the corrosive environment and the increased reliability requirements are important design considerations.
In contrast, the support structure suffers simultaneous aerodynamic and hydrodynamic loading which requires particular considerations during the design. Moreover, generally the soil behaviour has a larger importance offshore.

3.8 Evaluation and selection of sites and concepts for further development

In this section the different aspects / OWECS sub-systems considered in the feasibility study described in the previous sections of this chapter are evaluated. So far only global interactions between site, support structure concept, installation procedure and dynamics on one hand and site and grid connection on the other hand are considered. Moreover, important directives for the conceptual design phase (chapter 4) are given.

3.8.1 Site Selection

Six sites (table 3.2-1) have been selected within northern European waters as candidate hosts for the proposed OWECS. As an added advantage, the sites represent a wide range of environmental conditions, combining high wind speeds with far from shore locations, and relatively low wind speeds with proximity to the shore.
By a qualitative evaluation three sites with distinctly different properties have been chosen as base for the conceptual design of the OWECS sub-systems.

- NL-5 (IJmuiden, 50 km offshore)

most demanding environment (wind & waves conditions, water depth) and farest distance from shore, site interesting for (far) future large scale development in the GW range,

- S-1 (Blekinge)

moderate environmental conditions in relation to typical North Sea but demanding for Baltic conditions, considerable ice loading,

- NL-1 (IJmuiden, 8 km offshore)

still demanding environmental conditions but due to lower water depth and shorter distance from shore less exposed than NL-5, site interesting for development in the nearer future

Sufficient environmental information is available such that detailed design work could be undertaken for any of these locations.

The relative importance of the environmental qualities of each of the six sites for certain OWECS concepts will be assessed after the development of suitable concepts at the end of in the next chapter (section 4.7) with a cost model, allowing quantitative determination of the best combination of concept and location.

3.8.2 Wind turbine selection

The wind turbine employed within the conceptual design will be based upon the two existing concepts of the 3rd generation of the Näsudden design of the Kvaerner Turbin i.e. the geared WTS 80, respectively, the direct driven WEC 3000.
The 3 MW - 80 m size and the good prototype experience with the preceding generations make these turbines good candidates for an offshore adaptation. The comparison of different drive train concepts reflects current developments on the wind turbine market. Last but not least, the availability of the entire catalogue of design data and the presence of Kvaerner Turbin as project partner is an important consideration in the selection.

The specifications of the machine will be modified taking into account of the differences between the offshore environment and the land based locations it was originally designed for. Particular attention will be given to implications of the operation & maintenance aspects, paramount for offshore application. The benefits of more radical implications as increasing the rotor diameter, power rating or tip speed will also be investigated.

3.8.3 Support structure selection

From the wide spectrum of possible structural configurations and the two principle installation approaches three options will be investigated further (table 3.8-1).

configuration	foundation	installation	site
lattice tower	gravity (GBS)	floated	NL-5
monotower	gravity (GBS)	floated	S-1
monotower	piled	floated or lifted	NL-1

Table 3.8-1: Considered combination of support structure, installation procedure and site to be considered in the structural design

The lattice tower provides a stiff-stiff dynamic characteristic and is most like the jacket structure used in offshore technology. In contrast, the GBS monotower has soft-stiff characteristics.
Both these structures would be assembled either in a dry dock or at the quay side, obviating the need for costly offshore lifting equipment.
The third option, that of the monopile, is based on more traditional solutions and is very simple in construction. It has soft-stiff or by preference soft-soft dynamic characteristics and is likely to be strongly governed by combined aerodynamic and hydrodynamic loading.
Each support structure concept will be developed at a particular site likely to be most suitable for such a design (table 3.8-1).

3.8.4 Grid connection

It is clear than any cabling between individual turbines, and between the wind farm and the shore must be of the submarine variety. For the power collection, there seems little advantage in using anything other than AC technology. For the shore connection however, the decision between AC and DC circuitry is more difficult. The decision will only be possible after a detailed investigation, and will depend on the distance between the chosen site and the shore respectively the connection point to the public grid.

Wind farm cabling and aerodynamic farm efficiency is also influenced by the topological layout of the turbines, and here there are no reasons to depart from conventional on-shore practice. One exception is that the spacing of the turbines in the wind farm should be greater than that used on land.

3.8.5 Operation and maintenance considerations

Operation and maintenance related costs play a very important part in the economic performance of an OWECS. As such it is paramount that O&M issues are considered from the outset of the design process, and that a cost effective O&M

strategy is devised in a rational way. At this stage in the design process it is difficult to make statements regarding the O&M strategy to be used, other than the observations that it is necessary to develop the O&M concept parallel to the other aspects and that it will differ substantially from the approach used on-shore. A more detailed strategy will be developed as an integral part of the other technical work.

3.8.6 Overall dynamics

Dynamic considerations particular to OWEC should be taken into account already at an early state of the design process. Special attention has to be given to the different philosophies in offshore technology and wind energy technology, respectively.

Depending on the particular design and site conditions, dynamics are likely to be of higher importance for OWEC design in comparison to both design of onshore wind energy converters and most offshore structures. Careful dynamic analysis of the entire OWEC and the consideration of this procedure during the design process offer considerable cost reductions, especially if fatigue is governing.

4. Development of Concepts

4.1 Introduction

During the feasibility study in chapter 3 a number of sub-system concepts and related sites have been identified which will be further in the conceptual design phase presented in this chapter. Now the main dimension are determined and the final requirements on function, technology, construction and economics are fixed.
Figure 4.1-1 shows the followed procedure which is largely consistent with Step 2 ‘Conceptual design’ according to the integrated OWECS design approach [4.1-1].

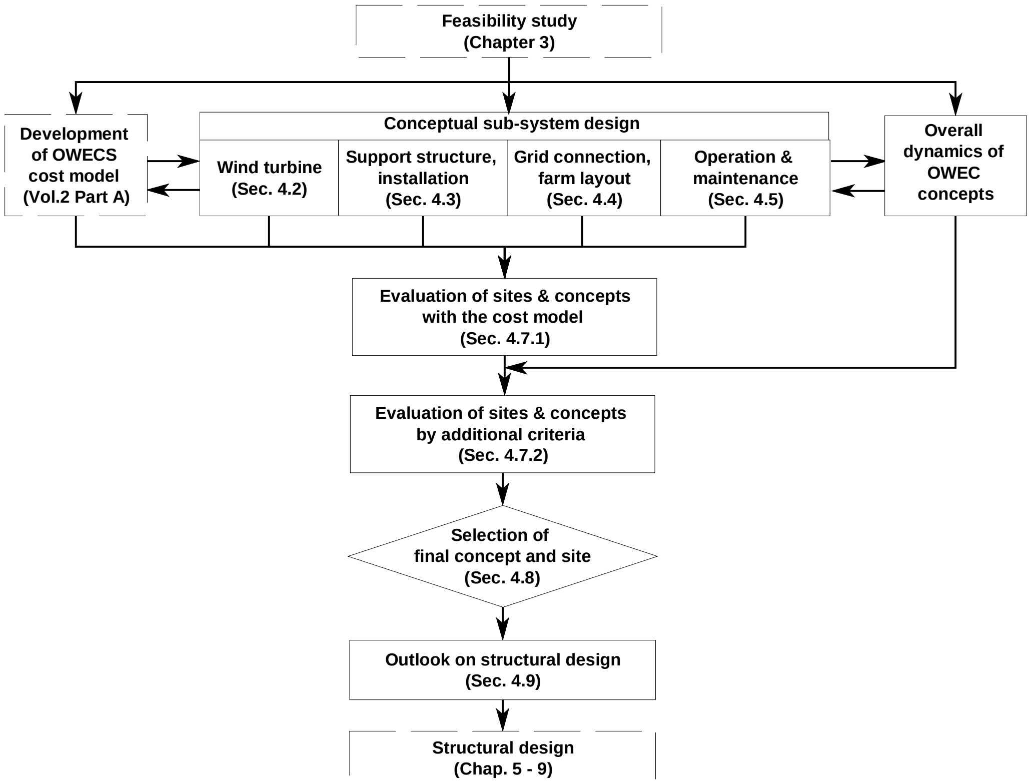


Figure 4.1-1: Flowchart of conceptual design and relation to chapters and sections of the report

Sections 4.2 to 4.5 present the development of the main sub-systems whilst overall aspects considered in parallel i.e. dynamics of OWEC and the development of the cost model are described by section 4.6 respectively Part A of Volume 2 [4.1-2]. Within sections 4.2 to 4.5 the possible sub-system concepts are evaluated mainly with respect to sub-system considerations. In contrast, aspects on a system level are taken into account in the overall evaluation in section 4.7. Next, in section 4.8 the choice for one concept at a particular site is done and finally an outlook on the following structural design phase is given in section 4.9.

4.2 Wind Turbine

4.2.1 Background

Kvaerner Turbin started the engagement in wind energy in the 1970ies. The development has most of the time been focused on large multi-MW turbines, and has been carried out in close co-operation with the Swedish utilities and research institutes within the research programme for wind energy. Design work, as well as manufacturing and erection of turbines, has been performed together with international partners.

The experience from three different projects is the reference for participation in this offshore study and forms the starting point for the conceptual design phase of Opti-OWECS. Kvaerner Turbin has designed and assembled two prototype 3 MW turbines on land 1989-1992. These machines are now in operation. Parallel to the 3 MW development, Kvaerner Turbin also participated in the industrial consortium which performed the offshore study called the Blekinge Project [4.2-1].
During the period 1992-1996 a development study was performed, called Development Study III, with the main objective to investigate the commercial future for the large 3 MW turbine. The result of this study are detailed design descriptions of two alternative 3 MW turbines including a cost estimate [4.2-2]. Figure 4.2-1 compared the energy cost for the different machines of Kvaerner Turbin development chain including build machine, economic target of the Development Study III (DS III) as well as estimated cost for a series production of the WEC 3000 concept.

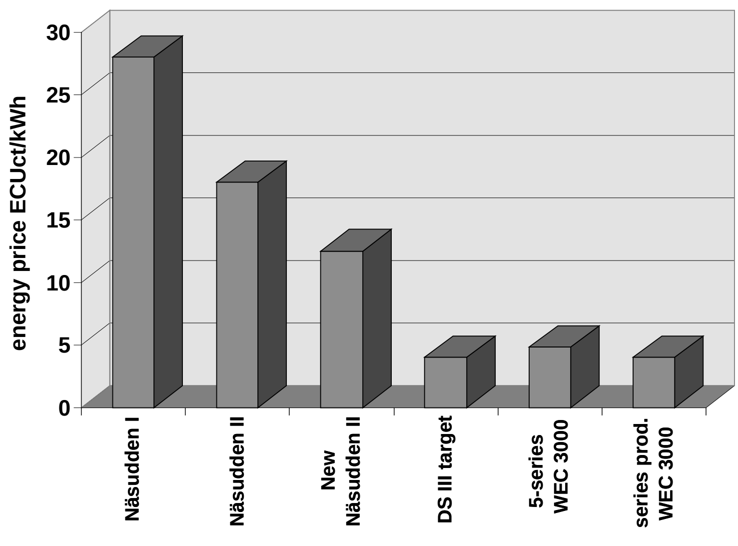


Figure 4.2-1: Cost reduction for the Kvaerner Turbin development chain

It can be seen that a commercial level can be achieved due to advanced design and based upon a long term production. The highest cost reduction with respect to the Näsudden II machine are reached in the blade and hub whilst it was only possible to reduce the machinery costs to a lower but still considerable level (table 4.2-1).

Component	New Näsudden II	Target DS III study	DS III result	Reduction
Blade	1.80	0.42	0.26	86 %
Hub	0.25	0.11	0.09	64 %
Machinery	1.55	0.73	0.84	46 %

Table 4.2-1: Cost reduction for components between Näsudden II and Development Study III (DS III).
Cost level in investment cost / annual energy yield (SEK/kWh/year)

The two designs of the Development Study III are briefly described below. These two turbine options where considered as design alternatives during the conceptual design phase of Opti-OWECS.

4.2.2 WTS 80L (land based version)

General

WTS 80 is a two-bladed, pitch regulated, horizontal axis wind turbine with a rated power of 3000 kW. The delivery includes a complete wind turbine assembled on the top of a steel tower. The unit also comprises equipment for unmanned operation. The control system can be connected to a remote monitoring system. In the development made to reduce the costs from Näsudden II, the most important design measures are:

- new blade design and manufacture
- straight drivetrain with generator in nacelle
- soft yaw system
- tubular steel tower

Important areas for improvement are also workshop assembly, site logistics and maintenance.

Turbine

The rotor has two wood-epoxy blades mounted on a fixed hub. The blades are connected to the hub through slewing bearings. The hub is cast in one piece in nodular iron. Externally the hub has a balcony for maintenance of the blade pitch system and a connecting console for the blade servo cylinders. Inside the hub is placed equipment for the blade pitch system. Most of the hydraulic outfit is however located in the nacelle in the non-rotating system, in order to increase availability and serviceability. The interior of the hub is reached through a hatch in the front panel of the servo console.

Despite the stiff hub, an increased dynamic flexibility of the turbine is reached thanks to the soft yaw system. This technique, together with a soft tower, is used instead of a more complicated teetered hub design.

Drivetrain

The front shaft bearing takes the thrust load. The second bearing is included in the gearbox. Behind the front bearing is a swivel arrangement for transfer of hydraulic oil to the blade pitch servos. The gearbox concept is a 3-stage planetary gearbox. The gearbox has a lubrication system with tank, pump, filter and air cooler. It is also equipped with monitors for temperature, pressure and vibrations. On the gearbox output shaft is a small disc brake mounted. This brake is mainly for use at maintenance operation.

The generator is placed behind the gearbox and connected with a flexible shaft to allow some misalignment and movement. The drivetrain has a tilt angle of 93º to the vertical plane.

Nacelle Structure

The bedplate is a welded steel design. It is connected to the tower through a yaw bearing of slewing bearing type.

The nacelle housing is a GRP structure. It has internal noise insulation for damping of the machinery noise. The nacelle hosts all the equipment for operation of the wind turbine: Lubrication system, hydraulics, oil tanks, filters, electric cubicles, ventilation system and control system. There is also equipment for the power cable transmission into the tower. Wind monitoring equipment and lightning protection is stationed on the nacelle roof.

Safety System

The blades will be pitched and the yaw brake will be engaged at an emergency situation or a grid failure. The safety system is redundant as the pitch function and the supervision both are doubled. The system for supervision and for initiation of an emergency stop consists of a hardware system and a computerised system. Both systems check overspeed, vibrations, manual stop buttons etc. Important transducers are also doubled.

Blade Pitch System

The pitching is hydraulically linked between both blades, resulting in a synchronous movement at pitching. The system has two parallel, independent circuits for pitching, in principle similar to a double circuit brake system in a car. In a normal situation both blades work in parallel, but each circuit can also operate alone at a fault in the other circuit. This design gives redundancy in the stopping system and no secondary mechanical brake is needed. The pitch system is supervised from the control system.

Yaw System

The yaw system continuously guides the turbine into the wind direction. The yaw direction is maintained with torque from the yaw gear motors. The oscillating side force from a two-bladed rotor is also used to achieve part of the yaw torque. By this, a soft and well damped system is realised with reduced loads on the rotor, nacelle and tower. The system is hydraulic and has 2-3 radial piston motors operating on gears on the yaw bearing. One motor is equipped with a mechanical disc brake, engaged at emergency stop and at parking. This brake also serves as a safety device if the twist limit of the power cables is reached.

Electric System

The generator is an asynchronous generator with two speeds. This is achieved with double windings. The weight of the generator is about 10 t. The voltage level is 6 kV. The power is transferred to the ground via twistable cables.

Control System

The control system is used for overall guidance and control of the wind turbine. It consists of a control computer and of hardware logic. The control system is decentralised into a number of local nodes. This reduces the cabling and also makes it possible to do a complete functional test on separately assembled equipment. Each node has its own I/O and processor capacity. The nodes communicate through a field bus.

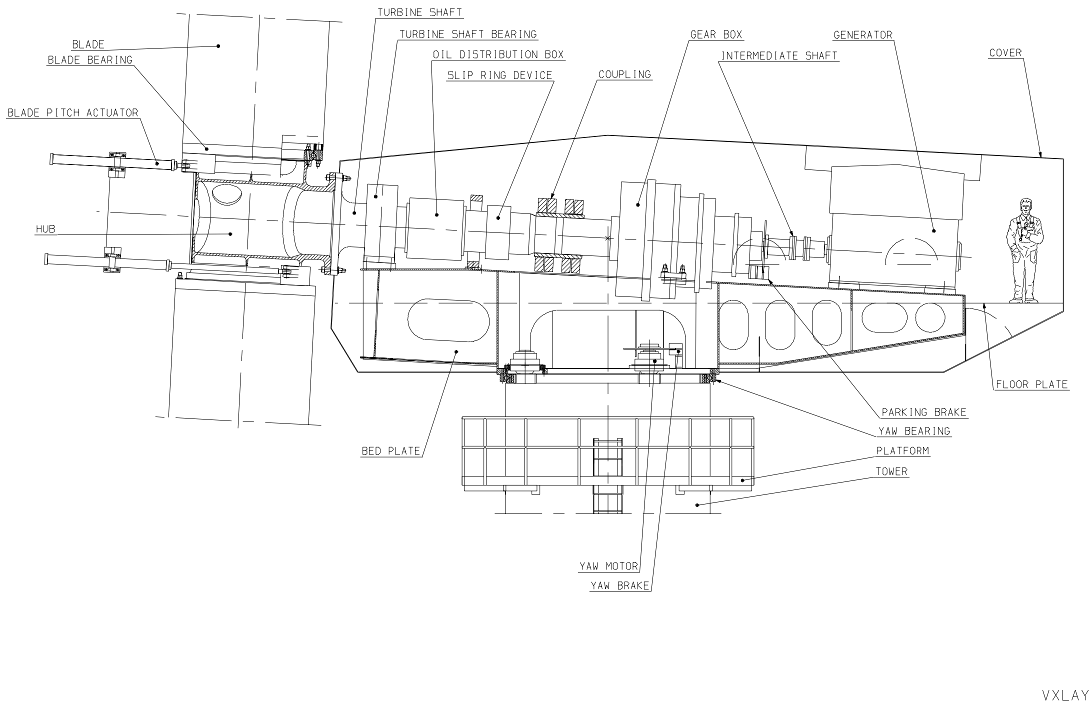


Fig. 4.2-1 WTS 80L (land based)

4.2.3 WEC 3000

During the work in Development Study III, the former German partner MBB introduced a new generator design from the south German company Heidelberg Motor. The concept is a direct driven permanent magnet generator together with a

frequency converter system. This design option was considered interesting and was incorporated into the development study. The turbine concept has, apart from the drivetrain, many design solutions in common with WTS 80:
- tower
- blades
- pitch and yaw systems
- dynamics

The main differences from WTS 80 are:
- direct drive concept
- variable speed
- nacelle structure

The nacelle is here also the load carrying external structure. There is no need for a separate nacelle cover as there is no specific bed structure inside the nacelle. This design philosophy with a load carrying shell construction was also used on the Näsudden I turbine.

The nacelle is a welded structure with two internal platforms for equipment. The housing is connected to the tower via a yaw bearing of slewing bearing type. The nacelle stores all equipment for operation of the turbine, except for frequency converter system, switch gear and transformer.

The permanent magnet generator has a diameter of 5.6 m and a length of 1.5 m and is bolted to the nacelle front cover. The generator is cooled by a water cooling system, controlled from the electrical system control computer. The power is transferred to the frequency converter on the ground via 32 twisting cables. The frequency converter system is stationed in a ground container.

The variable speed concept will reduce the dynamic loads on the turbine and will also reduce the power fluctuations to a minimum. This was not particularly investigated in Development Study III but measurement series from Aeolus II show the difference in the load situation compared to Näsudden II. Another experience from the soft tower design of Aeolus II is that passing of resonance frequencies during e.g. start-up and shut-down is no problem at all.

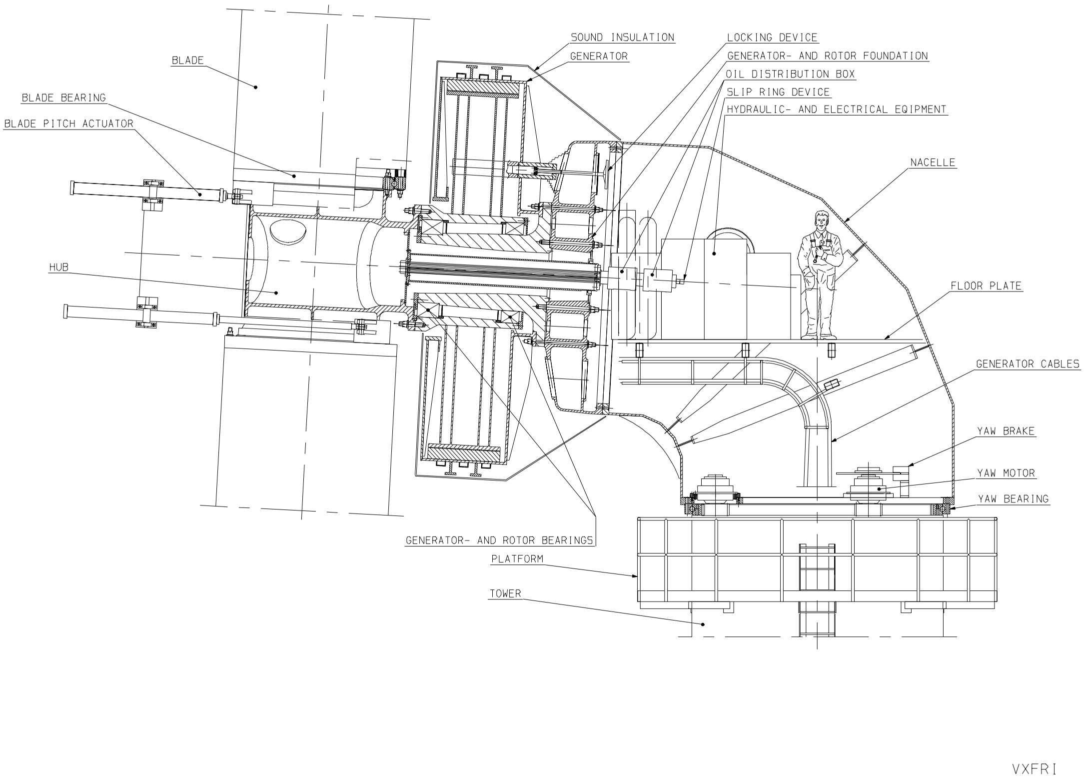


Figure 4.2-2: WEC 3000

4.2.4 Other design options considered in the conceptual design phase

For the offshore design some important additions have to be taken into account. There are important differences in the load and environmental situation. section 3.7. This will influence the structural design and the operational philosophy. Other significant areas are maintenance, availability and power supply. An option with an enlarged rotor was also taken into consideration.

Loads

The following three load cases from [4.2-3] were investigated:

E1.1. Extreme operation gust
E2.1. Occurrence of 50 year gust
Fatigue loads for a lifetime of 30 years

Offshore adaptation

The Kvaerner Turbin concept WTS 80 is designed for an onshore installation. Different measures for offshore adaptation of the turbine have been looked into:

- Heating, pressure inside nacelle
- Battery backup for 2 weeks
- Passive, redundant parking brake equipment
- Increased insulation of electrical equipment
- Redundant feeding of local power
- Radio link for communication
- External parts with zinc coating or stainless steel
- De-icing of wind sensors
- Control system
- Fire protection system

Rotor performance

A part of the conceptual design work has been an investigation of changed rotor performance. First an upscaling of the 3 MW turbine was examined. The WTS 80/WEC 3000 has, in its present design, a considerably higher specific power rating than most commercial turbines. If the specific power rating is decreased a relative decrease in loading would also be achieved. In addition, an enlarged turbine has significant influence on the energy yield. Three options were studied:

- rotor diameter 90 m, rated electrical power 3 MW (case 90 - 3)
- rotor diameter 90 m, rated electrical power 4 MW (case 90 - 4)
- rotor diameter 100 m, rated electrical power 4 MW. (case 100 - 4)

An aerodynamic design was made in each case by FFA in Sweden in order to achieve the change in loads and blade geometry [4.2-4]. Kvaerner Turbin evaluated the energy yield and from a simple cost investigation found the increased turbine cost. The result is that an increase of the diameter to 90 m for 3 MW is likely to be economical for a typical onshore location as the additional energy income more than counterbalance the increased turbine cost.

Parametric study of turbine size options						
Case	Rotor speed	rated wind speed	Rated thrust	Rated out-of-plane blade bending	Rated in-plane blade bending	Energy yield
80 - 3 (base)	19 rpm	13.9 m/s	1.	1.	1.	1
90 - 3	20 rpm	12.2 m/s	1.24	0.94	1.42	1.24
90 - 4	20 rpm	13.6 m/s	1.43	1.25	1.62	1.35
100 - 4	18 rpm	12.5 m/s	1.59	1.37	2.01	1.6

Table 4.2-1: Comparison of turbine size options (Blade bending at 15% of outer radius. Energy yield for Weibull parameters *A* = 9.6 m/s, *k* = 2.15)

Secondly a change of rotor speed has been analysed. The rotor speed for the land based turbine is 19 rpm. Offshore the noise requirements are lower and a higher rotor speed can increase the energy yield. It has also been seen that dynamically an increased rotor speed would have valuable effects on the structural design. The tower can be made stiffer without having the rotational frequency interfering with the first tower bending frequency. Rotor speed up to 23 rpm was considered for an 80 m diameter.

Rotor speed (rpm)	Tip speed (m/s)	2Ω frequency (Hz)	Energy yield (-)
19	81	0,64	1.
21	88	0,70	1.02
22	92	0,73	1.03
23	96	0,77	1.03

Table 4.2-2: The rotor speed options

Maintenance and availability

The maintenance costs for a wind energy converter at sea will be considerably larger than for the same wind turbine installed on land. This is mainly due to the higher transport cost for the maintenance personnel and equipment. It is therefore important to look at the maintenance requirements and costs. Different maintenance scenarios have been investigated. Kvaerner Turbin's experience from maintenance is limited as only three turbines have been built and operated. It is also considered that the possibility to reach the OWEC can be limited by hard weather conditions.

The starting point has been the assumed preventive maintenance for WTS 80 with Näsudden II as reference. From this level the scenarios for maintenance philosophies were a low level maintenance and a no-maintenance level. The following definitions are used:

Preventive maintenance (PM) is maintenance carried out in order to avoid unplanned stops of the machine. It can be divided into two categories of work:

- *regular planned maintenance (R-PM)*

Maintenance carried out from a previously made planning and instruction

- *state conditional planned maintenance (S-PM)*

Maintenance performed after inspections and conditional tests

Corrective maintenance (CM) is maintenance performed after a fault in order to put the faulty system into normal operation again. At the Kvaerner Turbin prototypes there has been, as said before, a lot of CM. It is however impossible at the present level of experience to quantify any rate of corrective maintenance. There is no information on MTBF, resource requirements etc. for the components used and corrected.

The preventive maintenance at Näsudden II and Aeolus II has during the 3 years of operation been at a lower level than foreseen. Most of the non-available time is of the category corrective maintenance, related to repair and rebuilding of systems due to malfunctions, faulty designs or faulty components. The preventive maintenance covers 70 hours annually as an average for the two units. The maintenance is at present not logged in detail. Therefore the different times are only estimates. Most of the maintenance is state conditional, i.e. it is carried out only if necessary. The inspection rounds are carried out with a considerably high frequency, with the smallest interval of once per week.

This study only covers the planned maintenance required for the turbine delivery from Kvaerner Turbin, i.e. parts above the tower are included and investigated. It is also assumed that the WTS 80, i.e. the alternative with a gearbox, is used as a model. The maintenance for WEC 3000 is very little known. The turbine design life is 25 years.

As part of the Opti-OWECS project two options for preventive maintenance have been investigated:

- ‘low maintenance’ concept
- ‘0-maintenance concept’

The philosophy for WTS 80 is to increase the maintenance interval to 6 months in step 1 and to 1 year in step 2. Step 2 will therefore be equal to the ”Low maintenance” alternative for the offshore unit.

The low maintenance level is based one a 1 year recurrence period. It is assumed that the unit is normally not visited by a maintenance crew in between the maintenance excursions.

For the 0-maintenance philosophy, the turbine is supposed to operate for a long time without maintenance. The assumption is that after commissioning and grid connection, a supervised test run is made. Engineers and mechanics can stay at the turbine, or in its vicinity, for some days having the possibility to repair and adjust malfunctions of components or systems. After the test run and the required adjustments, the turbine shall be left at its own and no maintenance should be carried out during a set period of time. The length of this period assumed to be at least 5 years. This time interval is used as there is a reasonably good chance to design systems with such a maintenance free operational period.

Components and systems were examined and table 4.2-3 is the result of the study.

Preventive maintenance hours for the turbine concepts of Kvaerner Turbin						
		Annual man-hours				
System	Action	N II	WTS 80	Low-M	0-M	Type
Leading edge	Refurbishment	5	5	5	5	S-PM
Surface	Lightning repair	1	1	0.5	0	S-PM
Blades		**6**	**6**	**5.5**	**5**	
Blade bearings	Grease lubrication	16	8	2	-	R-PM
Pitch bearings	Grease lubrication	2	1	0.2	-	
Pitch bearings	Exchange	3	3	1	1	S-PM
Hydraulics	Refurbishment	1	4	4	0.5	S-PM
Pitch system		**22**	**16**	**7.2**	**1.5**	
Turbine brake	Exchange of linings	10	-	-	-	
Turbine shaft bearings	Grease lubrication	-	2	2	1	R-PM
Gearbox	Exchange of oil	2	2	2	1	S-PM
Gearbox	Exchange of filters	1	1	1	0	S-PM
Drivetrain		**13**	**5**	**5**	**2**	
Electric system		**2**	**2**	**1**	**0**	S-PM
Yaw brake	Exchange of linings	5	-	-	-	
Yaw bearing	Grease lubrication	4	4	2	0	R-PM
Yaw gear	Grease lubrication	0.5	0.5	0.2	0	S-PM
Hydraulics	Refurbishment	2	4	4	0.5	S-PM
Yaw system		**11.5**	**8.5**	**6.2**	**0.5**	
Hydraulic syst	Exchange of oil	2	2	1	0	S-PM
Hydraulic syst	Refurbishment	2	2	1	0	S-PM
Hydraulic syst	Refurbishment	**4**	**4**	**2**	**0**	
Fire prot syst	Refurbishment	**5**	**0.2**	**4**	**2**	R-PM
Others		**8**	**6**	**5**	**2**	S-PM
TOTAL 25 years		**1788**	**1193**	**898**	**325**	

Table 4.2-3: Planned maintenance for the different concepts (NII = Näsudden II)

To draw conclusions about the right maintenance strategy is not very easy. From the experience we have in design and operation it is doubtful that the 0-maintenance philosophy will work. Normally a complicated system as a wind turbine, is dependent on almost 100% function of all components. Well trained inspectors are also very efficient in finding not only errors but, what is more important, indications about rising errors which can be taken care of in an early state. For the final design the low-maintenance philosophy with 1 year recurrence period is recommended for preventive maintenance.

To decrease the need for corrective maintenance, design changes to achieve an increased availability have been investigated. The conception has been to study the introduction of redundant systems and to look at higher quality designs. A third alternative is to remove complicated systems or simplify them. The systems chosen for deeper investigation in the final design phase are gearbox, hydraulics, control system, auxiliary power supply and fire protection system.

4.3 Support Structure and Installation Procedure

4.3.1 General

The result of an evaluation is described wherein, in which a number of specific support structure concept options have been assessed.

The work has focus on three support structure concepts (shown in Figure 3.3-2) ie:-
- GBS Lattice Tower - Floated Installation (Option 8b)
- GBS Monotower - Floated Installation (Option 4)
- Monopile - Floated or Lifted Tower Installation (Option 1/2)

These three concepts cover a wide spectrum of possibilities. The lattice tower represents stiff-stiff dynamic characteristic and is most like the jacket structure used in offshore construction. The self floating GBS monotower has soft-stiff characteristics. Both the lattice tower and the GBS monotower are assembled either in a dry dock or at the quay side, obviating the need for costly offshore lifting equipment. The final option, that of the monopile, is based on a form of piece meal construction with the pile installed first followed by the tower. This is likely to exhibit soft-soft or soft-stiff dynamic characteristics and to be strongly governed by combined aerodynamic and hydrodynamic loading.

Thought out the work, simultaneous consideration has been given to the design of the support structure and to its installation. This is crucial in the development of a cost effective design since installation constitutes such a major part of the support structure costs.

4.3.2 GBS Lattice Tower - Floated Installation

General Arrangement

A lattice tower has been configured to support the nacelle and rotor based on North Sea site conditions (NL-5 site) with a water depth of 25m (LAT).

The overall configuration details are given as follows:-
- Overall Height - seabed to underside of nacelle 80.7m
- Base Width (measured between leg centres) 50.0m
- Foundation Diameter (each) 9.0m
- Foundation Weight (total) 1000 tonnes

The upper half of the structure comprises a trussed framework with chord members to resist the overturning moment and to support vertical loads, diagonal members to resist the shear forces and plan elements to provide torsional restraint. The plan size over this part of the structure is limited to avoid interference with the passage of the rotor blade.

In the lower half of the structure no such limitation exists, with the three legs and associated bracing raked to achieve a large base size, the base size being important in limiting the environmental component of the foundation reaction.

The essential characteristics of the lattice tower design are given as follows:-

- stiff-stiff dynamic characteristics - so as to limit the dynamic amplification of hydrodynamic loading and to provide a robust arrangement,
- a multi-leg arrangement provides redundancy, further adding to the overall robustness of the structure and potentially results in wave cancellation effects,
- the floated installation resulting in substantially reduced offshore installation equipment and vessels.

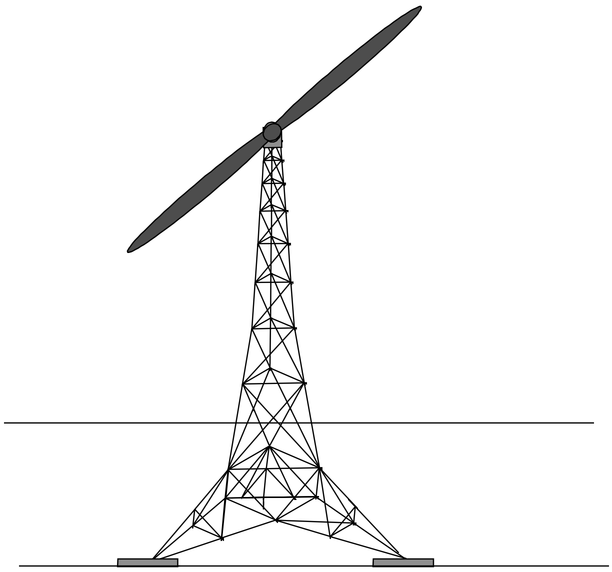


Figure 4.3-1 Lattice Tower

The lattice tower is made up of comparatively small diameter members with modest spans.

Fabrication

It is envisaged that construction would be in a dry dock with fabrication of several units being carried out simultaneously, as shown in Figure 4.3-2. As each unit neared completion, the nacelle and rotor would be installed and commissioned, then when all the units in the dock were complete the dock gates would be opened and pontoons would be floated in.

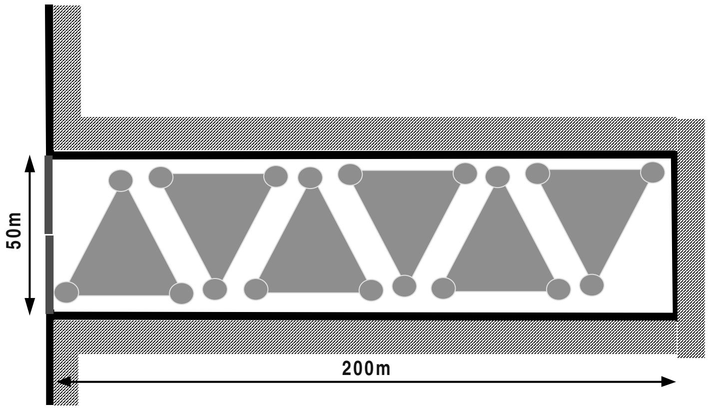


Figure 4.3-2 Dry Dock Arrangement

Installation

Each structure requires three pontoons, one for each leg, so as to float. Pontoons are purpose built and each comprises three vertically orientated buoyancy tanks with a workdeck spanning between the three at the upper elevation, as shown in Figure 4.3-3.

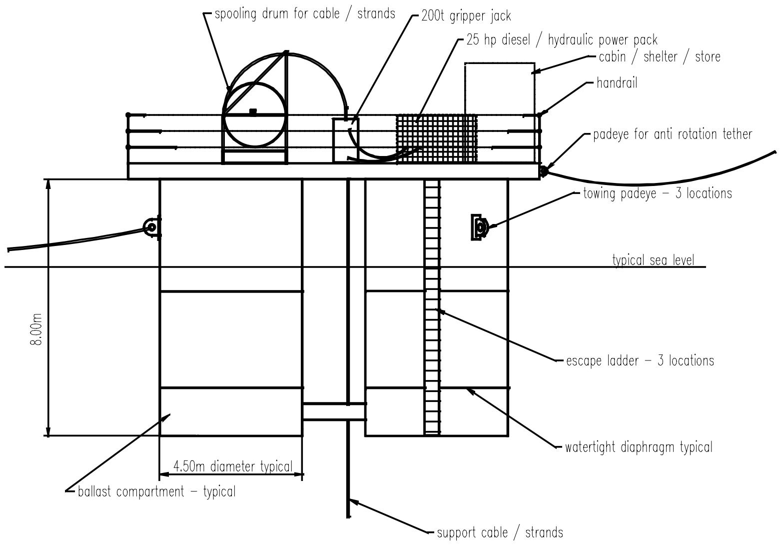


Figure 4.3-3 Pontoon Elevation

The pontoons are each equipped with a jacking system (shown in Figure 4.3-4 as hydraulically powered strand or gripper jacks).

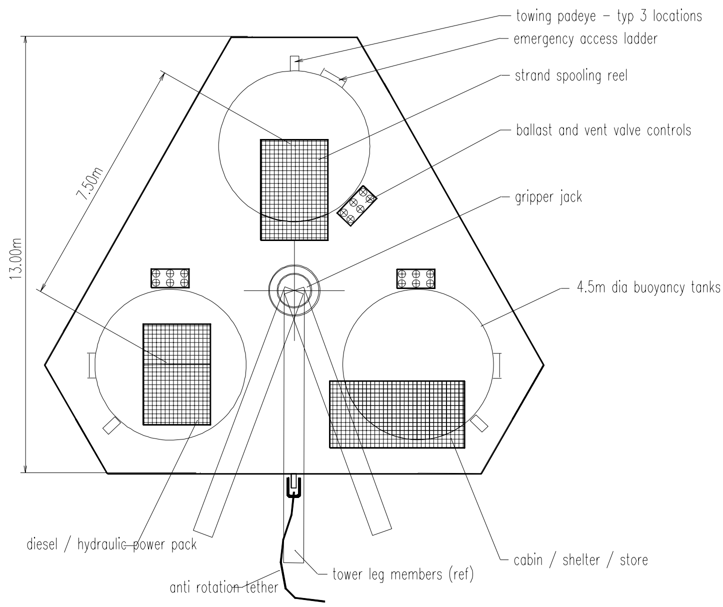


Figure 4.3-4 Pontoon Plan

The pontoons are floated in through the dock gates and positioned over each of the foundations of a single OWEC support structure. A jacking system is then attached to each of the foundations allowing the support structure to be gradually raised and secured for the tow; see Figure 4.3-5.

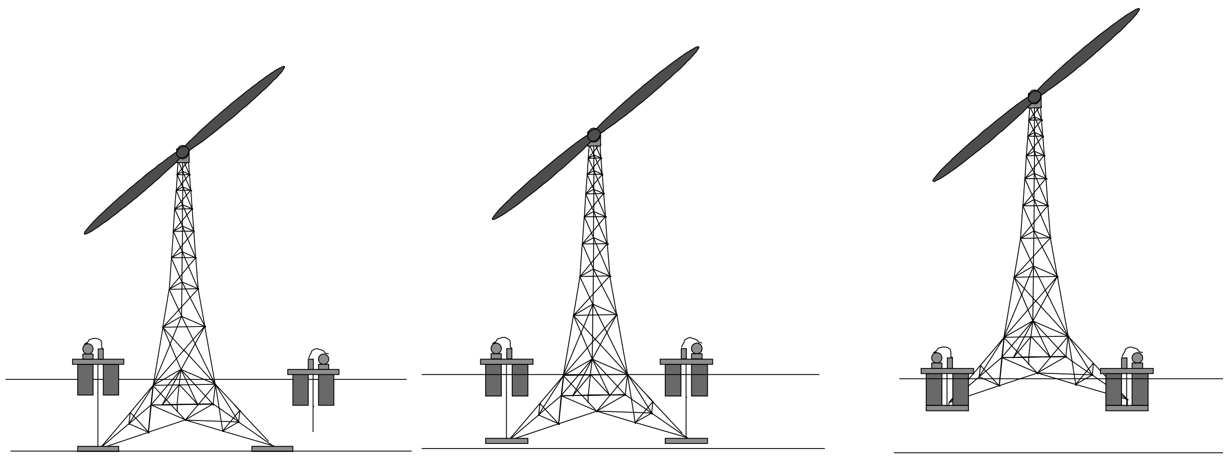


Figure 4.3-5 Preparation for Tow

Once secured, the floating unit is towed to the offshore site where the reverse procedure is adopted. The jacking system is reversed with the support structure slowly lowered to the seabed.

Decommissioning of the unit follows the reverse of the above procedure. The raising of the unit will take longer that the lower owing the adhesion between the underside of the base and the seabed but given sufficient excess buoyancy and time (several hours) the unit can be raised and transported away using the same equipment of tanks and jacking system.

The need for seabed preparation will depend strongly on the soil conditions that pertain. In most situations preparation measure are likely to checks for levelness and the removal of obstructions. Then following installation, some form of scour protection will be necessary, probably in the form of artificial seaweed.

Overview

The lattice tower, although potentially viable, has proved problematic under aerodynamic fatigue considerations. Its stiff dynamic performance attracts very appreciable dynamic response due to aerodynamic forces which combine with the high brace stress concentrations to produce poor fatigue performance particularly in the upper tower element where heavy walled chords are required to achieve satisfactory fatigue lives (Section 4.6.3).

The support structure has been subject to a range of analyses associated with both the fatigue and in-place conditions including those addressed to the geotechnical assessment off the foundations. The results demonstrate that, although sensitive to fatigue, the arrangement offers a fit for purpose extreme event design and with low sensitivity to soil stiffness variations (Section 4.6.2). Based on the assumed undrained soil conditions, the foundation exhibits relatively high utilisations in sliding.

4.3.3 GBS Monotower - Floated Installation

General Arrangement

A GBS monotower has been configured to support the nacelle and rotor based on the Baltic Sea site conditions (location S-1) with a water depth of 15m (LAT).

The overall configuration details are given as follows:-

- Overall Height - seabed to underside of nacelle 63.3m
- Foundation Diameter 25.0m
- Foundation Weight 3000 tonnes

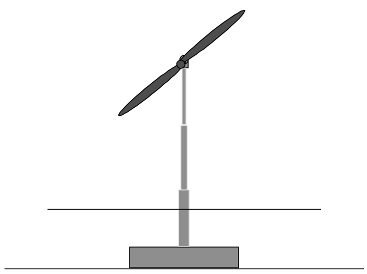


Figure 4.3-6 Monotower

The monotower comprises a single tower of tubular type construction. This is either manufactured as a long cone section or as tube sections which are tapered by the inclusion of short cone elements (as shown above).

The base forms the gravity base. This is either constructed of steel or concrete and contains ballast material i.e. sand, concrete, rock or iron ore.

The essential characteristics of the GBS Monotower design are given as follows:-

- with a natural period of 1.97 seconds (0.50Hz),, the monotower exhibits a soft-stiff dynamic characteristic ie with respect to the WTS wind turbine with a rotor speed of 19rpm.
- a single column arrangement which offers simplicity and the opportunity for application in ice conditions (for application at site S-1 the sea level variation was to great to justify the use of a ice cone).
- the floated installation resulting in substantially reduced offshore installation equipment, vessels and time.

Fabrication

Like the lattice tower, it is envisaged that construction would be in a dry dock with fabrication of several units being carried out simultaneously. As each unit neared completion, the nacelle and rotor would be installed and commissioned.

Installation

To achieve the bearing capacity predicted by geotechnical calculations and to minimise the susceptibility of the foundation to scour, the seabed beneath the foundation will be subject to some form of seabed preparation. The extent of this work will depend on the exact seabed surface conditions at the site and this may vary across the site. In the extreme condition it may be necessary to establish a bed of compacted crushed rock on a separating geotextile [4.3-1]. This though is unlikely to be necessary and a more likely requirement will be that the site will need to be survey to ensure levelness and the absence of obstructions and that scour protection probably in the form of artificial seaweed (which would be more likely to be laid after foundation installation).

Like the lattice tower, floating and lowering stability play an important part. Options for installation of the monotower support structure fall into four generic types, each with a multitude of possible variations. The four basic methods are described below:-

Stability Provided by a Heavy Base

With this option a very large base (at least 40m diameter by 5m high) is required. The lower part is filled with ballast whilst the upper section provides the necessary buoyancy to float the structure.

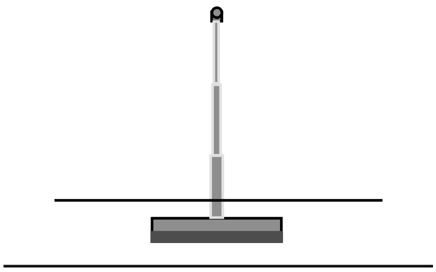


Figure 4.3-7 Heavy Base

Floating at a draft of some 2-3m, the water plane provides stability during transportation, whilst lowering stability is achieved by ensuring that the centre of gravity remains below the centre of buoyancy. Preliminary calculations associated with this method of installation suggest that the weight of the base could exceed 10,000 tonnes.

Stability Provided by Grounding Base
In shallow water depths the proximity of the seabed can be utilised to stabilise the structure during installation. Here the structure is deliberately inclined during lowering.

This introduces two benefits. Firstly, the stability offered by the water plane area of the base can be maintained over a much greater depth and secondly, once contact is made with the seabed, the reaction assists in stabilising the unit.

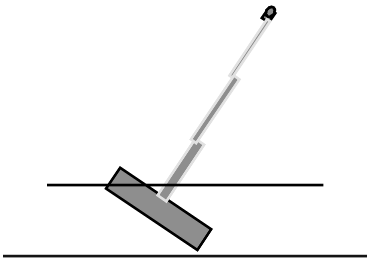


Figure 4.3-8 Grounding Base

The method has major benefits in very shallow water depths, however even in water depths of 15m and over the size of the base needed is excessive. The approach initially puts the soil under appreciable pressure and this may result in soil deformation leading to permanent inclination of the platform.

Stability Provided by Vertical Auxiliary Buoyancy
This method is more representative of the conventional approach for a problem such as this. Here auxiliary tanks are attached to the structure prior to sailaway.

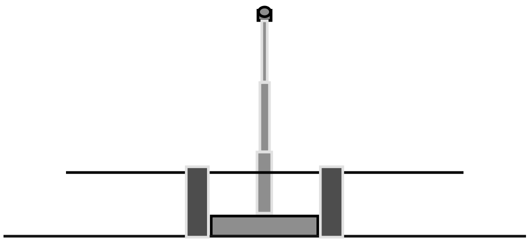


Figure 4.3-9 Vertical Auxiliary Buoyancy

These provide sufficient stability for both the tow and lowering sequence. Once safely secured on the seabed, the tanks are removed and returned for re-use. Preliminary calculations with this approach, indicate that the tanks could be relatively heavy.

Stability Provided by Horizontal Auxiliary Buoyancy
Like the above method this approach makes use of auxiliary buoyancy tanks, here though they are floated horizontally. Attachments of the auxiliary tanks can be made either at the column or at the base of the support structure. Connecting to the column necessitates some form of rolling joint which can offer freedom to vertical movement whilst providing moment restraint. Connecting to the base offers an all together more feasible arrangement with the base lowered or raised by a jacking system connecting the tanks and support structure base.

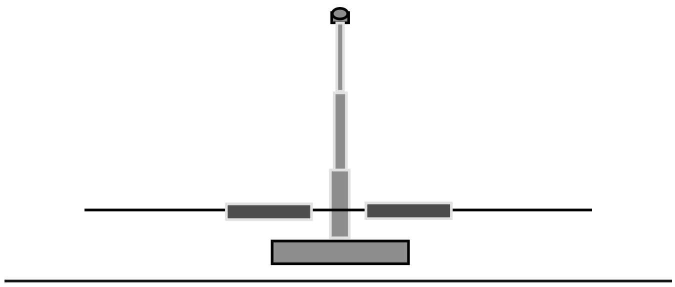


Figure 4.3-10 Horizontal Auxiliary Buoyancy

In practice the auxiliary tanks comprise two fairly standard shaped barges. Each structure requires two barges so as to float. The barges could be converted from other uses but would preferably be purpose built. Each would be equipped with suitable lifting equipment so as to be able to lift the OWEC unit, transport it, then lower it safely to the seabed. The lifting equipment may comprise strand jacks as used with the lattice tower or if the loads are sufficiently low, a simple block and tackle arrangement as given below may suffice.

Decommissioning of the unit follows the reverse of the above procedure. The raising of the unit will take longer that the lower owing the adhesion between the underside of the base and the seabed but given sufficient excess buoyancy and time (several hours) the unit can be raised and transported away using the same equipment of barges and jacking system.

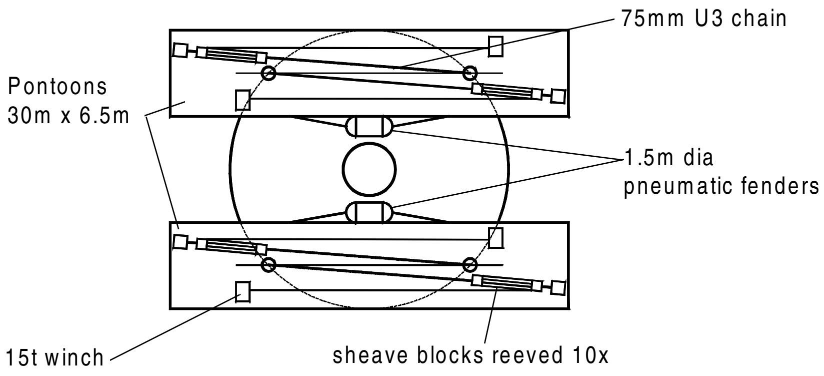


Figure 4.3-11 Possible Pontoon Configuration

Overview

The GBS monotower tower, although potentially viable, has proved problematic under hydrodynamic extreme loading considerations. Here very significant vertical loads which occur during the passage of the wave, have resulted in the necessity for substantial quantities of ballast material. This leads to increased ballast cost but also more complex installation procedures.

The support structure has been subject to a range of analyses associated with both the fatigue and in-place conditions including those addressed to the geotechnical assessment off the foundations. The results demonstrate that, although sensitive to fatigue, the arrangement offers a fit for purpose design with low sensitivity to soil stiffness variations (Section 4.6.2). Based on the assumed undrained soil conditions, the foundation exhibits satisfactory utilisations.

4.3.4 Monopile

General Arrangement

A monopile support structure has been configured to support the nacelle and rotor based on the North Sea site conditions (site NL-1) with a water depth of 20m. The structure comprises a pile which is installed first and a tower section which is either lifted or floated over the pile.

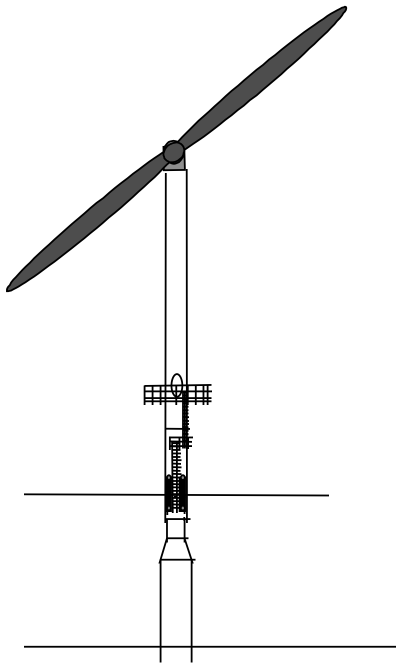


Figure 4.3-12 Monopile Configuration

The overall configuration details are given as follows:-

- Overall Height - seabed to underside of nacelle 79.0m (soft-soft
- Tower diameter approx. 2.8m solution)
- Pile penetration approx. 25m

At this stage in the design development consideration was given to both soft-soft and soft-stiff support structure concepts i.e. soft-soft with natural period of 3.5 seconds and soft-stiff with natural period of 2.8 seconds. Preference was however given to the soft-soft solution since although it was evident that fatigue design would be challenging the opportunities for achieving an optimal design (least weight/cost) were greater. This was apparent owing to the fact that the soft-soft solution benefited from improved damping (Section 4.6.1) and was governed by the fatigue design, whilst the soft-stiff solution was governed by stiffness criteria. This latter condition potentially lead to the requirement for a larger diameter tower with heavier wall thicknesses (Section 4.6.3, Table 4.6-2)

Fabrication

It is envisaged that prefabrication of the tubular tower elements and much of the outfitting would be carried out by a specialised contractor with assembly at a location close to the wind farm. At the assembly site the components parts would be unloaded and stored before being put together at the quay for transportation to the wind farm.

Installation

Installation of the tower and turbine is achieved by either lifting it in the conventional way or by floating it over the offshore installed pile. Float-over installation requires transporting the tower in the vertical orientation. One possibility is shown in Figure 4.3-13.

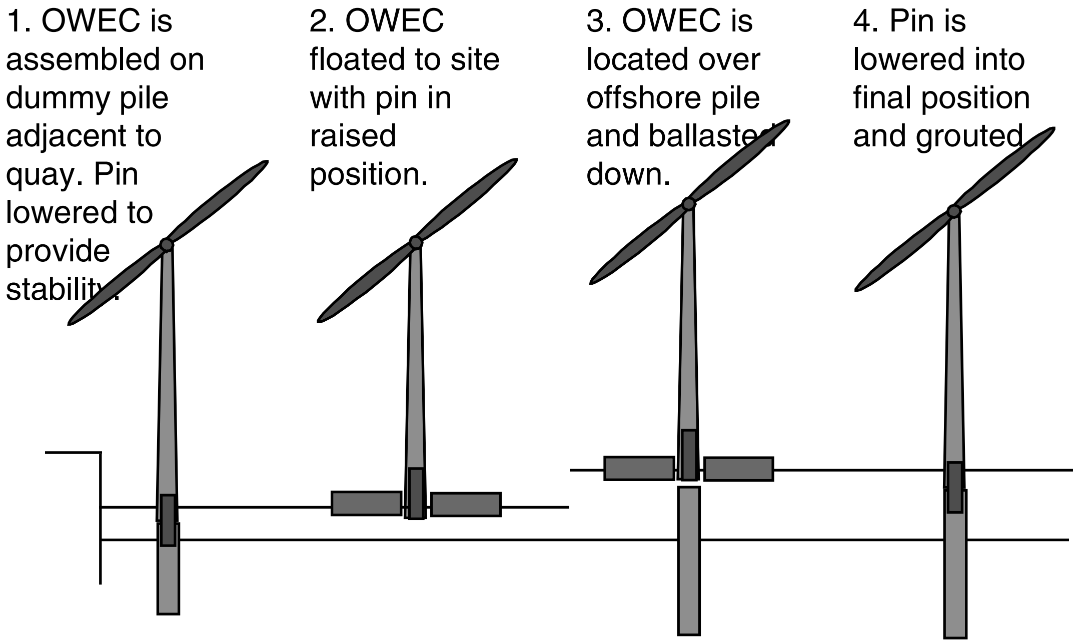


Figure 4.3-13 OWEC Fabrication and Float-Over Installation

In the above arrangement, the tower structure is erected at the quay side on dummy piles and is secured in the upright orientation by means of a pin that is lowered from the tower into the pile. When fabrication and the necessary commissioning work is complete, a specially adapted barge is floated in and securely attached to the tower. At this point the pin is raised and the vessel is raised either on a rising tide or by deballasting and is prepared for onward transport to site. Once at site the pin is lowered over the preinstalled pile and the vessel and tower is lowered either on a falling tide or by ballasting. Finally the permanent connection between the tower and the pile is effected by grouting the two together.

The use of a grouted pin between the pile and tower offers the opportunity for correcting some inclination in the pile that will inevitably occur. The tolerances of the grouted annulus between the pin and the pile/tower may be insufficient to correct the large inclination that could occur and is thought likely that a mitred bolted flange could be necessary to correct and final inclination.

Such a flange would indeed appear necessay for decommisioning the OWEC. It is anticipated that the tower, however installed, would incorporate a flange joint towards the lower end of the tower and that in decommissioning this would be released allowing the tower to be lifted away. The pile would be need to be cut at a level just below the seabed and lifted way. Cutting the pile would require divers working from within the pile and using diamond/abrasive cutting tools or shaped charges.

Overview

The monopile concept has been identified as offering the greatest potential of those support structure concepts reviewed, for the application at the offshore site under consideration. Its soft dynamic characteristics introduces greater damping and lower dynamic response leading to potentially improved aerodynamic fatigue loads (Section 4.6.4) whilst at the same time attracting greater damage from the hydrodynamic loading i.e. the result of having the structural frequency closer to the wave frequency range. The concept benefits from simple inexpensive construction methods and alternative approaches have been put forward for installation. Both of these i.e. lifting and float-over installation methods, warrant examination.

4.4 Grid Connection and Farm Layout Options

4.4.1 Overview

Previous studies have shown that an economic offshore wind farm should be large, particular due to consideration of the grid connection. The exact size is hard to specify, but somewhere in the region of 60 - 300 MW total power appears reasonable. There are a number of ways to physically arrange the large number of individual machines required for such installations. The layout chosen will influence both the aerodynamic efficiency of the whole farm, and the cost of wiring the individual turbines together.

In order to provide useful electricity, an OWECS must be connected to a land based power grid. This connection comprises two parts: firstly the individual turbines must be wired together to ‘collect’ the power, and secondly one or more cables must run between the offshore site and a public electricity grid onshore (the powert transmission). The choice of power collection scheme, however, is closely linked with to the array layout, which is why the two superficially disparate features are considered together in this section.

4.4.2 Grid connection

The ‘grid connection’ is considered to be the electrical system that collects the power provided at the turbine connection points, collects the power at the central cluster point(s) and transmits it to the onshore connection point with the public grid.

The power collection consists of:

- transformers to collection voltage (usually at every turbine)
- switch gear and circuit breakers
- cables or transmission lines inside cluster

The following components can be distinguished as comprising the power transmission system:

- transformer to transmission voltage
- inverters (if any)
- switch gears and circuit breakers
- transformers to voltage of the public grid (if any)
- cables or transmission lines

With regard to connection to the public grid, a distinction should be made between a wind farm, of say 60-300 MW, and one or several wind turbines. Due to the large amount of power involved the wind farm will be connected at a higher voltage level. This is advantageous because in general there are less restrictions in case of a connection at a higher level and more options are available for possible required adaptations (e.g. for reactive power).

Basic options for grid connection

In figure 4.4-1 the basic options for the grid connection are given; in principle these apply for both offshore as onshore wind farms. All kind of variations of these basic options are possible. No real technical restrictions are foreseen because nowadays electronic components are available for a wide variety of applications and they are modular. The main choice which has to be made is between an AC or DC connection to shore. Also for the power collection there is a choice between AC and DC. The first 2 options, A1 and A2, are the ones commonly used for onshore farms. Also an onshore farm exist with the layout according to option B. Option C, AC coupling of all wind turbines together with an DC connection to shore (‘AC island’), may cause technical problems with respect to achieving stable operation.

Options for components

In the following the options for the components will be discussed. Although the generator is, in this project, regarded as part of the wind turbine it will be discussed here because of its implications for the grid connection.

The generator types commonly employed in wind turbines are the induction generator and the synchronous generator. The advantage of the induction type is its simplicity and corresponding low cost, but it requires reactive power. The synchronous generator, in combination with a AC-DC-AC link, allows for variable speed operation of the wind turbine which results in a higher energy yield (assuming constant lambda operation) and lower fatigue loading. The voltage level of the common generators for megawatt turbines varies from 460 V to 1.2 kV. A higher voltage level (e.g. WTS80 concept) can be advantageous in order to reduce the cost for transformation to higher voltages for transmission.

Transformers are used to change the voltage level. A high voltage level is advantageous for power transmission because the losses (due to Ohmic resistance) depend on the square of the current; by increasing voltage level the current is decreased, for the same electrical power.

Several voltage levels can be used within an offshore wind farm. It is possible to employ a transformer for every wind turbine to bring the generator voltage level to the voltage level I. The power of a cluster consisting of a number of wind turbines can be collected and transformed to another voltage level II. The power of all clusters can then be collected at the connection point of the wind farm and prior to transmission to shore, transformed to voltage level III. The number of voltage levels will depend on the total power of the wind farm and on the cost of the transformers. The chosen voltage levels should be in accordance with European standards.

Switch gear, containing a circuitbreaker, are necessary to deal with any short circuits. The application of switch gears at each turbine and/or at the collection point(s) must be determined by the requirements, in terms of availability and safety, of the owner of the offshore wind farm.

For the transmission lines one has to consider both the collection inside the farm and the transmission to shore. The options for the collection inside the farm are to use (submarine) cables or overhead lines [4.4-1]. The substantial advantage of overhead lines is the relative (very) low costs compared to submarine cables (including laying costs). Perhaps offsetting this economic advantage is that their reliability in a marine climate might not be adequate, and it seems unlikely that overhead lines would be practical for very large turbine spacings. Furthermore it should be checked whether the lines might present an obstacle during installation and maintenance activities and whether the required large tower height is advantageous in a system consideration.

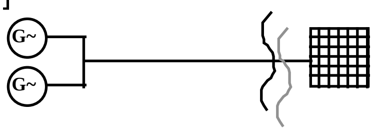
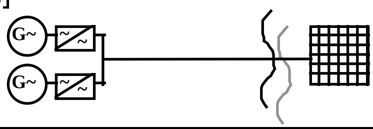
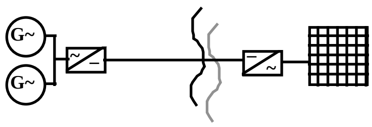
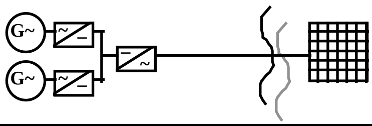
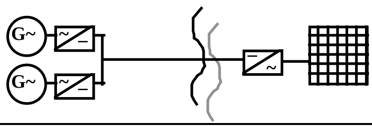
	AC Connection to shore	DC Connection to shore
AC Connection within the windfarm	[A1]  [A2] 	[C] 
DC Connection within the windfarm	[B] 	[D] 

Figure 4.4-1: Basic Grid Connection Options

AC versus DC technology

Transmission can be either be AC or DC. AC transmission involves high dielectric losses (the isolation material acts as a capacitor); these losses are proportional to the cable length and the voltage. Three wires are necessary for AC transmission corresponding to the 3 phases. DC transmission requires expensive converters. For short distances AC transmission is the most cost effective option and for large distances DC transmission is preferable. The cross over point depends on the costs of the components involved and can be further investigated.

HVDC (High Voltage DC) transmission systems have been increasingly used in recent years to transport electricity from remote energy sources to the distribution grid. At present the maximum capacity is 600 MW; for the year 2015 1000 MW is expected to be feasible at approximately the same cable cost per km [4.4-2].

Currently used generators operate with AC as well as the public grid. This means that, where an intermediate DC link is used, both AC/DC rectifiers and DC/AC inverters are required. The converter stations consist, amongst other items, of thyristor switches. They have to be placed in series because they can only switch a limited voltage (8kV). With developments in semi-conductor technology, it is expected that the voltage which can be switched by one thyristor will grow gradually. This means lower costs, at equal power, and lower energy losses. As alternative IGBT (insulated gate bipolar transistor) switches can be used which do not need reactive power.

Cluster layout

The design criteria for layout of the cables or lines within a cluster are the costs of the involved components and the reliability. A star connection results in the highest reliability compared to a circuit or chain connection. The higher capital costs for the extra cables for a star connection should be balanced with the higher energy yield.

4.4.3 Wind farm layout

The wind turbines in a farm can be placed regularly in lines (rectangular) or in several sub clusters as in the Blekinge study. A wind turbine which is placed inside the farm (and thus standing in the wake of another wind turbine) will experience a lower mean wind speed and a larger turbulence intensity. The larger turbulence results in larger fatigue loads. Models exists to predict these wake effects [4.4-3].

In order to limit the power losses, wind turbines in an onshore farm are placed at a distance of 3 to 5 D (rotor diameters) from each other perpendicular to the prevailing wind direction; in the other direction the spacing is 8 to 10 D. For offshore wind farms it may be necessary to have a larger spacing. The reasons for this are threefold.
Firstly, equalization between the mean wake velocity and the (unchanged) ambient wind speed outside the wake, needs a longer distance behind the turbine (because of the lower absolute turbulence intensity). Therefore offshore wind farms with the same spacing as onshore wind farms have lower aerodynamic cluster efficiency.
Secondly, the relative increase of the turbulence intensity in the wake is larger in an offshore situation. According to [4.4-4] the calculated increase of turbulence intensity in case of the Vindeby lay-out is about 100 % (from 7 % above sea to 14 % in the wake); onshore the increase would be about 40 % (from 14 % to 19 %).
Another reason to use a larger spacing is that in general the restrictions on the area available to the farm are less for an offshore situation. The lower losses due to a larger spacing should be balanced with the higher costs for the power cables (including laying costs and the power losses along these cables) inside the farm. The soil properties and variation of water depth at some specific sites may be such that the actual farm layout should be different from the ’optimum’ layout.
A fourth reason is the overall economics with respect to the levelised production costs. Any OWECS suffers higher investment costs in comparison to an onshore farm, which favours a larger turbine spacing.
In other to determine the layout of an actual wind farm use should be made of a wind farm efficiency code in combination with a cost model.

4.5 Operation and Maintenance Options

4.5.1 Introduction

Labour costs and spare parts are the main cost drivers of operation and maintenance (O&M) for onshore wind turbines. Furthermore an O&M service can be set up which enables a repair within one day. In contrast, the O&M costs of an offshore wind farm are dominated by the expenses of transportation to and from the offshore site and the expenses of possible lifting operations. The access to an offshore wind farm is limited by bad weather conditions. This requires a very reliable turbine in order to achieve an acceptable availability.
Careful consideration of the O&M strategy for an offshore wind farm is thus essential in order to minimise the number of expensive operations. In this discussion, attention will only be given to the requirements of the wind turbine; it is being assumed that the O&M for the support structure and grid connection are well-known and relatively small in comparison to those related to the wind turbines.

An operation and maintenance strategy can be established using the following steps:
- consider the OWECS objectives
- consider the turbine design
- consider the maintenance approach
- consider the O&M ’hardware’
- define the O&M strategy

In general the four latter aspects have to be (re)considered several times in order to reach the best O&M concept.

The chosen wind turbine design determines the O&M behaviour of the OWECS in the first place. The frequency of failures and the required preventive maintenance tasks depend on the reliability of the wind turbine. The maintainability of the turbine, e.g. how easy it is to exchange nacelles or other components, will have implications for the choice of lifting equipment and the endurance of the operation. These examples already show the importance of coming to the right decision when considering the wind turbine’s design and concept. An optimum operation and maintenance strategy will never lead to a system performing better than the design performance of the wind turbine.

The next step requires the selection of the appropriate maintenance approach which takes the requirements of the chosen wind turbine design into account. There are two different types of maintenance actions: Preventive Maintenance (PM) aims to reduce the occurrence of failures, and Corrective Maintenance (CM) that involves action only after a failure has occurred. Any approach to maintenance can employ, either or a combination of both of these actions.

With a knowledge of the wind turbine design and the maintenance approach, it is possible to estimate the resulting work load necessary for maintenance, in man hours per year, and to determine the number of personnel required to ‘operate’ the farm. Armed with this information, selecting the 'maintenance hardware' is the next step. Decisions about a possible maintenance base, crew transporting devices, lifting equipment, etc., have to be made. The size and type of any lifting equipment required depends on the wind turbine's size and maintainability. The number of crew transporting devices necessary depends on the chosen maintenance strategy and the failure rates of the turbines, which in turn determines the probability of simultaneous occurrence of failures. In choosing the crew transport device the expected weather conditions (wind speed, wave height and visibility) are important.

Finally, the maintenance strategy has to be specified. With respect to the overall objective, i.e. minimising levelised production costs, the O&M and capital costs involved have to be weighed against the produced energy, and thus income generated. Increasing the maintenance efforts will improve the overall availability of the wind farm but will also increase the costs related to O&M.

4.5.2 Possible hardware for operation and maintenance

Various specialised equipment is available for maintenance tasks on offshore installations. As far as OWECS are concerned the major issues are (1) the position and nature of a maintenance base from which activities can be 'launched', (2) the means by which personnel are transported to and from the OWECS and (3) the choice of heavy lifting equipment. Decisions must be made by balancing the additional hardware costs against any savings in maintenance costs and increase in energy production brought about through improved availabilities.

This section reviews the options available for the main maintenance equipment, and highlights their advantages and disadvantages.

Location of maintenance base

Maintenance operations may be considerably simplified by the adoption of a permanently or regularly manned maintenance base. It may well be possible, however for maintenance to be undertaken in a perfectly satisfactory manner without such a facility. A maintenance base, if necessary, can be located onshore, either at an existing harbour or a purpose built site, or offshore close to the wind farm.

From the outset, the proposal of a purpose built on-shore maintenance base along the coast in order to minimise the distance offshore wind farm to shore, can be ruled out. The sheer numbers of existing, well equipped harbours along Europe's coasts mean that a purpose built solution cannot be justified. The travelling time saved will not compensate the initial investment costs for erecting such a base, with facilities, including cranage, docking etc., that are readily available at any existing harbour.

Whether the costs of an offshore base are justified, depends to a great extent on the distance from the offshore wind farm to the nearest suitable harbour. The costs for crew transportation from a mainland base to the wind turbines and the additional costs for transporting every component, requiring major overhaul, to the mainland base have to be weighed against the erection costs of an offshore base.

Possible offshore maintenance bases

Three basic options exist for an offshore maintenance base. A support vessel can provide accommodation for crews, permanently stationed within the wind farm. In case of a sudden weather change while working on the wind farm, it offers a relatively safe retreat for travelling maintenance crews. The support vessel is able to move around the wind farm and so helps to reduce the travelling time between the individual wind turbines. At regular intervals it can return to a harbour for relief of crews and fresh stocks of spares etc. However, the support vessel does not offer a stable working 'platform', and certain maintenance operations will require a calm sea. In addition the available space onboard is limited. Thus, executing major overhauls, e.g. blades, gearboxes, on board of a support vessel at a regular basis seems very unrealistic.

A maintenance base can be sited on a fixed structure located centrally in the wind turbine cluster. The base can, in contrast to the support vessel, not only offer accommodation facilities but also workshops for overhauling complete nacelles or major components, such as blades or gearboxes. Combining the structure with the housing of the high voltage transfomer of the shore connection can be a possible way of reducing the initial investment costs.

The advantages of a support vessel can be combined with those of the purpose built support structure in a self propelled jack-up platform. It is able to move around the wind farm and, once jacked-up, it offers a stable working platform unaffected by the state of the sea. Such a self propelled jack-up platform seems to be the preferable choice since it can be equipped with both a high capacity crane as well as crew accommodation.

Crew transport

Access by helicopter or vessel seems to be the most reasonable approach for offshore wind turbines. A sample cost comparison of helicopter against vessel access shows that the helicopter offers the fastest but most expensive alternative. However, the downtime costs, saved by using the faster helicopter, do not compensate the higher operating cost of the helicopter.
The advantage of using helicopters for OWEC access, lies in the decreased weather dependency. This advantage also has to be weighed against the initial modification costs in order to adopt the OWEC for helicopter access.

Lifting equipment

At least two maintainability approaches for the wind turbine design concepts can be distinguished:

- At first, failures can be repaired through the exchange of individual components
- Alternatively, machines can be designed to allow the modular exchange of assemblies of components or of a complete nacelle.

The use of helicopters and of a lifting system built into the OWEC are both possible solutions if the first approach is chosen. However, it should be kept in mind that helicopter lifting operations are expensive, susceptible to wind gusts and therefore not possible in poor weather, and impractical if components have to be heaved in order to remove bolts, etc. The helicopter is the most expensive lifting device with respect to the ratio of costs and lifting capacity.

Lifting equipment built into the structure of the OWECS is ready at hand, whenever it is needed. Thus, a fast reaction time in case of lifting equipment demand, is ensured. However, providing every wind turbine with a lifting system means high initial investment costs.

For the second approach, the exchange of modules, three alternative lifting devices are practicable:

- crane vessel
- jack-up barge
- self propelled jack-up platform

Crane vessels come in three different types: the flat bottom barge type, the ship shape type, and the semi-submersible vessel type. Lifting operations with these types of crane are dependent on the wave height, which restricts the execution of the operations to certain weather conditions. Jack-up barges and self propelled jack-up platforms are also dependent on the wave height, but only while not being in the jacked up position. Once in working position, they offer a stable working platform where lifting operations can be executed almost regardless of the wave height. The lifting operation itself is, limited to a certain maximum wind speed, which is more or less the same with all three alternatives.

4.5.3 Possible maintenance strategies

It is possible to conceive of a number of plausible O&M strategies for OWECS. Each attempts to balance capital costs, operational costs, and energy production in a different way. In considering the ideas, it is important to remember that the objective is to minimise the levelised cost of the electricity produced by the offshore farm. This is not the same as maximising the energy production, and indeed the most economic scheme may be one which sacrifices a little amount of produced electricity for a great reduction in maintenance costs.

In practice, all wind turbine/OWECS concepts are likely to have teething troubles at their introduction. For a period immediately after the construction of a wind farm, say 6 months, a special commissioning maintenance regime will have to be adopted until the teething troubles are ironed out. For the subsequent mainstream operation, the following maintenance strategies have been identified.

The no-maintenance strategy

With this strategy neither preventive nor corrective maintenance tasks are executed. The failure, and thus shut-down, of individual wind turbines during operation of the wind farm is taken into account in the original OWECS design. One approach can be to incorporate redundancy in the number of wind turbines, that is, more wind turbines are built than are initially necessary to produce the farm’s design power output. During the lifetime of the plant, many machines will fail, but the redundancy should be sufficient for the farm to always meet or exceed its design power output.

Alternatively the decrease of OWECS availability over time has to be accepted as a design ‘feature’. Thus the rated capacity of the plant will decline towards the end of its life.
After a number of years the decision can be taken to replace failed turbines or nacelles in a batch of lifting operations.

The only-CM-maintenance strategy

With this strategy only corrective maintenance tasks are carried out. Wind turbines are repaired either as soon as they fail, or left unavailable until a number have failed which are then repaired in batches. Under this scheme, no permanent maintenance crews are needed for the actual corrective maintenance tasks. Suitable crew could be hired on a stand-by basis to be mobilised at short notice, or on demand from maintenance companies.

The opportunity-maintenance strategy

This strategy is very similar to the only-CM-maintenance strategy. The main intention is to execute CM tasks, on demand. However, if a wind turbine undergoes corrective maintenance, the opportunity is also used to carry out preventive maintenance tasks on the same turbine. This means that preventive maintenance is executed at very irregular intervals, and only after a failure of the wind turbine. Evidently the design of the wind turbine should allow a tolerance range with respect to PM interval. The philosophy behind this strategy is to reduce the number of visits to the wind turbines.

The PM & CM maintenance strategy

Under this scheme, a full range of PM tasks are pre-scheduled and carried out at all turbines to a well planned timetable. Complete CM is also undertaken as and when necessary. This is essentially the maintenance strategy currently employed for land based wind farms.

It has to be born mind that, for onshore wind farms, labour costs and spare parts are the main drivers of the O&M costs. The costs of transport and access to land based wind turbines represent only a minor part of the overall O&M costs. In contrast, for an offshore wind farm, O&M costs are strongly affected by the efforts for transportation and access to the OWECS. Therefore, for offshore installations, the number of visits to the wind turbines needs to be carefully controlled.

The light-PM and light-CM maintenance strategy

As with the previous strategy, both corrective and preventative maintenance work is carried out. The significant difference with the previous scheme, however, is that the scope of the operations is limited to those below a certain costs/complexity level. For example, replacement of small components, which can be performed with a minimum of equipment and a very small crew will certainly be undertaken. Large operations requiring heavy equipment and comparatively many workers, for example blade or nacelle exchanges, will not be permitted. Machines that required large scale repairs, will either be abandoned or replaced in infrequent batch operations, as with the no-maintenance strategy.

The idea behind this scheme is to achieve a reasonable balance between full scale, strategies, and radical, minimal or zero maintenance approaches. Full maintenance makes best use of the initial investment in the farm, but is operationally expensive. Minimal maintenance is cheap to perform, but wastes a certain amount of the initial investment by leaving failed machines standing idle.

The periodic check maintenance strategy

Wind turbines are accessed at regular, scheduled, intervals. During each visit, the wind turbines are thoroughly inspected, after which any necessary PM and CM tasks are completed. Aside from the regular visits, no other maintenance work is performed, so that, for example, failed turbines are left inoperable until the next scheduled visit.
Due to the seasonal variations of the weather conditions, this strategy fits well only if the check period is in phase with the seasons, i.e. once a year. Checking all the wind turbines in the summer season when weather conditions are most suitable is then possible similar to standard offshore practice.

4.5.4 Evaluation of maintenance strategies

Qualitative comparison of the proposed maintenance strategies cannot be taken very much farther. In order to provide a more solid basis for decision making, a simulation tool is developed for evaluating the strategies as a function of turbine design, overall OWECS design, and maintenance hardware (see also Volume 2 part b).

4.6 Assessment of the dynamic behaviour of OWEC concepts

A throughout dynamic analysis including among others time domain fatigue analysis is carried out for the three chosen OWEC concepts i.e. the GBS lattice tower, GBS monotower and the monopile all combined with the WTS 80 wind turbine [4.6-1]. Here only some particular aspects relevant for the selection of the final concept are highlighted. By this most attention is given to the lattice and monotower since the monopile is treated in more detail in chapter 9.

4.6.1 Effect of support structure stiffness on response behaviour and aerodynamic damping

The fundamental eigenfrequency of the support structure, also denoted as support structure stiffness, is a paramount design parameter. In this sub-section this aspect is explained with respect to the dynamic response behaviour of the support structure on the rotor excitations and the aerodynamic damping of the fore-aft movement.

Dynamic response on rotor excitations

Due to the rotation of the rotor the dynamic loads on the wind turbine are lumped close to discrete frequencies i.e. the rotor frequency and the lower blade multiples. Whilst the excitation with the rotor frequency (1P) is mainly fed by mass imbalance (which is quite moderate for a well balanced rotor) the higher harmonics are generated by atmospheric turbulence (so-called 'rotational sampling') and deterministic disturbance of the wind field e.g. wind gradients, yawed flow, etc.

The different dynamic tower characteristics of the three Opti-OWECS designs result in a distinctly different response behaviour which can be qualitatively explained even with a single-degree of freedom system. In equation 4.6-1 the dynamic amplification of the tower top loads is written as function of the dimensionless excitation frequency f_{excite} / f_0 , i.e. the ratio of excitation frequency (either the rotor frequency of the blade passing frequency) and the fundamental support structure eigenfrequency.

$$DAF_{tower.top}\left(\frac{f_{excite}}{f_0}\right) = \frac{1}{\sqrt{\left(1-\left(\frac{f_{excite}}{f_0}\right)^2\right)^2 + 4\,\xi_0^{\,2}\left(\frac{f_{excite}}{f_0}\right)^2}} \qquad \textbf{(4.6-1)}$$

where:

$DAF_{tower.top}$	Dynamic Amplification Factor of tower top loads
f_{excite}/f_0	ratio of excitation frequency and fundamental support structure eigenfrequency
ξ_0	damping ratio related to eigenfrequency

Figure 4.6-1 compares the dynamic amplification factor (DAF) of the tower top loads in wind direction respectively lateral to it. For convenience the same damping ratio (2% structural and 3% aerodynamic damping) is assumed for all three structure. The DAF of the strong blade excitation (2P) decreases significantly with decreasing stiffness and accounts for 3.9, 1.65 respectively 0.2 (!) for the stiff-stiff lattice tower, the soft-stiff monotower respectively the soft-soft monopile. In case of the soft-soft or soft-stiff design the 2P excitation is beyond the first eigenfrequency of the support

structure and has therefore in general a lower dynamic amplification factor than any practical stiff-stiff design. A certain reduction of the DAF of the lattice tower can be achieved with an increase in stiffness, however, only if the first eigenfrequency is beyond 1 Hz, which will be technically difficult and economically senseless, the DAF is similar to that of the softer monotower.
Fatigue analyses based on dynamic simulations fully confirm this tendency (section 4.6.4).

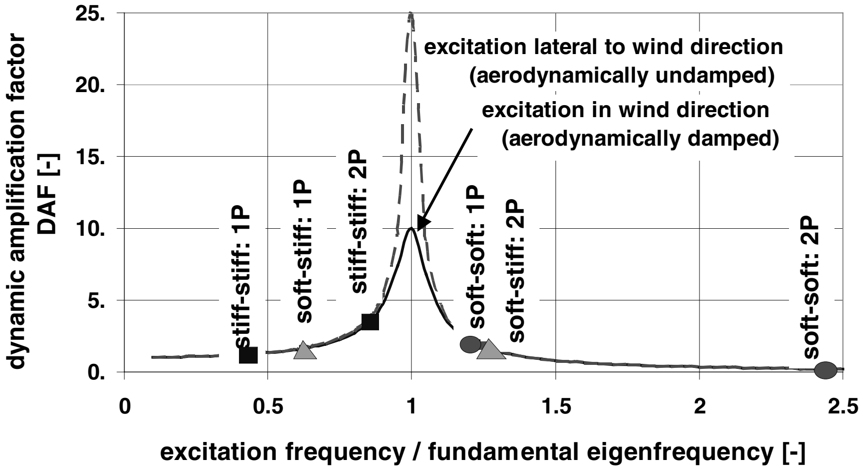


Figure 4.6-1: Dynamic amplification factor of the tower top loads for the three OWEC designs
(2% structural damping, 3% aerodynamic damping)

Aerodynamic damping

As explained in section 3.6.2 distinctly different aerodynamic damping is expected for the three support structures due to the difference in mass and stiffness.
The aerodynamic damping of the fundamental support structure fore-aft mode is analysed numerically with a perturbation technique as implemented in the DUWECS simulation code. Figure 4.6-2 displays the aerodynamic damping as a percentage of the critical damping as function of the wind speed. The WTS 80 is a pitch regulated machine which results in a considerable aerodynamic damping over the whole range of operational wind speeds. In contrast, for a stall regulated machine the aerodynamic damping vanishes or may even be negative in the stall region above rated wind speed.

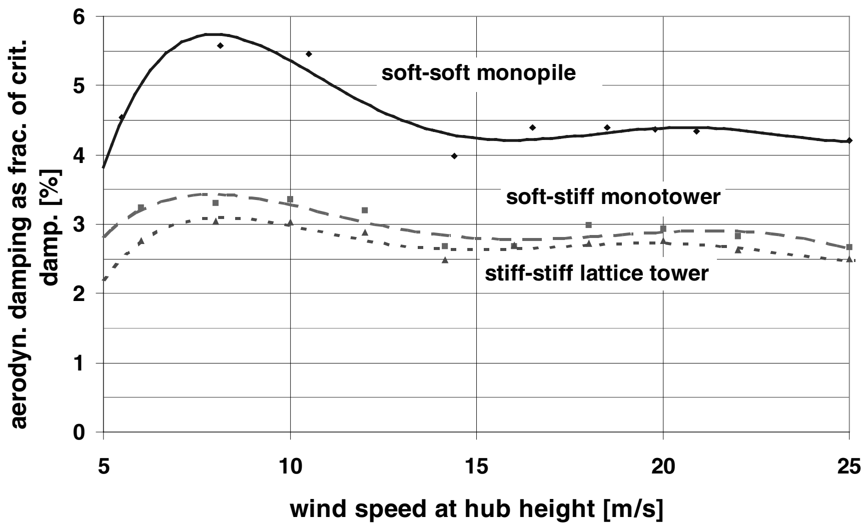


Figure 4.6-2: Aerodynamic damping of the first fore-aft mode of the three support structure concepts

Remarkably, the soft-soft monopile provides between 50% (at full load) and 80% (at partial load) more aerodynamic damping than the two other structures. Although the monotower and the lattice tower are distinct in the fundamental eigenfrequency and the associated mass, the difference in the aerodynamic damping is remarkably small; only a quarter percent of the critical damping. Application of the simple analytical estimate [4.6-2] provides similar results. Obviously for the lattice tower the reduction in aerodynamic damping due to the higher eigenfrequency is partly compensated by the opposing effect of a lower modal mass (table 4.6-1).

	monopile [1]	monotower [2]	lattice tower [2]
first eigenfrequency	0.29 Hz	0.52 Hz	0.76 Hz
dynamic characteristics	soft-soft	soft-stiff	stiff-stiff
modal mass (1st fore-aft mode)	182 t	176 t	169 t
Aerodynamic damping (analytical estimate)	4 %	2.0 %	1.4 %
Aerodynamic damping (calculated numerically)	4.3 %	2.7 %	2.5%

Table 4.6-1: Aerodynamic damping of the fore-aft mode at rated conditions - Comparison between analytical and numerical results

([1] nacelle mass 141 t, rotor speed 22 rpm; [2] nacelle mass 132 t, rotor speed 19 rpm)

Obviously the higher aerodynamic damping of the monopile is a benefit of this concept; however, a fatigue analysis of the combined wind and wave loading has to demonstrate whether the damping is large enough to counter the general sensitivity to wave loading and in particular the increased dynamic amplification associated with a first eigenfrequency coinciding with the upper end of the wave excitation range.

4.6.2 Sensitivity of gravity base foundations to soil properties

OWEC support structures should be insensitive to variations in the soil properties since the prediction of foundation characteristics is inherently uncertain and additional variations will occur within the wind farm area.
In order to limit the dynamic amplification of the periodic rotor excitations the **actual in-situ natural frequencies** should have a distance of at least 10% from the rotor speed (1P) and the blade passing frequency (2P for a two-bladed rotor). Interference with other higher integer multiples (4P, 6P, etc.) is generally less important but the actual effect will depend on the particular OWEC design and the wind conditions. Without further knowledge of the actual uncertainty in soil stiffness the **design values of the natural frequencies** should have a distance of at least approx. 20% to the 1P and 2P harmonics. Furthermore, as a weaker criterion one may demand also an approx. 10% distance to the higher harmonics 4P, 6P, etc.
Note that the values mentioned for the minimum clearance between periodic excitations and natural frequencies are based on a rule of thumb. If considerable interaction is expected the actual effect has to be further investigated by means of simulation of the OWEC.

Figure 4.6-3 shows the results of a sensitivity study on the effect of the soil shear modulus G_o on the dynamics of the monotower. Strictly interpreted the monotower, with the assumed soil shear modulus of 8.3 MPa, is just beyond the limit for ‘fit-for-purpose’ design. Nonetheless, even on an infinitely stiff foundation still a 10% distance of the first eigenfrequency to the strong 2P excitation is given. In the direction of softer behaviour a 50% variation of the soil parameter would be allowed before natural frequencies reach the 4P resonance range (note the 4P excitation has a lower energy content than the 2P harmonic).
Analogous investigations of the lattice tower show quite similar behaviour [4.6-1]. These results indicate that as long as firm soil conditions exist GBS support structures of OWEC suffer a low sensitivity for the uncertainties in the soil stiffness.

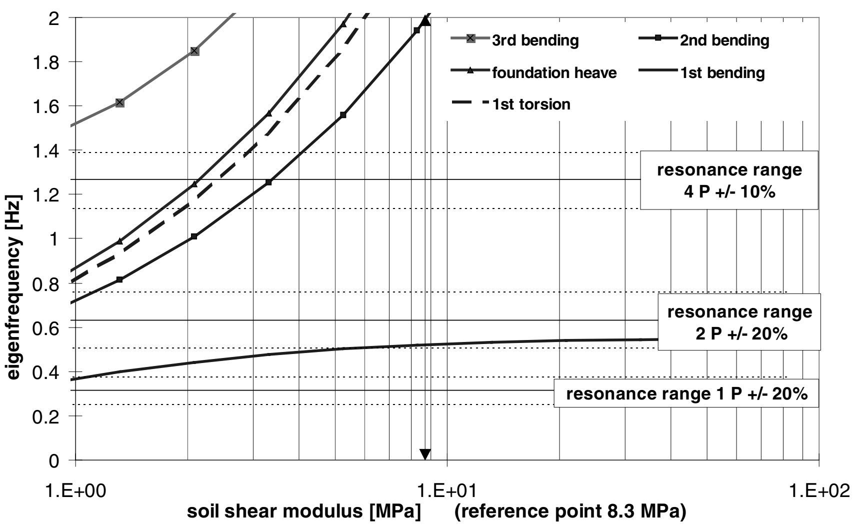


Figure 4.6-3: Sensitivity of the eigenfrequencies of the monotower to changes in the soil shear modulus (Solid horizontal lines: rotor excitation frequencies, dashed horizontal lines: boundaries of the excitation ranges. 6P excitation not considered.)

4.6.3 Fatigue analysis of monotower and lattice tower

Applied loading and analysis approach

Dynamic simulations in the time domain are carried out for the OWEC configurations with the monotower and the lattice tower, respectively, in order to study the effect of combined aero- and hydrodynamic loading [4.6-1].
Production loads cases for an annual mean wind speed at hub height of 8 m/s, turbulence intensity of 14% and wind shear exponent of 0.11 are considered in accordance with [4.6-3]. Furthermore a Rayleigh distribution of the seven wind speed classes is assumed.
A closed form relation between mean wind speed and sea state parameters i.e. (average) significant wave height and zero crossing period is assumed which has been derived from measured respectively hindcasted data [4.6-1]. Waves according to the modified Pierson-Moskowitz spectrum are applied collinear with the wind direction.

For the monotower dynamic response has been considered for the both wind and wave excitations. In contrast, a quasi-static response on wave loading is presumed for the lattice tower. This assumption, which has been established by [4.6-4], is convenient if internal member forces should be calculated since the applied modal superposition technique is not capable of a stress analysis of such a complex structure.

Analysis of the monotower

As shown at an example time history even for high wind speeds and thus high waves the effect of the hydrodynamic loading in the response of the overturning moment of

the monotower is hardly visible (figure 4.6-4). Near the cut-out wind speed the amplitude of the hydrodynamic load alone is approx. half of the response due to wind turbine loading alone. Nonetheless the overall response is still dominated by the wind effects.
A likewise result is found by a fatigue analyses for different loadings. The contribution of the wave loads to the bending stresses at the mudline can be detected only in the low cycle range of the cumulative rainflow cycle counting in figure 4.6-5. Therefore the equivalent overturning moment due to combined loading is increased only by about 4% with respect to pure wind loading.
The fatigue lifetime of the monotower at different cross section is larger than or close enough to the design lifetime in order to enable fit-for-purpose design in a later structural design phase.

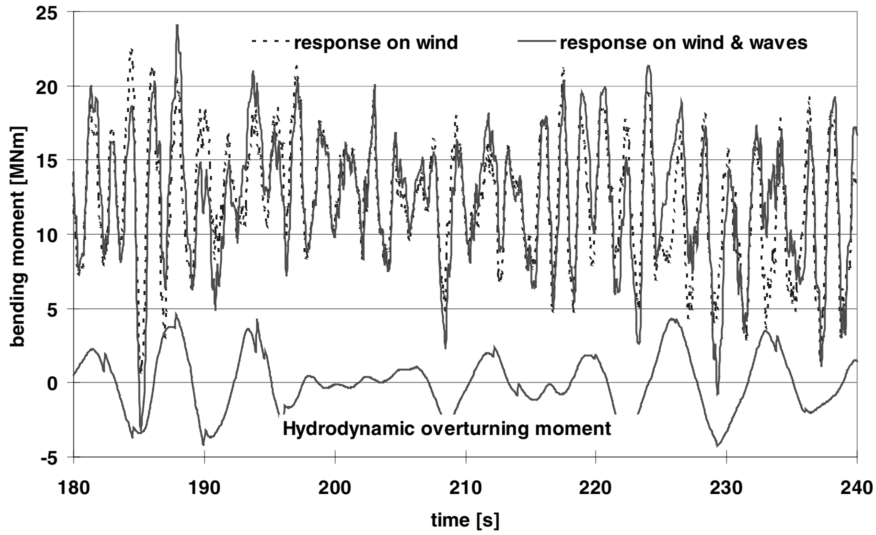


Figure 4.6-4: Example time history of the overturning moment at the monotower for V_{hub} = 24 m/s

It should be noted that the hydrodynamic forces will have a significant larger contribution to the overall loading at extreme conditions and for a deeper water site, a larger distance from shore or a more exposed sea environment e.g. in the North Sea.

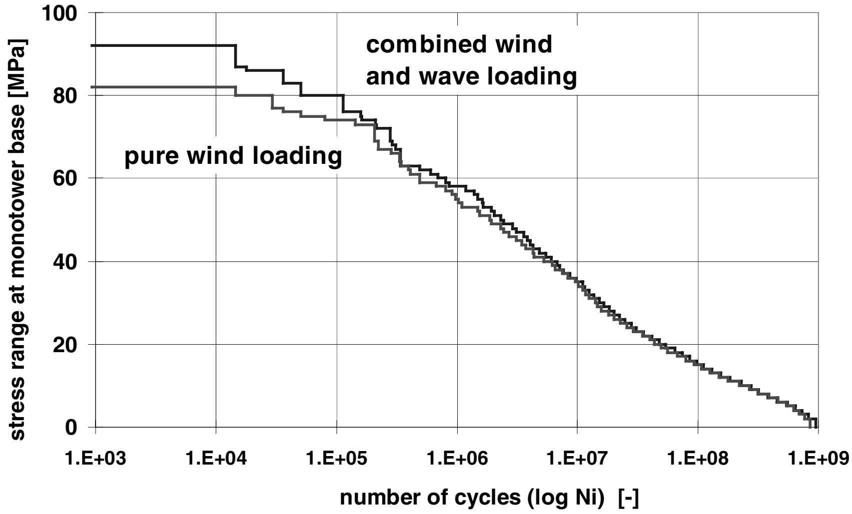


Figure 4.6-5: Cumulative Rainflow cycle counting of bending stresses at monotower base (lifetime 30 years)

Analysis of the lattice tower

The analysis of the lattice tower is more involved due to the complexity of the structure. For instance the magnitude wave loading also depends on the wave direction relative to the structure's orientation. Figure 4.6-6 compares the standard deviation of the hydrodynamic base shear i.e. integrated horizontal force averaged over the relevant directions with the rotor thrust loading and the response of the structural tower top force. The wave force and the structural tower top force have quite similar magnitude for higher wind speeds. However the overturning moment (not shown here) which is a better indication for the loading is again entirely dominated by tower top loads because the lever arm of the wind turbine forces is by a factor of 4 to 10 larger than for the effective wave forces.
Thus, more attention is given to a fatigue analysis of the aerodynamic loading. By this at all considered cross sections relatively high fatigue damages were found. The most probable reason is the higher dynamic tower top loads of this stiff-stiff support structure concept in comparison to softer designs (either soft-stiff or soft-soft). Note that a simplified load spectrum derived for a soft-soft tower (f_0 = 0.3 Hz) rather than a spectrum for a stiff-stiff tower has been used for the preliminary design.
In general the damage due to wind turbine loads in the submerged part of the structure is considerably lower than in the truss near to the tower top. In the upper part a fit-for-purpose design would require significant efforts for a re-design which reduce the economic attraction of this solution.
Again the situation becomes totally different at extreme conditions when the wind force on the turbine is strongly reduced and hydrodynamic forces dominate. According to environmental parameters each with a 50 years return period the aerodynamic force is only 13% of the total base shear [4.6-4].

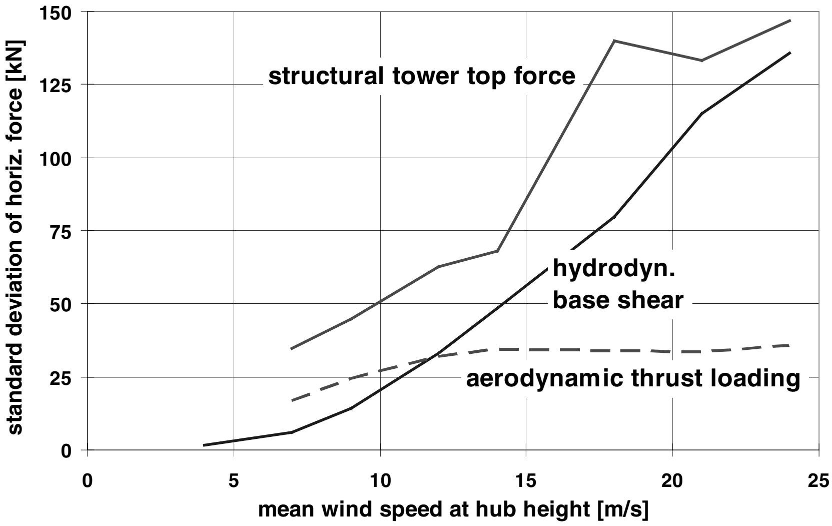


Figure 4.6-6: Standard deviation of the horizontal force (base shear) at the lattice tower against wind speed

4.6.4 Optimisation of support structure stiffness and rotor speed with respect to aerodynamic fatigue loading

Introduction

During the conceptual design of the lattice tower and monotower support structures quite considerable fatigue loads with origin in the wind turbine have been observed. Therefore a parameter study on the influence of support structure stiffness and rotor speed on aerodynamic fatigue loading is carried out to investigate whether these two important design parameters could be optimised. Three different rotor speeds and a wide range for the fundamental eigenfrequency of the structure corresponding to soft-soft as well as soft-stiff characteristics are considered.
The study deals only with aerodynamic rather than hydrodynamic or combined fatigue loads. Obviously both are important for an OWEC and with decreasing support structure stiffness the ratio between them will be shifted more and more to the wave induced fatigue.
However, such a parameter study on the combined loading is outside the scope of the investigation due to different reasons. Firstly, considering also the wave loading would introduce at least one additional parameter, for instance, the diameter of a monotower. Thus the number of considered configurations, 19 in this study, would be doubled or even tripled. Secondly, simulations would require considerable larger computational efforts both in duration of the time samples and CPU time per time step. Finally, aerodynamic fatigue is dominating hydrodynamic fatigue for the relatively stiff lattice tower and monotower.

Structural configurations, assumptions on loading and response

The WTS 80 wind turbine and its modelling within the design tools DUWECS is described in detail by [4.6-1]. Within this parameter study three different (constant)

rotor speeds are compared.
a.) 19 rpm (f_R = 0.32 Hz) base case
(considered for lattice tower and monotower)
b.) 22 rpm (f_R = 0.37 Hz)
c.) 25 rpm (f_R = 0.42 Hz)
For case a.) the original rotor design of the WTS 80 [4.6-5] is applied. For case b.) and c.) a modified aerodynamic blade design is used in order to take into account the increase in rotor speed. The new rotor design and its effect on the energy yield are described in detail by section 5.3.

The monotower support structure is the base case in this study. However, a simplified model of a monopile foundation is applied by considering a rigid clamping at a distance of 16 metres below the mud line (fixity length 4 diameters). So the fundamental eigenfrequency is reduced from 0.52 Hz (monotower) to 0.40 Hz (monopile). Parametric variations of the stiffness are applied by artificial scaling of the elastic modulus.[1]
An increased structural damping of the support structure of 3% is assumed in order to consider the damping effect from the flexible yaw system in a global manner.

The considered wind loading is identical to those of section 4.6.3. However, a simplified approach is followed in the calculation of the **internal** loads which are derived statically from the dynamic tower top loads rather than by considering also distributed inertia forces along the structure. Fatigue damage is estimated by Rainflow-Counting and Palmgren-Miner rule with a S-N curve of GL ‘type C’ and for a lifetime of 30 years. In this report the equivalent section bending moment with 2 10^6 cycles is used as a measure of the load severity.[2] It is derived from the resultant bending stresses due to the six dof tower top loading over the circumference of the considered cross section.

Comparison of different options for rotor speeds and support structure stiffness

In the comparison of the different options attention should be given to three main aspects. Firstly, a significant reduction of the fatigue loading is desired with respect to the lattice tower and monotower designs with first eigenfrequencies close to the 2P excitation of the base case rotor speed of 19 rpm. Thus one may be interested in the (absolute) minimum fatigue loading. Secondly, considering the stiffness criterion as well as the fatigue resistance, a balance of both requirements is needed. In other words the configuration with overall minimum fatigue loading might not be suitable if the required low stiffness can not be provided within the desired design range of the

[1] Note that this approach only affects the elastic forces rather than the inertia forces. Therefore it is not valid if the internal forces along the support structure should be derived from the local forces rather than from the tower top loading.

[2] The equivalent bending moment is chosen here because it is commonly used response variable. In [4.6-6] and [4.6-7] a so-called ‘required reference section modulus is introduced which is closer linked to the structural properties e.g. diameter and wall thickness and which offers a convenient way to consider the actual fatigue strength in the cross section defined by the wall thickness effect, stress concentration factor and partial safety factor for strength.

hub height. Finally, for softer designs the increasingly important effect of hydrodynamic fatigue has to be taken into account, at least in a qualitative manner.
For the 22 rpm case the equivalent bending moment is plotted against the tower height in figure 4.6-7. A fundamental eigenfrequency of 0.3 Hz (soft-soft) results in quite similar fatigue loads as a frequency of 0.44 Hz (soft-stiff). In such a case the tower height might become the decisive factor in the selection of the characteristics since soft-soft design will only be possible for higher tower heights and/or softer foundation behaviour e.g. monopile. For designs close to resonance i.e. f_0 = 0.35 Hz and f_0 = 0.67 Hz the influence of the tower top forces rather than the tower top moments become dominant since the loading increases almost linearly with distance from the top.

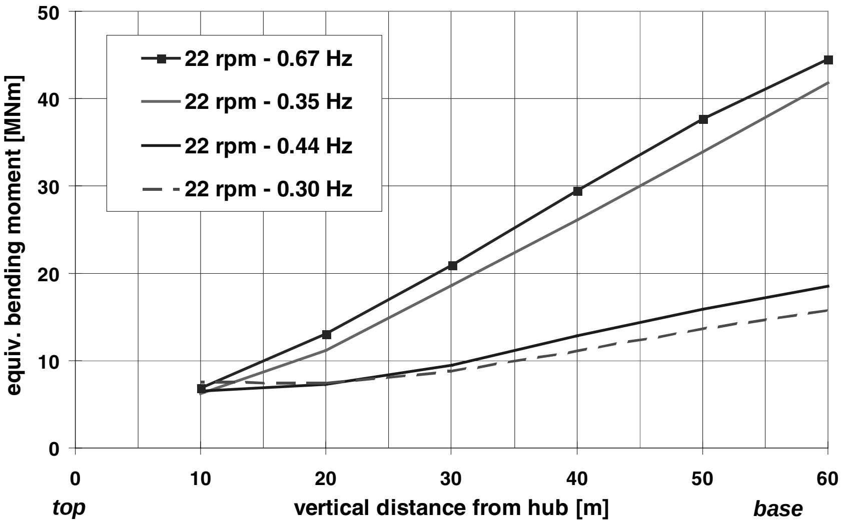


Figure 4.6-7: Equivalent bending moment due to tower top loading along the monotower (rotor speed 22 rpm)

Looking only at one cross section e.g. at the tower base the effect of the stiffness becomes clearer. Figure 4.6-8 shows the equivalent bending moment 60 m below hub height against the dimensionless excitation frequency. By this fatigue loading of the different configurations within the soft-soft and the soft-stiff region, respectively, can be related conveniently.

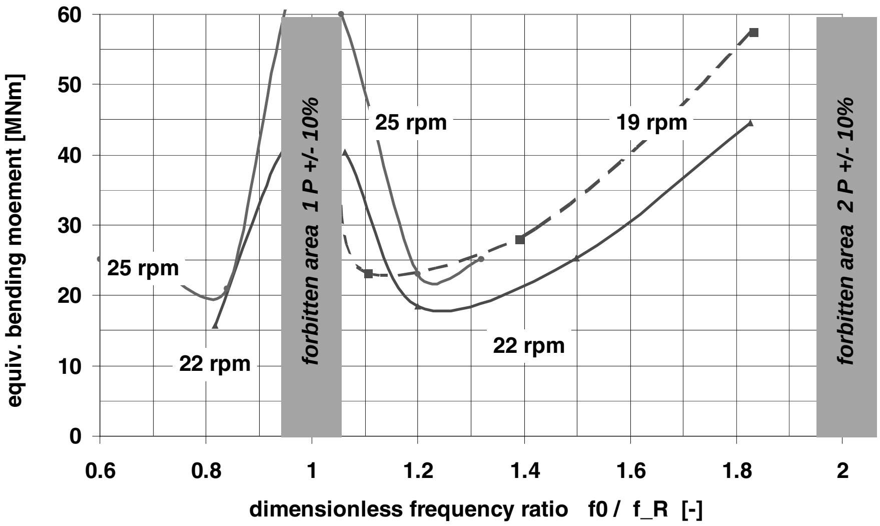


Figure 4.6-8: Equivalent bending moment 60 m below hub height against dimensionless frequency ratio

Comparing the three rotor speeds of 19 rpm, 22 rpm and 25 rpm the intermediate speed offers a number of advantages:

- The fatigue loading in the soft-stiff region is reduced by about 20 % with respect to the rotor speed options 19 rpm and 25 rpm, respectively.
- The design range of the fundamental eigenfrequency with minimum fatigue loads for 22 rpm is shifted to higher frequencies than in comparison to the case with 19 rpm. This is of particular advantage in case of relatively low hub heights and consequently inherently stiffer designs.
- Soft-soft design is an option in combination with rotor speeds of 22 rpm or higher. However such behaviour might be difficult to achieve for low structure heights.
- The rotor speed of 22 rpm provides (slightly) higher energy yield (section 5.3), reduced blade chord and mass and lower drive train loads compared with the base case rotor speed.
- For 22 rpm the blade tip speed of 92 m/s seems suitable for offshore application. In contrast 25 rpm will result in an aerodynamically less efficient behaviour and a rather high tip speed of 105 m/s.

Certainly a relation between support structure concept, site and hub height exist.
Based upon a qualitatively consideration a gravity based monotower for moderate water depth and low or minimum hub height might be possible only with a soft-stiff characteristics. Here a fundamental eigenfrequency around 1.2 times the rotor frequency offers minimum aerodynamic fatigue loads.
Unless the hub height is not increased significantly above the minimum height a soft-soft characteristics seems achievable only for monopile designs. Here however careful dynamic analysis of the combined aerodynamic and hydrodynamic loading is absolutely required.
So far the consideration was based upon a conventional (onshore) approach. Given a certain rotor speed, a suitable support structure design and stiffness was selected. Due to the larger freedom in choosing the rotor speed at an offshore site also another less conventional approach would be possible. For a certain structure concept the particular rotor speed could be selected which ensures operation free of

resonance and fatigue loads in an acceptable range. For instance, an equivalent bending moment of 25 MNm or less is possible at a location 60 m below the hub for fundamental eigenfrequencies between 0.25 Hz and approx. 0.55 Hz if a suitable rotor speed between 19 and 25 rpm is chosen (figure 4.6-9).

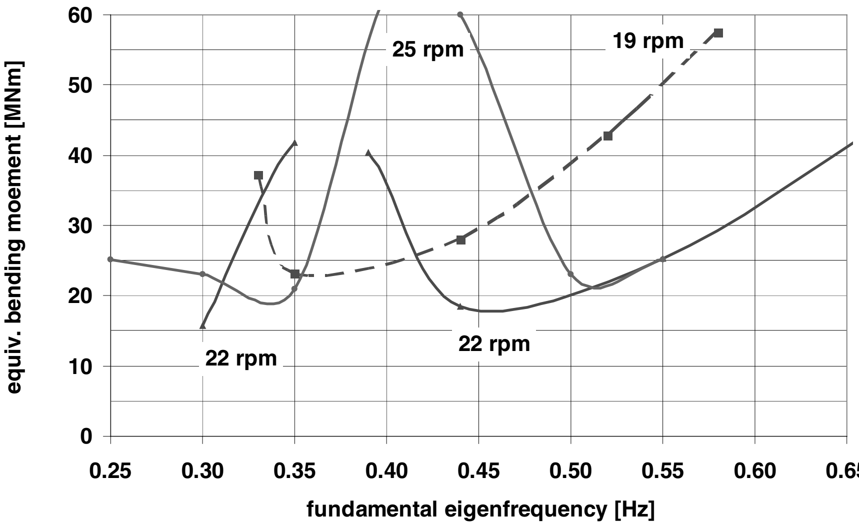


Figure 4.6-9: Equivalent bending moment at 60 m below hub height against fundamental support structure eigenfrequency

Obviously in a design approach integrating wind turbine as well as support structure design [4.6-8] both sub-systems will be optimised with respect to overall criteria e.g. dynamic behaviour, investment, energy costs, etc.

Preliminary support structure design

With aid of a spreadsheet developed by KOGL and DUT(IvW) two monopile support structures are designed in a preliminary manner for a overall height (to the nacelle interface) of 77 m above the mudline and 20 m water depth (LAT). Fatigue loads due to aerodynamic tower top loads as derived in the previous section are considered for a rotor speed of 22 rpm. Hydrodynamic loads are accommodated qualitatively by an additional safety factor along the pile. The forbidden 1P resonance range including a ±10% tolerance both for foundation uncertainty and distance to excitation lays between f_0 = 0.30 Hz and f_0 = 0.45 Hz.

The comparison of the two designs in table 4.6-2 shows a significant saving in pile weight of nearly 20% for the soft-soft design in comparison to the soft-stiff case. Moreover the softer monopile is more slender and can consequently easier, faster and cheaper be installed. The diameter of 4.5 m of the soft-stiff monopile is close to the maximum diameter that can be piled by Dutch contractors.
Although only aerodynamic fatigue has been considered it is likely that the soft-stiff monopile will also be governed under combined wind and wave loading by stiffness rather than fatigue. In this respect, the design is ‘easy’ and ‘uncritical’ but expensive to build and install. In contrast, a decision about the suitability of the soft-soft monopile requires a careful dynamic analysis and probably an iterative design where for instance also the influence of the pile diameter and the foundation properties on

the combined fatigue loading is investigated (section 6.6, chapter 9). Thus the design work is more expensive but offers clearly the larger potential for weight and cost saving.

dynamic characteristics	**soft-soft**	**soft-stiff**
governing design criterion	fatigue (qualitative)	stiffness, buckling
approx. fundamental eigenfrequency [Hz]	0.3	0.45
overall structural height above mudline [m]	77	77
pile penetration depth [m]	25	25
tower cross section (top) D [m] * tw [mm]	2.8 * 20	3.2 * 20
tower cross section (bottom) D [m] * tw [mm]	2.8 * 50	4.0 * 27
pile cross section (below mudline) D [m] * tw [mm]	3.2 * 80	4.5 * 75
tower weight [tonnes]	111	110
pile weight [tonnes]	294	379
support structure weight [tones]	405	489

Table 4.6-2: Comparison of preliminary monopile design for NL-1 site

Recommendations for the structural design phase

The importance of the support structure stiffness for the aerodynamic fatigue loading has been demonstrated. Moreover, rotor speed of the WTS 80 wind turbine and support structure stiffness have been optimized with respect to the wind turbine loads on the support structure.
A rotor speed of 22 rpm in combination with a fundamental eigenfrequency of the support structure close to the rotor excitation (1P) offers the most advantages with respect to fatigue loading, design range for the support structure stiffness and energy yield.
A preliminary analysis indicates that for this rotor speed and for a site similar to NL-1 a soft-soft monopile will have better economics as long as such a design is possible with respect to the combined aerodynamic and hydrodynamic fatigue.
In case the latter is not valid an even further increase of the rotor speed might be worthwhile in order to enable a soft-soft design with lower dynamic amplification of the wave loading.

4.7 Evaluation of sites and OWECS concepts

The prospects of offshore wind farms assembled from the site and sub-system concepts developed in the previous sections of this chapter are evaluated in this section. Economic analyses with the novel OWECS cost model will be employed to further reduce the range of sites, support structures, turbine concepts and wind farm size (section 4.7.1). The evaluation is broadened by consideration of some additional criteria, not implemented in the cost model but of certain importance for the success of the final design solution (section 4.7.2).

4.7.1 Evaluation of sites and main concepts with the OWECS cost model

Basic OWECS parameters for comparison

The novel OWECS cost model [4.7-1] developed in parallel to the conceptual design phase has been applied for a comparison of sites and OWECS concepts. By necessity, the comparison is approximate, with a large number of assumptions being required during the calculations.
Broad specifications of the farm assumed to be sited at each location are given in table 4.7-1. Environmental data for the calculations are based upon table 3.3-1.

Turbine type	Kvaerner - Turbine WTS-80 3 MW *or* WTS-80 upscaled to 4MW-90m
Structure type	soft-stiff monopile *or* monotower with gravity base *or* lattice tower with gravity base
Grid connection	AC (submarine) cable
Decommissioning cost	10 % of initial support structure and installation costs
Annual O&M cost	2 % of initial capital cost
No of OWEC	100
Turbine spacing ratio	9 diameters
Onshore distance to public grid	12 km
Structure height	80 m (seabed to nacelle)
Economic lifetime	20 years
Discount rate	5%

Table 4.7-1 : Basic OWECS parameters assumed for the comparison

Comparison of sites

The energy cost at the six sites pre-selected in chapter 3 have been compared using the Opti-OWECS cost model.

Figure 4.7-1 shows the energy costs in a normalised form for the base case OWECS at each of the pre-selected sites using however either the monopile or the gravity base (GBS) monotower support structure.

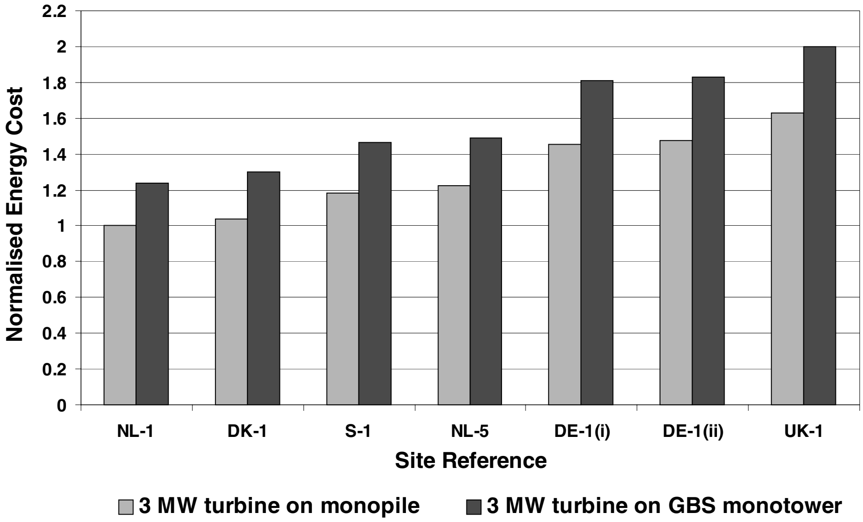


Figure 4.7-1: Comparison of energy costs for monopile and GBS monotower, respectively, between reference sites (Energy cost normalised by value for OWECS with monopile at NL-1.)

Independently from the applied support structure type, a clear trend can be seen between the different sites. The sites NL-1 and DK-1 show the best prospects. Note though that site DK-1 runs NL-1 such a close second economically that it is very difficult to choose between them only by economic considerations. The uncertainties implicit in cost modelling are such that it is not sensible to distinguish between both on the basis of these results alone. The other sites[3] all performed substantially worse and can be categorised either as providing average economics i.e. S-1 and NL-5 or showing poor performance i.e. DE-1(i), DE-1(ii) and UK-1.

It should be noted that some particular assumptions are underlying to this comparison.
Firstly, the costs for the wind turbine and the power collection within the wind farm are identical for all sites since no major turbine modification are foreseen and it is beyond the scope of the cost model to consider site dependent costs for cable laying.
Secondly, a constant overall height of the support structure has been chosen due to some practical considerations. An individual optimisation of the structural height for every considered combination of site, support structure and wind turbine concept would be very cumbersome. Furthermore, it has been observed that for some unlucky combinations of design parameters the model finds only a stiff-stiff support structure which is appreciable more expensive than a soft-stiff solution. For the chosen overall height the latter problem does not occur.

[3] For the purposes of this comparison, the German site DE-1 was split into two 'sub-sites' DE-1(i) and DE(ii). This was because the environmental specifications available in the literature for the Rostock site, which is co-incident with DE-1, covered a wind range of values. In essence DE-1(i) is at the onshore range of values for DE-1(i), with DE-1(ii) occupying the more offshore range of the spectrum.

As a consequence, the difference in energy costs due to site variations for the same OWECS concept are dominated by the cost for the power transmission and the energy yield.

A striking feature of the results is that, in broad terms, the best sites economically were those that also had the highest mean wind speed. In particular the favourable NL-1 and DK-1 sites have the second and third highest wind speeds respectively. Site NL-5 has the highest wind speed, but is not economically attractive. This is a result of its considerable distance from the shore which brings two detrimental effects. Firstly the grid connection capital cost for NL-5 is by far the largest, as shown in figure 4.7-2. Secondly, electrical losses in transmitting power to the shore become substantial over long distances, and thus, despite its higher mean annual wind speed, the annual energy production predicted for the NL-5 site is less than that for both NL-1 and DK-1.

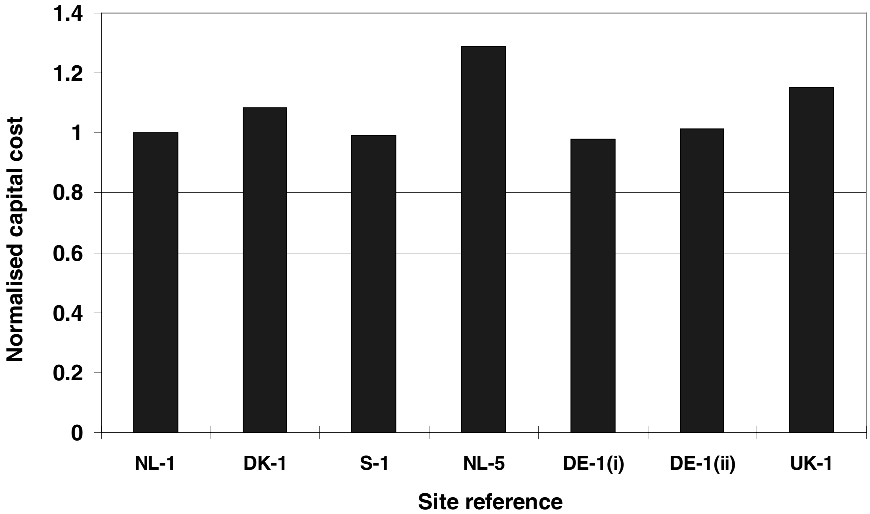


Figure 4.7-2: Comparison of capital cost for grid connection between reference sites
(Costs normalised by vale for NL-1 site.)

Figure 4.7-3 compares the predicted annual energy production for each site with the predicted energy cost, showing a clear correlation between high annual energy production and low energy cost.

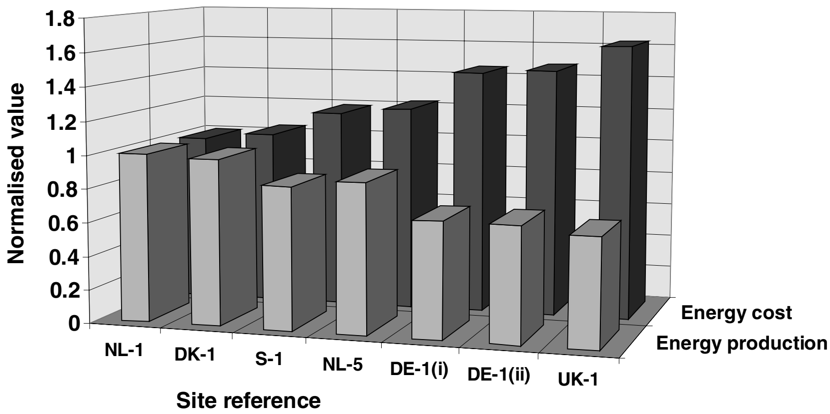


Figure 4.7-3 : Comparison of energy costs and energy production at reference sites (OWECS with 3 MW turbine and monopile. Diagram normalised by values for NL-1 site)

Comparison of support structure concepts

Next some more attention is given to the support structure concepts.
At every location the OWECS based on the monopile concept provides the most economically attractive result, and thus would appear to be preferable to a wind farm employing the gravity based monotower (figure 4.7-1).
It should be noted that strictly the monopile design is not viable for such exposed sites as NL-5. Even for the GBS monotower serious doubts exist whether it is suited for this particular location. Therefore the estimates for NL-5 should be interpreted carefully .
Further to the two support structure concepts mentioned so far also the performance of the lattice tower design has also been examined. However, due to its complexity this concept should be applied only at exposed 'deep' water sites as NL-5 or even more hostile. Moreover, since the cost model for this concept is not as refined as for the other two, it is not possible to perform calculations with similar accuracy for every site.
Results comparing the energy cost for the base case OWECS with both monotower concepts (i.e. monopile and GBS monotower) at NL-1, and for the GBS monotower and lattice tower at NL-5 are presented in figure 4.7-4.
Site NL-5 was selected for evaluation of the lattice tower because that concept was conceived to be most competitive at deep water, far from the shore sites, of which NL-5 is the best example. With respect to the limited viability of the GBS monotower at NL-5 its costs should be considered with care.[4] Thus the comparison is formulated to present the lattice tower as favourably as possible in relation to the other concepts.

It can be seen that the lattice tower concept is marginally more economic than the GBS monotower at site NL-5. Nevertheless wind farms with both of the concepts at NL-5 perform considerably more poorly than OWECS with the monopile or

[4] Another alternative for such exposed sites are braced monotower concepts (section 3.4.6); which are however not implemented in the cost model so far.

monotower concept at NL-1. By this comparison it is important to keep those differences between both sites in mind which do not influence the support structure design i.e. annual wind speed, power transmission costs and power losses due to the distance from shore.
Although the cost model barely offers an economic improvement of the lattice tower over the GBS monotower a braced or lattice tower concept might be required for exposed sites since it should be noted that maximum water depth for monotower design is in the order of 20 m (table 3.3-1).
However, considering less hostile sites than NL-5, as given by the five other locations, monotower designs and especially monopile designs are economically very attractive.

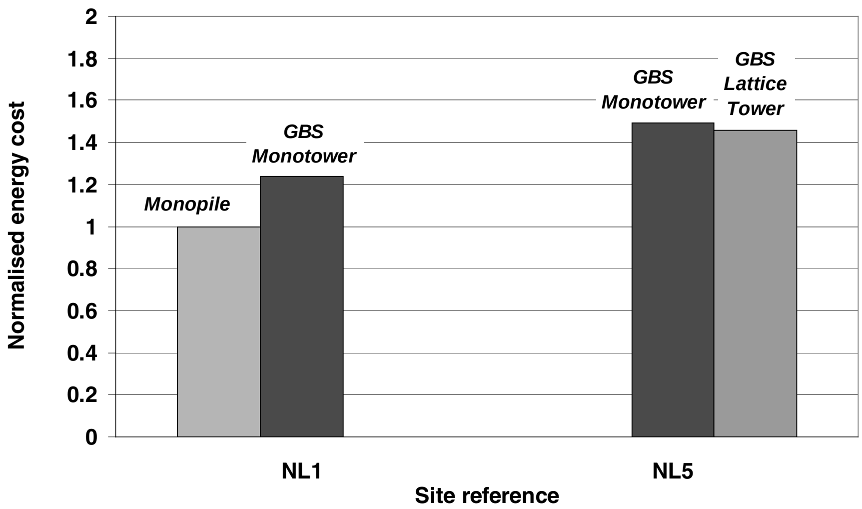


Figure 4.7-4: Comparison energy costs for OWECS based on different support structure concepts at NL-1 and NL-5, resp. (Energy costs normalised by value for OWECS with monopile at NL-1.)

Comparison of wind turbine concepts

Next some comparison of the wind turbine concepts with respect to rating and rotor diameter are carried out. Since the rotor speed variants mentioned in section 4.6 are very similar in energy yield the tool is not suited to compare them.
Results shown in figure 4.7-5 compare the use of the 3 MW - 80 m and a 4 MW - 90 m turbine, respectively, mounted on the monopile support structure at each of the sites. Wind turbine costs for the 4 MW - 90 m design have been extrapolated from the 3 MW machine with a rule of thumb derived from literature. Moreover, the same reliability and availability is considered for both turbine concepts which is a crude assumption with respect to the very limited operational experience with machines of that league.

As with the support structure comparison, sites NL-1 and DK-1 appears to offer the most economical energy in both cases. Under the mentioned assumptions only a small cost advantage is found for the large turbine which is in the order of 5% in energy costs for all sites. It should be noted that such differences are in the same order of magnitude as the accuracy of the cost model; moreover, changes in the underlying assumption e.g. wind turbines costs, etc. may alter the results in either direction.

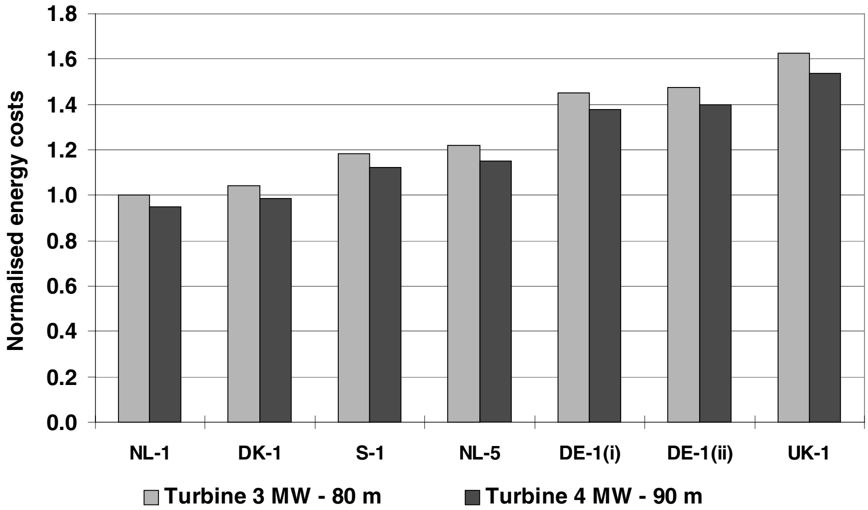


Figure 4.7-5: Comparison of wind turbine concepts
3 MW - 80 m and 4 MW - 90m, respectively, at reference sites
(OWECS with monopile support structure
and equal availability for different turbine concepts)

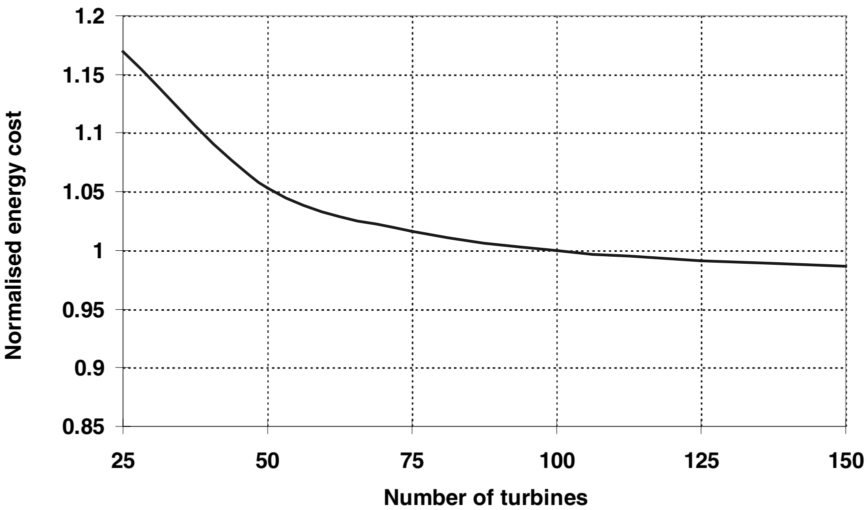


Figure 4.7-6: Influence of farm size on energy cost at NL-1 site

Evaluation of wind farm size

It was stated earlier (section 4.4.2) that a reasonable size for the proposed farm is between 60 MW and 300 MW.

The cost model has been used to investigate the economic effects of varying the overall farm size from 25 turbines (i.e. 75 MW overall capacity) to 150 turbines (i.e. 450 MW overall capacity). The results for site NL-1 are shown in figure 4.7-6. In this comparison no series effects on the wind turbine, support structure and grid connection costs neither influences on the aerodynamic farm efficiency are considered; still the results show clearly the economy of scale for large OWECS (here limited to the effect of the power transmission cable).

It is clear both that larger farms give better economics, but also that there is little to be gained in using more than 300 MW capacity. It should further be noted than such large plant might require a major reinforcement of the onshore power grid which would offset any trend in cost reduction. Thus an overall farm capacity at the highest end of the proposed range would be a reasonable size.

Concluding remarks from the economic comparison

Economic comparison has greatly reduced the range of viable sites and concepts. So far the preference lays on a OWECS of 300 MW at site NL-1 or DK-1 site employing the monopile support structure and an AC grid connection. Based on the assumptions of the cost model larger turbine concepts of 4 MW offer only a relative small cost advantage with respect to the 3 MW base case which in the order of magnitude of the accuracy of the cost model. For the NL-1 site and 100 times the 3 MW - 80 m turbine on a monopile support structure the cost model predicts an energy cost of about 4.3 ECUct/kWh[5].

4.7.2 Evaluation of sites and concepts by additional criteria

The decision on the final concept and site should be based also on factors other than the economic criteria considered so far.

Site selection

Although there is little to choose economically between the sites NL-1 and DK-1, the former is preferable for the following reasons

- NL-1 is likely to be closer to onshore grid infrastructure than DK-1
- Environmental information is more readily available for NL-1, from the excellent NESS Database, than DK-1. Note such data are required if the soft-soft monopile concept should be further developed.
- The NL-1 site is of potentially higher interest for the project partner Energie Noord West.

Wind turbine size

For the decision between the 3 MW base case and an upscaled 4 MW design it should be noted that both concepts are not of equal maturity. In the 4 MW range with rotor diameters of 90 or even 100 m there is no proven turbine available ‘off the shelf’. A commercial 3 MW machine is closer to current technology than an even larger design. This is of particular importance since offshore a significant improvement of the turbine’s reliability is required in relation to commercial state-of-the-art onshore machines in the 500/600 kW class (section 4.5). So the actual cost benefit with respect to the delivered kWh of a ‘big’ but novel 4 MW machine in

[5] All the values presented in this section have been normalised to the results for this selected site and concepts.

relation to gradual improved 3 MW turbine is less obvious and might be even negatively.
A larger rotor diameter and a higher rating has also consequences for the support structure which will become taller and suffer significantly higher aerodynamic loads. The larger height results either in a softer structure which is problematic certainly with respect to the dynamic wave loading of the preferred monopile design or a heavier structure if stiffness should be maintained. The combined aerodynamic and hydrodynamic fatigue at the demanding NL-1 site will even increase this problem.
As shown in section 4.6 other wind turbine options e.g. with increased rotor speed exist which also have advantages for the entire OWECS.

Wind turbine drive drain concept

There are two alternative turbine designs presented by Kvaerner Turbin during the conceptual design phase: WTS 80 and WEC 3000. The system integration of these turbines into the OWEC has been studied and the result suggest to use the conventional turbine design WTS 80 as the choice for the structural design phase.

Kvaerner Turbin originally proposed the WEC 3000 as the main course for further development, as this concept was thought to be the next one built in the expected continuation of the Swedish-German co-operation programme for large turbines. At the end of Development Study III (which coincided with the conceptual design phase of Opti-OWECS), it was however realised that a continuation of the bilateral project development was not at hand, and the direct driven generator technology was not likely to be exploited for the next generation of turbines.
The technology indeed looks very promising but probably needs evaluation in a smaller scale before it can be implemented in the 3 MW turbine. Parallel to the Opti-OWECS project Kvaerner Turbin has made internal concept evaluations and it is likely that the conventional turbine is a faster track to a commercial introduction of the 3 MW turbine. At this stage of offshore development it is recommended to follow the same design path as the land-based turbines take.

A very strong argument for the choice of turbine concept for an offshore installation is that the basic technology has a proven record on land. It is preferable to perform the development of systems and components for the wind turbine on land based, more available units.

Conclusive arguments for the choice of basic turbine concept:
- The WTS 80 is the most likely design concept to be realised in the further Kvaerner Turbin development.
- The WTS 80 is more conventional technology where most components are known from the earlier design Näsudden II.
- The variable speed concept of WEC 3000 has no clear advantage at offshore operation.
- The WEC 3000 has a generator and converter technology which is not at all developed. To initially utilise this technique offshore can be hazardous. Especially the environmental requirements for the permanent generator are not known and it would be unwise to place it in an even tougher marine surrounding.
- There are at the moment no evident indications that the WEC 3000 has advantages for the maintenance and the availability. In the long term this may be

the case when the design has a more proven operational record. The simplified drive train and reduced component set up which the removal of the gearbox means, should have this effect.

Support structure

In addition to having the most attractive economics, the monopile has the dynamic qualities most suitable for the turbine concept. There can be no doubt that the monopile should be selected.
Since the cost model is only capable of a soft-stiff monopile an even further potential for cost reduction exists by soft-soft design which feasibility has to be investigated during the structural design phase.

4.8 Final selection

After evaluation of both economic and additional criteria the selection of the site and the concepts for the final design is made. The selections for detailed development are summarised in table 4.8-1.

Site & concepts	**Selection / Decision**	**Reason / Comment**
Site	NL-1	• best economic performance
Support structure	monopile	• best economic performance • potential for further improvement (i.e. soft-soft)
Wind turbine	3MW - 80m geared concept, but significantly modified to suit offshore environment (including O&M issues)	• adequate economic performance • realistic and less risky goal for offshore application
Power collection	AC subsea cables	• industry convention
Power transmission	AC subsea power cable	• proximity of selected site NL1 to shore
Farm layout	larger spacing than onshore	• further investigation needed
Operation & Maintenance	opportunity based or PM & CM strategy purchase of a modified self propelled jackup platform	• detailed investigation required • strategy to be arrived at in close co-operation with turbine design.

Figure 4.8-1 : Summary of the selections made for the final design phase

4.9 Outlook in structural design

With choices for the OWECS site and concept now made the design will be worked out further in the following chapters (figure 4.9-1). The main sub-systems are treated separately by chapter 5 to 8 whilst chapter 9 considers the overall dynamics and chapter 10 presents a thorough economic evaluation of the final OWECS design solution.

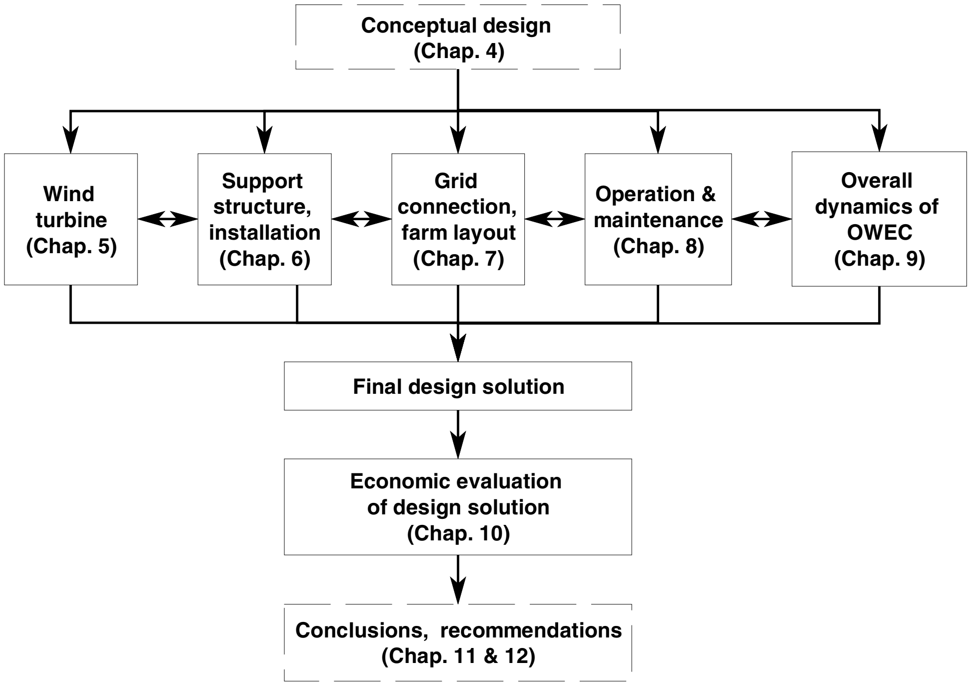


Figure 4.9-1: Flowchart on structural design and its relation to chapters in the report

5. Adaptation of the wind turbine to an offshore environment

In this section the process and the result of the measures taken to accommodate Kvaerner Turbin´s 3 MW wind turbine design to an offshore location are described. The work has been divided into two parts: design changes to have a more robust turbine and to conform with the marine environmental requirements; and design measures to increase the availability and to extend the maintenance interval.

5.1 Special requirements for offshore

The offshore location means a number of substantial differences to the design specification for the wind turbine:

- Marine environment increases demand on protection of components and systems
- Location requires longer maintenance intervals
- Location requires higher reliability (in order to ensure high availability)
- Remote stand-by capacity
- Noise is not as important as on land
- Structural weight is not critical during transport.

These items and precautions are taken into account in the design process.

5.2 Design Process

The choice of the turbine concept was made in the conceptual design phase and is discussed in section 4.7. The final turbine concept is the WTS 80M where M stands for the marine version of the land based original design, called WTS 80L. The most important argument for choosing the geared concept instead of a direct drive design is the more proven technology of the former.

Several options for the adaptation to the offshore environment were suggested and discussed during the conceptual design. At the structural design phase these alternatives have been evaluated once more. The results are presented here with a description of the design solutions chosen. Later in this chapter is a cost evaluation of the new design is given.

The main part of the design work considering the wind turbine is carried out with the experience inside Kvaerner Turbin as the base. It is believed that the turbine can to a large extent be optimised at an internal process at the turbine manufacturer with the above requirements in mind. Some requirements are given as objectives from the other partners in the project. Examples of this category are general simplification of the design as a way to increase the reliability and the minimum 1 year maintenance interval. Some design solutions are also chosen to optimise the total concept as they can be beneficial for other sub-systems. The increased rotor speed is an example of this (section 4.6).

5.3 Rotor design

5.3.1 Background

The 3 MW turbines of Kvaerner Turbin have a rotor diameter of 80 m. This rotor size leads to a specific power rating (kW per square meter swept area) which is above the average specific rating of large machines. Therefore an investigation of an enlarged diameter took place during the conceptual design. An increase of the rotor diameter is the most effective way to increase the energy production of the turbine. Another way to achieve this, but with a smaller effect, is an increased rotor speed and an optimisation of the aerodynamic design. A changed rotor speed can also influence the dynamic concept.

5.3.2 New design options

Rating

Three options were investigated at the conceptual design phase: 90 m / 3 MW, 90 m / 4 MW and 100 m / 4 MW. A cost increase of the turbine was compared to an increased energy production. The result was that for a land based turbine the increase to 90 m diameter would be cost effective and decrease the cost of energy. However for the offshore turbine the situation is different as the mean wind speed is higher and a higher power rating can be accepted. In the Opti-OWECS design case a limit of the hub height has been reached as the preferred tower structure, a soft-soft monopile, is at the lower limit of the fundamental eigenfrequency. If the stiffness of the tower is decreased even more, by making the tower shorter, the interaction of wave loads will increase the fatigue damage considerably.

Dynamics

During the conceptual design phase it became clear that the dynamic situation of the OWEC would benefit from slightly changed rotor dynamics (section 4.2). Because the rotor speed is critical for the noise level of a land based turbine, the tip speed of the WTS 80L is lower than it should be for optimal aerodynamic efficiency. An increased rotor speed is therefore likely efficient for the energy production and preferred with regards to the drive train design as the shaft torque is decreased.

New blade layout for higher rotor speed and offshore wind conditions

An increased rotor speed offers also benefits for the aerodynamic blade design since generally solidity is reduced for high tip speed ratios. A reduced blade area results in lower loads during idling or stand-still at extreme conditions. However the effect will be for the pitch controlled WTS 80 less relevant than for a stall controlled machine.
Furthermore, the offshore wind climate i.e. reduced turbulence and wind shear as well as lower extreme wind speed together with the lower torque load open the opportunity for a structural re-design of the internal blade structure. By other offshore

studies here a considerable cost reduction potential for the rotor and drive train has been indicated [5.3-1], [5.3-2]

5.3.3 Final blade design

Objectives

Evaluation of the different options with respect to considerations of the entire OWECS led to the following choices:

- conserve rotor diameter of 80 m
- conserve rated generator power of 3 MW
- increase of the rotor speed from 19 to 22 rpm
- one speed operation (22 rpm)
- aerodynamic design of the rotor blades for the new conditions

Based on the experience during the conceptual design (section 4.2) the main goals are reduction of the blade loads by maintaining a reasonable energy yield for constant diameter and rated power. As a welcome side effect the blade may become more slender, thus lighter and cheaper, due to a higher rotor speed.

In the next sub-sections the aerodynamic rotor design carried out by the Institute for Wind Energy is explained [5.3-3].

Analysis of the existing rotor blade U3_2 for different rotor speeds

The study was started with the rotor/blade layout of the WTS 80L developed by FFA [5.3-4] denoted U3_2 blade. The aerodynamic characteristics of the radial segments consist of 2d-performance for the FFA-W3-211 and LS(1)-417 airfoils, specified by FFA.[6]
Three rotor speeds of 19, 22 and 25 rpm respectively are considered together with a mean wind speed of 8.5 m/s at hub height. Furthermore a Rayleigh distribution for the wind speed, air density of 1.25 kg/m^3 and a hub cut-out of r = 5 m are assumed.

The calculations are carried out with a validated BEM-code (Blade-Element Momentum-code) which includes among other features the Prandtl tip-loss correction. The tool is widely used by the Institute for its consultancy work for the wind turbine industry.

[6] Remarks on the input for the aerodynamic analysis:

- The input characteristics are 2d-results, which are for the inboard sections not correct. The 3D. characteristics will show a considerable increase in lift and hence reduce the rated wind speed. However, because the rotor is (active) pitch regulated the high angles of attack are limited and therefore the 3D. effects are probably small. In contrast, these adjustments in aerodynamic properties will be important if one chooses stall regulation.
- The characteristics of the FFA-W3-211 airfoil are also used for the thicker inboard sections which is too optimistic considering the 2d-performance.

pitch angle [deg]	rotor speed [rpm]	Vrated [m/s]	rel. energy (aero.) [-]
-1.0 deg.	19	13.5 m/s	1.004
0.0 deg.	19	14.0 m/s	1
1.0 deg.	19	14.0 m/s	0.985
0.0 deg.	19	14.0 m/s	1
0.0 deg.	22	13.5 m/s	1
0.0 deg.	25	13.0 m/s	0.964

Table 5.3-1: Rotor speed concept for WTS 90
with original blade U3_2
(rated aerodyn. power 3.3 MW, $V_{cut\text{-}in}$ = 6 m/s, $V_{cut\text{-}out}$ = 25 m/s)

In a first step the performance of the original rotor blade was analysed (table 5.3-1). The accuracy of the rated wind speed is in 0.5m/s. A more precise value would suggest that the results of the calculations are extremely reliable, which is not in agreement with the rough approximation of the input characteristics for the airfoil segments.
The gain in energy yield for this pitch regulated turbine is not remarkable since any extra energy production can only be achieved in the small wind speed interval between the cut-in and the original rated wind speed.

Optimised blade design for high rotor speed and reduced loading

An optimisation is carried out within the goals mentioned in the introduction. Because the turbine is pitch regulated, for maximum energy yield a high power coefficient at the wind speed interval between cut-in and rated wind speed is needed. In practice this can be achieved by maximizing the power coefficient at the annual mean wind speed at hub height.

Due to the different number of revolutions per minute the tip-speed ratio varies and in general an increase in tip-speed ratio (which corresponds with higher rpm) reduces the chord along the blade span. This is the main reason for increasing the number of revolutions per minute especially because offshore the turbine noise is not very important. Increasing the rotor speed from 19 rpm to 22 rpm the chord reduction along the span was found to be significant while an even further reduction of the chord up to 25 rpm could be neglected.[7] The achieved reduction in the projected blade area of 12 % will result in a lighter blade with lower parking loads and thus a probably cheaper design.
Figure 5.3-1 compares the chord distribution of the original U3_2 blade and the new blade design. The chord, twist and thickness of the new layout are given by table 5.3-2.

[7] For reasons of stiffness consideration the maximum chord was kept the same for all rotor speeds.

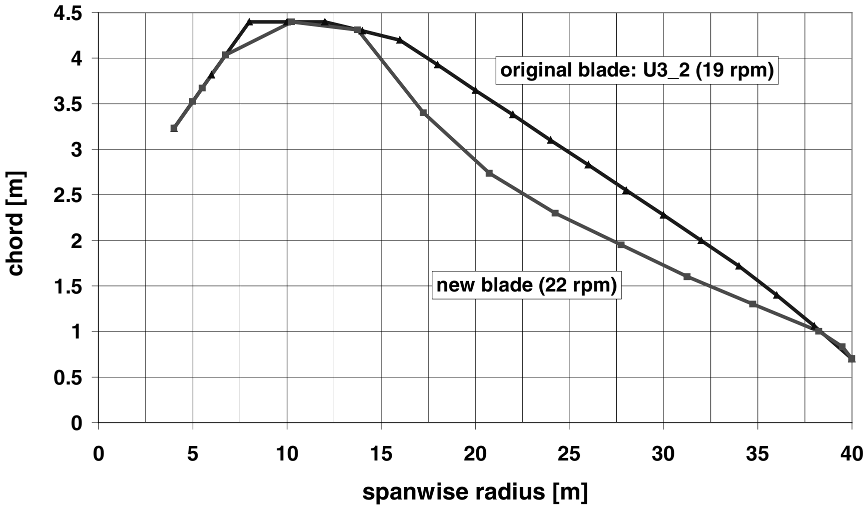


Figure 5.3-1: Comparison of chord distribution between original blade U3_2 for 19 rpm and optimised blade for 22 rpm

radius [m]	chord [m]	twist [deg]	rel. thickness [%]	comment
5.00	3.53	14.40	43.0	Thickness approximated
5.50	3.67	14.40	42.5	Thickness approximated
6.75	4.04	14.40	40.9	Thickness approximated
10.25	4.40	11.00	33.6	Maximum chord
13.75	4.31	7.96	28.8	
17.25	3.40	5.86	25.2	
20.75	2.74	4.48	22.9	
24.25	2.30	3.55	20.9	Thichness ~ 21.1%
27.75	1.95	2.66	19.1	
31.25	1.60	1.65	17.4	
34.75	1.30	0.80	15.6	Thickness ~ 15.0%
38.25	1.00	0.14	13.9	
39.50	0.83	0.05	13.3	
40.00	0.70	0.00	13.0	

Table 5.3-2: Blade layout WTS 80 optimised for 22 rpm

The new blade design for 22 rpm obtains a slightly higher energy yield (increase of 1%) than the original design for 19 rpm (table 5.3-3). The relative energy yield of the new blade for 25 rpm was calculated to be worse.

pitch angle [deg]	rotor speed [rpm]	Vrated [m/s]	rel. energy (aero.) [-]
-1.0 deg.	22	13.5 m/s	1.01

Table 5.3-3: Rotor speed concept for WTS 90 optimised for 22 rpm
(rated aerodyn. power 3.3 MW, $V_{cut\text{-}in}$ = 6 m/s corresponds with approx. 180 kW, $V_{cut\text{-}out}$ = 25 m/s)

Concluding remarks and outlook on structural re-design

The new blade layout proposed by the Institute for Wind Energy fulfils the need for load reduction which is analysed in further detail by dynamic simulations also carried out by the Institute (section 4.6). Unfortunately, the new blade is not able to increase the energy yield substantially. This result is obtained for a prescribed rotor diameter and rated power and the static blade load reduction is thus not a result of an iterative procedure considering fatigue loads, tower top weight etc. The result should be seen as the first step towards a new rotor design for offshore and should be improved when more considerations are taken into account.

The weight of the blade and thus also the costs will considerably be reduced for the new chord distribution and the more fatigue benign offshore wind condition.

A structural re-design of the internal blade structure has not further been investigated since it would be beyond the scope of the project and would require a major involvement of the blade manufacturer for the WTS 80 and its particular expertise with wood-epoxy blades.

5.4 Machine design

5.4.1 Protection requirements

The marine atmosphere means an increased impact on the turbine from water and salt. This can cause both extensive corrosion and harmful coating to hydraulic and electronic equipment. In the northern European seas also ice can be a design factor, which can influence performance and weight. For the site considered as the main candidate in this project, icing of the rotor is not foreseen as a large problem.

Surface protection

All parts in contact with the outside environment must have sufficient surface protection. This is the experience from the Aeolus II location at the Jade Bucht which is a location very close to the open sea (eastern North Sea). This means that painting with e. g. epoxy coating is not enough. It can be used only on very large and flat surfaces where the coat thickness is well controlled . The hub is cast iron and can only be painted. The alternatives to painting as surface protection are electro-zinc coating or protection with some petroleum based agent. Another way to avoid harmful corrosion is to choose a non-corrosive material. Stainless steel, bronze and plastic materials are example of this. The welded bed plate will be electro-zinc plated. This is a cost effective procedure compared to painting and gives a lesser inspection requirement of the result. All outside non-load carrying equipment like rails, ladders, screws, masts etc., should be of non-corrosive quality.

The quality level should be set with the objective to protect all parts of the turbine from corrosion during at least 10 years. Structural parts like the hub and bed plate should have a life time resistance to corrosion.

Temperature and moisture control

A minimum temperature and a dry environment inside the nacelle will be achieved with a combined heating and dehumidifying system. To have a minimum temperature of +15°C will give protection to the electronics used and will reduce the requirements on the separate oil warming system for oil tanks. External air is taken into the nacelle through filters and is then dehumidified and heated with two parallel working units. Two smaller units instead of one increases the MTBF for the total heating system and will also give a step function to control the capacity of the system at different ambient temperatures. If a de-icing equipment for the blades is incorporated an extra tempering unit could be used to pump heated air into the blades which will then have an exhaust valve at the blade tips.

Generally it is easier to heat up then to cool down the interior of a wind turbine. As there is no separate cooling system installed, the ambient temperature is the minimum achievable temperature level. For an offshore station this may be a problem also as the outside air may contain vapour and salt. The gearbox oil is cooled through an oil-to-air-cooler placed outside the nacelle. The generator and the transformer have their separate cooling systems through air intakes in the rear of the nacelle. Both these ventilation systems are separated from the nacelle environment.

The wind vane and the anemometer will be warmed up with electric wire heating at low temperatures. The wind logging equipment is also doubled for higher availability.

Closed compartment

To decrease the risk for corrosion and salt contamination a closed nacelle compartment will be designed. This is achieved through a pressurised interior. The fans will press outside air into the nacelle and the leakage to the outside is minimised, to achieve an over-pressure.

5.4.2 Complete nacelle

Figure 5.4-1 shows the nacelle layout for WTS 80M. The main difference from WTS 80L is the installation of the transformer in the nacelle, see section 5.4.4, section 7.2 and the therefore extended nacelle cover in fig. 5.4-1. This means that the nacelle is divided into two separate rooms. Other sub-systems having influence on the layout of the nacelle interior are the automatic lubrication systems, air-heating equipment and the power supply unit.

As in the WTS 80L there will be hand manoeuvred fire extinguishing equipment only. Bottles will be placed in the nacelle, in the tower top service platform and at the bottom service platform.
Moreover extra lifting equipment as described in section 5.5.3 is situated in the nacelle.

There will be one internal and one external escape way from the nacelle rooms. The internal path will lead to the tower top service platform. The external exit from both nacelle and transformer compartments will lead, via ladders, down to the balcony surrounding the tower top. The internal way to the transformer compartment is through a hatch in the nacelle upper floor. From the tower balcony escape ways are provided outside with a ladder with a rail for a safety belt, and inside through the ordinary ladder from the service platform.

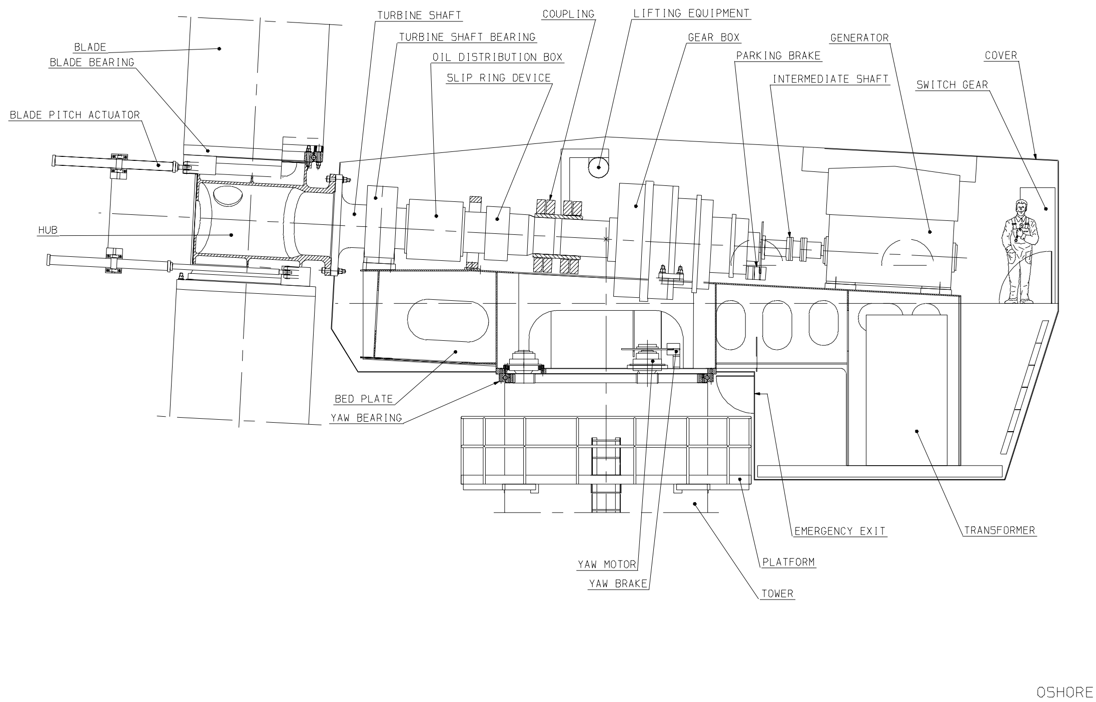


Fig 5.4-1 Complete nacelle of WTS 80M

5.4.3 Stopping system

The WTS 80L has no certain parking brake for use at stand-still, as the rotor is left free with feathered blades, able to idle slowly due to changes in the wind situation. This system design can be used only in combination with a fully operative yaw system as there are combined load cases with gale wind and certain rotor positions resulting in an exceeding of the ultimate load capacity.

The WTS 80M will therefore be equipped with an increased capacity parking brake on the secondary shaft, being able to park the rotor in a horizontal position at a fault in the yaw system. The procedure to stop the rotor in a near horizontal position is used on the Näsudden II and puts the parked rotor in a minimum load situation. At a stopping situation with loss of external power supply, but with a well functioning yaw system, the auxiliary power supply unit will be able to produce power for the yaw hydraulics.

5.4.4 Electrical system

The electrical system design has its starting point in the WTS 80L. Added to the offshore turbine is the integration of the transformer into the nacelle; under consideration of the consequences for wind turbine, support structure and grid connection. The transformer placement has been evaluated during the structural design, see section 7.2, and the nacelle placement has been chosen as the optimum design solution.

The transformer will be placed in a structure under the generator. This means that while the generator is standing on the bed plate the transformer is suspended in the bed plate structure. It is mainly a static gravity load and will only need some reinforcement of the structure. The nacelle cover will completely fence in the transformer, where the bottom will serve as an operating floor for maintenance personnel. Due to regulations in some countries, the transformer will be closed off from the rest of the nacelle with a wall, and can be reached only through a locked door. There will also be a second escape way through a door to the outside balcony. The transformer will be of a dry insulated type leaving no risk for oil leakage. It will be assembled into the nacelle compartment at the workshop assembly. The nacelle will also host a generator circuit breaker (switchgear).

5.4.5 Specification of the wind turbine

In the table below the main system data for the wind turbine are specified.

Rotor diameter	80 m
No of blades, rotor location	2, upwind
Rated power / rated wind speed	3000 kW/ / 13.7 m/s
Rotational speed	22 rpm
Power control	Blade pitch
Generator	Asynchronous 4 pole
Generator speed	1500 rpm
Transformer voltage	6 / 24 kV
Rotor weight	38 t
Weight above tower	135 t
Annual energy yield	10 GWh at V_{mean}=9 m/s

Table 5.4-1: Specification for the wind turbine

5.5 Operation & Maintenance considerations

5.5.1 Reliability and maintenance target

Maintenance target

The overall objective for regular planned maintenance (Preventive Maintenance) is to have a maintenance interval of one year as a minimum. All subsystems will have to be designed to meet this requirement. This is a relatively large deviation from the state-of-the-art technology for the present operating 3 MW turbine at Näsudden. Grease lubricated bearings, without automatic lubrication, today have a service interval of maximum 6 months. It is however assumed that the WTS 80 design can be adapted to achieve the service interval elongation. After a period of 5 years a larger service action is foreseen. With this the following regular service target set:

- Preventive maintenance is scheduled once a year and takes 2 x 8 hours for a crew of 2 persons.
- Every 5 years a larger preventive maintenance action takes place, covering 3.5 x 8 hours for a crew of 3 persons, with the need of an external crane for blade inspection and refurbishment.

Table 5.5-3 concludes the maintenance for the wind turbine sub-systems.

Reliability target

For the determination of failure rates of the WTS 80 M it is hardly possible to directly use existing information from the two operational 3 MW Kvaerner Turbin machines. The two reasons are that both of these machines are prototypes, and thus the experienced operational problems so far are not representative for the failure rates and modes of a commercial WTS 80, and further, the target should be to reduce the failure rates of the offshore WTS 80M version, according to the lowest levels found at present commercial onshore turbines. Thus, apart from the currently available WTS 80 experience, the requirements for corrective maintenance of mature commercial onshore wind turbines have been considered as well. (See sections 8.2 and 8.7 for a more comprehensive description.)

As was done before in the concept development phase, a large amount of failure modes has been categorised into six failure classes. For the first "Blades/heavy components" class the lowest failure rate was found for the popular Vestas V-39 turbine and is adopted for the WTS 80M design failure rate. This category does apply to blade failures requiring a blade repair or replacement with an external crane, as well as to any other major failure requiring such external crane assistance. The rate of the second failure mode "Gearbox/generator" was found to be relatively consistent for the commercial 500 kW designs considered, and is directly also applicable to a larger scale machine. In principle it seems relatively easy to apply electronics and control units in a redundant way into wind turbine and thus obtain a very low failure rate for "Electronic/control" failures. Kvaerner Turbin has regarded a specific layout for electronics and control. The failure rate in the category "Hydraulics" was assessed in a different way. The WTS 80M incorporates important hydraulically actuated functions such as pitching of the blades and yawing of the nacelle. By choosing high quality pumps, valves, cylinders and hydraulic oil Kvaerner Turbin has set a reduced failure rate for the WTS 80M design solution. For the category "Electrics" the lowest failure rate is found for the Tacke TW-600 and is set here as the target for the WTS 80M. Finally an advanced remote monitoring/control and resetting system will be implemented which will significantly reduce the number of failures, mainly in the last category "Others". The Kvaerner Turbin design solutions are further described in section 5.5.4.

This results in the following table:

Failure Classes	**Failure rate** (events/year)	**Crane assistance**
Blades/heavy components	0.32	yes
Gearbox/generator	0.14	no
Electronics/control	0.11	no
Hydraulics	0.15	no
Electrics	0.20	no
Others	0.10	no
Total	**1.02**	

Table 5.5-1: *Failure rate targets for the WTS 80M design solution*

The failure rate of 1.02 events per year implies that the average mean time between two consecutive corrective maintenance visits to each wind turbine is 18 months. When adequate preventive maintenance actions will take place as well when a wind turbine is serviced after a failure and is almost due to regular service, but in general the maintenance strategy applied is a PM+CM approach. Preventive maintenance will be scheduled to the summer when weather conditions are more benign, and loss of revenue due to downtime is less then during the winter season. For a further treatment of the O&M strategy see chapter 8.

5.5.2 System design with respect to maintenance

Lubrication

The one year maintenance interval means that automatic greasing has to be introduced at some points when grease lubricated bearings are in use. Several different systems are on the market today. One can either use separate accumulators for each lubrication point, or a central lubrication system. The latter is often used on lorries and other heavy vehicles. In this case the lubrication unit will be an spring manoeuvred accumulator placed in connection to the greased system which will push grease into the bearings at a certain interval. The accumulators will be manually charged once per year. It is generally a larger problem to take care of the used and surplus grease than to eject fresh grease into a bearing.

The following design options are suggested:

Component	Type of element	Greasing option	Waste collection
Blade bearing	roller bearing	central unit #1	tray manually emptied
Hydraulic cylinder hinge for pitch	glide bearing	dry lubricated	-
Main shaft bearing	roller bearing	central unit #2	tray manually emptied
Yaw gear	gear mesh	manual application	manual collection
Yaw bearing	roller bearing	manual	tray manually emptied
Generator	roller bearing	manual	surplus collected

Table 5.5-2: Grease lubrication option

The gearbox lubrication system is fully automatic. The system has its own tank, pump, filter and cooling system. The strategy for oil filter change on WTS 80L is conditional maintenance as the pressure drop over the filter is monitored. For the WTS 80M this strategy is changed to exchange of filter at the annual maintenance and to have a cleaning and recycling procedure for the oil filter at the service main station. The gearbox oil is tested through oil samples and an analysis of the condition together with an extrapolation of the remaining capacity is performed at the main service station after return of the maintenance crew. Change of oil is then planned for the following annual service period. With the filter rate used today together with a careful monitoring of the oil temperature at operation, the service life for the oil can be 5 - 10 years.

Hydraulics

For the hydraulic system the maintenance is limited to a yearly change of filter and to check for leakage. The latter is of the category unplanned maintenance. The filter grade is very high giving the system a long service life. Hydraulic oil has a tendency to age with a higher rate than lubrication oil. This is due to the pressure of the system and the breaking down of the additives. The service life of the hydraulic oil is probably limited to 5 years. Oil analysis is carried out in the same way as for the gearbox.

Spare hydraulic cylinders should be available on the support vessel for interchange of complete cylinders instead of a repair in situ, if leakage or any other damage is observed. Glide bearings will be exchanged at site.

Power supply unit

Annual maintenance is check of fuel and filling of diesel if necessary together with a manual start-up of the system.

Monitoring

For a more effective and successful maintenance an increased monitoring of the condition of the wind turbine is envisaged. All PLC-nodes have the I/O-capacity to monitor its host with respect to operational state, temperature and vibration. All these signals are possible to read at the land control station.

All signals considering the operation will be logged at the turbine and will be sent to land through e.g. an optic fibre communication link. Certain manoeuvres can be executed from land such as start, stop and yawing. If communication is lost the turbine PLC will be able to put the machine in a safe parked condition.

System	Component	Action	
		1y	5y
Blades	Outer surface	V	FR[8]
	Bolt connection	V	T
	Lightning protection		FR
Blade pitch	Blade bearings	VG	P
	Pitch cylinders	V	F
	Cylinder bearings	P	
	Valves etc.	V	F
Main shaft	Thrust bearing	G	P
	Oil distribution box	V	F
	Slipring unit	V	FR
Gearbox	Mechanical parts	V[9]	V[10]F
	Lubrication system	V	F
	Cooling system	V	F
	Lubrication oil	T	X
	Filter	FX	
Generator	Shaft bearings	G	
	Windings		V
Stopping system	Emergency stop	F	
	Mechanical brake	F	
	Brake linings		X
Yaw system	Gear mesh	VG	P
	Yaw motors		F
	Yaw bearing	VG	P
Hydraulics	Pump	VG	F
	Hydraulic oil	T	X
	Valves etc.	V	F
	Filter	FX	
Switchgear		V	F
Transformer		V	
Control system	Wind logging	V	F
	PLC	F[11]	
Power supply unit	Motor + generator	VF	G
	Fuel	R[12]	
Cables		V	
Platforms & ladders			V
Fire extinguishers		V	X
Nacelle	Bed plate, hub	V	R
	Nacelle cover	V	R

V visual inspection
T sample test
X exchange of component if necessary
F functional test, vibration finger print
P measurement of bearing play
R refurbishment
G greasing

Table 5.5-3: Preventive maintenance of the wind turbine sub-system

[8] Repair from a platform is carried out at this interval.
[9] Only from the outside
[10] Inside through inspection holes with endoscope etc.
[11] Continuously tracking itself
[12] Filling

5.5.3 Repair philosophy

Automatic repair

Some systems may have the possibility of automatic or remotely controlled repair. This is most obvious for the control system and other electronic equipment where alternative logical units can be used and back up cards are installed already from the start. Some special components are doubled to reach this possibility e.g. oil filters and wind logging equipment.

Cassette philosophy

The sub-systems or components should be changed completely at maintenance if found in poor condition. This means that spare components should be available on the support vessel. The interchangeable part should be designed as cassettes in order to make the exchange easy and quick and to minimise the risk for a faulty operation of the service sequence.

Sub-system	**Category of work** **M = mechanical** **H = oil system** **E = electric**
pitch cylinder	M H
pitch valve rack	M H E
hydraulic pump	M H
hydraulic pump motor	M E
hydraulic oil filter	H
central lubrication unit	M H E
gearbox oil filter	H E
gearbox oil pump	M H E
parking brake calliper	M H E
power supply unit	M E
heating device	M E
air filters	M
wind measurement	M E

Table 5.5-4 Repair/replacement work categories

Repair of heavy equipment

A few repair cases where lifting equipment must be used for the total handling are described in detail. These cases are also likely to occur during the life time.

Pitch cylinder replacement: A special protection and lifting adapter is connected to the faulty cylinder. The cylinder is disassembled from the blade and hub lugs. The nacelle hoist is used where the hook is taken out through a roof hatch and with a tackle arrangement connected to the lifting adapter. The adapter is disconnected from the hub and the cylinder is lowered down to the support vessel outside the tower. The lifting adapter will protect the cylinder if it in any case hits the tower. A new cylinder is mounted in the lifting adapter and hoisted up. The lifting adapter is stored in the nacelle when not in use.

Main shaft oil distribution box and slipring replacement: The slipring unit can be split and moved away sideways. The turbine shaft is fixed to the support ring in front of the slipring unit. The shaft coupling is disconnected and the oil distribution box is divided into separate rings each taken through the gap below the shaft coupling.

Thrust bearing replacement: The bearing is cut into two halves and replaced with a split bearing. For this operation and for similar where the weight is more than 300 kg, a heavier hoist equipment must be taken up to the nacelle first.

For nacelle equipment of large volume or with a mass exceeding 1500 kg exchange can only be done with the crane on the special service jack up rig. The equipment is taken through the roof of the nacelle and then lowered to the ground. Such parts are main shaft, gearbox, generator and transformer. It is also possible to exchange the rotor with use of this crane.

The ultimate choice for repair or exchange of the complete wind turbine is to take it down with a crane with the capacity of 150 t.

For repair on blades, inside hub and on yaw system, locking devices for protection from movement must be used. These tools are stored in the nacelle when not in use.

Lifting equipment

For replacement of components and for supply of tools and consumables up to the nacelle the OWEC will be permanently fitted with hoisting equipment as in table 5.5-5. In case of larger repair work extra lifting devices, jacks etc. must be taken from outside. The nacelle roof will have moveable panels so that heavy and large equipment can be lifted upwards and then lowered to the support vessel. This method is used for e.g. gearbox, main shaft bearing or generator in case of replacement or repair.

Position	Equipment	Capacity	Working area
No. 1a. Nacelle above tower	hoist	300 kg	nacelle to tower entrance (60m cable) inside tower
No. 1b. Nacelle with tackles to the roof and hub	hoist	300 kg	hub to support vessel outside the tower (85 m cable)
No. 2 Tower entrance	crane arm with hoist	300 kg	tower entrance to supply vessel (20m cable) outside the tower
No.3 Extra	hoist	1500 kg	nacelle to support vessel inside or outside tower (85 m cable)

Table 5.5-5: Lifting equipment

5.5.4 System design with respect to reliability

Gearbox

The gearbox lubrication system is equipped with two filter passages in parallel. The pressure drop over the filter is monitored. If one filter is blocked a PLC-controlled valve will lead the oil flow over the other filter. At maintenance both filters will be exchanged. The MTBF for the gearbox is already high. A careful monitoring of the temperature and a low operational temperature limit will secure a high availability and a long service life.

Hydraulics

The hydraulic system at Näsudden II has proven a high availability. This is reached through a good filtering of the oil and with the use of high quality parts. An increased quality assurance of the system components and of the workshop test procedure will be introduced. Careful and clean maintenance and repair performed by well trained personnel is most important.

Control system

The PLC is configured so that the central unit is doubled and a watch dog will switch over to the spare unit in case of malfunction. Spare nodes will also be assembled into the decentralised system and can be programmed to take over. Remote programming is possible from the land control station. A special ”first aid programme” is integrated into the system.

Power supply

The internal power supply for a wind turbine is normally provided by the grid through a local transformer. When the grid is lost an isolated machine needs power to perform the necessary operations to put the machine in a safe state. At Näsudden II the power supply for the necessary electrical manoeuvres is secured with a battery system. Power for the emergency stopping is, in case of grid loss, achieved through hydraulic accumulators in the pitch system as well as by spring force in the emergency disk brake. This supply system is however not sufficient for a longer period without external power supply.

The WTS 80M is equipped with a complete unit for self supply of electric power. This is a diesel driven asynchronous generator with the power in the order of 15 kW. This unit will in case of a grid loss automatically start up. There is still a small battery unit for the PLC in order to give the starting order to the diesel and to keep the necessary record of events in case of a total break down of the turbine. This supply is also used for communication with land. The diesel unit will start up as soon as an additional power supply is needed e.g. for loading of the battery unit, yawing to follow the wind, some additional heating, intermittent lubrication of the gearbox, light in tower and nacelle. A fuel tank of 150 l gives an operational time of several months.

Removed systems

Some sub-systems can be simplified or removed in the marine version of the wind turbine. This will reduce the energy cost but also give a small contribution to the availability.

As mentioned above there is no automatic fire extinguishing system. The experience from Näsudden II, which is equipped with an automatic CO_2-system is negative and the automatic system is taken away also on WTS 80L.

There is no elevator in the tower. The tower height is reduced and visits to the machine are foreseen only once a year.

The WTS 80L has a one speed generator concept. The lower speed range is not necessary as the noise conditions are more benign.

5.6 Cost evaluation

The unit cost for a 100-series of the WTS 80M wind turbine (thus excl. tower) are estimated by Kvaerner Turbin to 1.7 M ECU.

Table 5.6-1 shows the additional costs for the marinisation of WTS 80. The figures are not exact. They are based on both internal knowledge and on information from sub-suppliers. The total figure shows that the cost for the wind turbine is of the same level whether it is onshore or offshore. The supplementary costs for marinisation are largely recovered with the one speed generator concept and the optimisation of the blade for higher rotor speed and lower turbulence level.

A further cost reduction with respect to the standard onshore version is achieved by the elimination of the elevator.

Sub-system/component	**Added cost (kECU)**
Surface protection and non-corrosive material	10
Grease lubrication system	7
Oil filter	2
Environmental control	5
Power supply	5
Parking brake system	2
Transformer compartment	13
Nacelle cover	10
Control system and monitoring	6
Increased voltage level	6
Additional lifting equipment	3
One speed generator	*-25*
Decreased noise insulation	*-2*
Blade optimisation higher rpm, lower turbulence	*approx. -30*
Total (excluding transformer**)**	**appox. 12**

Table 5.6-1 Indicative cost summary for marinisation of WTS 80

5.7 Conclusions

The most important result from the work of Kvaerner Turbin in the Structural design phase is that a 3 MW offshore wind turbine is achievable, realistic and economic.

The changes of the mechanical systems and the principal layout of the turbine are not considerably radical compared to the land based turbine concept. This is also a conclusion we have drawn from studying the already built offshore windfarms in Denmark. It can probably be explained by the fact that the design goals in the turbine design work, have been taken similar for development of both landbased and offshore wind turbines, e.g. increased availability and service life. An important difference is that due to the higher maintenance costs offshore, more expensive design solutions to increase the service life further, can be used.

In the conceptual design phase targets for the marinisation of the wind turbine were defined. In order to meet these objectives the wind turbine itself has undergone design changes to achieve an adaptation of the land based turbine technology to offshore. The design suggestions were reconsidered during the Structural design phase and the following redesigns have finally been introduced:

- increased environmental protection of the nacelle as the sea water contaminated air is more aggressive in corrosion
- design for prolonged maintenance interval as a 1 year recurrence period was a target
- conceptual changes for increased availability and reliability

- implementation of equipment for handling of components
- change of rotor design and speed concept to change dynamic properties.

The most important mechanical design changes, compared to WTS80L, are the implementation of the transformer in the nacelle and the exclusion of the elevator in the tower.

Through introduction of an automatic lubrications system the 1 year maintenance interval could be reached. The yearly maintenance is carried out by 2 persons working 2 x 8 hours. Every 5th year a larger preventive maintenance period takes place. A crane will then be used if a blade overhaul is found to be necessary.

Due to the limited experience from failure rates of the very large wind turbines, it has been impossible to quantify any figures from the prototypes in operation. Data from smaller commercial machines have been used as a starting point for the OWEC design. With higher design quality and more reliable systems, it is concluded that a higher availability can be reached for the offshore turbine concept. An autonomous power supply system has been introduced and this will decrease the needs for immediate action at a grid fault.

For integration into the total OWECS the turbine rotor speed has been increased to achieve a better dynamic performance. This has developed a total dynamic system with properties well suited for the two-bladed soft turbine concept. A one-speed system is introduced. This can be done as the noise requirements offshore are more benign.

The cost figures for the WTS 80M are of the same order as for the land based version. The reason for the low cost difference is the reduction due to the one-speed generator and optimisation of the blade for offshore conditions i.e. higher rotor speed and lower ambient turbulence level. Placing the transformer in the nacelle contributes to the largest increase of costs.

6. Structural Design of Support Structure and Installation Procedure

6.1 Introduction

The support structure for the Offshore Wind Energy Converter is a vital component in the development of an Offshore Wind Farm. The purpose of the work described in this section has been directed primarily at the design development of a support structure of an OWEC.

The principal purpose of the support structure is to support the 80m diameter 3MW wind turbine (WTS 80 of Kvaerner Turbin) under the imposed aerodynamic and hydrodynamic forces associated with both operational and extreme event conditions.

An initial feasibility study is described in Section 3.4, in which a wide range of support structure concept options were assessed including combinations of gravity and piled foundation, monotowers and braced towers and floated and piled installation concepts. A more detailed account of three possible solutions is given in Section 4.3. From these three concepts, one, was identified for development.

The chosen OWEC support structure concept, a monopile, has the pile installed first, using either a floating crane or a jack-up, followed by the tower and wind turbine either lifted into place in the normal manner or alternatively floated-over the pile.

In addition to addressing the OWEC support structure, this section of the report contains a brief description of the single trafo support structure which is designed to support the four major 100MVA transformers and associated switch gear.

The site chosen for the development is in the demanding environmental conditions of the North Sea at a location of the Dutch coast in water depths ranging from 12-20m (LAT). Characteristic wind, wave and current conditions have been prepared for the site together with appropriate soil conditions.

6.2 Establish Design Criteria

6.2.1 Environmental Data

Water Depth

The water depth to lowest astronomical tide (LAT) at the selected sites is given as follows:-

	Min.	Max.
Water Depth (LAT)	12.0	20.0
Extreme Tide	2.0	2.0
Storm Surge	3.0	3.0

Wave, Wind & Current

The 50 year return sea state and current conditions were obtained from analysis of the NESS hindcast database [6.2-1]. Results relate to the maximum water depth shown above. The maximum extreme and operating wave heights have been based on GL criteria [6.2-2] and are given as follows:-

<u>50 Year Return Sea State</u>		
Wave Height Hs	6.9m	
Wave Period Tz	7.7s	
<u>Extreme Design Wave Conditions</u>		
Maximum Wave Height Hmax	12.8m	(1.86 x Hs)
Associated Period Tacc	9.5s	
Surface Current	1.1m/s	
Seabed Current	0.7m/s	
<u>Operating Design Wave Conditions</u>		
Maximum Wave Height Hmax	9.1m	(1.32 x Hs)
Associated Period Tacc	7.5s	(steepness 1/9)
Surface Current	1.1m/s	
Seabed Current	0.7m/s	

The above wave and current conditions are assumed to be omnidirectional.

The operating maximum wave height of 9.1m is used for convenience in preference to the less onerous wave height, associated with the wind speed in the operational range which are available through analysis of the NESS database. Use of this latter condition would have been justified if the extreme event load case (E1.1) has been found to govern the design. The issue is dealt with also in Section 9.4.1.

Hs \ \ Tz	0.5 s	1.5 s	2.5 s	3.5 s	4.5 s	5.5 s	6.5 s	7.5 s	8.5 s	sum
5.75 m							+	+		0
5.25 m							+	+		0
4.75 m							1			1
4.25 m							3			3
3.75 m						4	4			8
3.25 m						18	+			18
2.75 m					+	35				35
2.25 m					26	41				67
1.75 m				+	114	5				119
1.25 m				6	219	1				226
0.75 m				241	147	1				389
0.25 m	1		1	115	14	+	+			132
sum	1	0	1	363	521	105	8	0	0	998

Table 6.2-1 Wave Scatter Diagram (parts per thousand)

Under fatigue conditions the wave scatter diagram given by Table 6.2-1 is adopted combined with the wave directional probability rosette taken from Figure 6.2-1. Data is derived from the NESS hindcast database[6.2-1].

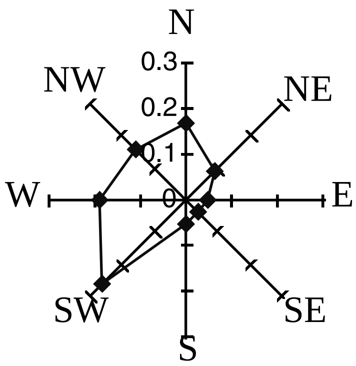


Figure 6.2-1 Wave Directional Probability Rosette

The marine growth profile, relative to mean sea level, is taken as follows:-

From	To	Thickness (mm)
Elev. +1.5	Elev.-9.0	50
Elev. -9.0	Seabed	Linear Reduction from 50mm to 0

The hydrodynamic coefficients adopted were as follows:-

C_d=0.70
C_m=2.00

The wave loading calculation takes no account of the presence of the cable conduit and boat landing elements. For the purpose of this study it was the intention to demonstrate that the tower and pile elements exhibited more than adequate fatigue lives. In practice, detailed calculations would be necessary to account for these items.

50 year return wind forces are based on Class I certification according to Germanischer Lloyd (GL) [6.2-2]. This requires that the structure is designed based on a 5 second wind speed which is derived from 10 minute mean wind speed of 50m/s. Guidance provided by GL results in a 5 second design wind speed of 60m/s. Similar to the conservative treatment of the extreme operating load case E1.1 here for convenience the extreme wind speed from Class I is preferred with respect to an extreme wind speed value derived for the actual site from the NESS database (Class S). The latter approach would have been worthwhile if extreme loads at 50 years conditions are governing. Both treatments are compared in section 9.4.2.

Extreme operating gust forces have also been calculated in accordance with GL requirements, based on a rated wind velocity of 13.5m/s and accounting for extreme changes of wind direction.

Both the 50 year return wind and extreme operating wind conditions are assumed to be omnidirectional.

6.2.2 Seabed Soil Conditions

Soil conditions have been assessed based on data from locations in the vicinity where the soils are fine to medium sands, typically medium dense with thin interspersed layers of silt and clay. The sand friction angle ϕ is taken as 30 degrees. Scour is commonly a problem at shallow water sites in the Dutch sector and some form of scour protection is likely to be required.

6.2.3 Turbine/Trafo Characteristics

Details of the turbine rotor and nacelle are described in chapter 5 whilst chapter 7 addresses the grid connection, the farm layout and requirement for the central trafo structure. This section summarises the important characteristics that influence the design of the associated support structures. These are given as follows:-

OWEC Support Structure

• Rotor Diameter	80 m
• Speed of Rotation	22 RPM
• Number of Blades	2 no.
• Diameter of Tower/Nacelle Interface	3.5 m
• mass of nacelle:	90 tonnes
• mass centre placed on x co-ordinate	-1.3 m
• hub and blades mass	39 tonnes
• mass centre placed on x co-ordinate	-6.2 m
• transformer mass (including support)	12 tonnes
• mass centre placed on x co-ordinate	+4.0 m

Trafo Support Structure

Main 100 MVA Transformers

- No 4
- Length 8.0m
- Width 5.0m
- Height 7.5m
- Weight 200 tonnes (each)

24kV Switch Gear

- No 20
- Length 1.7m
- Width 0.6m
- Height 2.0m
- Weight 1 tonne (each)

150kV Switch Gear

- No 6
- Length 5.0m
- Width 1.5m
- Height 3.0m
- Weight 10 tonnes (each)

6.2.4 Code of Practice

The support structure is designed in accordance with GL [6.2-2] i.e. in accordance with the design objectives (Section 2.5). Load cases are assembled to meet the specific partial safety factors given by the code requirements.

6.2.5 Air Gap Criteria/Minimum Support Structure Height

GL does not set any specific written requirement regarding the lowest elevation that the rotor can be set except by establishing a minimum air gap of at least 1.5m(clear distance above wave crest to structure which cannot be suitably designed to resist wave impact). This establishes the minimum height of the staging around the tower.

Based on informal contact with GL a minimum distance between the staging top of steel and the underside of the rotor blade has been established as 4.5m. This is loosely based on an old German standard (1982/1990) [6.2-3] whereby a person carrying

a load e.g. a ladder should be able to pass by safely. In practice the rotor would be stopped prior to boarding the structure.

The forgoing leads to the minimum support structure heights as given below:-

Description	Min.(m)	Max.(m)
Water Depth (LAT)	12.0	20.0
Tide	2.0	2.0
Storm Surge	3.0	3.0
Crest Height	5.5	8.3
Air Gap	1.5	1.5
Access Platform	0.3	0.3
Safe Working Height	4.5	4.5
Rotor Radius	40.0	40.0
Rotor Axis Offset	-3.0	-3.0
Total	65.8	76.6

Table 6.2-2 Minimum OWEC Support Structure Height (to underside of nacelle)

6.2.6 Dynamic Response Criteria

Dynamics are an essential item in the design of the support structure. The right choice of the dynamic properties and specifically the support structure eigen frequency is paramount. Unlike wave forces, wind excitation imposed by the rotor on the support structure is characterised by a number of distinct frequencies. Most notable is the speed of the rotor and the associated blade passing frequency i.e.:-

Wind Excitation Frequencies (resulting from wind turbine)
- rotor frequency = 0.37 Hz (22 RPM)
- blade passing frequency = 0.73 Hz (two bladed rotor)

The key issue in the design of the support structure is the avoidance of the above frequencies along with those frequencies that contain significant wave energy contributions i.e.:-

Wave Excitation Frequencies
- frequencies< 0.40 Hz (or periods>2.5secs)

In practice meeting this criteria may not be possible where a soft-soft structural response is desirable and the design may need to account a significant component of hydrodynamic loading.

Avoidance of the designated wind frequencies leads to three frequency ranges for locating the fundamental support structure frequency i.e.:-

Frequency bands
- 'stiff-stiff' - where the structure frequency exceeds the blade passing frequency
- 'soft-stiff' - where the structure frequency lies between the rotor and blade passing frequency
- 'soft-soft' - where the structural frequency lies below the rotor frequency.

In selecting any one of these three bands in which to locate the support structure frequency it is necessary to account for a general exclusion range with too high dynamic amplification of the loads and for possible inaccuracies. Natural frequency calculations, in particular, have a tendency to be particularly sensitive to the variability of foundation soils. To account for such inaccuracies a design tolerance is incorporated into the specification of the frequency ranges. The sensitivity of the natural frequency calculation to the foundation properties is analysed in Section 9.2.

$f_p <= f_r / (1 + \varsigma) / (1 + \eta^+)$ 'soft-soft' design
$f_p >= f_r / (1 - \varsigma) / (1 - \eta^-)$, $<= 2f_r / (1 + \varsigma) / (1 + \eta^+)$ 'soft-stiff' design
$f_p >= 2f_r / (1 - \varsigma) / (1 - \eta^-)$ 'stiff-stiff' design

where f_r is the rotor frequency
f_p is the support structure frequency
ς is the general exclusion range (taken as 7.5%)
η^+ is the positive foundation frequency tolerance (taken as 15%)
η^- is the negative foundation frequency tolerance (taken as 7.5%)

The following table summarises the extent of the frequency bands. The dynamic response is expressed in the traditional structural convention i.e. in seconds rather than Hertz.

	Stiff-Stiff Response	Blade Pass	Soft/Stiff Response		Rotor	Soft-Soft Response
	Upper Limit	Frequency	Lower Limit	Upper Limit	Frequency	Lower Limit
Period(s)	1.17	1.36	1.69	2.33	2.73	3.37
Freq(Hz)	(0.86)	(0.73)	(0.59)	(0.43)	(0.37)	(0.30)

Table 6.2-3 Frequency Bands

This suggest three viable alternatives viz.:-

- Stiff-Stiff Response Period<1.17 s
- Soft-Stiff Response 1.69 s<Period<2.33 s
- Soft-Soft Response 3.37 s<Period

It should be noted that for soft-soft support structures with rotor speeds in the given range, then the fundamental period of the structure will lie in a range of frequencies where significant wave energy is likely to occur. This in itself does not necessarily eliminate a soft-soft solution but it does require that very careful and detailed dynamic analyses should be performed to demonstrate the adequacy of the design (see Section 9.3).

6.3 Establish Structural Properties

OWEC Support Structure - General Arrangement

The monopile OWEC support structure has been configured to support the nacelle and rotor based on the North Sea site conditions given in Section 6.2. The structure comprises a pile which is installed first and a tower section complete with the turbine which is either lifted or floated over the pile.
The water depth at the final location ranges from 14 to 19 m (LAT) according to section 4.8 The goal of the work presented here is the development a viable design solution for the entire range of water depths. Therefore two alternative water depth have been considered i.e. maximum of 20m (LAT) and the minimum water depth of 12m (LAT).

Maximum Water Depth Condition

The overall configuration details are given as follows:-

• Height - seabed to rotor axis	79.6m	
• Height - sealevel (LAT) to rotor axis	59.6m	
• Height - seabed to underside of nacelle	76.6m	(see Table 6.2-2)
• Distance from access platform to blade tip	4.5m	(minimum)
• Tower diameter at nacelle interface	3.5m	
• Pile diameter at waterline	2.8m	
• Pile diameter at mudline	3.5m	
• Pile penetration	25m	

A feature of the design is the cone in the pile below sea level. By reducing the diameter in the wave zone in this way, the inertia dominated fatigue wave forces are substantially reduced leading to satisfactory fatigue design (Section 9.3).

The chosen member sizes are given in Figure 6.3-1.

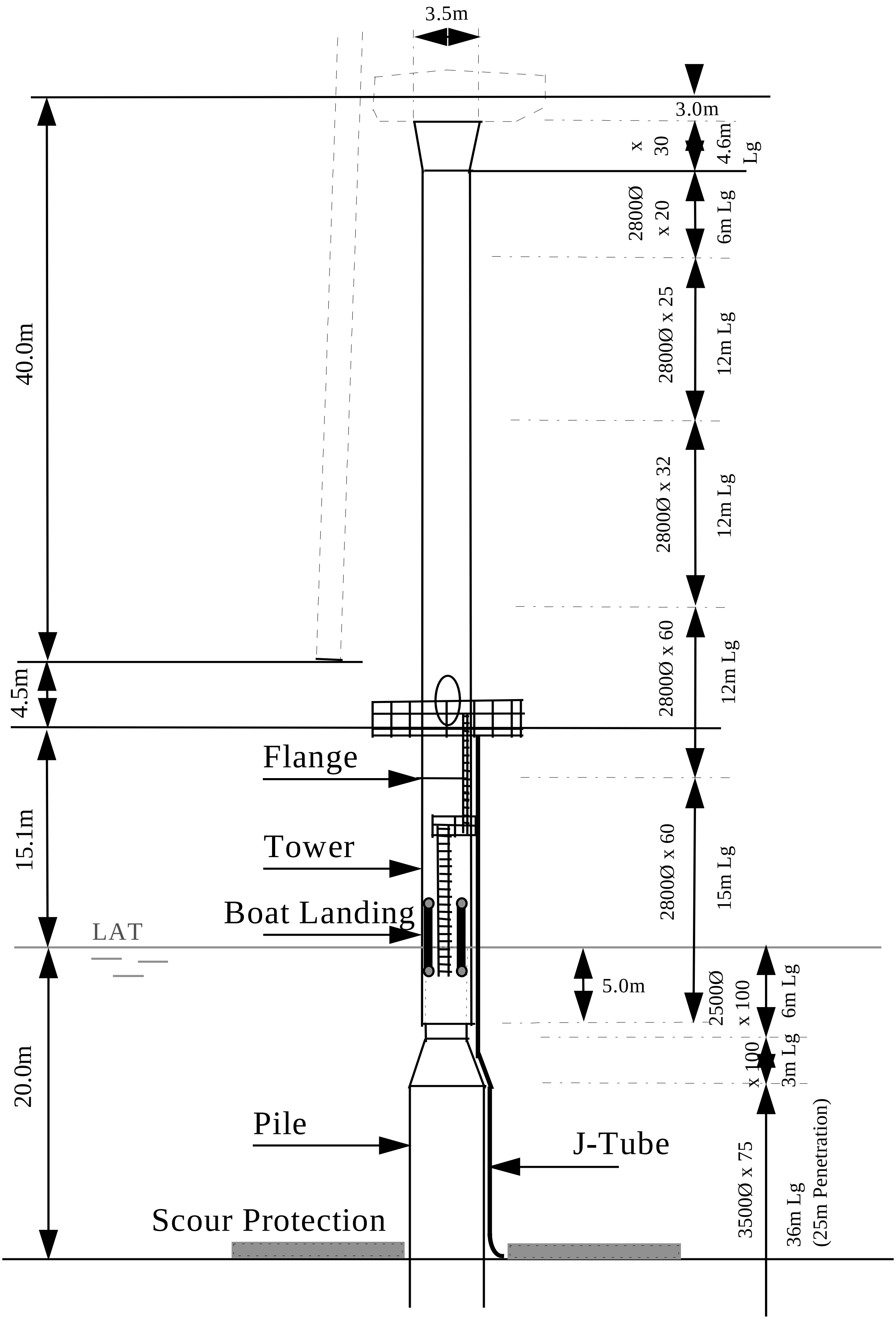


Figure 6.3-1 OWEC Support Structure - Maximum Water Depth Condition

Minimum Water Depth Condition

The overall configuration details are given as follows:-

• Height - seabed to rotor axis	71.6m
• Height - sealevel (LAT) to rotor axis	59.6m (as for max' w.dep)
• Height - seabed to underside of nacelle	68.6m
• Distance from access platform to blade tip	7.3m
• Tower diameter at nacelle interface	3.5m
• Pile diameter at waterline	2.8m
• Pile diameter at mudline	2.8m
• Pile penetration	25m

Being in shallower water the hydrodynamic loading is more favourable and likewise being shorter in overall terms, the support structure attracts smaller aerodynamically imposed moments in the pile. These factors offer the opportunity for a lighter and thus cheaper design. Depending on a detailed structural analysis, the overall height can be adjusted and/or the pile diameter reduced. An example of such a concept featuring a reduced overall height combined with a constant pile and tower diameter is shown in Figure 6.3-2. From the view point of design, manufacturing and installation there is no major problem as long as the basic concept is adopted in a modular manner to water depths between the minimum and maximum water depth.

For both considered water depths the overall height of the support structure is equal or close to the minimum structural height stated in section 6.2.5 for a number of reasons, viz:-

- dynamic amplifiaction of wave loading increases for a taller and thus softer structure,
- increased height results in a long lever arm of the rotor forces and thus higher bending loads in the lower part of the structure,
- installation (floated as well as lifted) and major maintenance is more difficult and expensive for taller structures certainly if height is considerably large anyway due to the rotor diameter,
- offshore in comparison to onshore, the relative gain in energy with an increase in hub height is lower whilst the capital costs probably increase stronger.

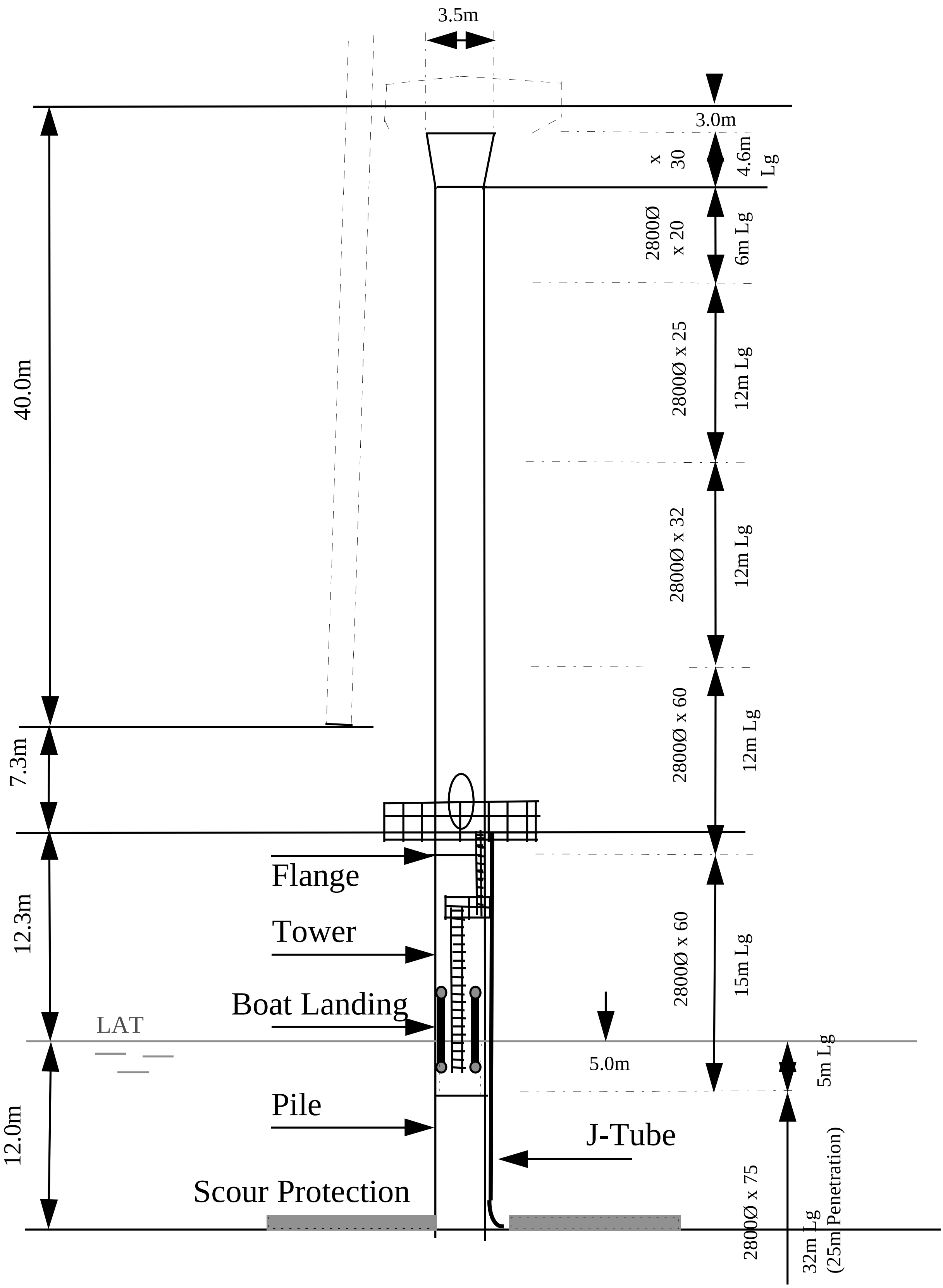


Figure 6.3-2 OWEC Support Structure - Minimum Water Depth Condition

Trafo Support Structure - General Arrangement

A single trafo support structure is required within the wind farm. For this a monopile OWEC support structure has been configured to support the transformers and switch gear based on the North Sea site conditions given in Section 6.2. The structure comprises a pile which is installed first and a tower section complete with beams and trusses with the modules and switch gear placed above.

A single water depth has been considered i.e. the maximum water depth of 20m (LAT).

The overall configuration details are given as follows:-

- Height - seabed to transformer top 55.5m
- Pile diameter at waterline 2.8m
- Pile diameter at mudline 3.5m
- Pile penetration 25m

The chosen member sizes are given in Figure 6.3-3.

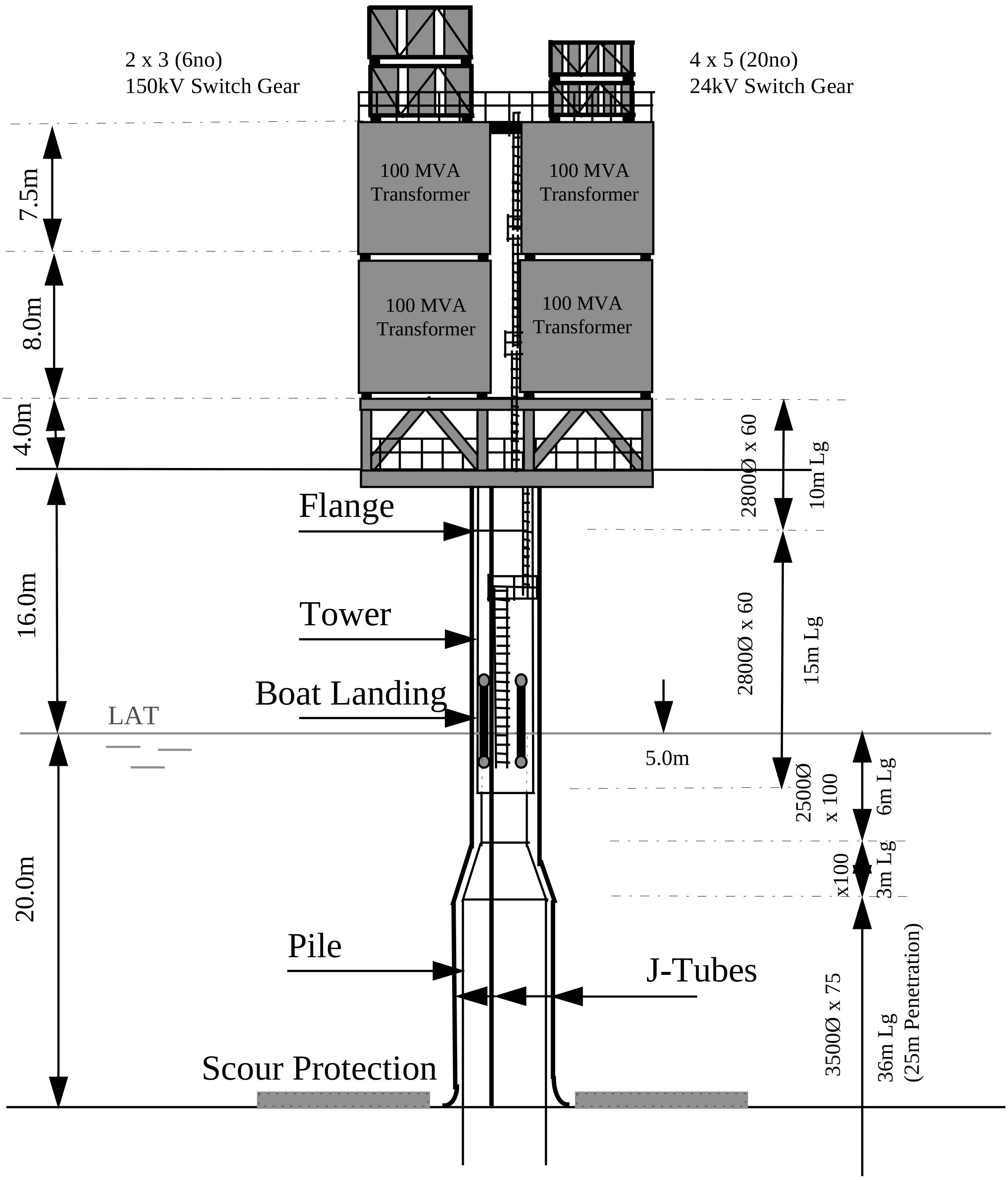


Figure 6.3-3 Trafo Support Structure

6.4 Generate Loading

Loads imposed on the OWEC support structure comprising the pile and tower elements derive from four principle sources i.e.:-

- Gravity Loads
- Hydrostatic Loads (negligible)
- Aerodynamic Loads
- Hydrodynamic Loads

Loads have been generated for the most severe water depth of 20m (LAT).
Loads have been expressed in the axis systems given in Figure 6.4-1.

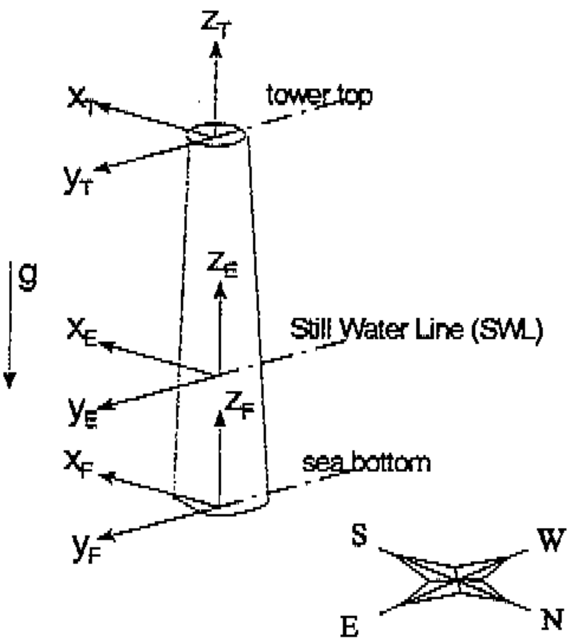


Figure 6.4-1 Axes Systems

Gravity Loading

Gravity loads associated with the turbine, tower and pile are given in the sea bottom axis system as follows:-

	Fxt(KN)	Fyt(KN)	Fzt(KN)	Mxt(KNm)	Myt(KNm)	Mzt(KNm)
Turbine						
Nacelle	0	0	-883	0	-1148	0
Hub/Blades	0	0	-383	0	-2372	0
Transformer	0	0	-118	0	472	0
Tower	0	0	-1717	0	0	0
Pile	0	0	-2737	0	0	0

Table 6.4-1 Nacelle/Rotor Deadload Forces

Aerodynamic Loading

The extreme wind forces on the nacelle/rotor are given in the tower top axis system as follows:-

	Fxt(KN)	Fyt(KN)	Fzt(KN)	Mxt(KNm)	Myt(KNm)	Mzt(KNm)
E1.1 Operating 1	450	7	-5	2250	420	-191
E1.1 Operating 2	-359	41	-55	-16	-2030	16
E1.1 Operating 3	390	2	-15	2670	530	-177
E1.1 Operating 4	-315	130	25	146	-6580	-186
E2.1 50 Year (gusts)	126	0	159.6	867	1095	-110
E2.2 50 Year (waves)	104	0	131.9	717	905	-91

Table 6.4-2 Nacelle/Rotor Wind Forces

Loads for the 'Operating' case are provided by Kvaerner Turbin and represent an extreme operating gust (GL Load case E1.1) at rated wind speed with successive stop operation whilst the '50 Year' case is representative of the 50 year extreme gust with the E2.1 based on a 5 second gust and the E2.2 case based on a 1 minute gust. Values given exclude partial safety but include gust response factors as appropriate.

Wind forces on the tower itself are given in the sea bottom axis system as follows:-

	Fxt(KN)	Fyt(KN)	Fzt(KN)	Mxt(KNm)	Myt(KNm)	Mzt(KNm)
E1.1 Operating 1	32	0	0	0	1600	0
E2.1 50 Year (gusts)	185	0	0	0	9250	0
E2.2 50 Year (waves)	153	0	0	0	7632	0

Table 6.4-3 Tower Wind Forces

The fatigue wind forces are obtained from time domain simulations as described in Section 9.3.

Hydrodynamic Loads

Wave forces on the structure have been derived based on the extreme/operating criteria given in Section 6.2.1. Forces expressed in the sea bottom axis system were obtained as follows:-

	Fxt(KN)	Fyt(KN)	Fzt(KN)	Mxt(KNm)	Myt(KNm)	Mzt(KNm)
E1.1 Operating	721	0	0	0	11536	0
E2.1 50 Year(gusts)	721	0	0	0	11536	0
E2.2 50 Year(waves)	1305	0	0	0	20876	0

Table 6.4-4 Pile/Tower Wave Forces

6.5 Natural Frequency Analysis

A natural frequency analysis of the structural arrangement comprising the pile, tower and wind turbine was carried out to identify the fundamental frequencies of the structure so as to confirm the premise of a soft-soft dynamic characteristic.

The analysis was carried out using KOGL's in house structural analysis software SEADYN. This uses a subspace iteration technique to compute the eigen values.

Features of the computer model adopted are described as follows:-

- The OWEC support structure was modelled as a series of beam elements extending from the lower extent of the pile, 25m below the seabed, to the rotor axis level, 79.6m above seabed level. The beam elements span between node points which are spaced at 1m centres below seabed and typically 3m spacing above mudline.
- The nacelle, hub and rotor were modelled as a series of interconnected lumped mass node points which provide connectivity from the top of the support structure to the centre of each of the blades. Beam elements are used representing the approximate stiffness of the associated elements. The blades are modelled in the vertical orientation.
- The stiffness properties of the support structure beam elements are calculated according to the chosen diameter and thickness. No attempt has been made to calculate the properties of the grouted connection between the pile and the tower. This is unlikely to have any significant influence on the results of the analysis.
- The influence of the soils was accounted for by a series of lateral (P-Y) springs which are placed at 1m centres up the length of the penetrating pile.
- The mass of the structure is calculated according to its properties with account made for both the mass of water contained within the submerged part of the pile and the added mass. The mass of the nacelle, hub and rotor was distributed based on the nacelle, hub and rotor mass distribution with the mass of each blade placed at its respective centre of gravity.

Results of the analysis are given as follows:-

Mode No.	Description	Period (Seconds)	Freq. (Hz)
1.	**Global Bending mode in Y-dir'**	3.458	0.289
2.	**Global Bending mode in X-dir'**	3.458	0.289
3.	**Global 2nd Bending mode in Y-dir'**	0.846	1.182
4.	**Global 2nd Bending mode in X-dir'**	0.836	1.196
5.	**Global Torsional mode**	0.473	2.114

Table 6.5-1 Natural Frequency Summary

The dynamic criteria governing the design of the OWEC support structure are described in Section 6.2.6. The monopile structure is targeted at achieving soft-soft dynamic characteristics as given below:-

- Soft-Soft Response 3.37 s <Period

The above is a demonstration that the predominate structural frequency is sufficiently remote from the damaging resonate frequencies. This is addressed by a sensitivity analysis described in Section 9.2.

6.6 In-Service Analysis

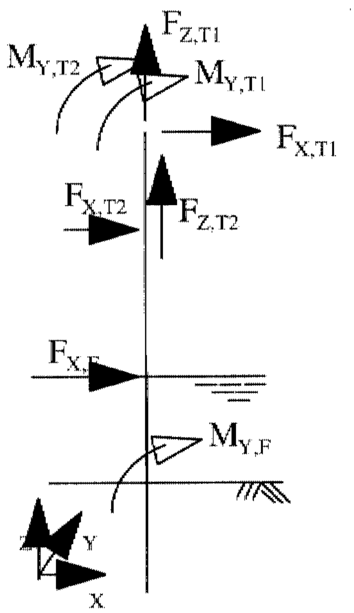
The structure with the highest loading i.e. at the maximum water depth is analysed throughout. Since the design is fit-for-purpose there must also be a design feasible for lower water depths down to the minimum water depth.

6.6.1 Extreme Event Design

The extreme event design has been undertaken to demonstrate the adequacy of the structure in terms of it strength and stability.

Given the simple and deterministic nature of the structure, the design has been based on hand calculation methods rather than resorting to computer based analyses.

The critical load case for the OWEC support structure design is the extreme operating condition i.e. Load Case E1.1 (Operation 2). This is summarised in the following table:-



Load Case E1.1

Nacelle Loading

$F_{X,T1} = 1.35$ x (-359)

$F_{Z,T1} = 1.35$ x $(-55) + + 1.1$ x (-1384)

$M_{Y,T1} = 1.35$ x $(-2030) + 1.1$ x (-3048)

Tower Loading

$F_{X,T2} = 1.35$ x (-32)

$F_{Z,T2} = 1.1$ x 1717

$M_{Y,T2} = 0$ (tower wind loads assumed to act at Nacelle)

Wave Loading

$F_{X,F} = 1.35$ x (-721)

$M_{Y,F} = 1.35$x (-11536)

Figure 6.6-1 OWEC Support Structure Extreme Loading

The structure being tall and slender is controlled by stability concerns rather than strength considerations. Over the majority of its height the diameter to thickness ratios of the tower and pile are outside a range where local instability would normally be problematic however towards the top of the tower some internal stiffening is likely to be necessary. For the remainder of the structure overall stability is the predominant design issue.

Consistent with GL which states 'that detailed buckling analysis may be carried out through according to recognised codes and standards', the overall buckling has been checked in accordance with API RP2A-LRFD [6.6-1]. Parameters adopted as given as follows:-

Overall Length (adopted)	L	93.6	m
Effective Length Factor	K	2	
Young's Modulus	E	205000	N/mm^2
Radius of Gyration (based on 2800 dia x 60 thk)	r	0.97	m
Yield Stress	F_y	350	N/mm^2
Column Slenderness Parameter	λ	2.54	
Compressive Resist Factor	ϕ_c	0.85	
Nominal Compressive Strength	F_{en}	54.32	N/mm^2
Bending Resist Factor	ϕ_b	0.95	
Nominal Bending Strength (adopted)	F_{bn}	350	N/mm^2
BM Amplification Reduction Factor	C_m	0.85	

Table 6.6-1 Buckling Parameters

Results from the overall stability assessment demonstrate that although elements in the mid height of the tower are highly utilised, all members exhibit satisfactory performance with utilisations of 0.9 typical in the tower and 0.6 typical in the pile.

6.6.2 Fatigue Analysis

Fatigue analyses have been carried out to demonstrate the adequacy of the OWEC support structure to sustain fatigue loading from both aerodynamic and hydrodynamic sources. The analyses have been carried out in two different ways as described below:-

- A time history analysis for combined aerodynamic and hydrodynamic loading. This is strictly the only completely applicable method by which the aerodynamic and hydrodynamic components of damage can be assembled in a consistent fashion. This analysis is described in Section 9.3.
- A dynamic spectral fatigue analysis for hydrodynamic loading only. This is strictly the most applicable method for handling hydrodynamic loads where the frequency range of the waves approach that of the structural frequency. This analysis is described below.

Application of Spectral Techniques
The application of the spectral techniques require a linear or linearised system to assess the spectral statistics and eventually the fatigue damage. As this technique is based upon the theory of superposition of individual components, the transfer

function (system) should be linear or may be linearised with respect to the input. For a truly linear system the response is linearly dependant on the wave amplitude which is reflected in the transfer function. However, as the response of the structure depends upon the applied loads, which are non-linear due to the drag component in the Morison equation, the selection of wave amplitudes for the calculation of the transfer function will yield differences in response level for different wave amplitudes. By means of a suitable linearisation of the non-linearities in the wave loading, spectral techniques may still be used to determine the stress statistics. On the monopile structure under consideration the inertia load predominate and the requirement to linearise the force input is minimal.

Analytical Approach
The basis of the analytical approach is described in [6.6-2]. The approach taken follows the following key steps:-

- a wave steepness calibration study is carried out to establish the steepness to be adopted in the spectral analysis,
- a natural frequency analysis is undertaken to identify the fundamental frequencies of the structure,
- a wave load analysis is carried out by stepping a series of waves of varying frequency (and direction) through the structure. A constant wave steepness is adopted. The resultant wave forces are linearised.
- a dynamic analysis is carried out of the structure. Given the size of the model, subspace iterations and static back substitution techniques are adopted.
- with the application of stress concentrations and partial material safety factors, hot-spot stress range transfer functions are prepared at all critical location on the structure.
- Based upon the description of the wave climate given by the scatter diagram response statistic are prepared which together with the fatigue strength reference value can be combined to provide the appropriate fatigue life calculation.

Parameters used in the analysis are given as follows:-

Design Fatigue Life	Life	20	years
Partial Material Safety Factor - above MSL	γ_m	1.25	
Partial Material Safety Factor - below MSL	γ_m	1.35	
Fatigue Strength Reference Value	$\Delta\sigma_R$	80	N/mm^2
Fatigue Strength Ref. Value - manway, flange	$\Delta\sigma_R$	71	N/mm^2
Stress Concentration Factor - general	SCF	1.00	
Foundation & Structure Damping	ξ_{strcuc}	1.5%	
Aerodynamic Damping (Spectral Analysis)	ξ_{aero}	3.5%	
Wave Steepness (Spectral Analysis)		1/15	
Wave Spectra	Pierson Moskowitz		

Table 6.6-2 Fatigue Parameters

The results of the both approaches, i.e. time domain as well as the frequency domain analysis, demonstrate even under the conservative assumption of unidirectional wave loading without directional spreading satisfactory lives over the complete height of the structure with lives (aerodynamic plus hydrodynamic) in the most critical locations typically in the range of 30 years or considerable longer (table 9.3.8, section 9.3.5). Moreover the results on pure hydrodynamic loading coincide to a satisfactory extent between both approaches.

No detailed analysis have been carried out of the areas of high stress concentration e.g. the accessway into the tower and the bolted flange connection, however local design features reducing the stress concentration are foreseen as commonly applied on wind turbine towers [6.6-3].

6.7 Ancillary Design

The ancillary features of the OWEC support structure are shown in Figure 6.7-1.

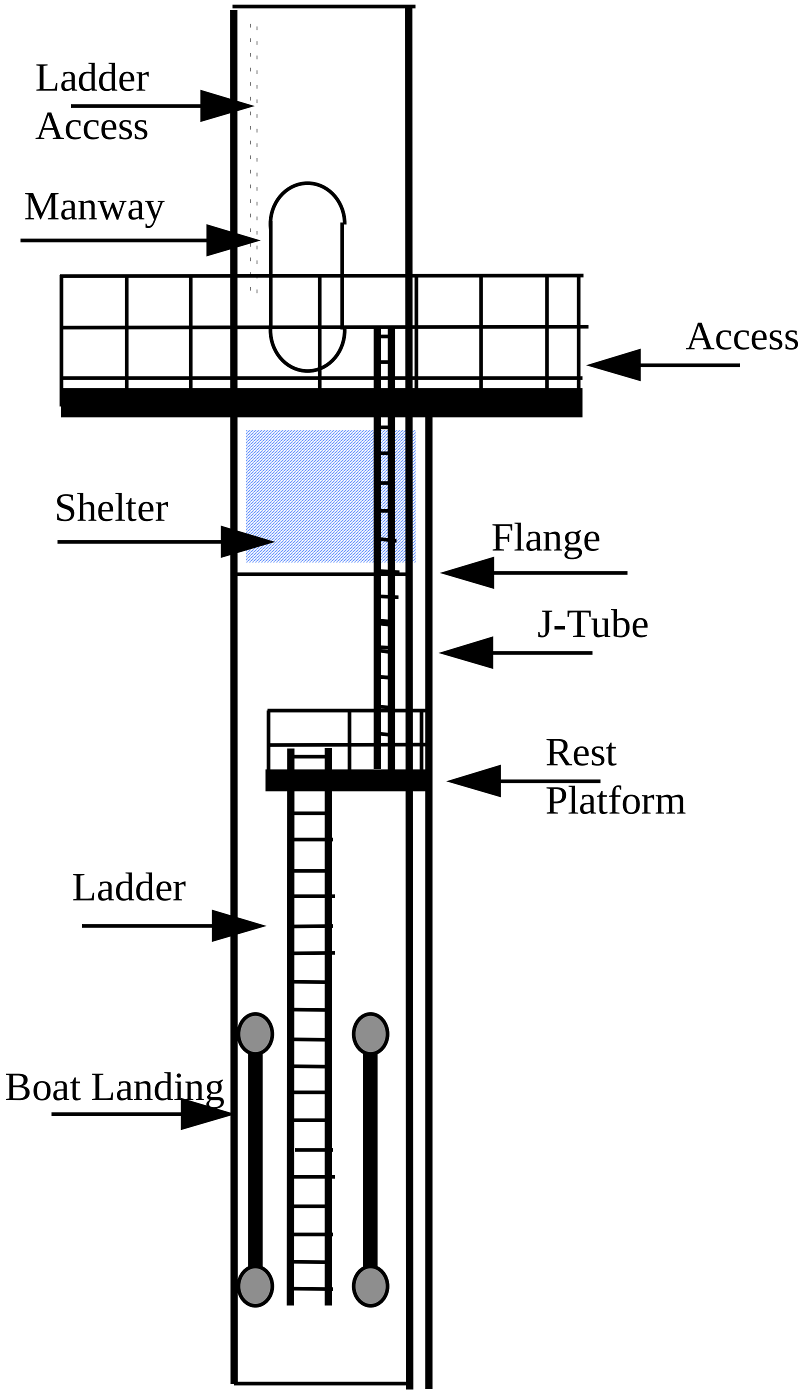


Figure 6.7-1 Ancillary Support Structure Features

6.7.1 Boat Landing and Accessways

Access to each of the OWEC structures will be by boat with personnel transferring directly from the boat onto a fixed OWEC ladder. To facilitate this operation a boat landing is provided. This comprises two longitudinally placed fender elements supported at at least one end by a shock cell which can absorb the energy from the initial impact with the vessel, followed by the mooring force during the transfer.

Once on board the OWEC personnel climb the ladder to a small rest platform and then on up to the main accessway round the tower. Here the manway door provides access into the inside of the tower where an assembly of ladders and platforms provide access to the top of the tower.

The transfer of heavier items, other than would be reasonably safe to humanly carry onto the structure, will require a small remotely operated crane deployed from the accessway round the tower (Section 5.5.3).

6.7.2 Cable Conduit

The cable conduit or J-Tube, as it is referred to, is located on the outside of the support structure. Outside is chosen in preference to locating the conduit on the inside of the pile, since this obviates the requirement for a subsea hole in the pile. Were a hole to be adopted then substantial reinforcement would be necessary to avoid cracking during pile driving. Free passage of water through the hole would also place additional burdens on the provision of corrosion protection to the inside of the pile. As detailed on the outside of the pile, the cable can be pulled into the platform using a winch conveniently placed on the access platform with the cable tails then threaded through a penetration in the tower wall.

6.7.3 Corrosion Protection

The support structure, above mudline would be protected both inside and out by a high integrity painting system. Below mudline, the pile would be unpainted since paint reduces the friction angle between the pile wall and the soil. It is anticipated that cathodic protection would be adopted to protect the submerged areas of the structure. This could be of the form of a passive system using sacrificial anodes or as an active system employing an impress current system. Either way, the system would be relatively simple and inexpensive.

6.7.4 Temporary Shelter

The exposed location of the proposed site leads to the possibility that the weather could deteriorate during the maintenance work and for this reason a very basic temporary shelter is provided within the tower, beneath the manway. It is anticipated that this would be sealed and be for emergency use only and that it would contain only the most basic facilities i.e. rations, bedding, lighting and a toilet. Potable water would need to be carried onto the installation each time it was visited.

6.8 Installation Procedure

6.8.1 Pile Installation

Prior to the installation phase, work starts at the site with a soils investigation. This is commonly undertaken in two phases i.e.:-

- a geophysical scan of the site so as to gather an appreciate of the underlying site geology and to identify any obstructions.
- a series of bore hole and cone penetration tests (CPT)

Results from the investigation are used in determining the size of the required pile and the expected pile driving condition.

Installation at the wind farm site starts with the placement of the pile. This can be installed in a number of ways e.g. using a vibrating hammer, a piling hammer or drilling equipment operated from either a floating vessel or a jack-up.

The exposed site location favours deployment of a jack-up with pile installation carried out from a stable base that this provides. Whilst numerous jack-ups are available for this type of operation some limitations may result from the substantial pile weight i.e. up to 280 tonnes. Here some contractors will have sufficient crane capacity, whilst others will either need to upgrade their cranage capacity or to insert a splice into the pile such that the pile is installed in two parts which are grouted together. Given the size of the wind farm this latter option is unlikely to be cost effective.

Piling from a jack-up will greatly limit the exposure to weather limitation (during piling) and should ensure greater control of pile verticality. Not-with-standing this, the control will remain an issue and it is anticipated that piling would be carried out either through a seabed template or preferably by using a vibratory hammer initially before switching to a conventional hydraulic hammer. In this way it is anticipated that vertically tolerances of the order of 1.5 degrees can be achieved.

6.8.2 Tower Installation

Rather more options are available for installation of the tower (inclusive of nacelle and rotor etc.). These are appraised as follows:-

Jack-up Installation

Jack-up lift appears at first glance to be the obvious method of installing the tower, nacelle and rotor. It forms a stable base from which to carry out the operation and is the preferred choice for carrying out the piling operation. It is however its inherent stability and hence lack of manoeuvrability that poses problems for the installation of the tower. Offloading the tower elements from a floating barge and then lifting them into place will most likely require a form of piecemeal construction with the tower, nacelle and rotor all installed as separate items. Given the number of OWEC structures proposed and the requirement for a dedicated maintenance vessel (Section 8.7) there may be justification in installing an exceptionally large crane on a jack-up and thereby avoiding the time consuming nature of piecemeal construction.

Semi-Submersible Installation

Lifting from a vessel is in principle most straight forward method of installation. Semi-submersible crane vessels represent the most stable floating platform from which to carry out offshore construction work. These are unlikely to be candidates since they would have difficulty operating in shallow water depths.

Ship Shaped Vessel and Flat Bottom Barges

Ship shaped vessels and flat bottom barges offer appreciably less stability for carrying out construction work and consequently are subject to weather delays. Ship shaped vessels with rotating cranes offer the best performance but as a result are in heavy demand, attracting appreciable day rates. Flat bottom barges with sheerleg cranes of a suitable size are in far greater supply and despite weather delays offer a cost effect approach to tower installation.

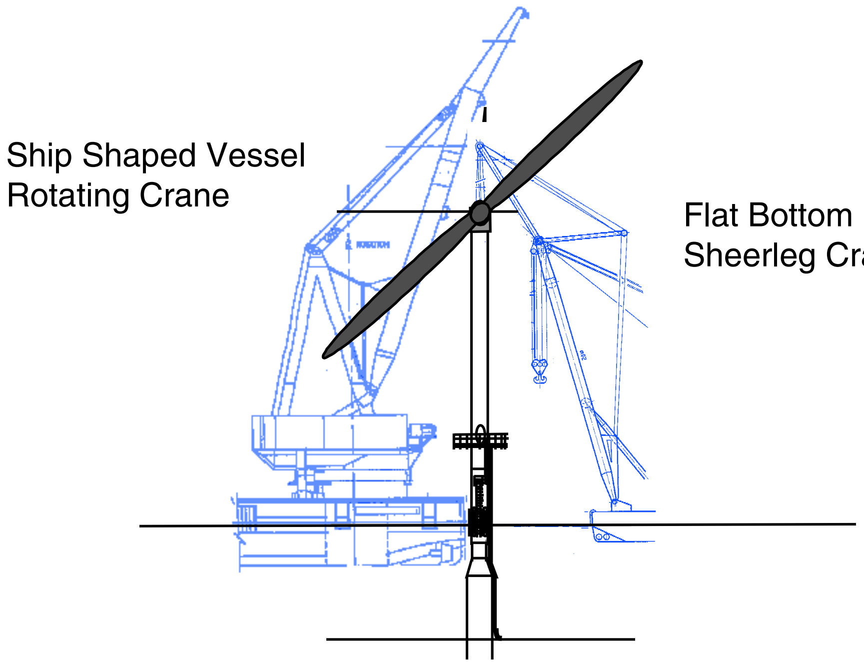


Figure 6.8-1 Tower Lifted into Place

Land Based Cranes

One way of combining the benefits of rotating crane with adequate reach but at a lower day rate is to use land based cranes as show below. Such a system could be adopted quite satisfactorily in sheltered locations. The proposed location is relatively exposed and its questionable as to the weather restrictions placed on this scheme would make it viable.

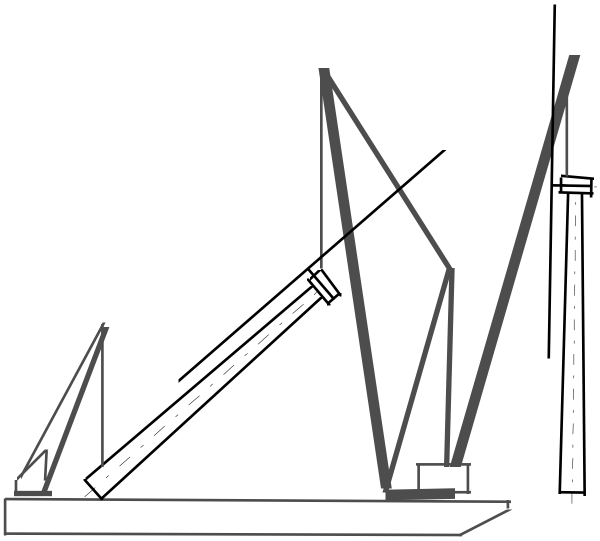


Figure 6.8-2 Use of Land Based Cranes

Float-Over Installation

With a float-over installation the tower is erected and floated out in the vertical orientation before being floated-over then lowered down onto the preinstalled pile. The scheme shown the tower is erected at the quay side on a dummy pile and is stabililised by a pin which is housed in the tower and lowered into the pile. The tower is secured to a barge in the vertical orientation ready for transportation.

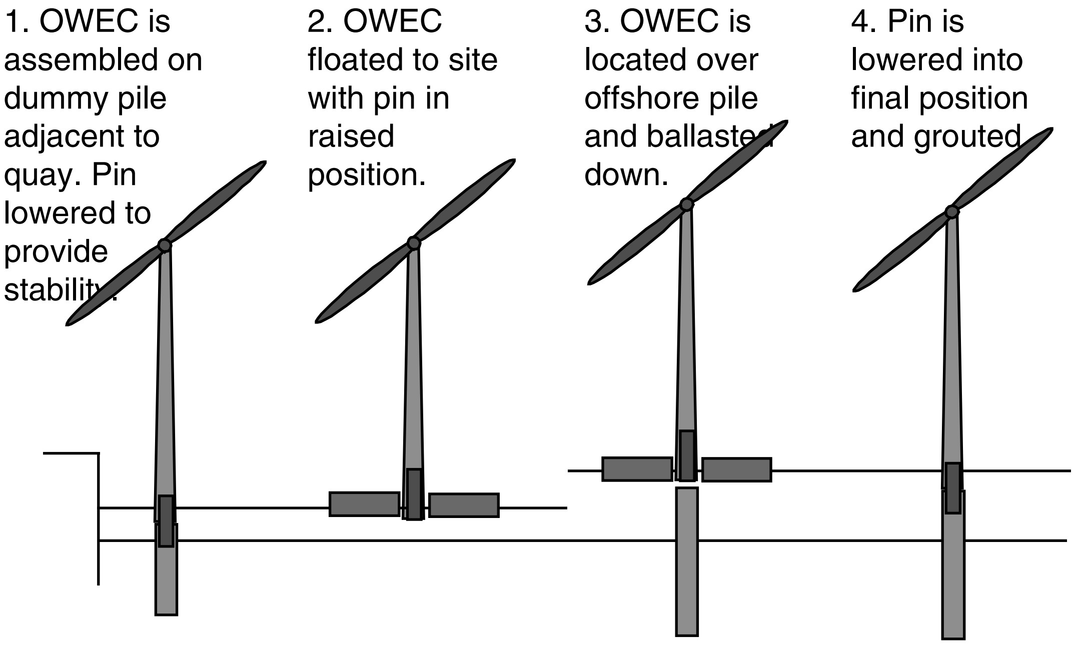


Figure 6.8-3 OWEC Fabrication and Float-Over Installation

The vessel required for this operation may need to be specially built although modifying an existing vessel is also an option. The vessel takes-on the tower at the quay side where it is moored adjacent to the tower and securely seafastened. Then, possibly on a rising tide, the barge is deballasted allowing the tower to be detached from the dummy pile. Once in a safe water depth, the barge is ballasted for the tow.

On arrival at the site the vessel is deballasted, if necessary, and safely moored over the offshore installed pile. Then follows the operation of ballasting the vessel down so as to safely transfer the support for the tower onto the pile. The seafastening is then released leaving the vessel to be towed away.

Motions analysis of the OWEC in a vertical orientation have been carried out to determine the transportation acceleration which can thereby be used to assess the strength and stability of the tower and seafastening. Based on a design towing seastate of Hs=4m, the horizontal sway acceleration at the tower centre of gravity (inclusive of nacelle/rotor) is 0.65g. As such, the tower elements have relatively high utilisations but more problematic is the seafastening. The moment at the base of the tower leads to very substantial reactions as shown in Figure 6.8-4. These need to be addressed in any seafastening scheme to be adopted.

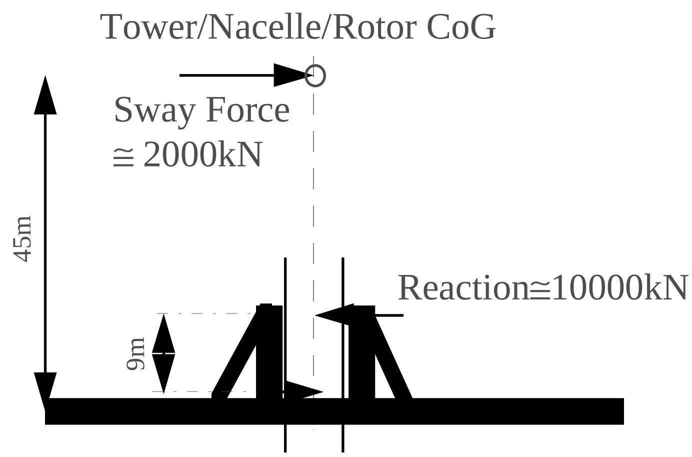


Figure 6.8-4 Seafastening Reaction

Chosen Installation Method

Based on the forgoing it can be concluded that all installation methods have their advantages as well as disadvantages and that the decision will be in some part dependant on the approach adopted for maintaining the structures.

For the purpose this study it is assess that installing the towers using a sheerleg crane offers the most cost effective method. It is anticipated that tower units complete with the nacelle and rotor could be installed as a single units at a rate of two per day (24 hour working) during the summer months (May-August). Under these circumstances vessel downtime of around 50% is anticipated i.e. a rate of 1 tower per day accounting for downtime with a total installation period inclusive of mobilisation of 4 months.

6.8.3 Transportation Arrangement

Two alternative, tower and wind turbine transportation orientations have been considered i.e. a vertical orientation and a near horizontal orientation as shown below:-

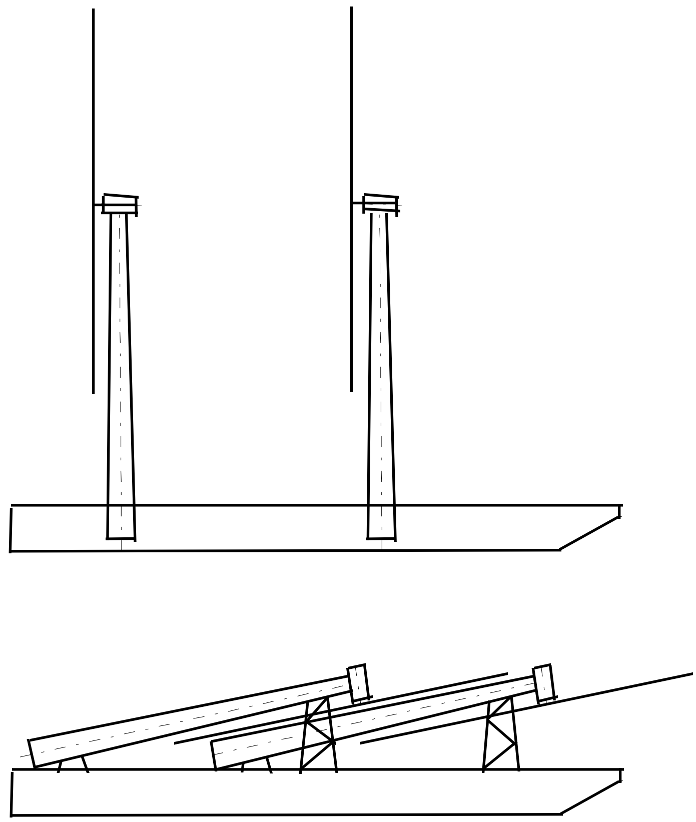


Figure 6.8-5 Transportation Orientation

In the near horizontal orientation the barge space requirements govern the size of the barge required whilst in the case of the vertical orientation, the transportation stability requirements govern. The result is, however, similar in both cases leading to a requirement for a 76.2m x 25.0m x 4.9m barge i.e. similar to the H-103 cargo barge.

Transportation in the vertical orientation is not regarded as feasible without substantial bracing to limit the bending moments shown in Figure 6.8-4.

6.8.4 Pile/Tower Connection and Levelling

The permanent connection between the tower and the pile can be effected by grouting the annulus between the tower sleeve and the tower. This technique is commonly used offshore to provide the structural connectivity between the jacket and the supporting piles. The technique relies on a sleeve inside which weld beads (sheer keys) have been welded at regular spacing. Into this is placed the pile which also has welded beads. A free annulus remains between the two which is then filled with grout slurry which then hardens to provide the required load path for shear in the tower to be transmitted to the pile.

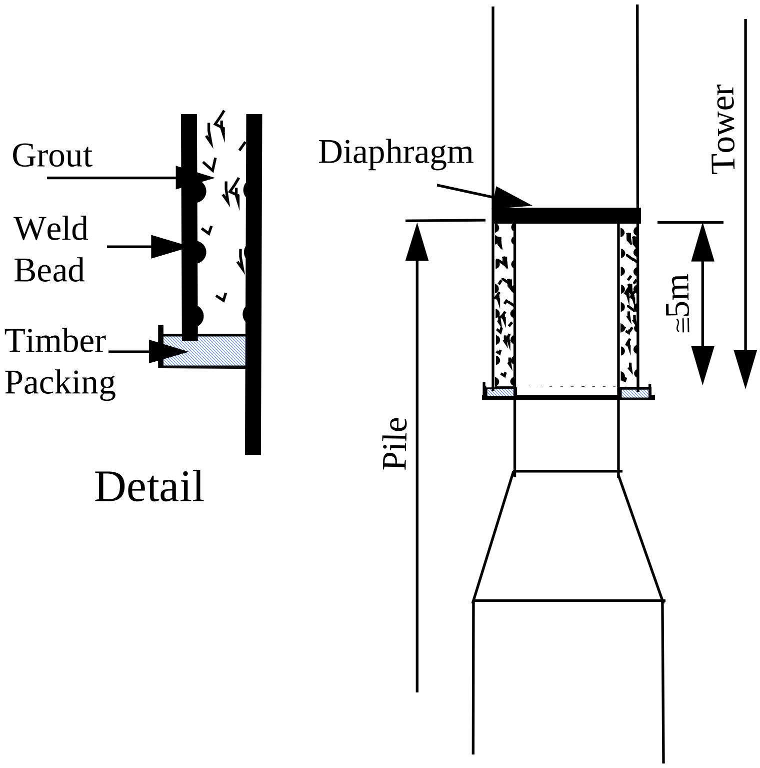


Figure 6.8-6 Pile-Tower Field Splice

The above detail offers some limited provision for rectifying pile inclination, however this is unlikely to be sufficient and therefore the tower incorporates a sloping flange (Figure 6.8-7). It is anticipated that the pile inclination would be measured following installation and if necessary the flange would be rotated to compensate. This would infer some time delay between the pile being installed and the tower being placed since rotating the flange would necessitate realignment of ladders, J-tube and boat landings etc.

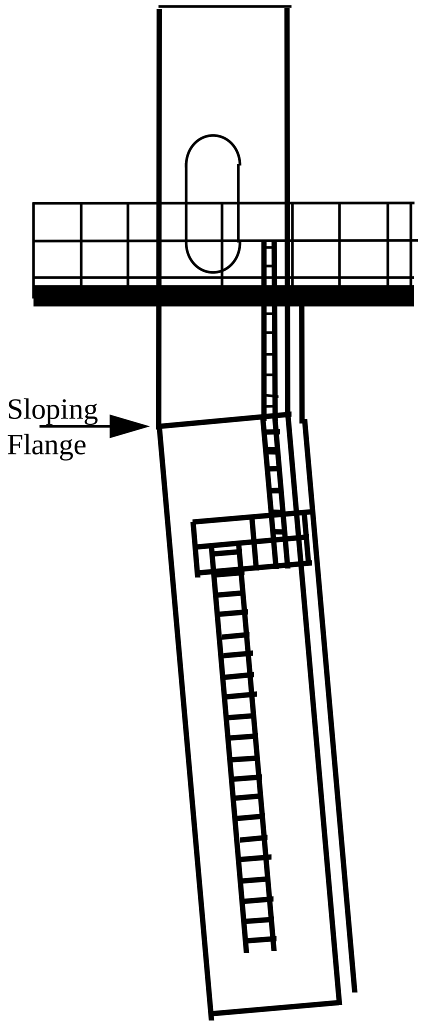


Figure 6.8-7 Sloping Flange to Account for Pile Inclination

6.9 Support Structure Operation and Maintenance

Maintenance of the support structure during the life of the installation will be limited to general monitoring and repair as required. Areas requiring particular attention are given as follows:-

- joints where fatigue is known to be onerous e.g. flanges and penetration
- painting system to be checked for mechanical damage and wear
- periodic and systematic monitoring of corrosion protection system
- boat landing and ladders to be checked for signs of mechanical damage or wear

6.10 Conclusions

The support structure is a vital component of the OWEC. Unlike onshore where the tower and foundations can be regarded as relatively straight forward elements of the design, the move to offshore introduces a number of complexities which make the support structure crucial in the overall economics of the wind farm.

A wide range of European site have been considered some in exposed locations such as the Noth Sea, others in the more sheltered waters of the Baltic Sea. The water depths addressed have ranged from 10m to 20m. For each site characteristic wind, wave and current conditions have been prepared together with appropriate soil conditions.

A very wide spectrum of possible support structure concepts have been considered as part of this work. Initial feasibility studies accounted for the widest possible variations of the most basic design parameters. Concepts were characterised by different methods of securing the structure to the seabed, by alternative means of installing the structures and by different structural configuration types. Particular emphasis was placed on the importance of the installation method and this has resulted in the development of some innovative installation methods. From this feasibility process, three quite distinct, concepts emerged as offering potential solutions to the problem as given as follows:-

- GBS Lattice Tower - Floated Installation
- GBS Monotower - Floated Installation
- Monopile - Floated or Lifted Tower Installation

These three concepts represent a very diverse range of OWEC characteristics e.g. they include both GBS and piled foundation, both floated and lifted installation and a range of configuration types. They also present concepts offering quite different dynamic characteristics. This diversity is beneficial and goes some way to limiting the risk of overlooking a potential optimum solution.

The three concept have been developed in some detail with consideration given to dynamics, fatigue and in-place loading. Indeed detailed analyses were carried out on each to identify the required dimensions and resulting weights. For each, the method of installation has been developed with consideration given to a range of alternatives. This has allowed a critical assessment of the comparative performance of the concepts together with an evaluation of their relative costs.

Each of these solutions have been demonstrated to offer a viable means of providing support to the turbine facilities over the duration of it operational life. Throughout this process three keys issues relating to the support structure have been prominent, viz.:-

- Dynamic Behaviour

The avoidance of the critical turbine and blade passing frequencies is well established in the design of onshore turbine support structures and in this sense offshore wind turbine offers no exception. The three chosen concepts are of particular interest since they each represent a differing facet of design i.e. the lattice tower is an example of a stiff-stiff structure, the monotower that of a stiff-soft structure and the chosen monopile design that of a soft-soft structure.

- <u>Fatigue Performance</u>

Fatigue has proved to be the main design driver for an efficient support structure design.

- <u>Ease of Construction/Installation</u>

Ease of construction/installation like the former issues is fundamental to achieving an optimal design.

These three issues have proved to be crucial in the quest for an optimal solution.

Of the three concepts, the monopile - with either floated or lifted tower installation was selected for further development. The site chosen was NL-1 off the Dutch coast - an exposed location with water depths ranging from 12m to 20m (LAT).

It was recognised that the treatment of the monotower dynamics would be critical and consideration was given to both soft-soft and soft-stiff designs. Initially concerns were raised as to the feasibility of a soft-soft design given the potential importance of hydrodynamic fatigue. In practice, the benefits of adopting a soft-soft design have proved to be appreciable and therefore substantial analytical effort has gone into demonstrating its satisfactory performance.

The monopile support structure which has been developed for Site NL-1 has been proven to be feasible and a entirely practical solution means of providing support to the turbine facilities over the duration of it operational life. The support structure provides the following facilities:-

- Pile
    - Cone element thereby providing the necessary section properties at seabed whilst minimising the wave load at sealevel.
    - Scour protection
    - J-tube
    - Corrosion protection
- Tower
    - Grouted joint securing the tower to the pile
    - Sloping flange to accounting for installation tolerances of the pile and later tower removal
    - Boat landing including ladders, rest platforms and access platforms
    - Manway access inside the tower and ladders and rest platforms to the nacelle
    - Emergency shelter provided within the tower, beneath the manway

7. Design of Grid Connection and Farm Layout

7.1 Introduction

In this chapter the grid connection and the farm layout for the design solution are elaborated, based on the conceptual design given in section 4.4. Because farm layout is a somewhat minor item, compared to the design of the other components, it is covered within the same chapter as the grid connection; these topics are interrelated: for the optimal farm layout the cable costs should be taken into account.
First the grid connection is described in section 7.2; the placement of the transformer, inside each OWEC, is covered in section 7.2.6. The farm layout is dealt with in section 7.3.

7.2 Grid connection

7.2.1 Overview

In section 4.7 it is decided that the reference wind farm consists out of hundred 3 MW turbines. For the design of the grid connection the same expertise and tools as for onshore farms can be applied. As explained earlier, the power from the wind turbines is first collected inside clusters. The clusters are connected to the main collection point from which power transmission takes place to shore. Because the intended location, the NL-1 site, is relative close to shore the logical choice is AC transmission. Also inside the clusters AC is chosen (common choice). The considered connection types inside the clusters are chain and circuit connection; for the connection between the clusters to the main collection point, a star connection will be assumed.

In the following subsection the type of cables, switchgear and transformers for the grid connection of the wind farm will be dealt with. In subsection 7.2.3 six possible grid connection options are further examined. As check, loadflow and short-circuit calculations are performed; these are discussed in subsection 7.2.4. The final choice between these options is based on technological and economic considerations and given in subsection 7.2.5. Finally, in subsection 7.2.6 the placement of the transformer for each OWEC is discussed.

The following information is taken from the wind turbine design (chapter 5). The generator base voltage is 6 kV and the maximum current rating 361 A giving a maximum capacity per turbine of 3.7 MVA. The P/Q curve used in loadflows is as given by manufacturer, see fig. 7.2-1. Furthermore it is assumed that the generator is equipped with a generator circuit breaker.

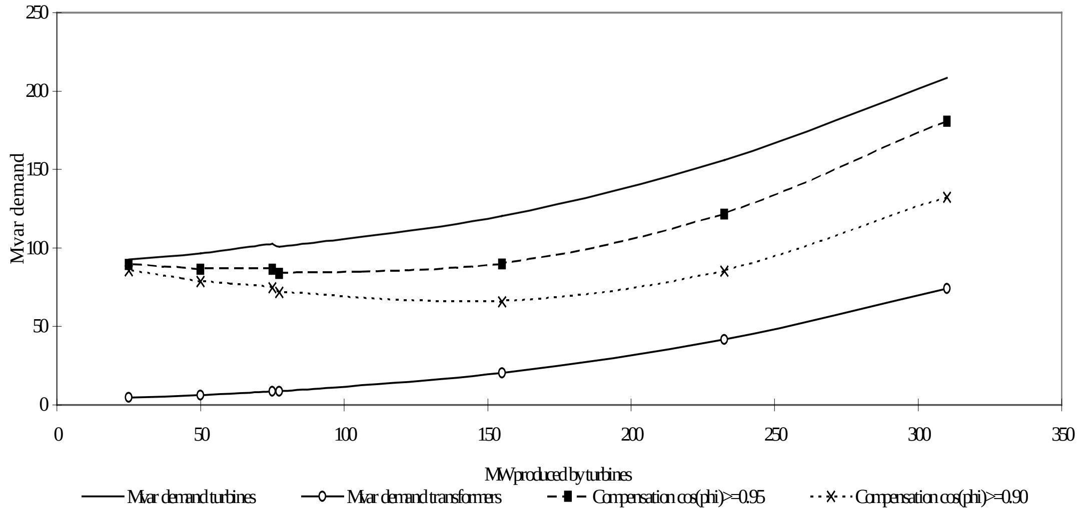


Figure 7.2-1: Reactive power demand as function of power produced.

7.2.2 Grid connection components

Type of cable inside clusters (power collection)

In order to maximise the water tightness it is best to choose a cable with a solid conductor. This reduces the risk of water seepage into the cable during laying as could happen in case of a stranded conductor. In order to reduce cost the conductor material chosen is aluminium. The cables are single core (one for each phase); it is assumed that the three single core cables can be laid as one (triangular) bundle. Conductor diameter depends on the number of turbines to be connected, this shall be discussed further on.
At each OWEC the cluster power cable from the previous turbine will be connected by means of a J-tube connected to the support structure (see also chapter 6); a second J-tube will guide the power cable to the next OWEC inside the cluster.

Choice of voltage levels

As a certain cable diameter can only carry a certain amount of current the voltage level chosen determines the maximum amount of power to be transported. Furthermore, a higher voltage level will reduce the electric transmission losses. In table 7.2-1 an overview is given of the maximum cable power rating as a function of cable diameter and voltage level chosen.

Conductor diameter	Current carrying capability	Voltage level			
sq. mm	A	6 kV	15 kV	20 kV	30 kV
185	415	5 MVA	11 MVA	14 MVA	21 MVA
400	710	7 MVA	18 MVA	24 MVA	36 MVA
800	1040	11 MVA	27 MVA	36 MVA	54 MVA

Values based on solid aluminium conductor. Thermal conductivity seabed assumed 0.5 W/mK.

Table 7.2-1*:* Rated power as function of cable diameter and voltage

A conductor diameter larger than 800 sq. mm has not been chosen as an option because it is not an ‘off-the-shelf’ type. From table 7.2-1 another table can be constructed, table 7.2-2, in which the total number of turbines is depicted that can be connected to one cable given conductor diameter and voltage level.

Cable diameter	Voltage level chosen			
sq. mm	6 kV	15 kV	20 kV	30 kV
185	1	3	3	5
400	2	4	6	9
800	3	7	9	14

Table 7.2-2: Number of turbines to connect to one cable

Especially at sea the cost of a cable is mainly determined by the cost of laying so it is best to opt for the largest diameter i.e. 800 sq. mm. As to the choice of voltage level we meet up with an idiosyncrasy in the business, whereas cable voltage levels range from 6 kV, 10 kV, 15 kV etc. switchgear voltage levels range from : 7.2 kV, 12 kV, 24 kV and upwards.

From the above it follows that whatever voltage level you pick you will always ‘abuse’ either the cable or the switchgear chosen. As the 36 kV switchgear is in a different league alltogether (in price, capacity and physical dimensions) it is best to settle for the 24 kV voltage level. Given a 800 sq. mm conductor up to 11 turbines can then be connected to one cable.

At the cluster points no transformer will be used, so the voltage level from the clusters to the main collection point is also 24 kV. The reason for this is that the achievable reduction in transmission losses does not balance the cost of the required transformers. Furthermore, probably very special (and thus expensive) arrangements would be necessary for the support structure in order to accommodate these transformers (due to their large dimensions and weight).

Cable to shore (power transmission)

Again 3 single core cables are used. Due to the rating it is not possible to lay the 3 cables in one triangular bundle but instead they should be placed in a flat plane (parallel); this will require 3 separate cable laying operations.
The main collection point will be situated in the middle of the wind farm; for a square wind farm layout the distance to shore equals approximately 15 km; for a rectangular layout approximately 20 km.

Note: according to the terminology (see the appendix of Vol. 1) the system boundary is set to the shore landing. For a more global study as Opti-OWECS, this is justified in order to avoid too much influence of the actual local infrastructural grid situation which varies a lot along the European shores.
For this specific case of a wind farm near IJmuiden, the grid connection on land is well known: the electricity station Velsen (a few kilometers from IJmuiden) will be

used. The voltage level for the transmission to shore equals 150 kV; this is dictated by the available voltage level at this station.

Choice of OWEC transformers

The best type of transformer for each OWEC (6/24 kV)to use is a cast-resin insulated type; these are maintenance free and can be taken apart for ease of installation. No forced cooling is necessary. Needed is 3.8 MVA capacity (including transformer reactive power).
The placement of the transformer inside each OWEC will be dealt with in section 7.2.6.

For the main collection point four transformers are applied of 100 MVA each. Dimensions (for each transformer) WxDxH 5000x8000x7500 mm. Weight in between 170 and 200 tons depending on manufacturer.

Choice of switchgear

A switchgear is the total unit consisting out of one or more busbars and one breaking device; switchgear with a limited power range are called ring main unit. Breaking devices comes in four types: circuitbreaker (can switch short circuit current), loadbreaker (can switch rated current), disconnector (can only be opened when no current is present) and fuses.
Three types of switchgear have to be chosen : One type within the turbine, 24 kV or 6 kV, the latter if no intermediate voltage level is chosen. Two on the main collection point, 24 kV and 150 kV.

Switchgear within the OWEC must be small so as to accommodate the limited space in the tower. Other constraints are maintainability, capacity and the environment. Smallest available switchgear is the cast-resin type SVS by Holec (containing loadbreakers), available in 12 kV and 24 kV versions. These are compactly build and their capacity ranges up to that of a 800 sq. mm cable.

The 24 kV and 150 kV switchgear on the main collection point have to be able to break the short-circuit current, so a circuitbreaker has to be installed. As a variety of equipment is available the ones chosen for this study are just the ones applied in the electricity supply area of Energie Noord West (ENW).

Turbine switchgear ratings should be (type referred to SVS cast-resin insulated):

Either :		Or :	
Busbar	1250 A - 25 kA - 24 kV	Busbar	800 A - 20 kA - 24 kV
Feeder	1250 A - 25 kA - 24 kV	Feeder	630 A - 16 kA - 24 kV
Dim. (WxDxH)	630x1100x1300 mm	Dim. (WxDxH)	420x700x1350 mm
Weight	600 kg	Weight	600 kg

Main collection point (type referred to MMS by Holec).
24 kV switchgear :

Transformer feeder / Busbar	2500 A - 25 kA - 24 kV
Feeder	1600 A - 25 kA - 24 kV

Dim.(WxDxH) 600x1700x2000 mm
Weight 1000 kg (rough estimate)

150 kV switchgear (type referred to Trisep by Holec):
Transformer feeder 2000 A - 31.5 kA - 150 kV
Busbar 3150 A - 31.5 kA - 150 kV
Dim. (WxDxH) 1500x5000x3000 mm
Weight 10000 kg (rough estimate)

7.2.3 Possible power collection options

Six different options have been studied. They vary in the type of cluster connection (chain or circuit connection) and in the farm layout (square or rectangular; just for convenience the number of turbines varies between 96 and 100). An overview is given below

	farm layout	cluster connection type
Option A	4*24	chain of 6
Option B	4*24	chain of 12
Option C	4*24	circuit of 12
Option D	10*10	chain of 5
Option E	10*10	chain of 10
Option F	8*12	chain of 3

Table 7.2-3: Overview of the different options

Option A

A rectangular farm, four rows of 24 wind turbines. Using a 630 A ring main units, 6 turbines in series, one cable to the main collection point. Giving a total of 96 turbines and a farm output of 288 MW.

Option B

A rectangular farm, four rows of 24 wind turbines. Using a 1250 A ring main unit and 12 turbines in series, one cable to the main collection point. Giving a total of 96 turbines and a farm output of 288 MW.

Option C

A rectangular farm, four rows of 24 wind turbines. Using a 1250 A ring main unit and 6 turbines in series, one cable to the main collection point and one cable (operated as a normally disconnected cable) to the next series of 6 turbines so as to reconnect in case of cable failure. Giving a total of 96 turbines and a farm output of 288 MW.

Option D

A square farm layout, ten rows of ten turbines. Using a 630 A ring main unit and five turbines in series. Total farm output 300 MW.

Option E

A square farm layout, ten rows of ten turbines. Using a 1250 A ring main unit and connecting ten turbines in series. Total farm output 300 MW.

Option F

A rectangular farm layout, 8 rows of 12 wind turbines. This is a rather unusual grid connection: there is no intermediate voltage level, so all turbines are connected on the 6 kV level. Using a 1250 A ring main unit 3 turbines can be connected in series. Total farm output 288 MW. In order to keep the short-circuit current levels within acceptable limits only six turbines are connected on one transformer at the main collection point.

Evaluation of options

Layouts are outlined in the following pages and estimates have been made as to the cost.
The required cable length depends on the spacing between the units. Considering the cable layout the total length can easily be determined; for each OWEC an extra length of about 80 m is needed from the seabed to the access platform (and vice versa).

The cable cost inside the farm (medium voltage) vary from 150 to 175 ECU/m; the cable laying costs are assumed to be equal to 200 ECU/m. Note, the cable laying costs are indicative because no experience exists with these kind of cable laying operations. The cable cost for the transmission to shore (high voltage) equals 800 ECU/m; the cable laying cost are 600 ECU/m (three times higher because three separate laying operations are required).

In case of option A, a cable failure will lead to a 6 % maximum loss of power. With option B this will increase to a maximum of 12 %. And in option C this will lead to 6 % at first and a minimum of 0 % after re-routing. Expenditure differences are mainly caused by amount of 24 kV cable used and number of 24 kV bays on the main collection point. Differences between the options are given in table 7.2-4.

S = Wind turbine spacing (m)						
Item	A	B	C	D	E	F
sq. mm cable used	400	800	800	400	800	800
Length cable (m)	142 S + 96*80	97 S + 96*80	150 S + 96*80	132 S + 100*80	116 S + 100*80	164 S + 96*80
Ring main unit	630 A	1250 A	1250 A	630 A	1250 A	1250 A
Number ring main units	272	280	288	280	290	256
No. 24 kV bays	20	12	20	24	16	48 (6kV bays)
No. 150 kV bays	6	6	6	6	6	18
No. 24 kV transformers	96	96	96	100	100	-
No. 150 kV transformers	4	4	4	4	4	16
Power loss due to cable failure	6%	12%	0%	5%	10%	3%

Table 7.2-4: Main data of the power collection options

7.2.4 Loadflows and Short-circuit levels

As seen from figure 7.2-1 the turbines need a lot of reactive power. And as there are a lot of transformers involved the need for reactive power will only rise. A rough estimate of the total amount of reactive power required can be made as follows : At maximum load the turbines require about 2.1 Mvar each totalling to about 210 Mvar for all turbines. The turbine transformers (if any) used have a rating of about 4 MVA and a shortciruit impedance of about 6 % adding about 21 Mvar. The total farm production is 370 MVA leading to 400 MVA transformer capacity from the 24 kV to the 150 kV level, normal short-circuit impedance of this type of transformer is about 15 % thus needing about 53 Mvar. So the total amount of reactive power needed is about 284 Mvar giving a $\cos(\varphi) \approx 0.74$. In order to increase the final $\cos(\varphi)$ to ≥ 0.95 (required from the utility) approximately 180 Mvar must be installed. One way of coping with this amount is to install a capacitor bank of about 14 μF at the 150 kV busbar; if necessary this can be placed onshore (not recommended).

The rated electric power losses are in the order of 4%.

Short-circuit calculations are based on IEC 909. Dynamic values should also be calculated. The most important points at which the short-circuit current should be known are depicted in fig. 7.2-2. Maximum values are tabulated in table 7.2-5. Calculations are only performed for options A, B, C and F as D and E will have approximately the same values. For option F the short-circuit currents at point 4 are critical; all other options are feasible.

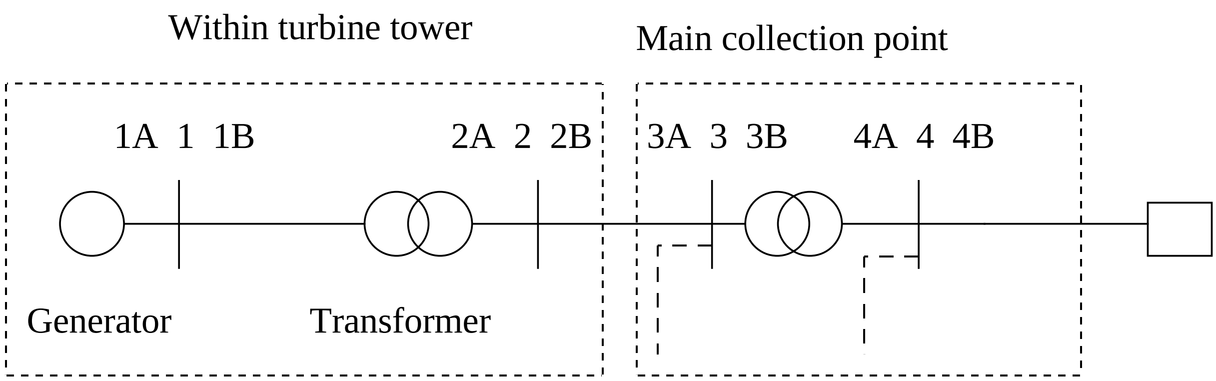


Figure 7.2-2: Most important short-circuit locations

Location	Option A	Option B	Option C	Option F
1A	2	2	2	2
1	7.5	7.5	7.5	17
1B	5.5	5.5	5.5	12
2A	1.4	1.4	1.4	-
2	20	24	24	-
2B	15	21	21	-
3A	15	21	21	5
3	24	25	25	23
3B	14.5	14.5	14.5	13
4A	2.6	2.6	2.6	1
4	25	25	25	44
4B	20	20	20	39

Table 7.2-5: Maximum value of steady state short circuit current [kA]

7.2.5 Final grid connection

The cost of the different solutions are given in table 7.2-6; for a fair comparison the costs for options A, B, C and F are scaled to a farm of 300 MW.

Option A	Option B	Option C	Option D	Option E	Option F
90 MECU	79 MECU	96 MECU	77 MECU	75 MECU	95 MECU

Table 7.2-6: Total grid connection costs for the different options

Based on the total costs option E is chosen: the cluster connection consists out of a chain of 10 turbines (800 sq mm cable at 24 kV); the transmission to shore takes place at 150 kV.

It should be stated that the preference for option E is not so strong. In case it is anticipated that there is a real risk of cable failure, option D could have been chosen because of its better reliability. For the refence OWECS no data was available on cable failure risks.

The above mentioned costs concern the major cost items; no cost estimates are included for automation, protection and maintenance. For the monitoring of the wind turbines it is an option to lay an optic fibre together with the laying operation of the power cables; assuming a price of 30 ECU/m and a spacing of 500 m the involved costs for the whole OWECS equals 4 MECU.

The most important price factor are the cables. These prices, however, can change strongly in a discussion with the manufacturer. The same holds for the cable laying costs.
All this should be elaborated in more detail in case of a real OWECS project.

In the following 2 figures the cost break down is given for the chosen option.

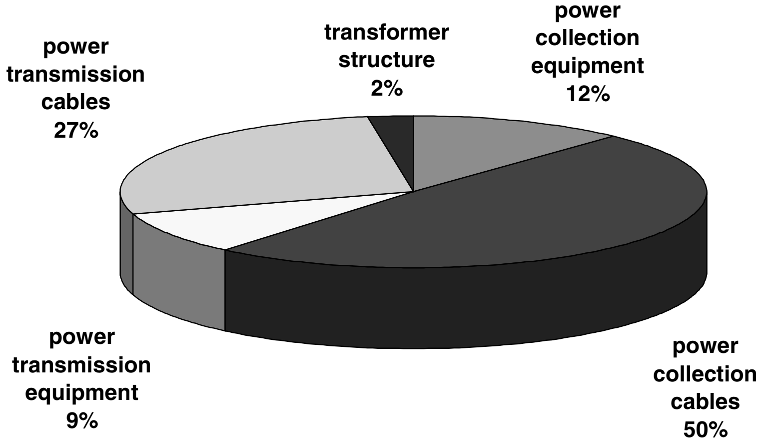


Figure 7.2-3 Cost breakdown of grid connection costs on component level for power collection and power transmission, respectively

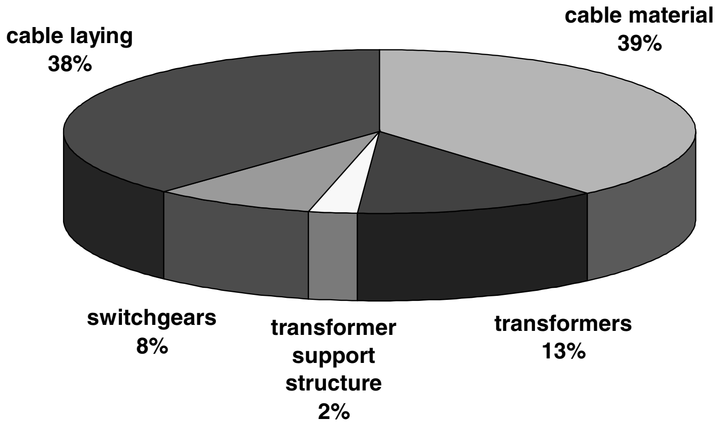


Figure 7.2-4: Cost breakdown of grid connection by components

7.2.6 Placement of transformer for each OWEC

The placement of the transformer will also influence the design work on the wind turbine and support structure. This means that this point should be settled on basis of the design of the total OWECS.
For the placement of the transformer there at least 4 options; the pro's and con's of these options are given below.
The reliability of the transformers is large; considering a wind farm of 100 units, it may be expected that during the lifetime (20 years) at most 1 transformer only will fail. So ease of replacing is a not so strong requirement.

All locations should satisfy the following two requirements:
- the transformer should be placed at an absolute dry place
- the transformer should be placed behind some partition-wall; this partitioned space becomes then a high-voltage room which should be accessible by special trained people only (due to regulations in some countries).

i) Inside the tower

The transformer can be pre-installed on land inside the (15 m.) tower segment which is installed on the foundation pile by means of grouting. It is also possible to place the transformer in the tower above the flange.
The advantage forms the low costs involved compared to the other options. The large disadvantage is that it will be difficult to replace it.
This option turned out not to be viable in combination with the soft-soft monopile design of chapter 6; there is not enough space available. Possible solutions to limit the dimensions of the transformer (separate trafo's for each phase; a trafo with a smaller rating in combination with extra cooling; a special kind of trafo which can be dismantled) are not recommended by the transformer manufacturer.

ii) On the access platform

Placing the transformer onto an access platform has the advantage of easy installation and replacement (in case of a fault). The disadvantage are the large costs involved to make the access platform suitable to bear the large weight.

iii) Transformer at the main collection point only

The obvious advantage of this option is that no transformer is needed at the OWEC (option F of section 7.2.3); the electricity is collected on generator voltage (6 kV). This results in a cable layout of 33 clusters of 3 wind turbines each.
The disadvantage is that for this situation more cable length (and thus costs) inside the farm is required. Furthermore it will be a difficult task to lay the 33 submarine cables and connect them through J-tubes to the support structure at the main collection point and the short circuit calculation turned out to be critical.

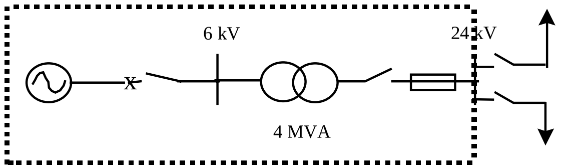
iv) Inside the nacelle

The advantage to place the transformer inside the nacelle is that it can be tested, in combination with the generator of the wind turbine, at the assembly hall. Moreover enough space is available and exchange is in principle no problem.
Note: also for a middle voltage (24 kV) cable, from nacelle to J-tube, cable twisting should be no problem. Transport problems due to the increased gross dimension of the nacelle are not relevant for offshore siting
A disadvantage, in this case of a soft-soft support structure, forms the increase of the nacelle mass. This results into a lower eigenfrequency (about 4%) of the support structure, which thereby will be more sensitive to the hydrodynamic loading. However it turned out that the higher towertop mass could be partly compensated by a decreased support structure height

Evaluation

After evaluation and discussion between the responsible partners for the design for wind turbine and support structure option ii) and iv) only remain from which the latter has been chosen mainly due to economic reasons.

Option A

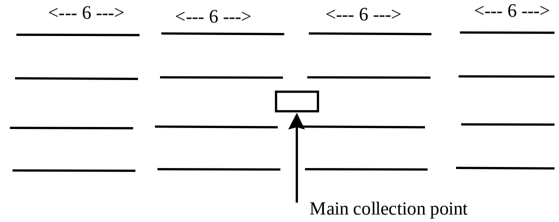


Per turbine needed :

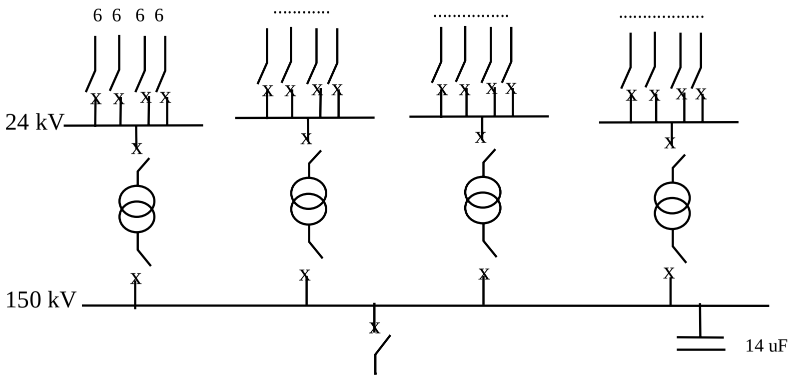
1 Transformer 4 MVA 6 kv/24 kV	57 500 ECU
3 SVS 630 A 24 kV loadbreaker bays	25 000 ECU

Basic characteristics SVS 630 A 24 kV
Feeder 630 A - 16 kA/1s
Busbar 800 A - 20 kA/1s
Dim (WXDXH) 420x700x1350 mm
Weigth 600 kg

Transformer dimensions
approx weigth 9000 kg
Dim (WxDxH) 2500x1400x2600 mm



Farm layout. Turbine equidistant spacing of S meter.
Cable used 400 sq mm solid Al conductor XPLE.
Approximate length needed 142 S + 96*80meter.
Price 350 ECU per meter (inclusive laying)



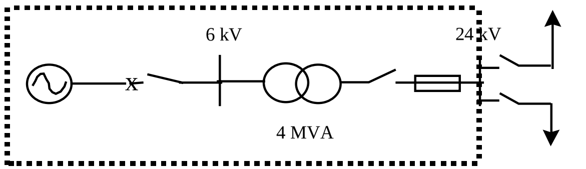
Main collection point

4 100 MVA transformers	4 000 000 ECU
20 24 kV bays	750 000 ECU
6 150 kV bays	3 000 000 ECU
20 km 150 kV 300 MVA submarine cable	28 000 000 ECU

Estimated cost Option A, turbine spacing S = 800 meter

Transformers		
	24 kV	5 520 000 ECU
	150 kV	4 000 000
Switchgear		
	24 kV,630 A SVS	2 266 666
	24 kV	750 000
	150 kV	3 000 000
Cable		
	24 kV	42 448 000
	150	28 000 000
Total estimated		85 984 666 ECU

Option B

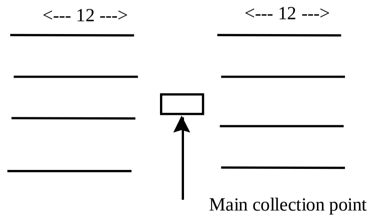


Per turbine needed :

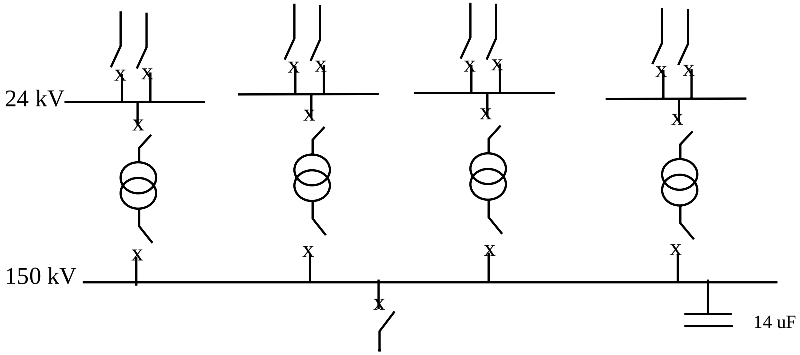
1 Transformer 4 MVA 6 kv/24 kV	57 500 ECU
3 SVS 1250 A 24 kV loadbreaker bays	30 000 ECU

Basic characteristics SVS 1250 A 24 kV
Feeder 1250 A - 25 kA/1s
Busbar 1250 A - 25 kA/1s
Dim (WXDXH) 630x1100x1350 mm
Weigth 600 kg

Transformer dimensions
approx weigth 9000 kg
Dim (WxDxH) 2500x1400x2600 mm



Farm layout. Turbine equidistant spacing of S meter.
Cable used 800 sq mm solid Al conductor XPLE.
Approximate length needed 97 S + 96*80 meter.
Price 375 ECU per meter (inclusive laying)



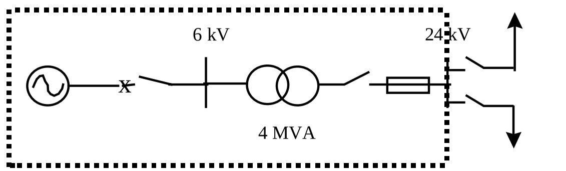
Main collection point

4 100 MVA transformers	4 000 000 ECU
12 24 kV bays	450 000 ECU
6 150 kV bays	3 000 000 ECU
20 km 150 kV 300 MVA submarine cable	28 000 000 ECU

Estimated cost Option B, turbine spacing S = 800 meter

Transformers		
	24 kV	5 520 000 ECU
	150 kV	4 000 000
Switchgear		
	24 kV, 1250 A SVS	2 800 000
	24 kV	450 000
	150 kV	3 000 000
Cable		
	24 kV	31 980 000
	150	28 000 000
Total estimated		75 750 000 ECU

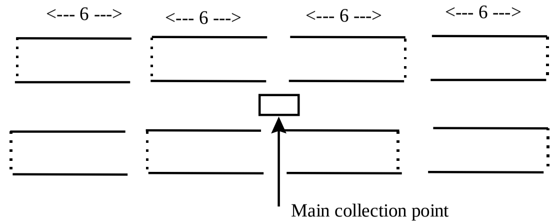
Option C



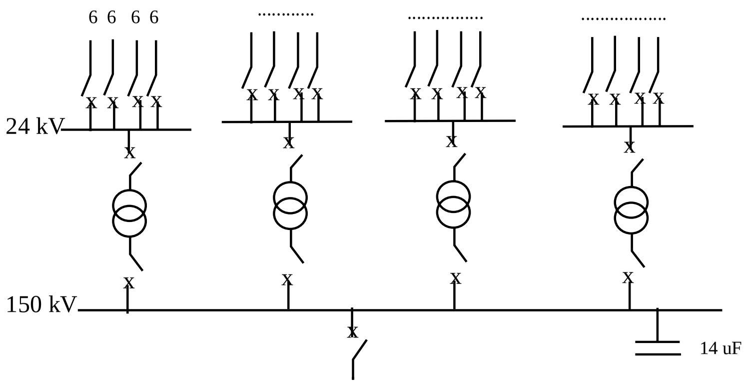
Per turbine needed :	
1 Transformer 4 MVA 6 kv/24 kV	57 500 ECU
3 SVS 1250 A 24 kV loadbreaker bays	30 000 ECU

Basic characteristics SVS 1250 A 24 kV
Feeder 1250 A - 25 kA/1s
Busbar 1250 A - 25 kA/1s
Dim (WXDXH) 630x700x1350 mm
Weigth 600 kg

Transformer dimensions
approx weigth 9000 kg
Dim (WxDxH) 2500x1400x2600 mm



Farm layout. Turbine equidistant spacing of S meter.
Cable used 800 sq mm solid Al conductor XPLE.
Approximate length needed 150 S + 96*80 meter.
Price 375 ECU per meter (inclusive laying)

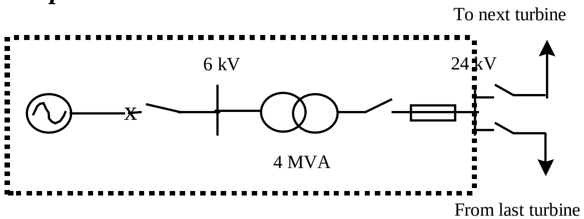


Main collection point	
4 100 MVA transformers	4 000 000 ECU
20 24 kV bays	750 000 ECU
6 150 kV bays	3 000 000 ECU
20 km 150 kV 300 MVA submarine cable	28 000 000 ECU

<u>Estimated cost Option C, turbine spacing S = 800 meter</u>

Transformers		
	24 kV	5 520 000 ECU
	150 kV	4 000 000
Switchgear		
	24 kV, 1250 A SVS	2 880 000
	24 kV MMS	750 000
	150 kV	3 000 000
Cable		
	24 kV	47 880 000
	150	28 000 000
Total estimated		92 030 000 ECU

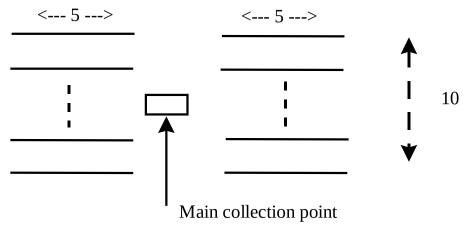
Option D



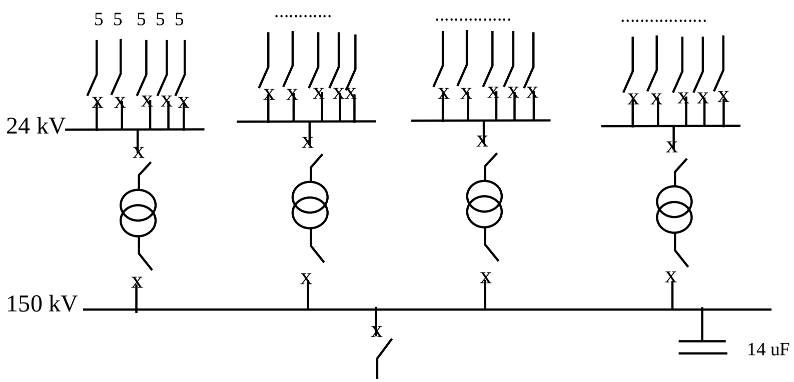
Per turbine needed :	
1 Transformer 4 MVA 6 kv/24 kV	57 500 ECU
3 SVS 630 A 24 kV loadbreaker bays	25 000 ECU

Basic characteristics SVS 630 A 24 kV
Feeder 630 A - 16 kA/1s
Busbar 800 A - 20 kA/1s
Dim (WXDXH) 420x700x1350 mm
Weigth 600 kg

Transformer dimensions
approx weigth 9000 kg
Dim (WxDxH) 2500x1400x2600 mm



Farm layout. Turbine equidistant spacing of S meter.
Cable used 400 sq mm solid Al conductor XPLE.
Approximate length needed 132 S + 100*80 meter.
Price 350 ECU per meter (inclusive laying)

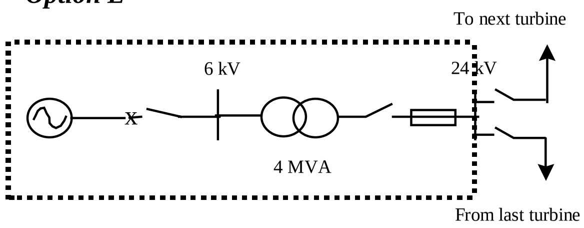


Main collection point	
4 100 MVA transformers	4 000 000 ECU
24 24 kV bays	900 000 ECU
6 150 kV bays	3 000 000 ECU
15 km 150 kV 300 MVA submarine cable	21 000 000 ECU

<u>Estimated cost Option D, turbine spacing S = 800 meter</u>

Transformers		
	24 kV	5 750 000 ECU
	150 kV	4 000 000
Switchgear		
	24 kV, 630 A SVS	2 333 333
	24 kV	900 000
	150 kV	3 000 000
Cable		
	24 kV	39 760 000
	150	21 000 000
Total estimated		76 743 333 ECU

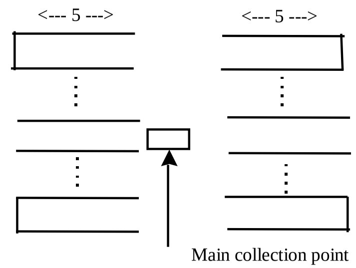
Option E



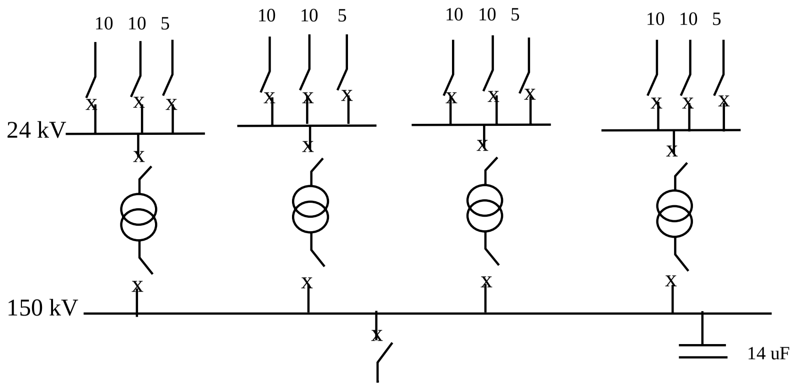
Per turbine needed :	
1 Transformer 4 MVA 6 kv/24 kV	57 500 ECU
3 SVS 1250 A 24 kV loadbreaker bays	30 000 ECU

Basic characteristics SVS 1250 A 24 kV
Feeder 1250 A - 25 kA/1s
Busbar 1250A - 25 kA/1s
Dim (WXDXH) 630x1100x1350 mm
Weigth 600 kg

Transformer dimensions
approx weigth 9000 kg
Dim (WxDxH) 2500x1400x2600 mm



Farm layout. Turbine equidistant spacing of S meter.
Cable used 800 sq mm solid Al conductor XPLE.
Approximate length needed 116 S + 100*80 meter.
Price 375 ECU per meter (inclusive laying)

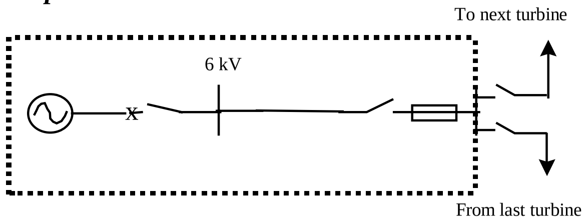


Main collection point	
4 100 MVA transformers	4 000 000 ECU
16 24 kV bays	600 000 ECU
6 150 kV bays	3 000 000 ECU
15 km 150 kV 300 MVA submarine cable	21 000 000 ECU

<u>Estimated cost Option E, turbine spacing S = 800 meter</u>

Transformers		
	24 kV	5 750 000 ECU
	150 kV	4 000 000
Switchgear		
	24 kV, 1250 A SVS	2 900 000
	24 kV MMS	600 000
	150 kV	3 000 000
Cable		
	24 kV	37 800 000
	150 kV	21 000 000
Total estimated		75 050 000 ECU

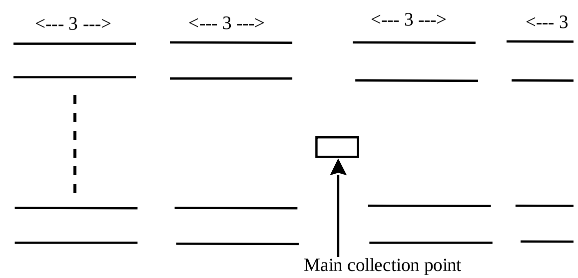
Option F



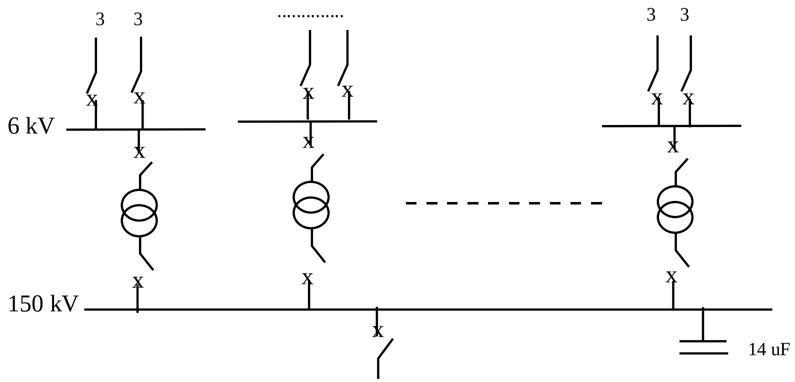
Per turbine needed :

3 SVS 1250 A 6 kV loadbreaker bays 30 000 ECU

Basic characteristics SVS 1250 A 24 kV
Feeder 1250 A - 25 kA/1s
Busbar 1250A - 25 kA/1s
Dim (WXDXH) 630x1100x1350 mm
Weigth 600 kg



Farm layout. Turbine equidistant spacing of S meter.
Cable used 800 sq mm solid Al conductor XPLE.
Approximate length needed 164 S + 96*80 meter.
Price 375 ECU per meter (inclusive laying)



Main collection point

16 25 MVA transformers	4 000 000 ECU
48 6 kV bays	2 000 000 ECU
18 150 kV bays	9 000 000 ECU
15 km 150 kV 300 MVA submarine cable	21 000 000 ECU

<u>Estimated cost Option E, turbine spacing S = 800 meter</u>

Transformers		
	150 kV	4 000 000
Switchgear		
	6 kV, 1250 A	2 560 000.
	6 kV, 2500 A	2 000 000
	150 kV	9 000 000
Cable		
	24 kV	52 080 000
	150	21 000 000
Total estimated		90 640 000 ECU

7.3 Farm layout

7.3.1 Introduction

This section describes the optimization of the farm layout for the chosen reference site NL-1. This site is about 10 km North-West from IJmuiden and is depicted in figure 7.3-1. As stated in section 4.8, a relative large wind farm size of 300 MW is chosen as reference case, because of economic reasons and a future, instead of near future, OWECS is an objective of the Opti-OWECS project.
As minimum distance to shore 10 km is taken; the other borders of the NL-1 area are determined by area’s used by marine traffic or military purposes. Inside the area there is one oil platform (CP-Q8-B) connected with a oil pipeline; also another oil pipeline and two (telecommunication) cables cross the NL-1 site. On the map the water depths are indicated (LAT) and the positions of the ship wrecks.

It is further assumed that the distance to shore is large enough to exclude visual and noise aspects for the determination of the farm layout.
For the placing of the OWEC’s a minimum distance of 500 m to the oil platform and 100 m to the oil pipelines and cables will be taken. For the crossing of power cables of the OWECS with the oil pipelines (or cables) permission should be required from the owners of the pipeline (or cable). Usually such a permission is obtained if a minimum separation of about 0.5 m between power cable and oil pipe is guaranteed (e.g. by means of a mattress). The spacing between the OWEC units will be 500 m (~6D) or more. This is regarded to be large enough in order to avoid problems during installation and O&M operations in respect with ships wrecks; the positions of the ship wrecks are therefore not considered any further for specifying the farm layout.

For the design of the support structure (chapter 6) a minimum LAT of 12 m and a maximum of 20 m is assumed, which put almost no limits on the use of the NL-1 area.

A wind turbine which is placed inside a farm, and thus standing in the wake of another wind turbine(s), will experience a lower mean wind speed. The resulting energy loss depends on the particular farm layout at a given site (which determines the wake situations) and the area of the site (thus the wind turbine spacing). The lower losses due to a larger spacing should be balanced with the higher cost for the power cables, including laying costs, inside the farm (the other cost components of an OWECS can be considered to be independent of the spacing).

For calculation of the farm efficiencies the standard code FLaP (Farm Layout Program developed by the University of Oldenburg, [7.3-1]) has been applied. As input the wind climate at the location is needed and also the turbine data; these will be described in the first two subsections. Next, the farm efficiencies will be determined in subsection 7.3.4 for some basic configurations. Finally the final farm layout is fixed, which is based on this information and some other considerations.

7.3.2 Wind climate

For the wind climate of the NL-1 site it is no option to use data from a meteorological station on land because this involves a land instead of the present sea climate. Instead, meteorological data at a location close by the NL-1 site have been obtained from the NESS database [7.3-2]. For this NESS gridpoint 83-49 the hourly mean wind speeds (for each 3-hour interval) are available for 9 complete years, the periods '77/'79 and '89/'94, which totals 26287 values. The values concern the wind speed of the effective neutral wind at a height of 19.5 m. Also the wind direction is recorded.

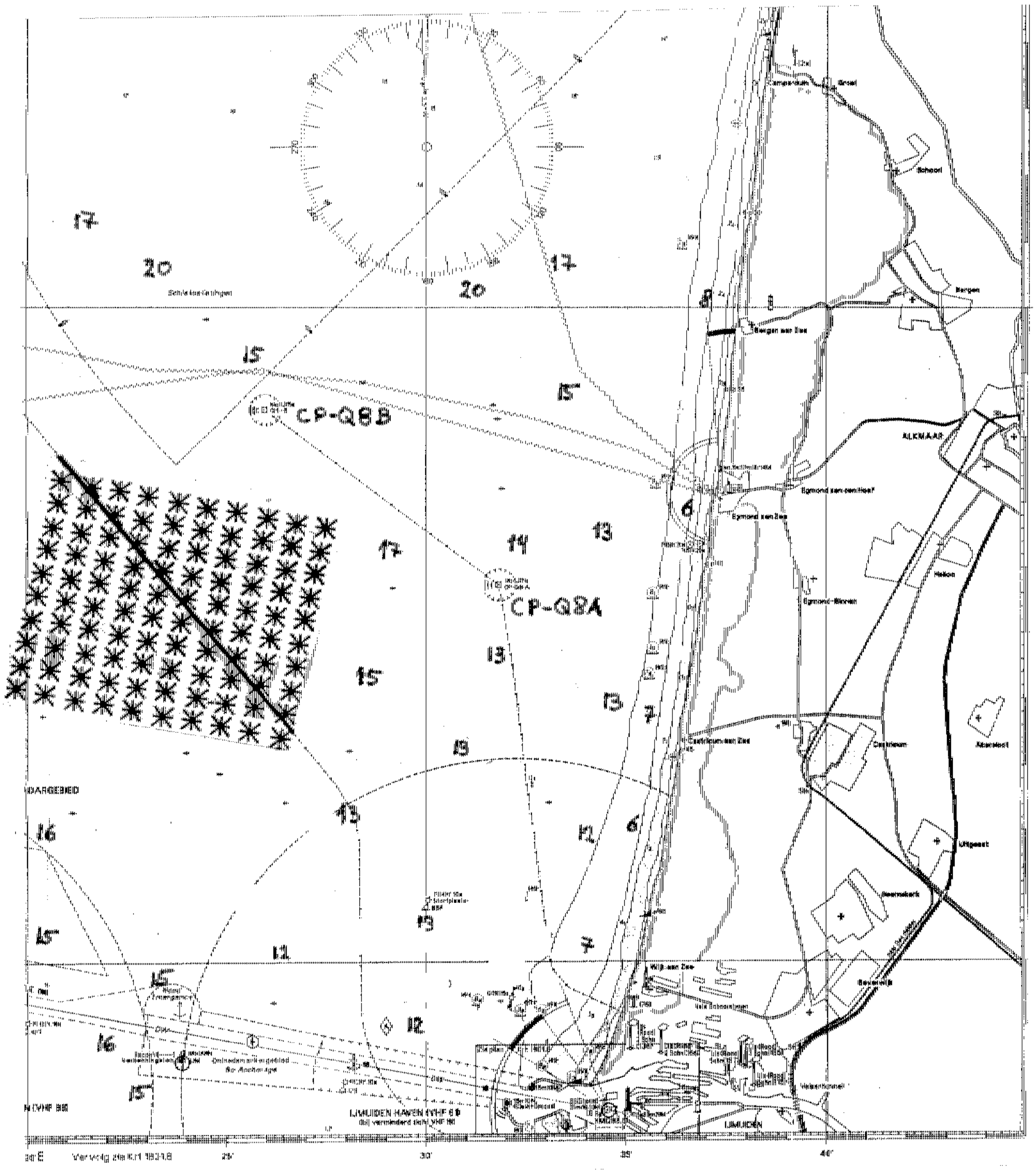


Figure 7.3-1: Map of the NL-1 site

In order to investigate the wake situations inside the farm several wind directions should be considered. In accordance with common practice the wind rose is divided into 12 sectors of 30 degrees each. The first sector correspond with the interval 345 - 15 degrees (with 0 degrees: true North). The frequency of occurrence of the wind sectors have been obtained from the NESS database. For each sector a wind speed histogram has been determined applying wind classes of 1 m/s width. A Weibull probability distribution function, with shape parameter k and scale parameter A, can be fitted to such a histogram. Because our interest concerns the energy yield the method proposed in [7.3-3] is adopted. This method gives two requirements for the fitting:

- the total wind energy in the fitted Weibull distribution and the observed distribution must be equal
- the frequency of occurrence of wind speeds higher than the observed average speed must be the same for both distributions

The combination of these two requirements leads to two non-linear equations in k and A, which can easily be solved.

The parameter A, which is proportional to the mean wind speed for given k, can be extrapolated to the required hub height (assumed to be 60 m) applying the wind shear formula:

$$A_{60} = A_{19.5} * \frac{\ln(60/\, z_0\,)}{\ln(19.5/\, z_0\,)} \qquad (7.3\text{-}1)$$

with z_0 = 0.0002 the terrain roughness for open sea

According to [7.3-3] no correction is applied to parameter k.

Although the period of available data seems rather long (9 years) it is short compared to a 30-year interval which is common for climatological purposes. Therefore the obtained values for parameter A are divided by a factor (in order to be conservative) to correct for the required long-term average. Based on the determined standard deviation found in the 9 values for the yearly mean wind speed, the correction factor is set to 1.02. If a long term mean wind speed at some other meteorological station is available, it is possible to determine this correction factor in another way. The correction factor can than be set equal to the ratio of the mean of the yearly mean wind speeds at that station for the corresponding years and the long term mean wind speed at that station. However, such data was not available.
The final obtained wind rose is given in figure 7.3-2. The mean wind speed at hub height equals 8.4 m/s. The optimum wind sector, the sector with the most energy content per year, is sector 9 (240 degrees). This data will be used further to determine the farm efficiency.

Uncertainty in estimated annual mean wind speed

As stated above, the annual mean wind speed will vary considerable from year to year. For the NL1 site the standard deviation of the annual mean wind speed, derived from the NESS data, turned out to be about 10%. This implies that it should be anticipated that the yearly energy yield of the OWECS will also show large yearly variations; in the order of 20%.

The above determined long term average mean wind speed for the NL1 location turned out to be lower than the estimated value of 9.0 m/s from a Dutch feasibility study [7.3-5] which has become available very recently. The reason for this difference is (yet) unknown. It is possible that the NESS data are not suitable for the prediction of the annual mean wind speed. Another explanation may be the applied method to correct for the long term average. Further research on this item is strongly recommended.
Just for reasons to be consistent throughout this report the mean wind speed derived from the NESS database is used furtheron. In order to already indicate the consequences of a different annual mean wind speed, the anual energy yield (electrical) are given for the chosen wind turbine for the design solution: 9.1 GWh and 10.4 GWh corresponding to an annual mean wind speed of 8.4 and 9.0 m/s resp. As can be seen from the parameter study in chapter 10, such a difference in the mean wind speed correspond with a variation in the energy costs of about 0.7 ECUct/kWh.

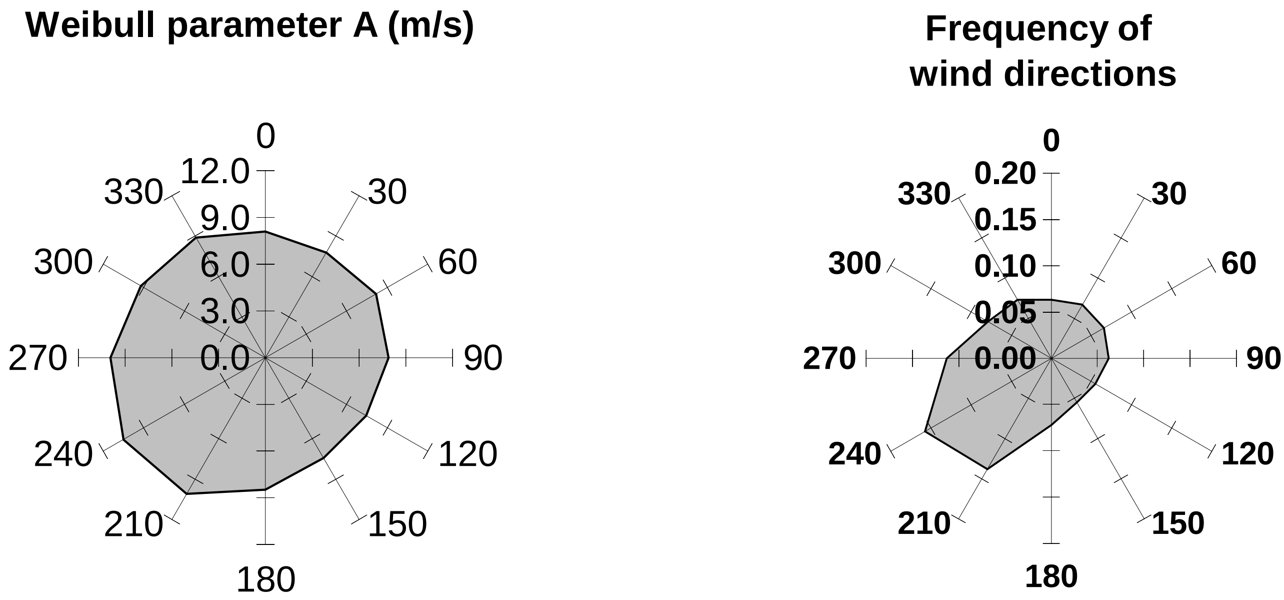


Figure 7.3-2: Wind rose at the NL-1 site

7.3.3 Wind turbine data

For determination of the farm efficiencies the power curve of the considered wind turbine is required and also the thrust curve (which determines the wake). For the modified WTS-80 turbine (for the specifications see chapter 5), with a rotor diameter of 80 m, these curves are calculated using the inhouse package PROPSI of the Institute for Wind Energy (based on the standard blade element-momentum theory). The WTS 80 turbine is pitch regulated and will therefore, generally speaking, have a smaller velocity deficit in the wake than stall regulated wind turbines.

7.3.4 Farm efficiencies for some basic options

For the wind climate at the NL-1 site the yearly energy yield of a single WTS 80 turbine equals 9.14 GWh/year (assuming a 100% availability and a generator efficiency of 90%), which correspond with a capacity factor (ratio of annual energy output to rated power times 8760 hr) of 35%. In order to obtain some insight in the farm efficiencies (ratio of energy output of total farm to energy output of a single wind turbine times the number of wind turbines) for the envisaged wind farm two basic options has been considered: a layout of 10*10 turbines and a 25*4 layout, see figures 7.3-3 and 7.3-4.

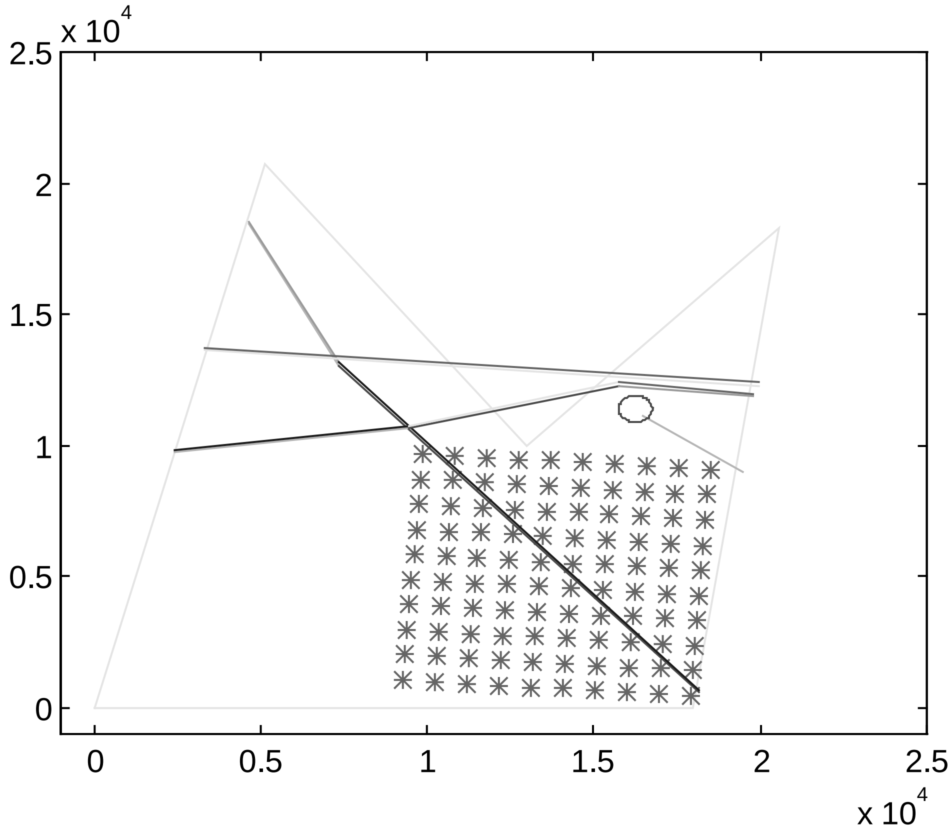


Figure 7.3-3: The 10*10 farm layout

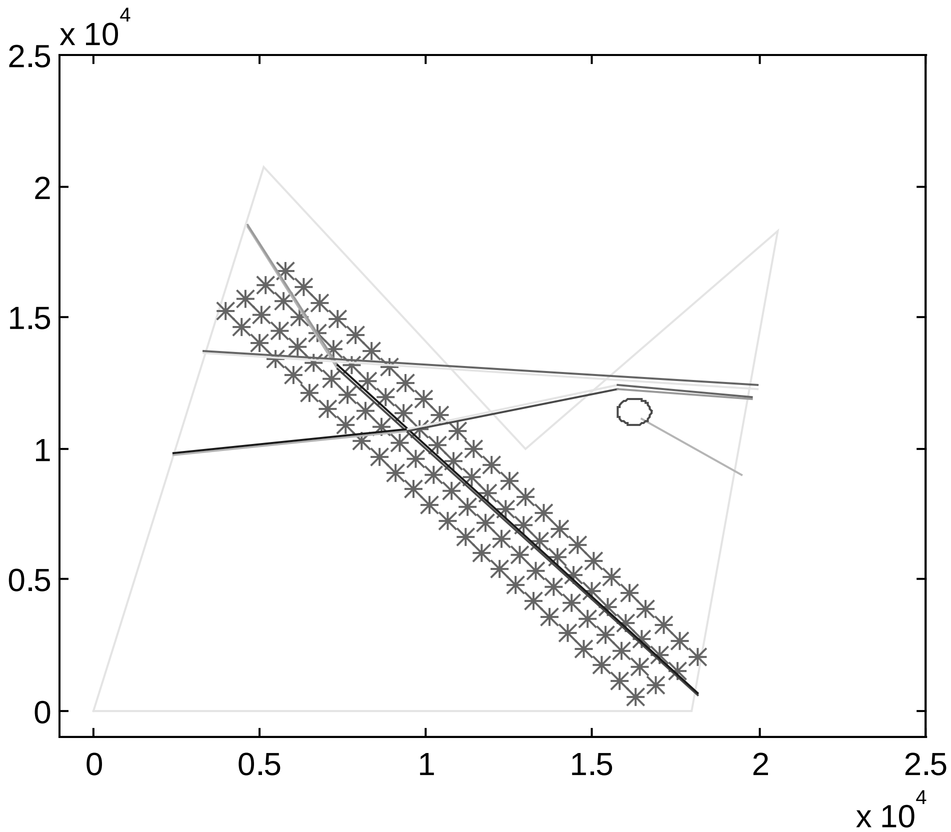


Figure 7.3-4: The 4*25 farm layout

The effect of spacing for the 10*10 farm is given in table 7.3-1 (assuming an orientation such that one side is facing North). The values are calculated with the aid of FLaP. The farm efficiency is determined via estimation of the velocity deficiency in the wakes behind the wind turbines. This velocity deficiency depends on the free mean wind speed, the axial force of the wind turbine and the distance behind the turbine. Note: a wind turbine placed (partially) in the wake of another turbine also experiences a larger turbulence intensity; this has been taken into account in the design of the OWEC.
For the efficiency of the total farm also multiple wake situations (for each wind sector) are taken into account. For a single wake a model developed by Risø [7.3-4] is applied in FLaP; for the superposition of wakes the so-called PARK model [7.3-4] is implemented. These methods are up-to-date standard procedures for the computation of wind farm power production. The absolute accuracy of the results is in the order of 1%; it is assumed that the relative accuracy is better so the farm efficiencies are given in tenth's of percents.

spacing (in D)	farm efficiency (%)
8	90.0
10	93.2
12	95.0
14	96.2
16	97.0

Table 7.3-1: Farm efficiencies as function of spacing (given in rotor diameters), for a wind farm layout of 10 rows and 10 columns and equal spacing in the two directions. The orientation is such that one side is facing North

For the given wind climate it does not seem worthwhile to have a different spacing in the two directions; the difference in farm efficiency between a 8 D / 10 D spacing and a 10 D / 8 D spacing turned out to be less than 0.1%. In other words, with respect to the energy yield of the wind farm, the wind rose at the NL-1 site turn out to be rather uniform.

The effect of the orientation of the farm is given in table 7.3-2. Beforehand it is very difficult to predict the ideal orientation. On one hand it seems advantageous to place one of the sides of the square perpendicular to the optimum wind direction (the direction with the most annual energy contents), in order to limit the number of multiple wake situations. For the reference case this correspond with an orientation of 60 degrees (in table 7.3-2). On the other hand, facing one of the corners to the optimum wind direction creates a situation in which the turbines in 2 corners experiences small wake effects. From table 7.3-2 it can be seen that the last effect is dominating.

orientation (in degrees)	farm efficiency (%)
0	93.2
15	93.0
30	93.0
45	92.9
60	92.8
75	93.0

Table 7.3-2: Farm efficiencies as function of orientation (zero degrees correspond with a side of the square facing North; clockwise rotation), for a wind farm layout of 10 rows and 10 columns and equal spacing of 10 rotor diameters in the two directions

The dependency of the spacing and orientation of the other basic option, 25*4 array, is given in the tables 7.3-3 and 7.3-4. Also a 33*3 array has been investigated but the efficiencies turned out to be not significantly different from a 25*4 array.

spacing (in D)	farm efficiency (%)
8	91.4
10	94.1
12	95.6

Table 7.3-3: Farm efficiencies as function of spacing (given in rotor diameters), for a wind farm layout of 4 rows and 25 columns and equal spacing in the two directions

orientation (in degrees)	farm efficiency (%)
0	94.1
30	94.3
60	94.1
90	94.3
120	93.8
150	93.5

Table 7.3-4: Farm efficiencies as function of orientation (zero degrees correspond with the longest side of the rectangular facing North), for a wind farm layout of 4 rows and 25 columns and equal spacing of 10 rotor diameters in the two directions

7.3.5 Final farm layout

Trade off between efficiency and cable costs

In the previous section the farm efficiency is considered as function of the spacing. The cable costs (inclusive cable laying costs) inside the farm are of course also influenced by the spacing. A trade-off between farm efficiency and cable costs can be performed by applying a cost model; the result is shown in chapter 10 (as part of a parameter study). The optimum spacing for the 10*10 farm is about 12 D, see figure 10.3-8. Note that the cost variations are limited for a large variation in the spacing.
The optimum spacing varies between 10 D and 14 D for (large) variation in the total capital cost, economic parameters or cable cost.

Selection of final layout

A 10 D spacing is chosen because the difference in energy costs (ECUct/kWh) with respect to a 12 D spacing is marginal but much less space is required.
The chosen spacing is larger than what is common for onshore wind farms: 3 to 5 D (perpendicular to the prevailing wind) and 8 to 10 D (in the direction of the prevailing wind). Offshore spacings can be larger due to the relaxed restrictions on used area. For comparison, the Vindeby wind farm, 2 lines of 5 and 6 turbines, has a spacing of 8.6 D (in both directions). The Tunø Knob farm, 2 lines of 5, has a spacing of 5.1 D and 10.2 D (between the lines) resp.
Although the farm efficiency of the 25*4 farm is slightly higher than that of a 10*10 farm layout, the latter is chosen due to three reasons. First the required transmission cable costs from the main collection point (situated in the middle of the farm, see section 7.2) and shore will be much less for the 10*10 layout (in the order of 5 MECU). The second reason is that the oil pipeline and communication cables initiate

fewer problems for this layout. The last reason is that the variation in water depth is smaller so less modifications for the support structures over the farm are required.

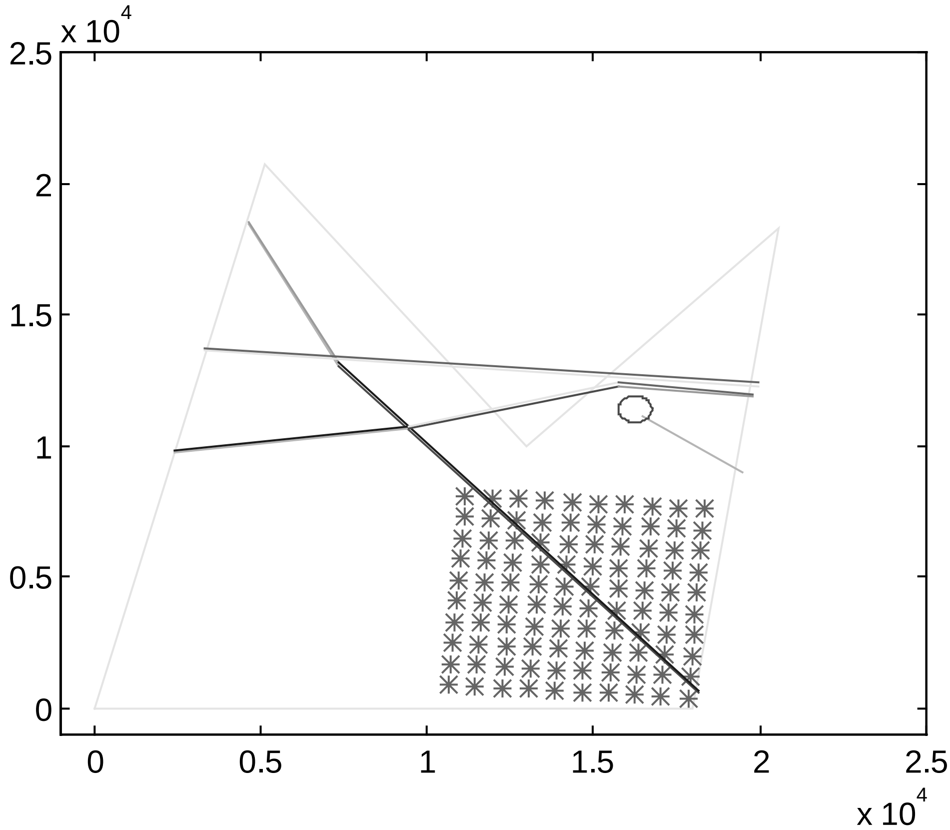


Figure 7.3-5: The final farm layout

Further fine tuning of the farm layout (e.g. honey comb layout) seems not worthwhile regarding the small variation of energy cost versus spacing.

See figure 7.3-5 for the final chosen layout. The distance to shore of the main collection point is about 15 km; the variation in water depth is about 14-19 m (LAT). The number of cable crossings with the oil pipeline equals 6. In order to prevent a chaotic seabed near the main collection point (at the middle of the farm) the cables can be collected to 4 bundles of 3 (say, about 200 m from the main collection point). The number of cable crossings with the oil pipeline equals 6; it is possible to decrease this to collect the cables again in bundles.

The annual mean wind speed at hub height equals 8.4 m/s. The yearly energy output of a single wind turbine equals 9.1 Gwh/year (assuming a 10% loss in the generator). The farm efficiency for the chosen layout is estimated to be 93 %.

It may be concluded that during the feasibility and conceptual design phase of a project a uniform spacing of about 10 D may be assumed for a pitch regulated wind turbine. During the structural design phase it will not take much effort to perform a farm efficiency study as given in this chapter in order to arrive at a more optimal layout; but it should be noted that the possible gain in energy costs which can be achieved will be limited (in the order of 0.1 ECUct/kWh).
Generally speaking, the farm layout will be more important for a stall regulated wind turbine, due to the larger wake effects.

8. Operation and Maintenance Design Solution

8.1 Introduction

A large number of distinguishable maintenance strategies can be applied at a given OWECS. The optimal choice will however depend upon the maintenance characteristics of the wind turbine applied in the offshore wind farm as well as upon the maintenance infrastructure and the maintenance hardware available at or near the site.
The most determining variable for determination of the most appropiate maintenance strategy is however the failure profile of the wind turbine. Therefore this chapter will be devoted mainly to maintenance of the wind turbine. The required maintenance operations of the support structure are dealt with in section 6.9; this is included in the estimated O&M costs in section 8.8.

Since no wind turbines exist to date which are especially designed for offshore application it is not possible to obtain representative failure rates and maintenance demand data directly. Instead it will be tried to determine a realistic target based upon onshore wind turbine experience. The resulting maintenance profile will then determine the infrastructural and hardware requirements for performing adequate maintenance within the OWECS.
The design of the wind turbine for RAMS (Reliability Availability Maintainability and Servicebility), as explained in Volume 1, has not been applied because this was outside the scope of the project (and not in line with the considered wind turbine base case).

Concering the operation of the wind farm it is assumed that this can be identical to that of a (large) onshore wind farm. For future, very large offshore farms this will no longer be the case and some operation strategy (or even storage) will be required to adopt the energy supply to the energy demand.

In section 8.2 the maintenance demand for commercial wind turbines will be considered. The
applicability of a no-maintenance strategy will be examined in section 8.3. The necessary lifting equipment and transport is given in section 8.4 and 8.5 resp. An evaluation of possible maintenance strategies is made in section 8.6 on basis of a Monte Carlo simulation code. Finally, the developed maintenance strategy for the design solution is given in the sections 8.7 and 8.8.

8.2 Maintenance requirement assumptions for mature commercial wind turbines

With respect to the determination of maintenance characteristics of wind turbines placed in an offshore wind farm the following approach is taken:
First an assessment of the O&M behaviour of currently available onshore machines is made. Although a limited number of large multi megawatt machines have been

built throughout Europe in the past decade it is concluded that their O&M demand is not representative for future commercial machines of similar size [8.2-1].

Since a large number of commercial wind turbines in the 500 - 600 kW range have been in operation over the last years it is proposed that their maintenance characteristics provide a better starting point for the determination of maintenance requirements to be assumed for wind turbines placed offshore. The most suitable information for this purpose is found from a data base of wind turbines operating along the German coast in the state of Schleswig-Holstein [8.2-2].
From about 1,400 wind turbines in operation in this area the data of 500 kW turbines of three different modern designs of renown manufacturers are taken. With the selection criteria that at least 25 wind turbines of identical design had to be in operation for more than one year following the commissioning period, the failure data of the Vestas V-39, Tacke TW-600 and the Enercon E-40 are used as a starting point. For these three commonly used wind turbines an average failure rate of 2,3 failures/year is found. The wide range of registered failure modes for these three types is next reduced to 6 common failure classes. Furthermore a reduction of the total failure rate with about 25 % is assumed to be achievable for wind turbines without major modification of the design. Thus a Base Case design with respect to O&M is defined, see table 8.2-1. This Base Case has a reduced total failure rate of 1,79 failures/year.

Failure Classes	Events/ year	MTBF [hours]
1. Blades/heavy components	0.44	19923
2. Gearbox/ Generator/ Yaw	0.14	62614
3. Electronics/ Control system	0.29	30227
4. Hydraulic	0.22	39845
5. Electric	0.37	23692
6. Others	0.33	26564
Total	1.79	-

Table 8.2-1: BASE CASE Failure Rates

The failure rates, or their reciprocal equivalents the Mean Times Between Failure (MTBF), of the various failure modes adopted for the Base Case design are all 25% below the average values for the machines presently used in commercial land based wind farms.
The repair time of the failures, as well as the need of (external) maintenance equipment is very much dependent upon the specific structural design chosen for the

wind turbine. The Base Case O&M demand is further defined with repair times between 4 and 48 hours, (classes "6. Others" and "2. Gearbox/Generator/Yaw/" respectively). This is the repair time needed from the moment that repair crew and equipment have arrived on the site.

Furthermore it is assumed that a repair in the failure class "Blades/heavy components" requires the need of an external crane. Failures in the other five classes are assumed to be repairable without heavy external equipment.

Although there is of course some relation between the failure class name and the actual failure of a specific design, this should not be interpreted too strictly. The Base Case O&M demand table simply states that failures requiring external cranage have an event rate of 0.44 per year. By the way, this is not equivalent to saying that there is yearly chance of 44% that an (external) crane is needed for repair. From the stochastic Poisson process related to this failure rate it can be seen that after one year there is a chance of 36% of cranage maintenance or what is equivalent, the chance of 5 years of operation without a "class 1" failure is 11%.

Apart from the repair of failures ("Corrective Maintenance") machines need also regular care ("Preventive Maintenance"). Base Case Preventive Maintenance is assumed to take place every 3500 hours. This should be interpreted as a nominal time interval (comparable to the regular mileage service of a car). For wind turbines located offshore it is assumed that such service work takes place when the weather permits a visit to the turbine. No penalty is assumed when PM does not take place, provided there is sufficient repair crew available to take advantage of the first oncoming possibility of access.

8.3 No-maintenance strategy

Within discussions about offshore application it is sometimes proposed to provide no maintenance at all to an offshore wind farm. Then it is argued that it might be advantageous to apply a major overhaul say only every 5 years to replace turbines that have failed. In figure 8.3-1 the number of available wind turbines in a 100 unit sized OWECS is shown as a function of their failure rate under a No Maintenance strategy [8.3-1].

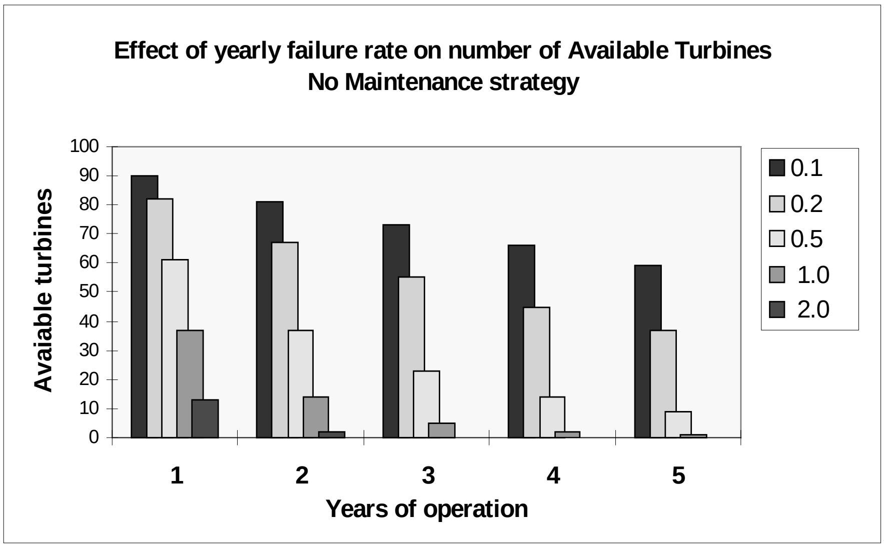


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Figure 8.3-1: Availability of OWECS in a No-Maintenance strategy

With the failure rates assumed in table 8.2-1 it is easily seen that such a way of "maintaining" the wind farm is a non option. Even when the failure rate is reduced drastically, to let's say 10% of the Base Case total failure rate, the availability in the fifth year of operation is only 45%, which is evidently unacceptable. Reducing the no maintenance interval to once every 3 years means an availability in the third year of 64%. which is probably still unacceptable.

When it is then realized that a reduction of the (total) failure rate to a value significantly lower then 0.2 failures/year together with a refrain from any preventive maintenance activity over a period of 3 to 5 years is necessary to obtain a reasonable availability (say always above 80%) it is clear that OWECS adopting a no-maintenance strategy are not a foreseeable option in the near future.

8.4 Analysis of the offshore cranage problem.

Repair actions of onshore wind turbines often need the assistance of an external crane. When the Base Case turbines are used for offshore application the required cranage is reduced, but still inevitable. It is in general quite probable that (large) offshore wind energy converters for the near future will be designed such that at least some repair actions still require the use of an external crane. Thus it is relevant to address the cranage possibilities for offshore wind farms.

Cranes for offshore work are available in several types and sizes. Usually the weight of wind turbine components is not a limiting factor for the choice of the type of crane. The lifting height as well as the water depth can be a restriction to the deployment of certain type of cranes, apart from of course the financial consequences. In [8.2-1] a systematic evaluation of all possible hoisting facilities which are applicable to an offshore wind farm have been assessed. The conclusion is that in a wind farm of a reasonable size, say of about 100 wind turbines the use of a purchased and modified self propelling jack up platform turns out to be most cost effective. Of course the number of turbines requiring a cranage action determines its economics. The financial cross over point is found when about 15 to 20 cranage actions are needed each year. With the Base Case O&M assumptions it is then favourable whenever the size of the wind farm exceeds 60 units.

Self propelling jack up platforms are commonly used for exploration of oil fields. They are readily available as second hand items and consist of a platform of typically 500 to 1500 m^2. Three or four legs, of a typical length of about 100 m are used to jack up the platform floor hydraulically or electrically.
When floating, the platform can propel itself to a new location where it jacks itself up to working position.

The legs of the platform are well suited to be equipped with a crane. Such a crane can crawl itself up along one or two legs into working position at hub height of the wind turbine. Furthermore the platform can be used as a base for maintenance crew, maintenance work and overhaul actions. It may as well be a place for stock keeping, thus reducing the time to repair failures that have occurred.
Caution is required when an OWEC is accessed by the jack-up in order to avoid damage to the power cables. This will imply consequences with respect to the direction from which the OWEC can be approached. Moreover, repeated access at nearly the same location within a short period, say one to two years, might be problematic due to the foot prints of the spud cans in soft soils.

8.5 Access of offshore wind energy converters for maintenance

The most favourable way to achieve access to a turbine is to use a small boat. This can either be of a gol boat or a tender type. The first one is usually applied for transport of port pilots, the second for transporting personnel from and to ships. The gol boat is faster in its operation while the latter has a larger capacity.
Although a helicopter is sometimes suggested as a means of transport from and to the wind turbines it turns out to be not very favourable. In the first place it requires the provision of a helicopter landing platform on each OWEC, which is a very expensive gadget, even for large wind turbines. In the second place it does not even make much sense in terms of costs of a maintenance operation.

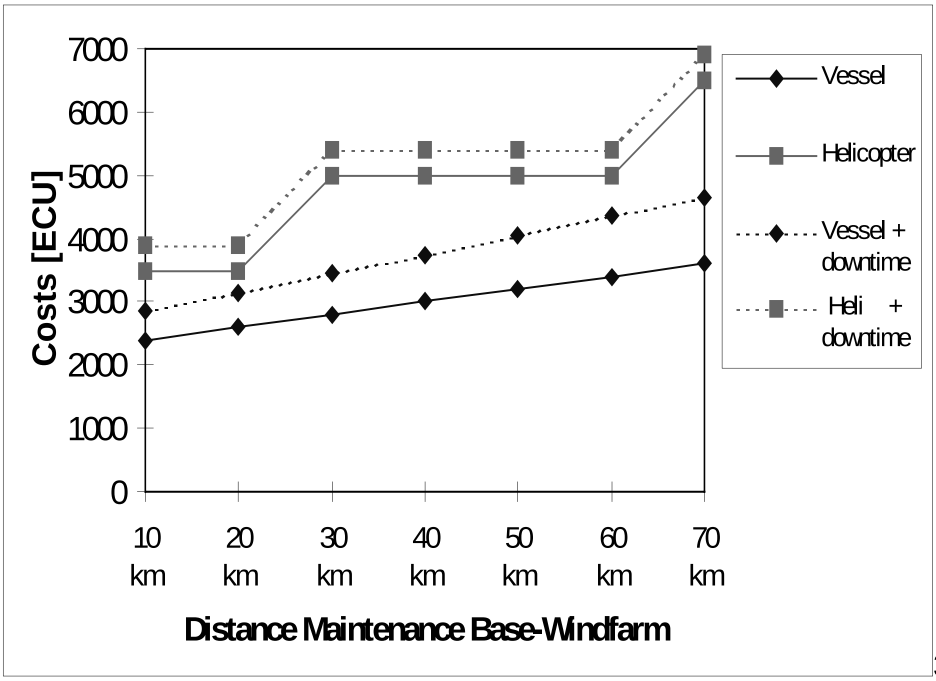

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Figure 8.5-1: Cost comparison of helicopter vs vessel

Figure 8.5-1 shows the cost (in ECU) of a one day maintenance operation as a function of the distance base-wind farm with a vessel and a helicopter as a means of transport. The helicopter is rented on a hourly basis. For that reason the costs of transport by helicopter shows steeper increase at 30 and 70 kilometers distance since an extra 1 resp. 2 helicopter rental hours are then needed for the complete operation.
The dotted lines show the costs when downtime of the turbine is also taken into account (assuming a 1.2 MW machine). Obviously a maintenance action by helicopter has a shorter duration due to the short travel time. Thus the downtime cost of the turbine is less. Figure 8.5-1 however shows that the total costs are lower when a vessel is used for transport.

Transport with a helicopter from a land base to the jack up platform may be of interest in occasional situations, e.g. when immediate assistance is needed for major maintenance work or when official inspection by an expert is required.

8.6 O&M simulations of OWECS

Bossannyi and Strowbridge [8.6-1] showed that O&M operations in an onshore wind farm are not so easy to analyze in a straight forward way, because of the interaction of the various stochastic processes. This can certainly be stated for maintenance operations in an offshore wind farm of say 100 wind turbines with a maintenance profile as described in the Base Case design operating in a hostile environment with often high winds and high waves and thus limited accessibility to the turbines. The approach of a Monte Carlo simulation program found in [8.6-1] is further developed to simulate maintenance actions under random simulation of wind and wave conditions, random wind turbine failures, predefined maintenance crew deployment and given availability of maintenance equipment. The stochastic weather simulation has different storm length, storm interval and average wind speed parameters for summer and winter season. Furthermore spare part logistics can be assessed with the program. Further details are given in Volume 2, part b.

A parameter study is performed with respect to the O&M demand of the wind turbine using the code [8.3-1]. A wind farm with 100 Base Case wind turbines having a rated power of 1.2 MW forms the starting point of this study. With the program the availability of the wind farm for a given deployment of crew, equipment and stock management can be determined. The weather characterization, determining both accessibility to the wind turbine as well as its potential energy yield is one of the major actors. High winds in winter lead to high energy yields, but also to a high penalty for unavailability when a failure cannot be repaired due to inaccessibility.

Subsequently the effect of variations with respect to the failure rate on the availability of the wind farm with 100 wind turbines is assessed.
A decreased failure rate obviously leads to an increased availability and thus to an increased energy yield. Of course the increase of reliability of the wind turbine also implies a higher capital investment. When this, together with the price of wind electricity, is known it is possible to determine the best trade-off between extra capital investment and increased income from the achieved extra electricity production.
A parameter variation is also performed with respect to the deployment of crews. When an extra maintenance crew is committed to the wind farm the availability will increase, as well as the O&M costs.

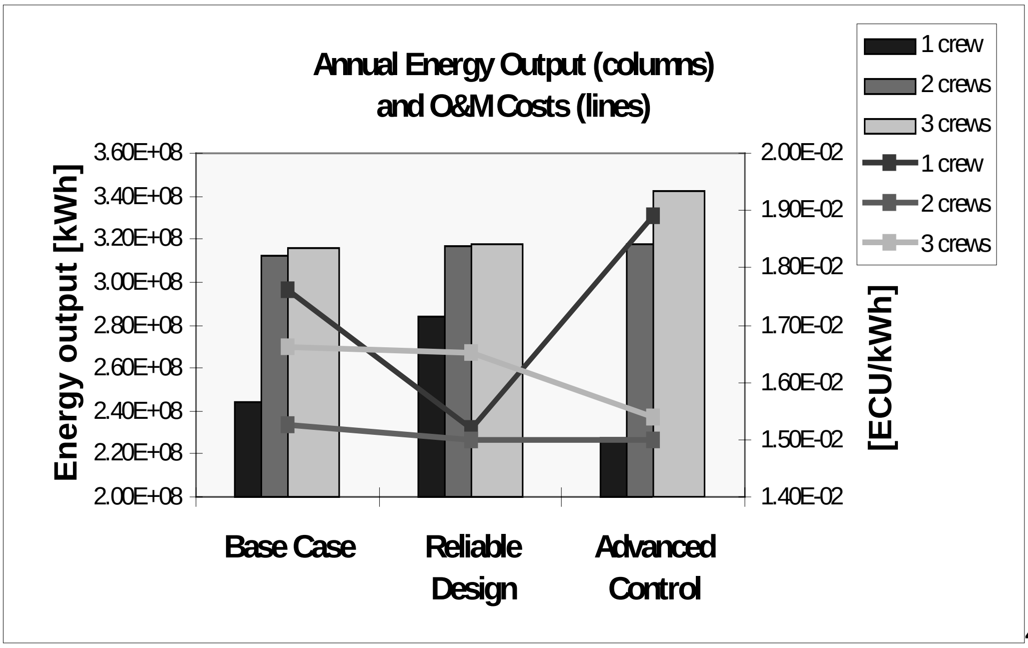
In table 8.6-1 a number of assumptions used in the simulations are given. It should be stated here that the cost figures are only indicative. They are e.g. quite dependent upon the actual cost of the purchase and modification of the lift boat. Furthermore the spare part costs have been set to zero, and shopkeeping costs have not been taken into account by the present simulations.

Yearly Fixed Maintenance Costs:	
1. Modified Jack-up 2. Vessel 3. Consumables 4. Spare parts	3.10 MECU 0.55 MECU 0.20 MECU 0.00 MECU
Crew data:	
5. Hourly wage 6. Number of workers per crew 7. Number of shifts 8. Hours per shift 9. Travel time (single) 10. Number of crews	50 ECU/person 2 1 12 1 hour 1, 2, 3

Table 8.6-1: Cost and crew figures used for the Monte-Carlo simulations

Also the maintenance costs of the submerged part of the wind farm (support structure and cables) have not been taken into account, as well as costs for the operation of the wind farm (monitoring costs, legal charges etc). Thus the given costs of table 8.6-1 should be used only for the present comparative study.

Figure 8.6-1, taken from [8.3-1], shows the result of some of the parameter variations performed with the program. The Reliable Design has a 20 % decreased failure rate with respect to the Base Case, whereas the failure rate of the Advanced Control design is increased with 20%. Furthermore it is assumed that the Advanced Control design has a potential energy yield which is 10% higher than the Base Case and the Reliable Design. The simulated weather involved an 18% storm (or inaccessibility) percentage.
The columns show the yearly energy yield as a function of the deployment of crew. The potential energy yield of the farm (at 100 % availability) equals 325 GWh/year (and 357 GWh/year for the Advanced Control design).



4

Figure 8.6-1: Energy output and O&M Costs related to Crew Deployment and Wind Turbine Design.

With one crew, consisting of 2 people working for 12 hours per day over 7 days per week (thus effectively consisting of 4 persons), the availability of the wind farms turns out to be 74, 86 and 63 % for the three consecutive designs. Note that wind turbines with present day failure rate would have given even lower values whereas a similar onshore wind farm with the same crew deployment would have had an availability in the order of 96 to 98 % !!

With the deployment of two crews these kind of availability figures are recovered again, except for the Advanced Control design, (availability of 88 %). However the assumed 10% gain in potential energy output implies that the actual output of the offshore wind farm equipped with Advanced Control wind turbines is equivalent to the wind farm with one of the other two designs.

With respect to the O&M costs it can be seen from figure 8.6-1 that in all three cases it seems favourable to have two maintenance crews working in the wind farm. For a wind farm equipped with the Advanced Control design it is however still advantageous to deploy the third crew as well. The costs of O&M do increase from 0.015 to 0.0154 ECU/kWh but as a consequence the yearly energy yield is also increased from 318 to 342 GWh/year. This means that the extra expenditure of 0.5 MECU for the extra crew results in an electricity gain of 24 GWh/year. This leads to a profit when the price for the extra kWh exceeds 0.021 ECU/kWh which is evidently the case [8.6-2].

8.7 Towards the OWECS O&M design solution.

PM assumption

For the determination of the 3 MW design solution the maintenance requirements of the mature commercial onshore wind turbines have been reconsidered. The rationale behind it is that it should be possible in the design of a dedicated 3 MW offshore wind turbine to use developed expertise with respect to reduction of the failure rates of at least a number of components. Especially for components that are not too specific for a given design and size this is conceived to be possible. This results into reduced values for the Base Case failure rates in the categories "Blades/heavy components" and "Electrics".

The lowest "Blades/heavy components" failure mode found for the three commercial designs used to set up the Base Case design failure mode characteristics was found for the popular Vestas V-39 turbine and is thus adopted for the design solution. For the category "Electrics" the lowest failure rate is found for the Tacke TW-600 and is set here as well as the target for the design solution.

The Base Case failure rate in the category "Hydraulics" was assessed in a different way. The design solution incorporates important functions as hydraulic pitching of the blades and yawing of the nacelle. By choosing high quality pumps, valves, cylinders and hydraulic oil Kvaerner Turbin has set a reduced failure rate for the design solution (see also chapter 5).

In principle it seems relatively easy to apply electronics and control units in a redundant way into the design solution. Either by duplication of systems or by taking over tasks with other system a failure rate of 0.29 x 0.29 = 0.08 might be achievable. Discussions with Kvaerner Turbin regarding their specific lay out for electronics and control using a number of local intelligent nodes resulted in a reduced rate based upon the application of an extra spare intelligent node able to take over tasks from any of the active nodes.

Furthermore an advanced remote monitoring/control and resetting system will be implemented which will significantly reduce the number of failures, mainly in the category "others".

Failure Classes	Base Case events/year	Design Solution events/year	Cranage needed
Blades/heavy components	0.44	0.32	yes
Gearbox/generator	0.14	0.14	no
Electronics/control	0.29	0.11	no
Hydraulics	0.22	0.15	no
Electrics	0.37	0.20	no
Others	0.33	0.10	no
TOTAL	**1.79**	**1.02**	

Table 8.7-1: Failure rate comparison of Base Case and Design Solution

The resulting overall failure rate is thus 57% of the value used for the Base Case design considered in earlier Opti-OWECS O&M assessments and thus about 45% of present 500/600 kW mature commercial onshore turbines.
The failure rate in category "Blades/heavy components" does apply to blade failures requiring a blade replacement with an external crane, as well as to any other major failure requiring such external cranage (which in the case of the design solution may also be the transformer located in the nacelle).
The OWECS design solution is assumed to be a 100 unit wind farm, and thus some 27 repair actions requiring an external crane are needed each year with the O&M design solution having a failure rate as in table 8.7-1.
This implies that also for the design solution the use of a self propelling jack up platform, being part of the permanent O&M hardware available in the offshore wind farm is most economical.

CM assumptions

With respect to regular service the following scheme is set up for the 3 MW design solution according to information of Kvaerner Turbin:

- Preventive maintenance is scheduled once a year (every 8766 hours) and takes 2 x 8 hours for a crew of two persons
- Every 5 years a large preventive maintenance action must take place
  This takes 3.5 x 8 hours for a crew of three persons, but no external crane is needed.

O&M strategy

The failure rate of 1.02 events per year implies that a Corrective Maintenance visit is paid to a wind turbine statistically every 18 months. Of course the opportunity will be taken to perform Preventive Maintenance actions as well when a wind turbine is serviced after a failure and is almost due to regular service, but in general the maintenance strategy is a PM+CM approach.
Preventive maintenance is planned in the summer period when weather conditions are more suitable and loss of revenues due to downtime are less then in the more stormy winter season.

8.8 Availability and O&M costs for the design solution.

With the failure rates as assumed in the previous section (table 8.7-1) and with the preventive maintenance requirements for the WTS 80 M as given by Kvaerner Turbin it is relatively easy to determine the availability of the OWECS as a function of the maintenance efforts by means of the Monte-Carlo simulation program described earlier. Employment of 2 crews which are stand by for 12 hours a day every 7 day of the week (effective employment of four people) turns out to be sufficient to fulfill the maintenance requirements for the OWECS consisting of 100 units located at a distance between 10 and 20 kilometers from shore in a physical environmental (wind and waves) obstructing any maintenance actions for 25% of the time (which follows from the NESS database). For traveling the maintenance crews have a manned vessel to their disposal as well as a permanently available manned liftboat. Note: the proposed site for the farm NL-1, happens to be very close to the Dutch harbor IJmuiden.

From the Monte-Carlo simulations a maximum achievable availability (when land based) of 98.5% is found which drops down to 96.5% under the same maintenance strategy for the location of the design solution. With an adopted farm efficiency of 93% and a potential yearly energy output of a single (3 MW) wind turbine equal to 9.1 GWh/year the netto energy output of the actual farm consisting of 100 wind turbines is estimated to be 787 GWh/year. The costs given in table 8.6-1 have been used as well to determine the O&M costs. This results into a cost of 0.0058 ECU/kWh. It should be stressed again that this figure does not represent the total O&M cost.

Other maintenance costs

To the costs given in table 8.6-1 the costs of permanent (onshore) monitoring of the wind farm and the costs of legal charges, insurances etc have to be added. These are estimated to be in the order of 1 MECU/year (although this may be too optimistic in practice). Furthermore some cost figure for spare parts has to be determined. Within the German MWEP monitoring program dealing with about 1400 onshore wind turbines [8.8-1] it is found that within a period of 5 years some 10% of the main components (mainly blades and gearboxes) have been replaced. This would thus be in the order of 2% per year. On one hand one might expect this value to be less than 1% for the present design solution since the failure rate is reduced significantly, but on the other hand the material cost of smaller repairs also have to be taken into account. Based upon the cost of 1.7 MECU per turbine the yearly spare parts cost per WTS 80M turbine are estimated at 30 kECU/year. Then the total O&M cost of the turbines of the design solution adds up to 8.75 MECU/year.

Maintenance for support structure and grid connection

Finally the inspection and maintenance costs of the support structure and the electrical infrastructure have to be taken into account as well. It is anticipated that every 5 years a visual inspection of the support structure is performed in phase with major PM of the turbine. This would mainly imply extra inspection crew cost, which is estimated to be about 0.25 MECU yearly. No significant costs are foreseen with respect to the electrical infrastructure.

Final evaluation

Thus total O&M cost end up to about 9.0 MECU/year leading to a total OWECS O&M cost of 0.011 ECU/kWh.

9. Overall dynamic assessment

During the course of the Opti-OWECS project the attention for dynamics as one particular design driver for OWECS has increased continuously from the early feasibility study (section 3.7) to the conceptual development (section 4.6) and the structural design of the final solution. Therefore an entire chapter is devoted to a thorough assessment of overall dynamic behaviour of the proposed design. After a comment on structural reliability considerations in section 9.1 emphasis is put on the support structure in a threefold manner: modal analysis (section 9.2), fatigue (section 9.3) and extreme event analysis (section 9.4) under combined aerodynamic and hydrodynamic loading.

OWEC(S) dynamics is a fairly new field of research. It should be noted that an objective of the Opti-OWECS project is the **application** of the dynamic analysis of OWEC rather than the **development** of such techniques and the required tools. A considerable step forward has been made in the understanding, but some questions remain that require investigation in further projects as, for instance, by [9.0-1], [9.0-2]. So a practical analysis approach is adopted that is tailored to a design situation requiring several calculations of different configurations, parameter studies, etc. This procedure is regarded as successful but certainly not as a final answer. Therefore this chapter is a demonstration of the viability of the chosen concept with respect to dynamic considerations rather than a documentation of a (partial) certification calculation.

9.1 Prospects of a reliability based design method for the NL-1 design solution

Experience in designing offshore structures for the petroleum industry suggests that the required ultimate strength for the in-place condition while the structure is exposed to extreme storms is often governing over other design drivers like e.g. fatigue, transportation, etc. The required design values for wind, waves and current are usually determined in a conventional manner. On the basis of site measurements or hindcast databases for each met-ocean variable the 50 or 100 year return period value is determined while ignoring any correlation between the met-ocean variables. The resultant separate, say, 50 year wind, 50 year wave and 50 year current are then conservatively assumed to occur simultaneously and to act in the same direction. This will lead to a “design load” which is clearly much more severe than the “true” 50 year load.
Application of the reliability based design method to a support structure design for a proposed site in the Dutch North Sea (NL-5), as presented and discussed in [9.1-1], has demonstrated that a conventional design approach is indeed very conservative. An overestimate of 40 % has been demonstrated for the lattice tower concept in 25 m of water depth. In the method the correlation between the met-ocean variables is fully taken into account and sets high demands on the availability and quality of a met-ocean database.
However, experience gained in the conceptual design phase of the Opti-OWECS project revealed that other design drivers than ultimate strength are

governing for a monopile OWEC support structure at the NL-1 site. It appeared that transportation, installation, stiffness requirements and especially the fatigue behaviour of the OWEC are dominating the design. It should be noted that for the NL-1 OWEC also an ultimate strength check has been performed using a conventional approach (sections 6.6.1 and 9.4). As this particular OWEC design also appeared to be 'fatigue driven', it was decided not to apply the reliability based design method for this NL-1 design solution.

9.2 Sensitivity of the dynamic behaviour to the monopile foundation

Analogous to the investigation with respect to the gravity base foundations of the monotower and the lattice tower (section 4.6) the sensitivity of the monopile support structure to variations in the stiffness of the foundation is studied. The analysis is carried out with the aid of the general purpose FE code ANSYS 5.2 [9.2-1], including among others the following features:

- appropriate beam element model of the support structure
- nacelle and rotor considered as lumped mass and inertia at the tower top (rotor horizontally parked)
- lateral soil stiffness according to P-y-curves provided by KOGL in the form of non-linear springs (spacing 1 m)
- hydrodynamic added mass for water depth 21 m (MSL)
- 10 % increase in mass along tower to allow for internal equipment
- stiffness of grouted joint considered (concrete B55)

no.	eigenfrequency [Hz]		mode
	actual found. stiffness	infinite found. stiffness	
1	0.288	0.336	1st bending in y-dir'
2	0.292	0.337	1st bending in x-dir'
3	1.29	1.96	2nd bending in y-dir'
4	1.33	2.00	2nd bending in x-dir'
5	3.17	4.26	3rd bending in y-dir'
6	3.25	4.47	3rd bending in x-dir'

Table 9.2-1: Monopile bending eigenfrequencies for different foundation properties

Table 9.2-1 gives some low eigenfrequencies derived for a rotor thrust of 300 kN, which equals approx., the rated loading. The first eigenfrequency for an infinitely stiff soil is 17 % higher than for the actual soil conditions.
A convenient illustration of the foundation stiffness is the calculation of a (fictitious) apparent fixity length i.e. the distance below the mudline of a rigid encastre which results in the same fundamental eigenfrequency [9.2-2], [9.2-3]. The calculated length of 3.7 times the pile diameter is similar to the value of 3.3 diameters valid for one of the OWEC at the first Dutch offshore wind farm Lely with a comparable monopile foundation [9.2-4].

Due to the relatively firm soil conditions (medium dense sand with a friction angle of 30 degrees) and the considerable pile dimension the non-linearity of the foundation within the operational load range is quite small. The first three bending eigenfrequencies shown in figure 9.2-1 vary as result of non-linearity by about ± 2 % for the first and third mode and between +3 % and -4 % for the second mode around the reference values at rated conditions.

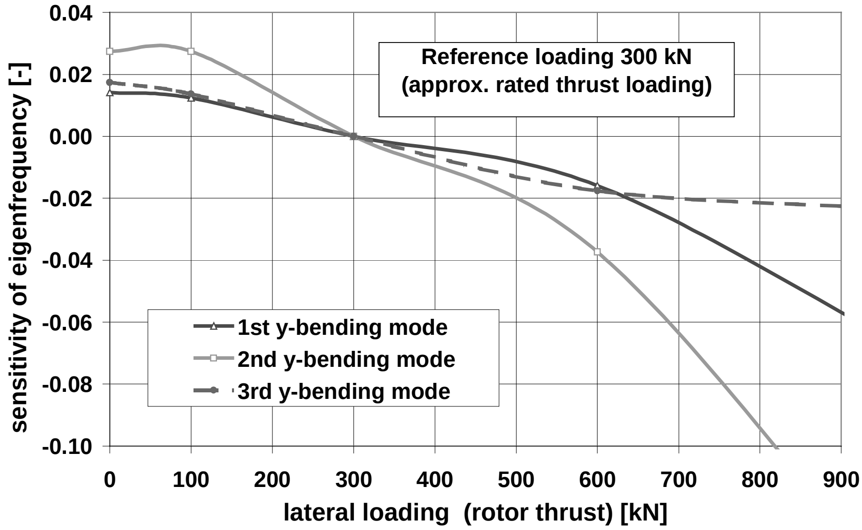


Figure 9.2-1: Sensitivity of the first bending modes to variations of the lateral pile loading by the rotor thrust (pre-stress effect)

Likewise a low sensitivity of the eigenfrequencies is found with respect to variations of the soil stiffness due to the inherent uncertainties in the estimated or measured properties as well as spreading within the wind farm area. Again the reason lies in the rather stiff foundation behaviour. As seen from figure 9.2-2 a significant decrease of the fundamental eigenfrequency (i.e. larger than 5 %) is only achieved if the stiffness of all soil springs is reduced by 60 % or more. Higher soil stiffness has an even smaller effect; 2 respectively 10 times higher stiffness corresponds with an increase of only 2.6 % respectively 10 %. In the latter case a 10 % distance to the excitation with the rotor frequency (1P) is still maintained.

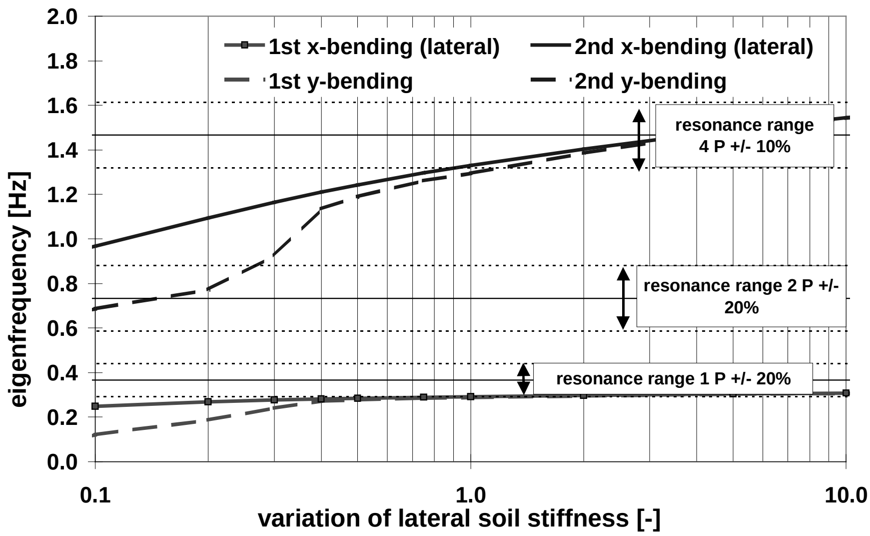


Figure 9.2-2: Sensitivity of the first two bending modes to variation of the soil stiffness (Solid horizontal lines: rotor excitation frequencies, dashed horizontal lines: boundaries of the exclusions ranges for the design values of eigenfrequencies)

The established insensitivity of the dynamics to the soil properties is essential for the validity of the design since any significant change would result in either increased rotor excitations or even more pronounced hydrodynamic fatigue. Moreover, the relatively stiff foundation offers benefits with respect to a moderate increase of the pile bending with depth below mudline (section 9.3.4, figure 9.3-3) and a lower sensitivity to hydrodynamic excitation than for a support structure with the same fundamental eigenfrequency but softer foundation [9.2-5].

9.3 Fatigue analysis of the support structure

9.3.1 Environmental and loading conditions

Wind conditions

The OWEC is considered as class S type [9.3-1], thus wind conditions are derived for the conditions of the actual site. Furthermore the guidelines for OWECS of Germanischer Lloyd (GL) are applied with the following modifications:
Turbulence intensity has been reduced from 14% to 12% in accordance with the low ambient turbulence level and the applied large spacing of 10 rotor diameters.
Wind loading is considered to be rotor loading only during the normal production mode.[1]

Hydrodynamic conditions

Hydrodynamic loading is described as unidirectional, stochastic wave loading according to the (modified) Pierson-Moskowitz spectrum. Although this spectrum is strictly valid only for fully developed sea states it is still commonly used in offshore technology.
For the particular site misalignment of wind and wave direction is small, so waves are propagating collinear with the rotor orientation. Moreover, in a separate investigation is has been found that the overall loading of the final monopile design is reduced if the wave direction is oblique to the rotor orientation. Note that this is not self-evident since the aerodynamic damping is active only in-line with the rotor orientation.
The met-ocean parameters are averaged over all wind and wave directions. This practical assumption reduces the computational effort by a factor of about 10 or even more. In order to get an indication about the significance of the effect two cases are compared; unidirectional loading with one fixed direction and unidirectional loading applied under eight directions with the probability of the associated wave direction sectors (section 9.3.6).
A constant mean sea level (MSL) of 21 m corresponding to a maximum water depth of 20 m LAT within the design range of the monopile design (i.e. LAT 12 - 20 m) is assumed.
Standard values of Cd = 0.7, Cm = 2.0 are assumed as hydrodynamic coefficients. So far marine growth has not been accounted for.

[1] For a more accurate analysis also start-up and shut-down procedures, both at cut-in and cut-out wind speed, as well as a stochastic wind loading on the parked wind turbine and its support structure should be taken into account.

Correlation of wind and wave parameters

For an OWEC suffering aerodynamic and hydrodynamic loads of similar magnitude the correlation of both loading types is crucial. Unfortunately, for most sites relevant for OWECS the knowledge of the correlation of wind and wave conditions is poor. On one hand a wave scatter diagram of significant wave height against zero-crossing period can often be found in the literature, which may be more or less suitable for the actual location. On the other hand a wind speed distribution may be available. However, suitable information about the correlation of wind and waves and directional effects is missing and cannot be obtained though simple analytical wave models, such as according to Pierson-Moskowitz [9.3-2] which are only valid for deep water locations, long fetch and long duration. Sophisticated numerical wave models have recently been developed but are expensive to use and might therefore only be available for large offshore wind energy projects.

In other cases relations between the mean wind speed and the corresponding average sea states may be available [9.3-3]. However such data refer often to entire regions rather than particular sites and information on the scattering and the probability of the met-ocean parameter is missing. So their usage for reliable OWEC design calculations is rather limited. Figure 9.3-1 shows the (average) significant wave height for the NL-1 site as a function of the mean hourly wind speed.[2] It can clearly been seen that the deep water Pierson-Moskowitz relation is too conservative. On the other hand the relation averaged linearly over all directions does not account for the distinct distribution of the wave energy on the different directions. Within this investigation these relations are only used for the calculation of extreme loads during the production states of the OWEC (section 9.4). Moreover, they illustrate in a compact manner the wind and wave climate at the considered site.

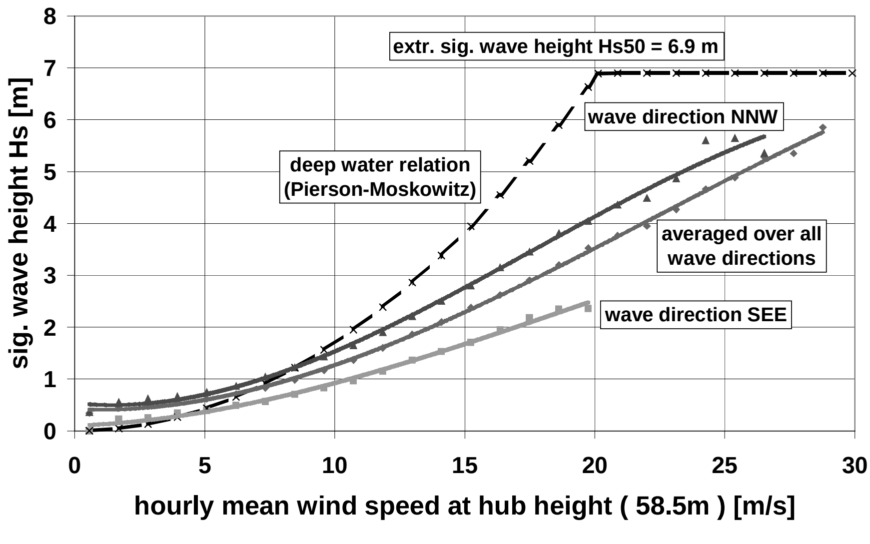


Figure 9.3-1: Relation between mean hourly wind speed at hub height and (average) significant wave height for NL-1 site

Within the Opti-OWECS project for the very first time in an (offshore) wind energy application, use has been made of a hindcasted database of (correctly correlated)

[2] In contrast to, for instance, voluntary fleet observation data the figure is derived from hindcasted data valid for the particular site.

met-ocean parameters. This is the state-of-the-art in advanced offshore technology [9.3-4]. The high-quality database NESS (North European Storm Study) includes all storms during a 30 years record (relevant for extreme event analysis) as well as 9 years of continuous 3-hour records which are useful for fatigue analysis purposes [9.3-5].

Obviously, it is not possible to consider the details of all 27007 recorded sea states[3] and one has to extract a limited number of 'typical' load cases so-called to be used as lumped sea states. One manner of lumping is to end up with lumped sea states having damage of about the same order of magnitude. Which sea states result in similar loads and can therefore be grouped together depends on the particular OWEC, its operational mode and its response behaviour. The presence of dynamic response e.g. to sea states with low wave periods close to the fundamental structural period and to the wind turbine excitations makes this task even more complex.

Against the background of ongoing research a practical approach for the fatigue analysis based upon a number of assumptions and simplifications has been followed:

- The database has been divided into two sets according to the normal operational modes of the OWEC, i.e. idling below cut-in or above cut-out, and power production. In the former case the mean hourly wind speed at hub height is either below 5 m/s or equal to or above 22.7 m/s.[4]
- Wind loading on the support structure and the non-productive wind turbine has been neglected with respect to loading on the operating rotor or wave loading on the structure, respectively.
- Significant wave heights and zero-crossing periods, respectively, have been binned in scatter diagrams with class widths of 0.5 metre respectively 1 second. This treatment resulted in 21 idle and 22 production sea states. (See all non-zero entries in the two scatter diagrams in tables 9.3-1 and 9.3-2.)
- The application of wind speed classes with a width of for instance 2 m/s would have increased the number of sea states to an impractical number above 100. Therefore the distribution of the mean hourly wind speed for each H_s-T_z bin has been analysed and only a limited spread has been observed. After comparison of different averaging methods the linear average of all wind speed values for a certain H_s-T_z bin has been associated with these wave parameters.
- In order to further reduce the number of load cases and to account for the rather low probability of occurrence of some sea states, similar sea states have been lumped according to a state-of-the-art method in offshore technology [9.3-6]. In fact, 6 idle and 8 production sea states remain which are marked as solid boxes in the scatter diagrams (tables 9.3-1 and 9.3-2). Finally, table 9.3-3 provides the load parameter and the probability of the lumped sea states.

[3] In this context a sea state describes the set of the met-ocean parameters within a 3 hour sample i.e. especially, significant wave height, zero-crossing wave period, wave direction, mean hourly wind speed and wind direction .

[4] Note that it is assumed that the turbine is stopped for the entire 3 hour sample if the extreme one minute wind speed (i.e. 1.1 times the mean hourly wind speed) of that sample is equal to or above 25 m/s.

Hs \ \ Tz	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	8.5	sum
6.75 m										0.0
6.25								**0.08**		0.1
5.75				**Idling, high: Vw >= Vcut_out**			**0.04**	**0.3**		0.3
5.25							**0.3**	**0.08**		0.4
4.75		**lumped sea state**					**0.7**			0.7
4.25							**0.7**			0.7
3.75						**0.6**	**0.04**			0.7
3.25						**0.2**				0.2
2.75		**idling, low: Vw < Vcut_in**								0.0
2.25					**3.4**	**0.4**				3.8
1.75				**19**	**58**	**0.7**				77.7
1.25	0.68		**1.0**	**65**	**12**	**0.1**	0.11			79.0
sum	0.7	0.0	1.0	84.2	73.4	2.0	1.9	0.5	0.0	164

Table 9.3-1: Wave scatter diagram in parts per thousand for sea states with wind speeds outside the production range (stand-still or idling)
(Lumped sea states are marked by solid boxes)

Hs \ \ Tz	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	8.5	sum
6.75										0.0
6.25										0.0
5.75		**production sea states**					**0.5**			0.5
5.25		**Vcut_in <= Vw < Vcut_out**					**2.7**			2.7
4.75						**3.4**	**4.1**			7.5
4.25		**lumped sea state**				**18**	**0.3**			18
3.75						**35**				35
3.25					**26**	**41**				67
2.75				0.1	**114**	**5**				119
2.25				**6**	**216**	**0.3**				222
1.75				**222**	**89**	**0.3**				312
1.25	0.1		0.1	**50**	**2**					53
sum	0.1	0.0	0.1	278.5	447.3	102.7	7.6	0.0	0.0	836

Table 9.3-2: Wave scatter diagram in parts per thousand for sea states with wind speeds inside the power production range
(Lumped sea states are marked by solid boxes)

no.	sea state	Vw,hub	Hs	Tz	probability
[-]	-	[m/s]	[m]	[s]	[ppt]
1	Idle,low 1	< 5	0.69	3.50	85
2	Idle,low 2	< 5	0.75	4.51	71
3	Idle,low 3	< 5	1.25	4.59	3.8
4	prod. 8 m/s	8.1	1.12	4.27	587
5	prod. 10 m/s	12.1	1.75	4.53	119
6	prod. 15 m/s	14.9	2.25	4.50	26
7	prod. 14 m/s	14.1	2.25	5.50	41
8	prod. 17 m/s	16.5	2.75	5.50	35
9	prod. 19 m/s	18.4	3.25	5.51	18
10	prod. 20 m/s	19.9	3.75	6.01	7.5
11	prod. 21 m/s	20.9	4.35	6.50	3.2
12	Idle, high 1	> 25	3.66	5.54	0.88
13	Idle, high 2	>25	4.53	6.50	1.40
14	Idle, high 3	>25	5.59	7.07	0.84
sum					998.8

Table 9.3-3: Environmental conditions for fatigue load cases
Probability in parts per thousand (ppt).

9.3.2 Load cases considered and fatigue analyses

As it is common in design standards load cases are defined by combination of operating conditions and external conditions. According to GL only normal conditions have to be considered for both categories. This recommendation has been extended; beside the normal operational conditions, i.e. stand-by, power production (and start-up / shut-down procedures), also the state following a fault has been considered. The justification for this modification is twofold.
Firstly, due to limited access to the OWEC, the availability will be significantly lower than for state-of-the-art onshore wind energy converters. It is very likely that within an offshore wind farm some OWEC units with poor performance will show only availability between 70 and 80 % or even lower.
Secondly, depending on the site and OWEC design the hydrodynamic loading of the support structure during non-availability periods with wind speeds in the production range and thus absence of aerodynamic damping can be significant and possibly even worse than the loading during the production state.

	(Normal) External conditions				
	I: waves	**P: wind & waves**	**P: waves**	**P: wind**	**P: waves**
Mean wind speed *V*	outside production range (I)	inside production range (P)			
Wind field	none	Turbulence, shear, etc.	none	turbulence, shear, etc	uniform
Mechanical wind turbine loads	none	yes	none	yes	none
Hydrodyn. loads	PM sea state	PM sea state	PM sea state	none	PM sea state
Normal operating conditions production (P)	_ _ _ _	**PP: wind & waves**	_ _ _ _	**PP: wind**	**PP: waves**
Normal operating conditions Idling (I)	**II: waves**	_ _ _ _	**IP: waves**	_ _ _ _	_ _ _ _

Table 9.3-4: Combination of operating conditions and external conditions for the considered five fatigue load cases

Table 9.3-4 provides the combinations of operating and external conditions considered which result in five types of load cases. The denotation of the load cases comprises three parts, the operating condition (I = idling i.e. stand-by or stopped, P = production), the range of the mean wind speed at hub height (I = outside, P = inside production range) and the type of loading (wind, waves or both).
The load case ‘IP: waves’ corresponds to the mentioned condition after the occurrence of a fault and with wind speeds in the production range. For the time being start-up and shut-down procedures have not been considered.

Next, by combination of certain load cases five different types of loading or fatigue analyses have been defined (table 9.3-5). Obviously the first one concerning combined wind and wave loading during full availability is the standard analysis, which is always required. The relevance of type 2 and 3 will depend on the significance of dynamic wave response of the support structure. Finally, the last two analyses are fictitious since never pure wind in a calm sea nor pure wave loading in a steady wind will occur. Nonetheless, these two investigations are important for an understanding of the significance of the different loadings.

Type	Denotation of analysis	Load cases	Comment
1	wind & waves (full availability)	II: waves, PP: wind & waves	most common (standard) analysis
2	waves & no aerodyn. damping (zero availability)	II: waves, IP: waves	relevant if significant **dynamic** wave response
3	wind & waves (reduced availability)	II: waves, IP: waves, PP: wind & waves	combination of type 1 and 2 according to time fraction of availability and non-availability, relevant if severity of type 2 is higher than of type 1
4	pure wind	PP: wind	used just for comparison since PP: wind is a fictitious load cases
5	waves & aerodyn. damping	II: waves, PP: waves	used just for comparison since PP: waves is a fictitious load cases, Quantifies by comparison to type 2 the effect of aerodynamic damping

Table 9.3-5: Relation between different fatigue analyses and load cases

9.3.3 Structural modelling and analysis approach

Dynamic simulations are carried out with the DUWECS code and its related tools [9.3-7].
The turbulent wind field is described by longitudinal turbulence and a varying yaw angle of +/- 30 degrees. The aero-elastic model comprises first flap and lead-lag blade mode and the fore-aft mode of the tower in combination with blade-element momentum theory. A reduced mass eccentricity of the rotor (e_M = 0.001 R) is considered.[5]
At full load conditions power regulation is active by means of a single loop PI pitch controller including proper actuator characteristics.
The tower is loaded by the 6 dof tower top loads although only horizontal forces and moments have an effect on the dynamics described by 14 bending modes with eigenfrequencies up to about 20 Hz. Different damping effects such as structural damping of the grouted joint and the steel structure, hydrodynamic and soil damping are taken into account by a constant modal damping ratio of 1.5 %.

[5] Note, it is state-of-the-art of several blade manufacturers that mass imbalance is between 5 to 10 times smaller than mentioned in the GL guidelines for well balanced rotors.

In the following a model with only 50 % of the estimated foundation stiffness and consequently with a 3.5 % lower fundamental frequency of 0.28 Hz is taken as reference case. In this manner the lower bound of an assumed tolerance range for the foundation stiffness has been considered since the hydrodynamic loading increases for a softer foundation.

Hydrodynamic loading is generated by application of the linear wave theory with Wheeler modification in combination with the Morison equation. For short wave lengths and for locations below the transition of the support structure's diameter the latter approach is close too or just beyond the limit of validation since then the wave length become smaller than five times the diameter. However, partner KOGL concluded an investigation of this issue with the conclusion that diffraction effects are not really significant.
For all sea states three representations of 20 minutes each have been simulated.
Rainflow counting and Palmgren-Miner rule are used for the fatigue analysis with parameters established in section 6.6.2.

9.3.4 Load characteristics

Effect of wave excitation on the tower top motion and on the rotor

The wave excitation of the tower top and of the flapwise blade bending is investigated by analysis of simulated time series. Table 9.3-6 compares the standard deviation of tower top motion (displacement and acceleration) in the load direction and the standard deviation of the flapwise blade root bending moment for four different types of loading at near-rated conditions (mean wind speed 14.9 m/s, H_s = 2.25 m, T_z = 4.5 s).

Load case type (see table 9.3-4)	**Comment**	**std (u_{ttop}) [m]**	**std ($\ddot{u}_{ttop}$) [m/s^2]**	**std (M_{flap}) [MNm]**
PP: wind & waves	combined loading	0.076	0.087	1.122
IP: waves	waves & **no aerodyn. damping**	0.075	0.127	(not calculated)
PP: wind	pure wind	0.058	0.042	1.121
PP: waves	waves & **aerodyn. damping**	0.043	0.068	0.044

Table 9.3-6: Comparison of standard deviation of tower top and blade excitation for different types of loading (mean wind speed 14.9 m/s)

Although the increase in the tower top vibration amplitude between pure aerodynamic loading and combined wind and wave loading is about 40% no effect is seen in the flapwise blade response. Very similar results are observed for other sea states with sometimes even larger wave excitation of the tower top.

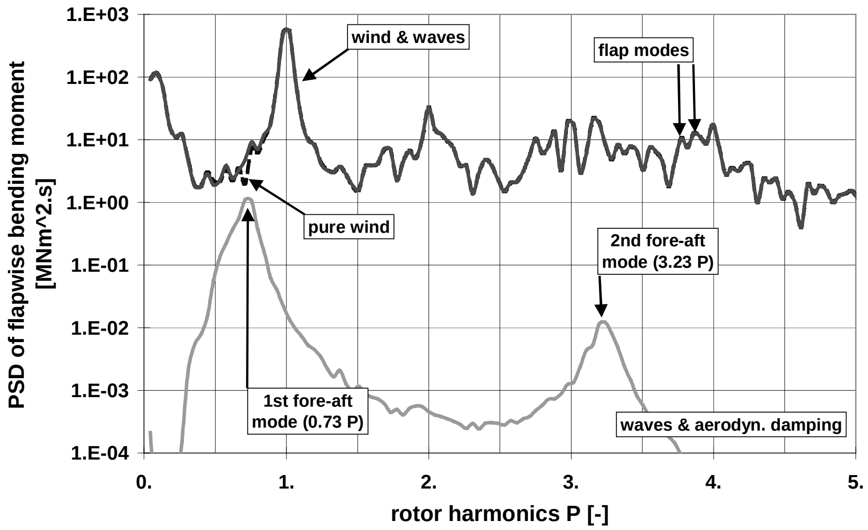


Figure 9.3-2: Power spectrum of flapwise blade root bending moment for different loading at wind speed 14.9 m/s

For a significant blade excitation considerable tower top acceleration and excitation energy in a range close to the flapwise natural frequencies of the rotor would be required. Referring to the values of the acceleration in table 9.3-6 and the response spectra in figure 9.3-2 it is clearly seen that both effects are not pronounced. Aerodynamic excitation due to turbulence and deterministic effects affect a relatively wide frequency range covering all lower support structure and blade bending natural frequencies. In contrast, wave effects are found only in a low frequency region including the fundamental support structure mode.

The low blade excitation by the hydrodynamic loads can be explained qualitatively with a single degree of freedom model of the flapwise blade dynamics, which is excited by inertia forces due to the tower top accelerations.[6] The dynamic amplification **(9.3-1)** is written as function of the dimensionless excitation frequency f_{tower}/f_{flap} i.e. ratio between support structure and flap eigenfrequency [9.3-8].

$$DAF_{flap}\left(f_{tower}/f_{flap}\right) = \frac{\left(f_{tower}/f_{flap}\right)^2}{\sqrt{\left(1-\left(f_{tower}/f_{flap}\right)^2\right)^2 + 4\,\xi_{flap}^2\left(f_{tower}/f_{flap}\right)^2}} \qquad \textbf{(9.3-1)}$$

where:

	DAF	Dynamic Amplification Factor of flap response due to tower top motion
	f_{tower}/f_{flap}	ratio of support structure and flap eigenfrequency
	ξ_{flap}	damping ratio related to flap eigenfrequency

[6] The ratio between blade mass and equivalent tower top mass is so small that for this purpose the interaction between support structure with nacelle and rotor is described as a forced vibration of the rotor due to kinematic excitation at the hub.

Considering the low frequency ratio of f_{tower}/f_{flap} = 0.2 and the high aerodynamic flapwise damping of more than 20% the DAF for excitation by the first fore-aft mode is only 0.035. Although a DAF of 1.1 is related to the second support structure eigenfrequency (f_{tower}/f_{flap} = 0.85) the excitation energy is much lower for this mode than for the fundamental mode. So both modes do not result in a significant blade response either due to a low DAF or low excitation energy.
Consequently, and in line with earlier investigations [9.3-9], [9.3-10], in the following emphasis is given to the dynamic behaviour of the support structure described by an integrated model of the OWEC.

Maximum bending moment along the pile

The stiffness of the soil as well as of the pile have also an effect on the location of the pile cross section with the maximum bending load. For rated load conditions the maximum bending moment occurs between 1.1 and 1.7 times the diameter below the mudline depending on the load characteristics (figure 9.3-3). Hydrodynamic loads generate a lower ratio between overturning moment and base shear (i.e. the effective lever arm of the horizontal force) than aerodynamic loads at the tower top. Therefore the relative increase in the pile bending moment with depth is larger for hydrodynamic loads than for tower top loads. Moreover the maximum bending due to hydrodynamic effects occurs in a larger depth.

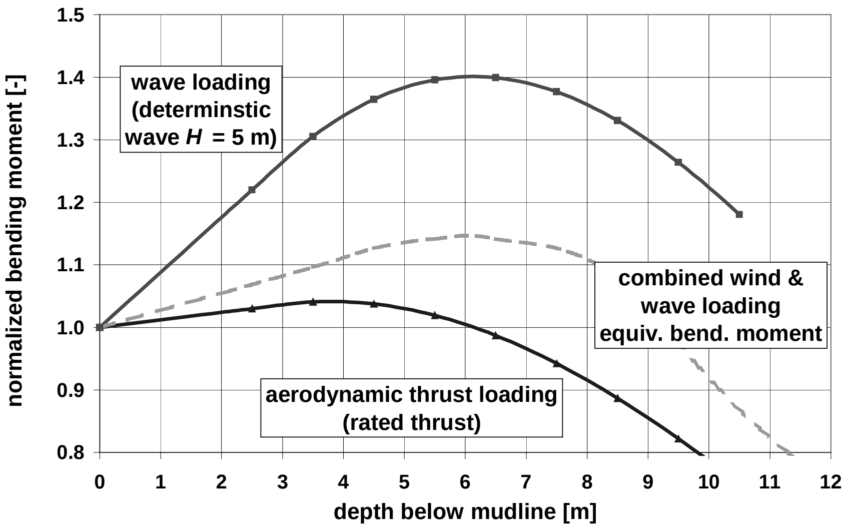


Figure 9.3-3: Distribution of bending moment along monopile for different type of loading
(Bending moment normalized by value at mudline.)

If wind and wave loads on the pile are of similar order of magnitude the different characteristics are averaged. The highest equivalent bending moment for combined wind and wave loading occurs with a relatively flat maximum at about 6 m depth and is only 15 % higher than the bending moment at the mudline.

Dynamic amplification of wave loading

Monopile support structures are prone to dynamic wave excitation due to their low stiffness and the absence of cancellation effects as well-known from multi-leg platforms. In analysing the dynamic amplification of the wave loading, which is commonly expressed as Dynamic Amplification Factor (DAF), one has to distinguish on one hand the transfer function between e.g. the hydrodynamic overturning moment (OTM) and the bending moment at mudline derived for elementary waves. On the other hand a DAF can also be related to a loading variable of an entire sea state. Here the latter way is followed as the DAF is defined as ratio between the standard deviations of the bending moment at mudline and the OTM from the simulation of an entire sea state.

The DAF related to the wave loading depends mainly on the fundamental eigenfrequency, the stiffness distribution [9.3-11] and the system damping which here accounts for 1.5 % due to structural effect plus 4.2 to 5.8% aerodynamic damping which is active only in the direction of the rotor orientation and during power production (section 4.6.1).

Figure 9.3-4 illustrates the paramount importance of the aerodynamic damping on the response. During idling (loading type II: waves and IP: waves) the DAF rises up to 4.5 for sea states with high peak frequencies but low wave height (i.e. 1 m or lower). For the sea states most relevant for the fatigue damage (section 9.3.5) the DAF without aerodynamic damping ranges 2.5 to 3.4. Under these conditions with relatively high probability the peak frequencies[7] are lower (0.13 to 0.16 Hz) and the significant wave heights of 3.25 to 1. m are more moderate. In contrast, with aerodynamic damping (loading type PP: waves) the DAF is limited to 1.7 to 2.0 in that region.

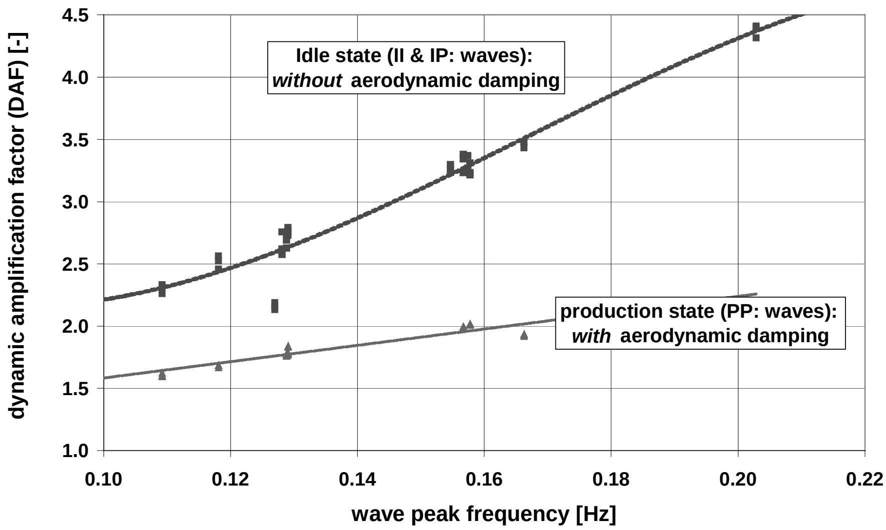


Figure 9.3-4: Effect of aerodynamic damping on the Dynamic Amplification Factor (DAF) of hydrodynamic sea state loading
(DAF related to standard deviation of overturning moment)

[7] The peak frequency is associated with the maximum of the wave energy spectrum. For a Pierson-Moskowitz spectrum the peak frequency is 0.71 times lower than the zero crossing frequency.

9.3.5 Results of the fatigue analysis of the final solution

The achievement of sufficient fatigue life has been identified as one major design driver for the soft-soft monopile support structure. In this section it is demonstrated that the design is indeed fit-for-purpose and that this requirement is met due to careful design work and dynamic analysis of a model of the entire OWEC.
In order to get an understanding of the combined wind and wave loading as well as of the individual load components different fatigue analyses with load case combinations defined by table 9.3-5 are carried out for various cross sections along the support structure.

Load magnitude and section utilisation

First of all, the magnitude of the loading and the fatigue utilisation of the sections are analysed in a global manner. Since the fatigue damage is not suitable for a comparison of the severity of different load spectra, the equivalent (constant range) bending moment for $2{\cdot}10^6$ cycles and 20 years is calculated and illustrated together with the maximum fatigue resistance in figure 9.3-5. In addition table 9.3-7 provides the numbers for four cross sections.

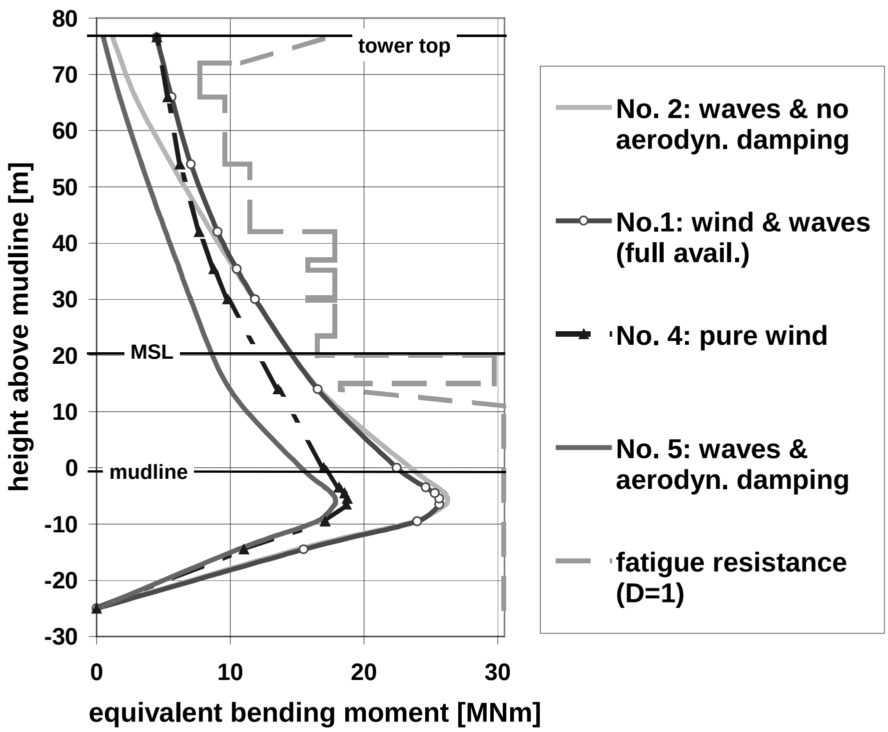


Figure 9.3-5: Comparison of the different types of fatigue loading and fatigue resistance along the support structure
(Equivalent bending moment for 20 years and $2{\cdot}10^6$ cycles.)

Location	Below mudline	Pile transition	Tower flange	Near tow.top
height above mudline [m]	-5.5	14	30	66
No. 1 - wind & waves (full avail.)	26.0	16.8	12.0	5.6
No. 2 - waves & no aerodyn. damp.	26.4	16.8	11.8	2.9
No. 4 - pure wind	18.7	13.7	10.0	5.3
No. 5 - waves & aerodyn. damping	18.0	10.0	7.1	1.8

Table 9.3-7: Equivalent bending moment in MNm (20 years, $2 \cdot 10^6$ cycles) for different types of loading at four cross sections

The load distributions are all smooth roof-shaped functions with their maximum some 6 m below the mudline. In contrast, discontinuities due to changes in wall thickness, safety factors for material and different values for the reference fatigue strength characterise the fatigue resistance. Especially the sections just beneath respectively above the grouted joint show high utilisations. In the grout of the joint itself only relatively small stresses, i.e. equivalent bending stresses (20 years, $2 \cdot 10^6$ cycles) of 3 to 5 MPa, are predicted by a simple beam model which however considers the actual stiffness of the grout and the surrounding steel pipes.
For this OWEC and this particular site the ratio between wave loading with consideration of aerodynamic damping (5) and wind loading (4) increases from about one-tenth at the tower top to one at the critical pile section. Therefore no real contribution of the waves to the combined wind and wave loading (1) is seen at the top whilst a significant increase of about 40% of the combined loading with respect to the individual load components (4), (5) occurs at the pile. The effect of the aerodynamic damping which yields the difference between the two types of wave loading (5) and (2) illustrates once more the magnitude of the dynamic wave response. Up to about 20 m above MSL the wave loading during idling or stand still (2) shows almost equal magnitude with the combined wind **and** wave loading.

Fatigue load spectra

In a next step the cumulative Rainflow cycles counting for a section with similar wind and wave loading, i.e. the critical pile section 5.5 m below mudline respectively a location with dominating wind loading i.e. 13.6 m below the hub (66 m above mudline), are compared in figures 9.3-6 and 9.3-7, respectively.
Although in the former case the four considered spectra are similar in terms of total number of cycles and stress range in the low cycles region their severity is different (second and fourth column of table 9.3-7). Their different shape in the high cycle range can explain this. The magnitude of stress ranges above 10^7 cycles seems to be decisive for the equivalent loading (table 9.3-7) and the estimated lifetime (table 9.3-8).

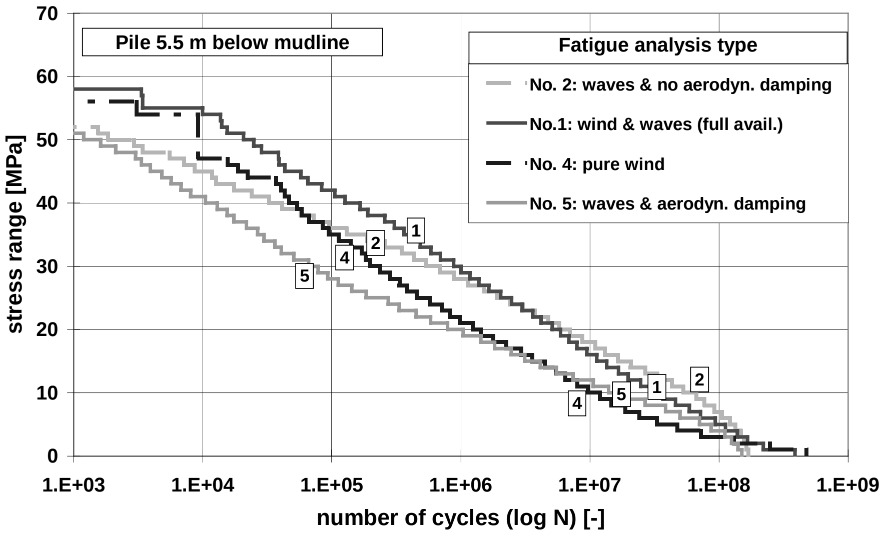


Figure 9.3-6: Cumulative Rainflow counting of bending stresses at critical pile section with wind and wave loading of similar magnitude

(Order of increasing load severity: No. 4, 5, 1, 2)

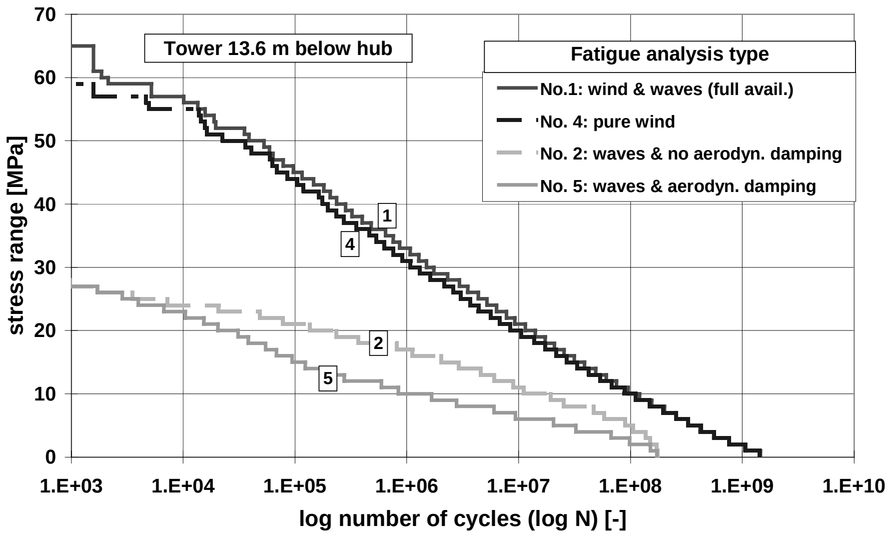


Figure 9.3-7: Cumulative Rainflow counting of bending stresses at location dominated by wind loading near tower top

(Order of increasing load severity: No. 5, 2, 4, and 1)

Estimated fatigue life

Table 9.3-8 shows the estimated lifetime based upon Palmgren-Miner damage accumulation for four cross sections. The minimum estimated life of 27.8 years for combined wind & wave loading (1) is found at the pile transition and is just above the design life of 20 years. For all other considered sections lower fatigue damage is found. Considering also the different mean wave directions even longer lives will be achieved (section 9.3.6).

Location	Below mudline	Pile transition	Tower flange	Near tow.top
height above mudline [m]	-5.5	14	30	66
No. 1 - wind & waves (full avail.)	38.8	**27.8**	63	87
No. 2 - waves & no aerodyn. damp.	38.3	29.5	81	2500
No. 4 - pure wind	142	62	127	113
No. 5 - waves & aerodyn. damping	218	303	800	20000

Table 9.3-8: Estimated lifetime in years for different types of unidirectional loading applied always for the same direction at four cross sections

Distribution of damage on load cases

Next the severity of the different load cases and their contribution to the total damage is investigated for the critical pile cross section.

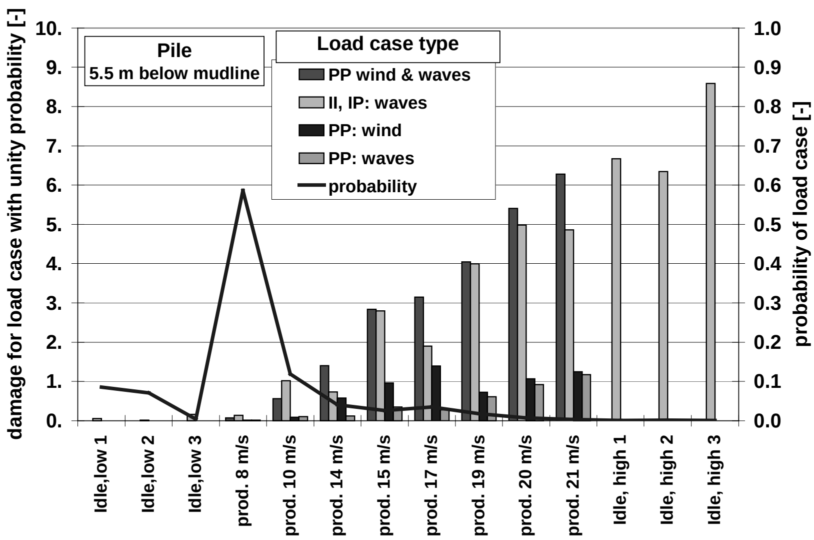


Figure 9.3-8: Distribution of damage at critical pile section on load cases for unit probability (columns) and probability of load cases (solid line)

Figure 9.3-8 shows the specific damage per load cases (columns), where each load case has a probability of occurrence of one, i.e. duration of 20 years. The actual probability of each load case (solid line) is also shown.

The following observations can be made. Below a mean wind speed at hub height of 10 m/s the specific loading is considerably lower than above it. The damage of the combined loading as well as the wind loading generally increases with wind speed.

The pitch controller is only activated for post rated wind speeds above 13.7 m/s. Therefore the larger damage for the sea states at 15 and 17 m/s in comparison to higher wind speeds might be a result of the sub-optimal switching behaviour of the controller.

Although the significant wave height does not decrease with the plotted order of the sea states the damage due to hydrodynamic loading for 14 and 17 m/s is lower than

for 10 and 15 m/s, respectively. The obvious reason is the higher dynamic amplification of the latter two sea states in comparison to the two former sea states (table 9.3-3).
Again the effect of the aerodynamic damping on the specific damage is pronounced as it can be expected from the magnitude of dynamic amplification plotted in figure 9.3-4. The ratio of damage between waves without and with aerodynamic damping, respectively, reaches a value of 13 (!) at low wind speeds of 8 m/s and decreases to a still considerable magnitude of 4 at 21 m/s.
In terms of damage no simple relationship exists between fatigue due to pure wind and pure wave loading with aerodynamic damping, respectively, on one hand and the fatigue due to the simultaneous action of wind and waves on the other hand. The damage due to the combined loading is always several times larger than the sum of the damages due to wind and due to waves alone. For instance, for the sea state with a mean wind speed of 17 m/s the damage due to wind alone seems to dominate the wave effects because the former is five times larger; still the damage of the combined loading is 125 % higher than for pure wind loading.

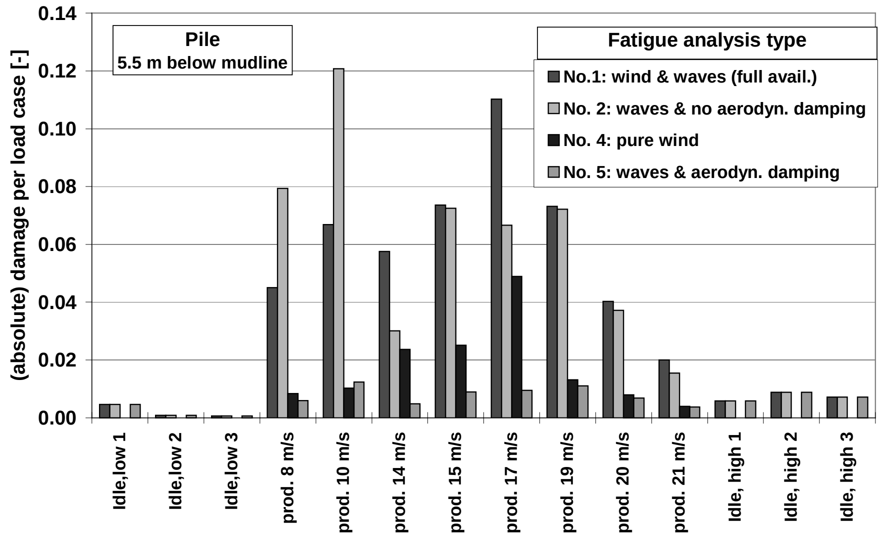


Figure 9.3-9: Distribution of damage at critical pile section on load cases (actual probability of load cases considered)

Taking the probability of the different load cases (plotted as a solid line in figure 9.3-8) into account the contribution of the load cases to the total damage is shown by figure 9.3-9.
Damage below cut-in and above cut-out condition accounts only for about 5% of the total. Also, at high production wind speeds (20 m/s and higher) relatively small damage occurs. In contrast, half of the total damage is related to the three load cases of 15, 17 and 19 m/s, which only have a probability of 8%. Another third of the total damage is found for the sea states between cut-in and rated wind speed.
As pointed out in section 9.3-1 lumping of sea states in the scatter diagram has been done in order to reduce the number of load cases and achieving similar magnitudes of damage for the different lumped sea states at the same time. For the production sea states and the conditions beyond cut-out the results seem satisfactory. Still one may wonder whether especially the sea state at 8 m/s with a probability of occurrence of 59% (!) and a wide range of spectral peak frequencies from 0.14 to

0.23 Hz (i.e. zero crossing periods 3 to 5 s) close to the fundamental structural period is an appropriate model of the actual loading. On the other hand a further lumping of the second and third sea states below the cut-in wind speed would be suitable.

9.3.6 Parameter study

The results from the previous section are extended by a parameter study on three effects: wave directionality, diameter of the pile near the water line and wind turbine availability.

Wave directionality

At the NL-1 site a quite pronounced dependency of the wave and wind loading on the mean direction is observed (figure 9.3-1). Waves with the mean direction NNW coming from the open North Sea are on average about 70% higher than those under directions from the shore e.g. SEE. Moreover, for the less severe directions the maximum hindcasted wind speed is lower. E.g. no hourly wind speed higher than 20 m/s is recorded for some directions during the 9 years covered by the database.
In the previous section only one loading direction is taken into account and the wind and wave climate is averaged over all directions. A proper consideration of the different loading for different directions would require several times higher computational efforts. Therefore the loading has been applied unidirectionally, which is regarded as conservative.
Here a simplified approach is followed to still enable an estimate of the effect of the distribution of the loading over different directions. The (averaged) loading has been distributed with the frequency of eight wave sectors (figure 6.2-1) on the circumference of the structure.[8] A priori it cannot be judged whether this treatment is conservative, probably it is not, therefore it is used only in this more qualitative parameter study rather than in the previous sub-section.
In fact, for all considered loading types the fatigue loading is reduced by about 20% and the estimated life is increased by 110 to 140% (table 9.3-9). Thus the minimum fatigue life occurring at the top of the pile transition is estimated to be between 27.8 and 60 years; most likely it is closer to the upper bound of this range.

[8] Although some differences exist between the probability of wind and wave directions, consideration of the wind rose obtains approximately the same distribution of the fatigue loading.

Loading	Equivalent bending moment [MNm]		Estimated fatigue life [years]	
	unidirectional loading	actual distribution of directions	unidirectional loading	actual distribution of directions
No.1 - wind & waves (full avail.)	16.8	13.6	27.8	61
No. 2 - waves & *no* aerodyn. damping	16.8	13.3	29.6	70
No. 4 pure wind	13.7	11.1	61.7	131
No.5 - waves & aerodyn. damping	10	7.9	303	714

Table 9.3-9: Effect of directional loading on equivalent bending moment ($2\cdot10^6$ cycles, 20 years) and estimated life at cross section with largest fatigue damage (i.e. pile transition)

Diameter of the pile near the water line

The reduced diameter of the pile near the water surface is a particular feature of the design solution which is also found at other monopile structures in the offshore industry in order to effectively reduce the wave loading [9.3-12], [9.3-13] and [9.3-14]. In order to compensate (partially) for the reduced stiffness the wall thickness at the smaller diameter has been increased from 75 to 100 mm. Still this section shows quite a high fatigue utilisation, i.e. 91% in terms of stresses.
Therefore the effect of the pile diameter near the water surface has been investigated. Simulations as described in the previous sub-section have been carried out with an identical structural model (i.e. same eigenmodes), however for a constant hydrodynamic diameter of 3.5 m along the entire pile. Most sea states, certainly the frequent ones, are dominated by hydrodynamic inertia loads which vary with the square of the member diameter and which are significant only relatively close to the water line. Therefore it is not surprising that for waves without aerodynamic damping (loading type No. 2) an increase of the diameter by 25% (increase in gross section area by 56%) results in 48% higher fatigue loads below the mudline. The wind loads are not affected by the pile diameter, so the combined wind and wave loading (No. 1) is only 25 % higher for the cylindrical pile. Consequently, the fatigue life at several cross sections drops below the design value and the importance of the tapered pile design is clearly demonstrated.

Wind turbine availability

In section 9.3.5 (figures 9.3-5 to 9.3-7 and tables 9.3-7 to 9.3-8) no results are given for fatigue loading type No. 3 wind and wave for reduced availability since within the range of accuracy the loading No. 2 waves and no aerodynamic damping (or zero availability) is not significantly higher than loading No. 1 wind and waves (or full availability). However, consideration of the availability would indeed be relevant in case of any further increase in wave loading, e.g. due to a more severe wave climate, an even softer structure or a larger diameter of the pile near the water surface.
The results of the parameter study on the pile diameter are used to explain this effect. Under such conditions the dynamic wave response during non-production

(either due to stand-by or after the occurrence of a fault) and without the presence of the significant aerodynamic damping becomes larger than the combined wind and wave loading during normal production.[9] So the worst case for the support structure is given for the OWEC with the lowest availability within the farm. Based upon simulations of the O&M behaviour of the wind farm (chapter 8) a value of about 80% is estimated for the design solution.

In figure 9.3-10 the fatigue life of two cross sections (tower flange and subsoil pile) is plotted against the (minimum) availability for the tapered respectively the cylindrical pile. For the design solution (tapered pile) non-availability gives a reduction of the loads and an increase in life. In contrast, the life decreases for the cylindrical pile with decreasing availability. Beneath the mudline the estimated life is smaller than the design value anyway. However at the tower flange where wave effects are present only due to dynamic response the critical availability is about 64 %.

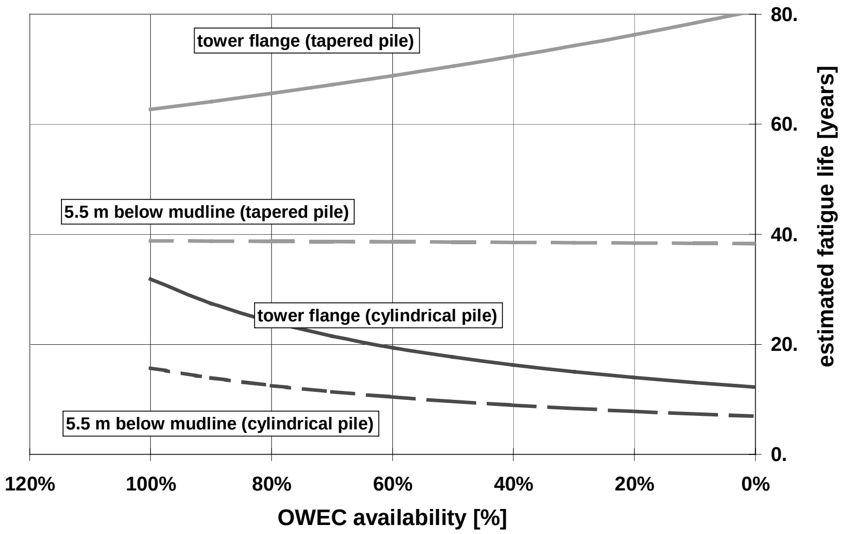


Figure 9.3-10: Effect of OWEC availability on fatigue life of the tapered respectively cylindrical monopile

9.4 Extreme Combined Wind and Wave Loading

Some consideration is given to extreme loads in order to demonstrate that the support structure of the design solution is indeed governed by stiffness and fatigue loading. Extreme loads during power production (load case E1.1) calculated by a dynamic analysis are compared with extreme quasi-static loads during stand-by at 50 years condition (load cases E2.1 and E2.2).

For the latter case also the influence of the assumed OWECS type class defined by the GL standard is compared.

[9] Same probability of the considered load cases is assumed during avialability as well as non-availability. Due to the dependency of maintenance on the weather conditions the availability during severe environmental conditions and during the winter season will be lower, however.

9.4.1 Extreme loading during power production (Load cases E1.1)

The load case group E1.x of the GL standard deals with the extreme load during the basic state power production together with extreme external conditions for the wind speed between cut-in and cut-out which produces the highest load on the structure. The sea state is to be assumed according to the mean wind speed.
Here only the load case E1.1 ‘Extreme operating gust and reduced wave loading’ is considered. Since wind loading is dominant other load cases of combined aero- and hydrodynamic loading as for instance E1.5 ‘Extreme wave and reduced gust’ are not further investigated. Figure 9.4-1 gives the contribution of the wind and wave on the response of the overturning moment as function of the mean wind speed.
The response to a so-called ‘(1 - cos) gust’ with an amplitude of 13 m/s and a maximum acceleration of 5 m/s^2 is simulated dynamically for several wind speeds within the production range. Controller behaviour and the dynamic response of the OWEC turn out to be essential. The pitch controller of the WTS 80 is fed by the deviation of the rotor speed from the stationary value and is active only at full load conditions (wind speed above mean wind speed).
The highest response due to aerodynamic loads (solid line with markers) is found at partial load since under such conditions there is considerable delay in the controller reaction and the tower motion undergoes a considerable overshoot in the wind direction. At high wind speeds the stationary loads on the structure (dashed line with markers) are reduced anyway and the controller reacts without such long delay. Moreover, smaller pitch variations and lower pitch rates are required to counter the gust.
For the relation between the significant wave height H_s and the mean wind speed the most severe wave direction i.e. NNW (figure 9.3-1) is assumed. Steady state response on elementary wave trains with a height of 1.32 times H_s is considered since a quasi-static or transient loading with only one wave cycle is probably not safe. Ranges for the associated wave period T_{ass} have been established in accordance to HMSO guidelines [9.4-1] and within each range the period closest to the fundamental structural period is assumed. Therefore at low wind speeds up to about 8 m/s resonance occurs and a considerable dynamic amplification with respect to the quasi-static loading is observed (difference been solid and dashed line). The wave response at 8 m/s is of the same order as for wind speeds above 20 m/s.
Considering the combined wind and wave loading it is amazing that the most severe loading occurs at partial load conditions where an approximately constant but high level of overturning moment is given. Of course, such characteristics depend strongly on the power regulation scheme of the wind turbine (stall or pitch control), the controller behaviour and the ratio between dynamic wind and wave loading.

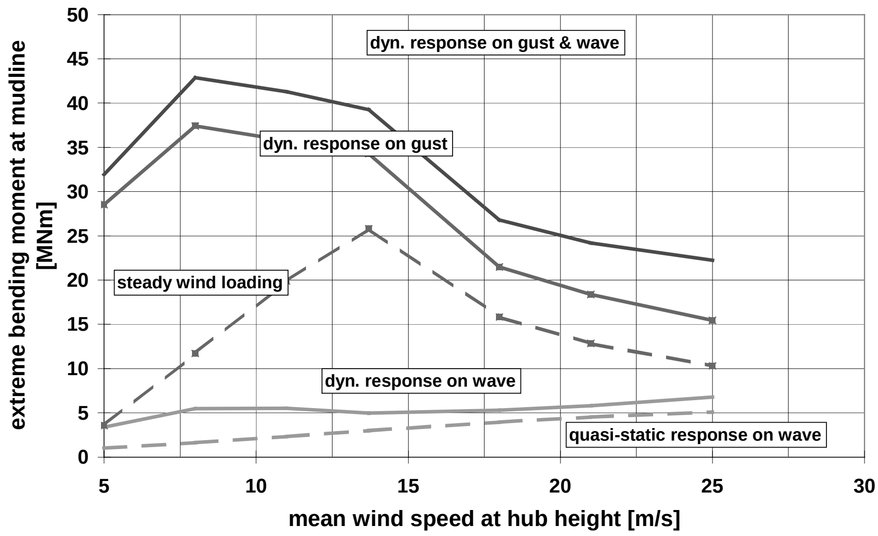


Figure 9.4-1: Maximum response of the overturning moment (characteristic load) on load case E1.1 'Extreme operating gust and reduced wave loading ' against mean wind speed

In the analysis of load case E1.1 in section 6.6.1 for convenience a constant relation between mean wind speed and reduced wave height is assumed by considering the reduced height of the 50 years extreme wave also as operational wave. This is conservative even if the reduced 50 years wave is calculated quasi-statically. Further, the treatment is justified since extreme loads are not governing and the hydrodynamic loading at power production turns out to be only a small fraction of the overall loading. In this particular case the simplified assumption on the operational wave results in less than 10 % higher overall loading at the mudline.

9.4.2 Extreme loading during stand still (Load cases E2.1 and E2.2)

The annual mean wind speed at the NL-1 site is above 8.5 m/s at a hub height of 58.6 m above MSL. Therefore type class I with an extreme 10 min mean wind speed of 50 m/s at hub height has to be considered unless type class S is applied. For the latter case a site specific extreme mean wind speed of 36.5 m/s has been derived from a 25 years long hindcasting data set out of the NESS database.
A site-specific S class certification might be worthwhile for such a large-scale offshore wind farm with 100 OWEC units. In this section the consequences on the extreme loads at 50 years conditions are investigated.
The overturning moment at the mudline due to the combined wind and wave loading are calculated for the two GL load cases E2.1 (50 years 5 s gust and reduced wave 1.32 times H_{S50}) and E2.2 (50 years extreme wave 1.86 times H_{S50} and reduced 1 min gust). Other assumptions are given by section 6.2.1. Furthermore gust response factors and tower drag coefficients according to the German DIBt standard [9.4-2] respectively DIN 4133 [9.4-3] are applied.

Figure 9.4-2 compares the design overturning moment for the different extreme load cases. As mentioned earlier the extreme operating condition is most severe. Although both 50 years conditions show nearly reversed contribution of aero- and hydrodynamic loads their overall loading at the mudline is similar.
Further a significant difference between class S and class I condition is observed. The more accurate description of the environment by the class S provides 35 % and 28 % lower loading for load case E2.1 and E2.2, respectively, than the more general class I.
Consequently a considerable optimisation potential by class S certification is seen in case 50 years conditions are governing.

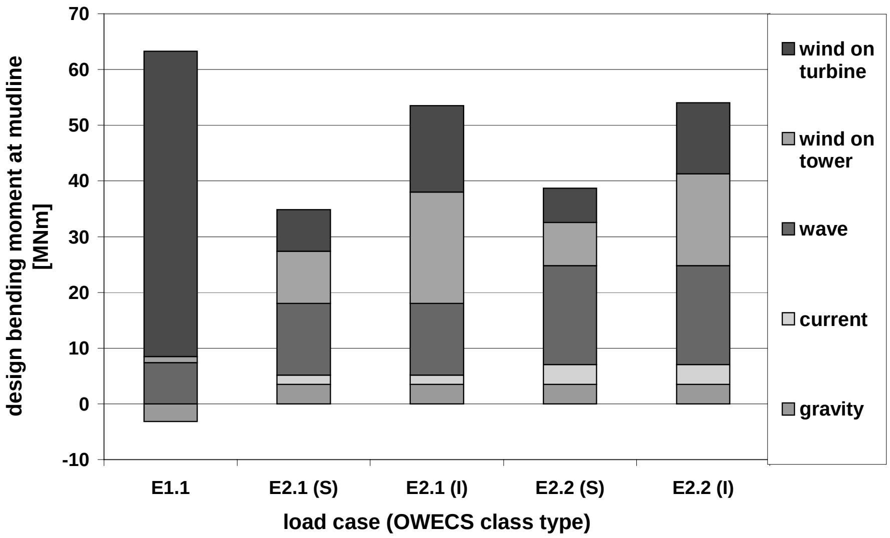


Figure 9.4-2: Overturning moment (design load) for different extreme load cases

(Gravity load considered as favourable for E1.1 and unfavourable for E2.x. Current load defined as combined wave and current load minus pure wave load.)

10. Economic assessment of the OWECS

The structural design phase, described so far in chapters 5 to 9, is concluded by a detailed economic analysis. This evaluation of the design solution is divided in four parts: estimate of the investment and energy costs (section 10.1), sensitivity analysis with respect to sub-system costs and energy yield (section 10.2), parameter study with the novel OWECS cost model (section 10.3) and finally discussion of the economic achievements and comparison with other projects and recent studies (sub-section 10.4).

10.1 Estimate of investment and energy costs

Investment costs

Investment cost based on December 1997 price level and other data are compiled from the structural design (table 10.1-1).
The total capital costs for the 300 MW OWECS are estimated on 372 MECU corresponding to specific costs of 1240 ECU/kW installed capacity respectively 740 ECU/m^2 swept rotor area.

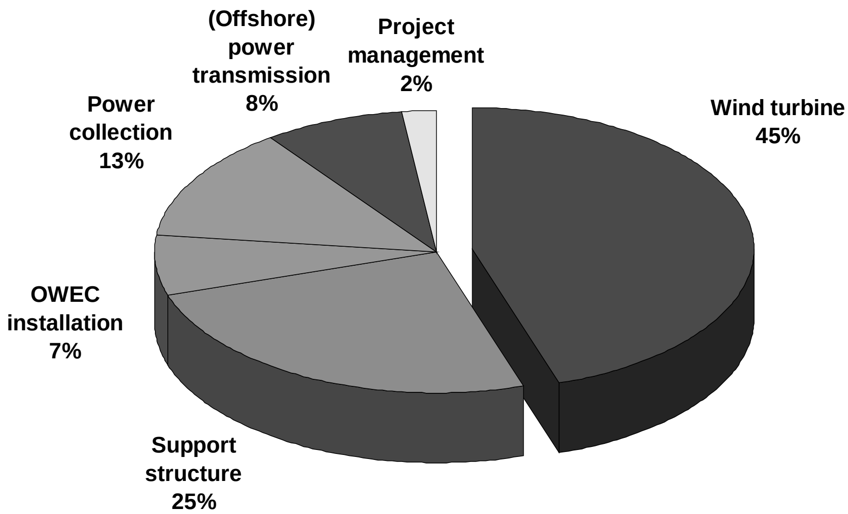


Figure 10.1-1: Breakdown of initial capital costs for the Opti-OWECS design solution

Main design data	
Farm capacity	300 MW i.e. 100 times 3 MW
Wind turbine	WTS 80 M (3 MW - 80 m)
Support structure	soft-soft monopile
Offshore grid connection	AC submarine cables 24 / 150 kV
Array efficiency	93% (uniform spacing 10 *D*)
Transmission efficiency	96%
Availability	96.5%
Net annual energy yield	787 GWh/year
Site data	
Location	Dutch North Sea, near IJmuiden
Estimated annual wind speed (60 m)	8.4 m/s (A = 9.5 m/s, k = 2.2)
Distance from shore	11.4 - 18.6 km 15 km (from central cluster point)
Water depth	14 - 19 m (LAT)
Economic data	
Wind turbine cost	170 MECU
Support structure and installation costs	118 MECU [10]
Offshore grid connection cost	77 MECU
Project management cost	2% of total capital cost
Total capital costs	372 MECU (1240 ECU/kW)
Operation & maintenance cost	9 M ECU / year
Decommissioning cost	10% of initial capital
Economic lifetime	20 years
Real interest rate	5%
Levelised Production Costs (LPC)	5.1 ECUct/kWh

Table 10.1-1: Main design and economic data of the design solution.

Accounting for 45% of the total costs the wind turbine is the sub-system with the largest cost share. In comparison support structure and installation costs (32 %) and offshore grid connection costs (21%) are of significantly lower importance which can be expected as their contribution reduces if multi-megawatt converters are employed. Further reason can be seen in the successful optimisation of the support structure and installation for the particular site and design (chapters 6 and 9) and the relatively moderate costs involved in the offshore power transmission for a distance from shore of only 15 km.

Costs for two support structures (figures 6.3.2 and 6.3.2) designed for a water depth of 12 and 20 m (LAT), respectively, have been estimated. For the actual range in water depth of 14 to 19 m (LAT) the linear average between both unit costs is assumed to be applicable.

In accordance with the particular design conditions stated in section 2.2.2 no costs are considered for the onshore grid connection. For the particular site onshore grid

[10] Support structure costs are based upon an exchange rate of £ 0.65 to ECU 1.

connection costs would account only for a relatively small amount as long as no major grid reinforcement, which would be beneficial also for other plant or consumers, have to be paid. The effect is studied in some detail in section 10.2.

Energy yield

The net annual energy yield of the farm at the shore connection point has been calculated based upon an annual mean speed of 8.4 m/s at 60 m height (section 7.3.2) to 787 GWh/a. It should be noted that this estimate is likely to be conservative with respect to the assumed wind conditions since other recent studies [10.1-1], [10.1-2] consider higher wind speeds at similar sites.
Table 10.1-2 compares the energy yield for different assumptions on the wind conditions. Note that both the gross energy yield and the cluster efficiency have been adjusted according to the different wind conditions, however, a constant farm availability is assumed. For this particular site a non accessibility for maintenance (‘storm percentage’) of 25% has been derived from the high quality NESS (North European Storm Study) database. Therefore the availability is assumed to be independent from the uncertainty in the estimate of the gross energy yield.

Parameter	Opti-OWECS	JOUR 0072 [10.1-1] NL Nearshore [10.1-2]
Annual mean wind speed at 60 m	8.4 m/s	9 m/s
Gross energy yield	914 GWh/a	1040 GWh/a
Storm percentage (time fraction non accessibility for maintenance)	25 %	25 %
Farm availability	96.5 %	96.5 %
Cluster efficiency	93 %	93.8 %
Transmission efficiency	96 %	96 %
Net energy yield	787 GWh/a	904 GWh/a

Table 10.1-2: Energy yield associated with different wind conditions

Operation and Maintenance costs and decommissioning costs

The novel Monte-Carlo simulation tool (section 8.6) has been used to estimate the operation and maintenance (O&M) cost on 9 MECU/a associated with an availability of 95.6%. It should be noted that this relatively high O&M costs, which correspond to 2.4% of the initial capital costs or 1.1 ECUct/kWh, are required to ensure a high availability which again is required to achieve optimum levelised production costs.
Decommissioning cost are accounted for as 10 % of the initial capital costs to be paid at the end of the plant’s lifetime.

Levelised Production Cost (LPC)

Energy costs are calculated by a standard cost discounting approach for the levelised production cost according to the International Energy Agency [10.1-3]. [11]

Based upon economic parameters as usually applied by public sector utilities, i.e. 20 years loan and 5% real interest rate [10.1-4] and an annual mean wind speed of 8.4 m/s at 60 m height, the levelised production costs are estimated on 5.1 ECUct/kWh. In case of a higher mean wind speed of 9 m/s at hub height the energy cost would be lower, approx. 4.4 ECUct/kWh.

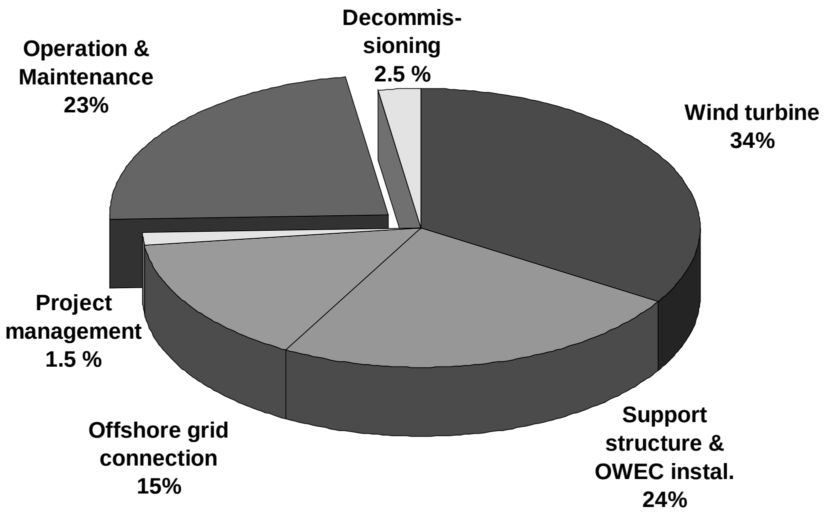


Figure 10.1-2: Contribution of energy costs for Opti-OWECS design solution
(8.4 m/s annual wind speed, 20 year loan, 5% real interest)

In the cost breakdown of the estimated energy costs (figure 10.1-2) a high contribution of 22 % of the O&M costs is observed. This is justified by the considerable costs involved in offshore operations. Further, optimum energy costs require high OWECS availability which can only be achieved through high O&M costs. In contrast, decommissioning costs account only for a small fraction of less than 3% of the energy costs.

[11] The levelised production cost LPC is given as the ratio of the total discounted cost and the total produced energy. By assuming that the annual energy output E_y (after all losses, at the grid connection point onshore) is constant from year to year the price per energy unit can be calculated as:

$$LPC = \frac{I_{tot}}{a\,E_y} + \frac{TOM}{E_y} \qquad (10.1\text{-}1)$$

LPC	levelised production cost
I_{tot}	total investment cost
a	annuity factor
E_y	annual energy output
TOM	total levelised annual 'downline' costs (i.e. annual operation & maintenance and discounted decommissioning costs)

The annuity is the total amount of money including interest and amortisation instalments that has to be paid per year.

10.2 Sensitivity on economic parameters, sub-system costs and energy yield

The sensitivity of the energy cost calculated for the design solution to changes in the economic conditions, the cost of each subsystem and the overall energy production has been investigated.
This section of the study was performed in a very simple fashion, simply changing the values of the each parameter and observing the effect on the overall energy cost as calculated with equation (10.1-1). No account was taken of what might be termed “derivative effects” (see section 10.3). For example, any ‘real life’ reduction in the cost of the grid connection might well result in a poorer quality connection, with greater losses in transmission to the shore.

Economic parameters

Purely economic parameter that influences the energy cost are the economic lifetime (repayment period) and the real interest rate. The manner in which the cost of energy varies with both parameters is shown in figure 10.2-1. Taking into account typical values used for commercial projects in different EU member states (table 10.1-2) [10.2-1] the estimated energy costs (based upon an annual wind speed of 8.4 m/s at 60 m) range between approx. 5.75 and 8 ECUct/kWh.

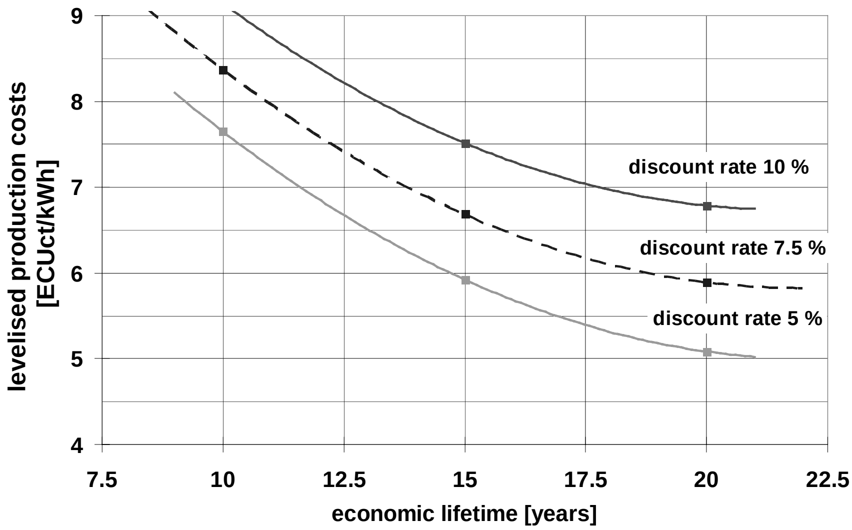


Figure 10.2-1: Influence of economic lifetime and real interest rate on energy cost
(Annual mean wind speed at hub height 8.4 m/s)

	real interest rate	repayment period
Denmark	7 %	20 years
Germany	Varies, 5 % upwards	10 years
The Netherlands	4 to 5 %	10 years
United Kingdom	Developer’s choice	15 years

Table 10.1-2: Real interest rates and repayment periods used for commercial wind farms

Sub-system costs, O&M costs and energy yield

Figure 10.2-2 illustrates the sensitivity of the energy cost on variations in the sub-system costs, O&M costs and energy yield. Energy cost for 20 year loan and 5% real interest rate have been normalised by the reference value i.e. 5.1 ECUct/kWh.
Clearly, the energy production has the greatest sensitivity to the overall cost. Sensitivities to the changes in the costs of the sub-systems correspond to their contribution to the energy costs (Figure 10.1-2).
There are two conclusions of potential interest to OWECS designers that can be drawn from the results.

Firstly, the great sensitivity of the energy cost to the energy production means that great care must be taken in estimating its value for a proposed OWECS. Relatively small errors in the energy production will be magnified into comparatively large errors in the predicted energy cost.
This effect is quite unpleasant since reliable prediction of the wind conditions is difficult due to the lack of long term measurements offshore and the complex influences of fetch and atmospheric stability. Furthermore, the significant improvement of the wind turbine reliability and innovative operation and maintenance solutions (chapter 8) are required to ensure high availability in the order of 90% to 97%. Without such measures availability may drop on a unacceptable low level in the order of 70% to 80 % and energy costs will increase accordingly in a dramatic manner.

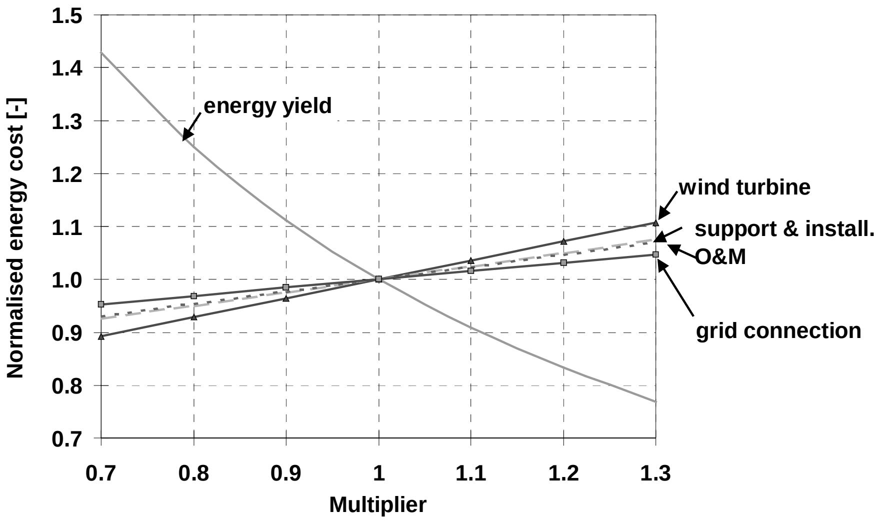


Figure 10.2-2: Sensitivity of energy costs on variation of sub-system costs, O&M costs and energy yield

Secondly, there would seem to be most scope for incremental improvements in the economics of the OWECS from increasing the amount of energy it produces. Surprisingly large penalties in the costs of the sub-systems could be tolerated in order to achieve improved energy production. For example, a 10% increase in energy production would be economically worthwhile even with an increase in the turbine cost of approximately 30%. Options to achieve a higher energy yield should carefully be investigated since application of sophisticated turbine concepts with high

aero-mechanical efficiency might reduce the availability due to the lower reliability of complex mechanism.
Striving further to reduce the costs of the subsystems appears to be less attractive than improving the energy production. Even though the turbine is the subsystem with the greatest influence on the energy cost, a 10% reduction in the turbine cost would only bring a less than 5% reduction in the energy cost.

Onshore grid connection costs

For a real project onshore gird connection costs must not be ignored. Here the effect is studied only in a qualitative manner since investigation of the particular conditions onshore i.e. grid infrastructure, connection to large-scale consumers in the vicinity, etc. were beyond the scope of the project.
For the NL-1 site a suitable 150 kV high voltage grid connection point is very close to shore and an onshore cable of about 5 km length only would be required.[12] From table 10.2-1 showing the influence of the length of the onshore power transmission cable on the energy cost, it can be seen that the effect would be marginal in this case.

Length of onshore power cable [km]	0	5	25	50
Sensitivity of energy cost [-]	1.00	1.002	1.012	1.025

Table 10.2-1: Sensitivity of energy costs on length of onshore power cable
(No reinforcement of onshore grid connection point or public grid considered.)

However quite substantial cost is made if a major reinforcement of the grid connection point and/or of the public grid would be required and would burden the project.[13]

10.3 Parameter study based on the OWECS cost model

10.3.1 Introduction

The cost model has been employed to perform integrated studies of the influence that variations in the value of certain parameters might have on the cost of energy produced by the design solution OWECS. Unlike the studies in section 10.2, the calculations do attempt to take account of “derivative effects”, at least to the limited extent that the cost model is able to simulate them.
Interactions that are of particular importance in this section include:

- dependency of availability and O&M cost on both mean annual wind speed and distance from shore
- effect of distance from shore on power transmission costs, electrical energy losses, availability and O&M cost,
- dependency of energy yield and power collection costs on turbine spacing

[12] The vicinity of the shore connection point provides an oil fired plant of 846 MW, two 150 kV transformer stations of 500 MVA and 360 MVA, respectively, and a large heavy industries complex.
[13] In order to indicate the order of magnitude of grid connection costs reference is given to [10.2-2] where cost of about 30 MECU are mentioned for a reinforcement associated with a plant of only 100 MW capacity.

As we have seen, the cost model is a valuable tool for comparative studies. It is however, essentially an approximate device, and some discrepancy between its estimates and the real design solution is to be anticipated. In order to ensure that results from the studies bear as close a resemblance as possible to reality, and are not unduly distorted by any imbalance in the relative importance of the subsystems, the cost model has been calibrated to reproduce the subsystem costs of the design solution almost exactly.
Such a calibration was necessary either due to the inherent simplification of the cost model e.g. constant ratio of diameter to wall thickness of support structure, no range of water depth within the wind farm, uniform wind rose in the energy yield calculation or slightly different cost data underlying the cost model e.g. grid connection costs.

It is instructive to compare the final economic evaluation of the design solution with the predictions of the cost model described in section 4.7.1. The original estimate for the site NL-1 produced by the model predicted an energy cost of 0.043 ECU/kWh, which is substantially below the figure related to the design solution. Close examination, however, shows that some of the parameters assumed for the original calculation differ from those for the final evaluation. Table 10.3-1 lists the effected parameters with their “before” and “after” values.

Parameter	**Conceptual design**	**Final design**
Annual mean wind speed at 60 m height	9 m/s	8.4 m/s
Distance to shore	8 km	15 km

Table 10.3-1 : Parameters for NL-1 that differ between conceptual design (section 4.7.1) and final design (chapter 10).

To more sensibly evaluate the performance of the model with respect to the design solution, it was used to re-evaluate site NL-1 with data revised according to table 10.3-1. The model based re-evaluation produced an energy cost estimate of 0.050 ECU/kWh, which ‘predicts’ the real cost of 0.051 ECU/kWh very well.

10.3.2 Parameter studies

Further use has been made of the calibrated cost model to investigate the influence of some important parameter variations on the cost of energy from the design solution.
No parameters with main impact on the support structure design e.g. water depth, overall height of the structure have been investigated since the relation between such parameters and the governing criteria i.e. fatigue loading due to combined wind and waves is far too complex for a cost model. As a consequence of the governing criteria any analysis of other parameters related to the extreme loading e.g. design wave height, extreme 50 year wind speed, etc. has not been performed since no sensitivity can be exepted in suach a case.

The results will be considered here on a parameter by parameter basis.

Mean annual wind speed

The annual mean wind speed, one of the strongest parameters for the economics of a wind farm, has been investigated under the assumption that the base case wind turbine design e.g. rated wind speed, power rating, reliability, etc. is not adapted on the new wind conditions which in reality obviously would be the case.

In figure 10.3-1 the normalised energy cost is given as function of the annual mean wind speed. At first sight it is surprising that the energy cost rise again for mean wind speeds above 10 m/s. The yearly energy yield indeed rises with increasing mean wind speed although it flattens for very high mean wind speeds, due to the fact that the rated wind speed of the turbine remains the same. The fact that the energy cost rises for very high wind speeds is due to the rapid decrease of the OWECS accessibility; for a mean wind speed of 13 m/s the storm percentage (i.e. the percentage of time at which the weather prevents transport of O&M crew) equals 62. This implies that it will take a long time to repair failed turbines.
This again illustrates the paramount importance of a good O&M strategy for future large scale offshore wind farms, which will be located more offshore.

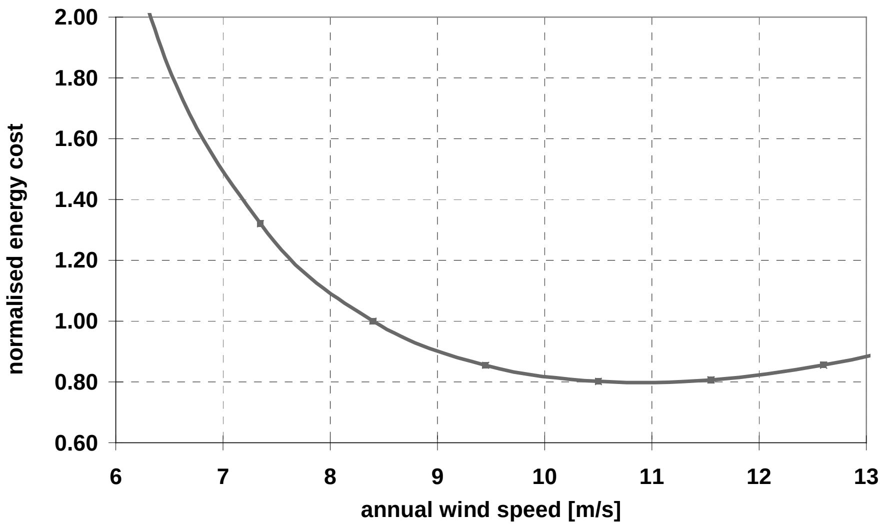


Figure 10.3-1: Sensitivity of the normalised energy costs on the mean annual wind speed
(Wind turbine design not adapted for changes in the wind conditions.)

Distance to shore

Another parameter which has a strong impact on the energy costs is the distance to shore, as illustrated in figure 10.3-2. Both the transmission cable costs as the electrical losses increase with distance to shore. Furthermore the availability of the wind turbines will drop because of the increased travel time for O&M crew.
For large distances (say beyond to 50 km) it becomes worthwhile to consider DC transmission.

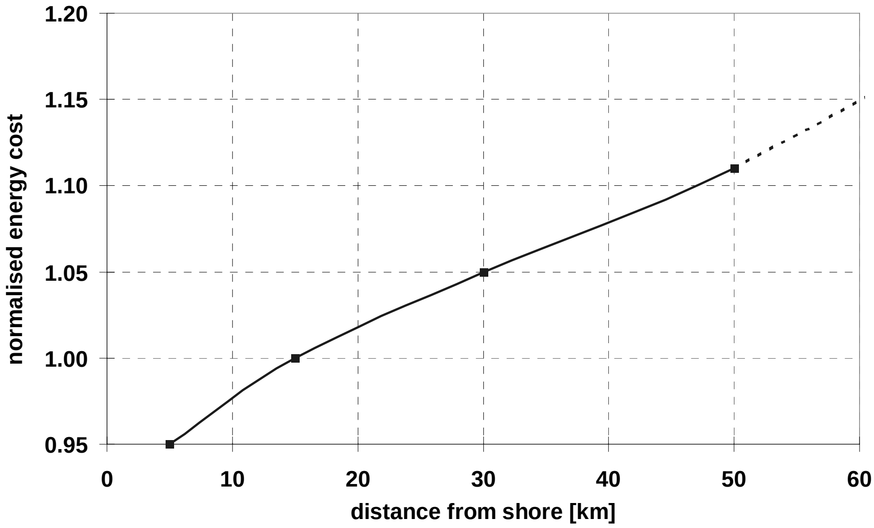


Figure 10.3-2: Sensitivity of normalised energy cost on distance from shore
(Only AC grid connection considered, constant annual wind speed)

Size of wind farm (number of OWEC units)

In almost all studies on offshore wind energy it is stated that offshore wind farms will be economically attractive for large farms only. Also figure 10.3-3 leads to such a conclusion. Although series effect are only partly considered the cost increase strongly for small farms due to the large expenses for the power transmission and the O&M infrastructure. Furthermore it is seen that not much can be gained in this respect by farms comprising more than 100 units.

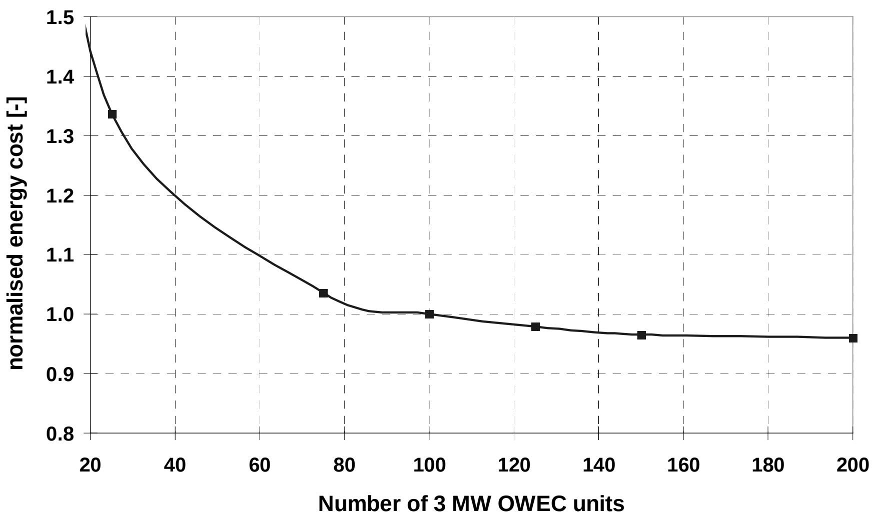


Figure 10.3-3: Sensitivity of normalised energy cost on number of wind turbines (wind farm size)

Spacing ratio

Increase of the turbine spacing will have a positive effect on the farm efficiency but the investment costs will become larger due to the required longer cables, see chapter 7 (figure 10.3-4). Therefore an optimum spacing can be anticipated. As shown in figure 10.3-5 it turns out that for the design solution a spacing of 12 rotor diameters leads to the minimum energy costs.
As stated in chapter 7, for the determination of the farm layout, the required area for the wind farm should also be taken into account which probably leads to a lower spacing than the optimum found form the balance of grid connection costs and energy yield. A slightly lower spacing is certainly justified due to the very flat minimum of the energy costs.

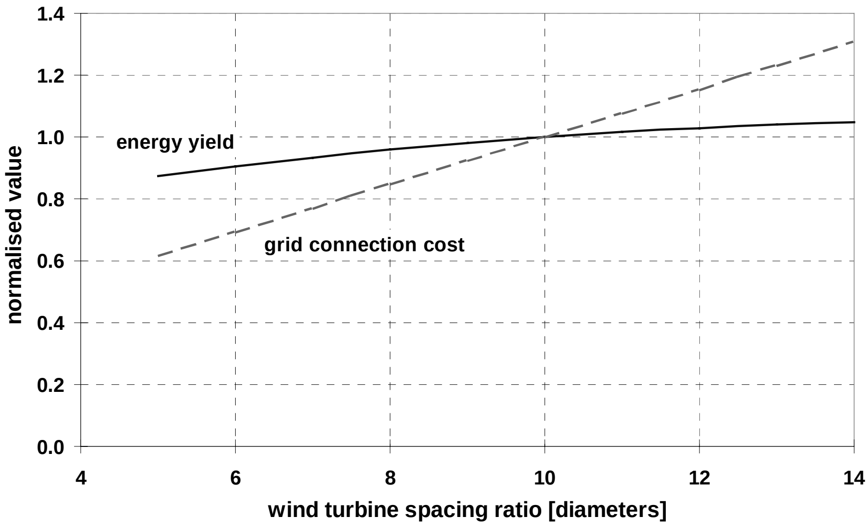


Figure 10.3-4: Sensitivity of energy yield and grid connection costs on wind turbine spacing

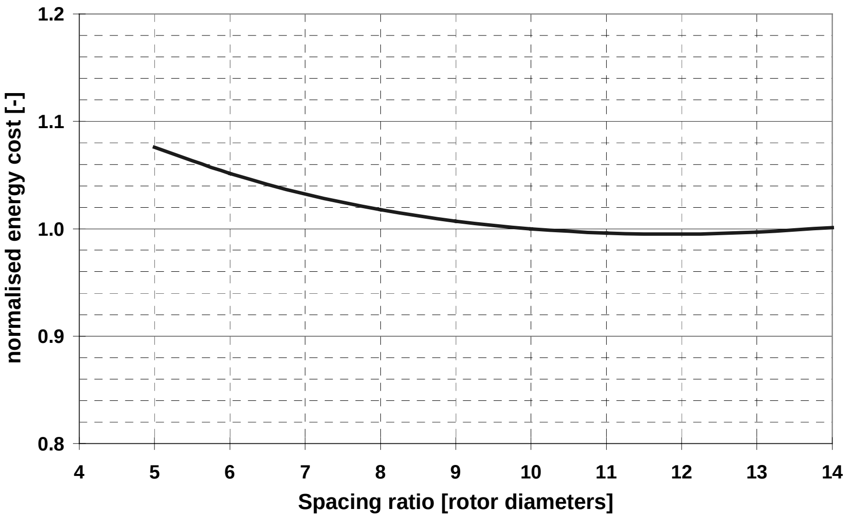


Figure 10.3-5: Sensitivity of normalised energy cost on wind turbine spacing

10.4 Discussion of the economic achievements

In order to judge the economic value of the design solution the results are compared to some other recent projects and studies on offshore wind energy (table 10.4-1). Moreover the result of the structural design phase is judged with respect to the associated objectives of the Opti-OWECS project.

So far five offshore wind farm exist today from which the two Danish plant Vindeby (1991) [10.4-1] and Tunø Knob (1995) [10.4-2] as well as the Dutch Lely wind farm (1994) [10.4-3] are considered here. Further attention is given two very recent studies based upon wind turbines in the megawatt class i.e. the prime location 'Horns Rev' of the Danish Plan of Action for Offshore Wind Energy [10.4-4] and the Dutch Nearshore study [10.4-5]. Finally, the British Phase CII study (1991) [10.4-6] is selected as a typical contender of the older studies related to large multi-megawatt OWEC.[14]

Any economic comparison of the different studies is difficult and is therefore only of more or less qualitative nature. Beside the inherent inaccuracy of any paper study also significant differences exist in price level, economic parameters, exchange rates, environmental and technical conditions and complicate a comparison. Therefore here not only the energy costs but also a number of specific costs and energy yield are used. Levelised production costs are all based on an repayment period of 20 years and a real interest rate of 5% regardless the economic parameters used in the original studies.
For the Opti-OWECS design solution also a second higher mean annual wind speed of 9 m/s instead of the reference value of 8.4 m/s is used in order to enable a fair comparison with the quite similar sites of the Horns Rev and the Nearshore study. This correction does not imply any judgement on the accuracy of the wind speed value in a certain project rather it simply demonstrates that even for similar sites quite distinct estimates are possible if no measured long term data exists.

Despite all differences some trend can be seen in the different projects.

Firstly, a dramatic economic achievement is observed between on one hand the old studies carried out in the 1970s and 1980s from which the Phase CII is a typical representative and on the other hand of the small scale prototypes and the studies from the mid to end 1990s.

Secondly, a learning curve can be seen from the small scale prototypes and the latest studies which is founded on improving maturity of the technology and increase in the size of both the wind turbines and of the entire wind farms.

Thirdly, offshore wind energy likewise to wind energy on land is approaching the cost level of other energy sources. For instance typical energy costs based on 5% real interest rate of coal and gas fired plant range in the order of 3.7 - 5.5 ECUct/kWh and 3.1 - 4 ECUct/kWh, respectively. Further comprehensive information on the

[14] From the various OWEC design options in the study here the full-pitch regulated, two bladed teetered '70 IA' design with a diameter of 70 m and a rated power of 3 MW is considered.

economic situation of wind energy and its relation to other plant is provided in the appendix of the Vol. 3 [10.4-7].

Finally, the Opti-OWECS design solution achieves a prime position with respect to the state-of-the-art and it is clear that it meets its particular objectives (sections 1.1 and 2.2.2) i.e. demonstration of a commercial large-scale OWECS to be build in a medium time scale and identification of optimal designs which lead to a significant reduction in energy costs.

Study / project	**UK Phase CII**	**Vindeby**	**Lely**	**Tunø Knob**	**Horns Rev**	**NL Nearshore**	**Opti-OWECS**	
Year, price level	Jan. 1991	1991	1994	1995	Jan. 1997	1997	**Dec. 1997**	
Site	UK North Sea	DK Baltic Sea	NL IJssellake	DK Baltic Sea	DK North Sea	NL North Sea IJmuiden	**NL North Sea IJmuiden**	
Capacity [MW]	711 * 3	11 * 0.45	4 * 0.5	10 * 0.5	80 * 1.5	100 * 1	**100 * 3**	
Wind speed [m/s]	8.3 (~55 m)	7.5 (40 m)	7.7 (42 m)	7.5 *) (43 m)	9.2 (55 m)	9 (60 m)	**8.4 (60 m)**	9 (60 m)
Capital per kW [ECU/kW]	1900	2168	1720	2197	1648	1883	**1240**	
Capital per swept rotor area [ECU/m^2]	1500	908	652	920	769	approx. 1000	**740**	
Energy per swept rotor area [kWh/m^2]	1276	978	735	1256	1644	approx. 1500	**1566**	1798
Capacity factor	19%	27%	22%	34%	40%	34%	**30%**	34%
Capital per MWh [ECU/MWh]	1175	928	886	732	467	628	**473**	412
Cost of energy [ECUct/kWh]	13	8.6	8.3	6.6	4.9	6.4	5.1	4.4

Table 10.4-1: Economics of Opti-OWECS design solution is relation to other recent prototypes and studies
(Energy cost for 20 year loan and 5 % real interest rate, exchange rates ECU 1 : £ 0.65 : HFL 2.23 : DKK 7.1, *) estimate of author)

11. Conclusions

11.1 OWEC Design Solution and Design Approach

From the work in the structural design phase the most important conclusion is that the reference offshore wind farm is technical achievable, realistic and economic.

The integrated OWECS design methodology, considering the offshore wind farm as an entire system (see Volume 1), has been applied succesfully.

11.2 Site Selection and Sub-system Design

Site Selection

A wide range of European sites have been considered, some in exposed locations such as the Noth Sea, others in the more sheltered waters of the Baltic Sea. The water depths addressed range from 10m to 25m. For each site characteristic wind, wave and current conditions have been determined together with appropriate soil conditions.

Wind Turbine

The wind turbine itself has undergone a number of design changes for an adaptation of the land based turbine technology to offshore conditions:

- increased environmental protection of the nacelle
- design for prolonged maintenance interval
- conceptual changes resulting in increased reliability
- implementation of equipment for handling of components.
- change of rotor design and speed concept to change dynamic properties and to reduce blade costs.
- location of the transformer in the nacelle

With higher design quality, more reliable systems and an appropiate O&M strategy, it is concluded that under an equivalent strategy a higher availability can be reached for the offshore turbine concept.

To achieve a better dynamic performance the turbine rotor speed has been increased for integration into the total OWEC.

Support Structure

From the feasibility process, three quite distinct, concepts emerged as offering potential solutions to the problem as given as follows:-

- GBS Lattice Tower - Floated Installation
- GBS Monotower - Floated Installation

- Monopile - Floated or Lifted Tower Installation

Each of these solutions have been demonstrated to offer a viable means of providing support to the turbine facilities over the duration of it operational life. Throughout this process three keys issues relating to the support structure have been prominent:

- Dynamic Behaviour
- Fatigue Performance
- Ease of Construction/Installation

The monopile support structure for site NL-1 has been proven to be a feasible and an entirely practical solution means of providing support to the turbine facilities over the duration of it operational life. The support structure provides the following facilities:-

- Pile
    - Cone element thereby providing the necessary section properties at seabed whilst minimising the wave load at sealevel.
    - Scour protection
    - J-tube
    - Corrosion protection
- Tower
    - Grouted joint securing the tower to the pile
    - Sloping flange to accounting for installation tolerances of the pile and later tower removal
    - Boat landing including ladders, rest platforms and access platforms
    - Manway access inside the tower and ladders and rest platforms to provide access to the nacelle
    - Emergency shelter provided within the tower, located beneath the manway

Grid Connection and Farm Layout

- In essence this design methodology is the same as for onshore farms.
- Standard software is available for loadflow and short-circuit calculations as well as for the determination of farm efficiencies.
- For the reference solution a trade-off is performed between farm efficiency and cable costs; furthermore the required area of the wind farm (installed MW/km^2) is taken into account.
- The following reference solution is determined:
    - AC collection and transmission
    - chain connection inside clusters; star connection between clusters
    - the transformer of each OWEC is placed inside the nacelle
    - the farm layout is a square of 10 by 10 turbines
    - a spacing of 10 D in both directions
    - the farm effieciency equals 93 %
- The application of farm layout codes requires not much work but it should be kept in mind that the possible gain is in the order of 0.1 ECUct/kWh.

Operation and Maintenance

- It is generally recognised that operation and maintenance (O&M) for an OWECS is an important aspect but other/previous projects did not yet studied it.

- In the scope of Opti-OWECS a new design tool is developed for the evaluation of O&M strategies,. based on Monte Carlo simulations.
- It is assumed that in (near) future external lifting equipment will still be necessary for the replacements of (faulted) blades and other heavy parts. The overall failure rate of the wind turbine is determined at 1.0 events/year (based on failure rates of commercial wind turbines and expected improvements for the considered 3 MW wind turbine). Preventive maintenance (PM) is scheduled once a year.
- For the reference solution the following characteristics are determined:
    - OWECS not accessible 25% of the time (due to high winds or waves)
    - PM & CM based O&M strategy
    - 2 O&M crews (of 2 workers); standby 12 hours a day, 7 days a week
    - crew transport by manned vessel
    - lifting operations by self propelling jack up platform
    - farm availability 96.5 %

Overall dynamics of OWEC

- Depending on the particular design and site conditions, dynamics are likely to be of greater importance for OWEC design, both in comparison to design of onshore wind energy converters and most offshore structures. Careful dynamic analysis of the entire OWEC and the consideration of this procedure during the design process offer considerable cost reductions, especially if fatigue is governing.
- Fatigue due to combined wind and wave loading govern the design of the soft-soft monopile support structure. In order not to increase the fatigue loading by higher response to either hydrodynamic of rotor excitations, the design stiffness has a upper and lower bound.
- Combination of state-of-the-art methods for dynamic analysis from both wind energy technology and offshore technology together with considerations particular to OWEC design obtain a viable design solution. The economic potential of the soft-soft design can only be reaped due to the use of such sophisticated methods. Moreover, the soft-soft design can only be applied up to a water depth of about 20m (LAT) due to particular design features as reduced pile diameter at the water line, relatively stiff and insensitive pile foundation, low hub height, etc.
- The highest extreme loads occur during power production of the OWEC for the extreme operating gust combined with a reduced gust. The characteristics of the pitch control system together with dynamic amplification of the wave loading produce the highest loads for a mean wind speed **below** rated.
- A significant optimisation potential might be given by OWECS class S instead of class I certification in case where extreme loads at 50 years conditions are governing.

Economic Assessment

- Offshore wind energy is fully feasible and energy costs in the order of 5 ECUct/kWh (20 years loan, 5% rate of interest) are achievable at sites with good wind conditions (annual mean wind speed of 8.4 m/s at 60 m).
- The O&M cost account for 22% to the energy costs, this relative large amount is required in order to obtain a sufficient availability.

- The parameters which have the largest impact on the energy costs are the mean annual wind speed, the wind turbine availability and the distance to shore.

12. Recommendations

The work described here made substantial progress in the development of cost effective offshore wind farms (OWECS). Concepts have been put forward that have been demonstrated to be viable and which are based on essentially existing technology. In this way the present work has made significant progress to establishing a basis for further OWECS design.

General

The OWECS guidelines of Germanische Lloyd were, as far as known by the authors, used for the very first time in a design situation. Application proved to be successful, nonetheless verification, further development and clarification of particular issues should be adressed in the near future.

Wind Turbine

- investigation and exploration of new technologies should be started, like the pm-generarator concept, onshore; mature and proven designs only should be introduced in an offshore environment.
- work should proceed on increasing the maintenance interval, possibly by introducing new technical designs

Support Structure

- analytical tools should be developed further allowing a combined assessment of fatigue damage from hydrodynamic and aerodynamic sources.
- further work should be directed towards the ancillary details of the design including the boat landing, grouted pile/tower connection and flanged joint
- work addressing the workability of jack-ups and lift vessels should be undertaken to establish the weather risks. This would allow more accurate cost estimates for the marine elements of the work.
- outline work should be addressed to the design of a purpose built/adapted vessel to be used for OWEC installation and maintenance.

Grid Connection and Farm Layout

- for future OWECS at larger distances to shore, the DC transmission option should be further examined.
- the methods and involved costs for cable laying should be studied in more detail.
- The availability of long term wind data (30 years) should be assessed or alternatively, methods to estimate the long term mean wind speed should be developed for the determination of the anual energy yield

Operation and Maintenance

- The required availability of future OWECS should be adressed by application of an integral RAMS (Reliability Availability Maintainability and Serviceability) design approach.

Overall dynamics of OWEC

- Although successful, the analysis approach of the overall dynamics of OWEC should be further refined and verified by measurements on suitable offshore wind energy converters of different type and at distinct sites.

- Dynamic considerations particular to OWEC should be taken into account already at an early stage of the design process of OWECS. Special attention has to be given to the different philosophies in offshore technology and wind energy technology.

Economic Assessment

- Implementation of more design options of the OWECS components into the cost model.

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Appendix A: Directory of wind turbine features

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1. Rotor power control options

1.1 Stall control - fixed pitch

This method of operation utilises aerodynamic stall to control rotor power levels above the rated windspeed. At low windspeeds the aerofoils work efficiently. At higher windspeeds the angle of attack of the air onto the blades causes the aerofoil to stall and become inefficient by strongly increased drag forces, so reducing power below the rated power. At still higher windspeeds (usually 25m/s) the rotor must be stopped because the "inefficient" lift forces would drive the rotor above the rated power of the drive train.

Advantages

- simple passive system
- no moving parts
- great experience throughout the world with stall controlled turbines

Disadvantages

- not as efficient as pitch control in energy capture terms
- care must be taken in designing the rotor for the site wind conditions
- no load shedding in high windspeeds
- rotor braking must be provided (This is usually aerodynamic braking)

1.2 Active pitch control

In active pitch control the blades are moved around their longitudinal axis to give the optimum pitch angle at all windspeeds. The blades are set in bearings at the hub. A mechanism rotates the blades on signals from the control system. Various mechanisms are used for this, either hydraulic/mechanical systems or electric motor drives.

Active pitch control is the control system used in many medium and large wind turbines. e.g. Vestas (DK), Windmaster(NL), Kenetech(US), Zond(US), Enercon (DE), WEG (UK).

In most cases, the pitch angle adjustment is actuated by hydraulic systems; consequently hydraulic power must be transmitted into the rotating system. This calls for solutions using hollow main shafts or rotating seals. A promising alternative is offered by actuation through individual electrical drives for each blade (Enercon), however, the problem then becomes the need for electrical power in the rotating system, which must be supplied through sliprings. An added advantage of the electrical solution is the possibility of independent blade pitch movement, adding redundancy to the safety system.

Advantages

- improved annual energy output compared to stall controlled rotors
- provides aerodynamic braking
- reduced loads in high windspeeds
- reduced shock loads on drive train

Disadvantages

- pitch systems are unable to precisely match rapid changes in windspeeds, so fatigue damage is not greatly reduced compared with stall controlled rotors
- costly bearings and mechanism required
- lower reliability because of higher number of moving parts
- blades must be torsionally stiff

1.3 Active stall control

This is a variant on active pitch control. The mechanism is similar but control of rotor torque is by stall. The blades are rotated into a particular set position for a particular range of windspeeds. The mechanism and control system can be much slower acting than in active pitch control. Examples are the Nedwind turbines in the Lely offshore wind farm.

Advantages

- higher energy capture than pure stall control
- lower speeds and loads on pitch control mechanism
- somewhat improved reliability over active pitch systems

Disadvantages

- mechanism and bearings for pitch control still required albeit rather simple

1.4 Tip pitch control

This method uses a pitchable blade tip, rather than the whole blade to control rotor speed. The outer one third of the blade produces most of the power and this method puts the control where it is needed. This method was in favour in the mid 1980’s (e.g. Howden) but has fallen out of favour because of perceived reliability problems.

Advantages

- higher energy output than stall control is possible
- smaller moving blade area as whole blade does not have to move
- smaller mechanism and bearings required

Disadvantages

- activation mechanism must be fitted into a small space in the blade itself
- access to mechanism is difficult for maintenance
- the reliability of tip pitch mechanisms needs to come up to the level of full span pitch mechanism
- all other disadvantages of active pitch control

1.5 Passive pitch control

Passive pitch control uses centrifugal and aerodynamic forces to adjust the pitch angle dynamically in response to rotor speed and wind speed. This can only be used in conjunction with variable speed wind turbines. The optimum pitch angle for any rotorspeed/windspeed combination can therefore be achieved. The use of passive pitch control has been restricted, so far, to the smaller commercial machines such as Lagerwey 80 or 250 kW and Vergnet. Interesting results have been obtained in the Dutch Flexhat experiments with passive partial-span pitch control.

Advantages
- passive mechanism needs no power to operate, so no need to get power to blades through rotating couplings
- higher annual energy capture than stall possible

Disadvantages
- can only be used in conjunction with variable speed turbines

2. Blade options

2.1 Flexibility

The purpose of increased blade flexibility is to reduce blade loads. Blade flexibility is measured by the ratio of the first blade flapping (bending or hinging) eigen (resonant) frequency to the rotational frequency. The lowest attainable eigen-frequency of exactly 1P is realised for a blade with a central flapping hinge, allowing free flapping, without spring action at the hinge. Stiff blades (3 to 4P) are more commonly used. Hinged blades have been used successfully by manufacturers of smaller turbines, notably Lagerwey (NL) and Südwind (DE). The Dutch 1 MW NEWECS-45 turbine has a relative flexible blade with a flapping eigen-frequency of 2.3 P, this leads to a load reduction of some 20% as compared to stiff blades. Load reductions through blade flexibility have been recently demonstrated in the Dutch Flexhat research project, where a blade flapping frequency of < 2P was realised through the use of flex beams.

2.2 Material options

Although not a conceptual issue, the use of different blade materials is important in machine design. The first generation of existing rotor blades has manufactured from glass fibre reinforced polyester (GRP). Manufacturers are increasingly switching to glass-fibre epoxy in the form of pre-impregnated mats (so called pre-pregs). These allow a much improved quality assurance, and are becoming the standard material now for wind turbine blades.

Carbon-fibre epoxy has also been used to a limited extent. Both lead to lighter blades, especially carbon fibre. The cost reduction of this last material over the past few years have made it a promising option.

Wood-epoxy has been used by WEG & Howden (UK) and Windmaster Nederland (NL), using the technology of wood plies bonded together with epoxy resin.

Steel has been used as the load carrying spar in some experimental large machines (Growian (DE), LS-1 (UK), but it offers no advantage compared with GRP blades.

3. Rotor speed options

3.1 Fixed speed

Most wind turbines operate with a fixed rotor speed, or two discrete rotor speeds. Most pitch controlled and almost all stall controlled turbines use fixed speed operation.

Stall control is nearly always combined with fixed speed operation. This makes stall operation a cheap and effective design route.

The induction generator is locked into mains frequency. An increase in power from the rotor increases the slip of the generator producing more power at the generator terminals.

Two speed operation is quite common. This uses a double wound generator which can operate at two different speeds. The low speed is used at low windspeeds and the high speed a high windspeeds. This increases the efficiency of the generator at low windspeeds, increasing overall energy capture.

3.2 Full variable speed

Under most wind regimes, the energy capture from variable speed wind turbines is greater then for fixed speed machines. The rotor can be run very near to the peak co-efficient of performance throughout most of the operating windspeed range, up to the rated wind speed. Variable speed turbines can offer an improvement in energy capture of up to 6% compared to fixed speed stall regulated machines.

Variable speed operation enables turbines to absorb the energy in wind gusts by momentarily increasing the rotational speed of the rotor. With fixed speed operation, this energy is transferred as shock loadings into the drivetrain components. Such loading on fixed speed machines means that stronger, and hence more expensive, components are needed in comparison with variable speed machines. Thus variable speed operation offers advantages in terms of the size of mechanical drivetrain components.

Operating at variable speed means that at low windspeeds the rotor speed is decreased, leading to reduced aerodynamic noise in comparison with fixed speed operation. The reduced noise nuisance that this offers is of little significance for far offshore wind power plant, but may be important for inshore wind farms. Most variable speed machines have relied on active pitch control (e.g. Enercon (DE), Kenetech (US)).

Passive aerodynamic controls can well be combined with variable speed operation, as illustrated by the rotors of the Lagerwey 18/80 (NL) and Flexhat turbines. As the rotor speed increases, the centrifugal force acting on the rotor blade can be used to alter its pitch. The change in the blade pitch angle reduces the drive torque on the rotor, limiting its speed effectively.

To achieve a fixed frequency electrical output from a variable speed wind turbine requires a two step conversion process. The generated variable frequency AC current must first be transformed to DC current, from which a fixed frequency AC current can then be synthesised. The electronic system needed for such conversions can be expensive, but this must be offset against the savings in drivetrain components that variable speed permits.

The same electronics necessary for variable speed operation also render direct drive electricity generation (see D3) practical, without the need for additional equipment. This eliminates the need for a gearbox, thereby offering further savings in the costs of mechanical equipment. In the variable speed large wind turbines which have been built the most common choice of electrical system has been that of an synchronous generator with a frequency converting AC-DC-AC system. In an equivalent (machine commutated) system based on an induction generator, a voltage supply for commutation is needed. This solution has been used successfully by Lagerwey in sub 100 kW systems. The Nordic, a 1 MW machine based on NWP 400 (S), uses an induction generator. In the USA, variable speed operation is implemented in the Kenetech 33m turbine.

The AWEC-60 turbine at Cabo Villano (Spain), is an early MW turbine using an induction generator in over-synchronous cascade mode. This solution offers less speed variation (30%) than the synchronous generator with AC-DC-AC conversion for the full power, but has the advantage of needing power electronics for part of the power only. The use of sliprings in this set-up is a potential maintenance problem that must be assessed.

Still another possibility is the induction generator with cyclo-convertor as used for the former Growian turbine by MAN in Germany. This system is not of much interest at present due to its complexity and relatively high costs.

Advantages
- increased energy capture
- reduced loading on components
- noise reduction
- passive aerodynamic control possible
- can be combined with direct drive generator

Disadvantages
- extra cost of power electronics
- maintenance aspects of electronics offshore
- wider excitation range of structural eigenfrequencies especially of the tower.

3.3 Partial variable speed

This uses a variable slip generator to obtain many of the advantages of full variable speed without the penalties of cost. This system has been developed by Vestas as “Opti-slip” system. It uses an optical link to control the effective impedance of the generator rotor, enabling the modulation of the slip frequency, thus lowering drivetrain shock loading and improving power quality.

4. Drive train options

4.1 The function of drive train

The purpose of the drive train is to convert the power on the rotor shaft to electricity at the generator terminals. The rotor is characterised by a low rotational speed and high torques. Electricity generation needs a high relative speed between the moving and stationary parts of the generators at low torques. Typical fixed speed generators work at either 750, 1000 or 1500 rpm.

The second function of the drive train is to transfer unwanted forces and reaction loads to the bedplate or support structure in an efficient manner.

4.2 Geared options

4.2.1 Modular drive train

This is a drive train where the main components are attached separately to a connecting bedplate. It usually consists of : main bearing, low speed shaft rear bearing, gearbox, high speed shaft and generator. Mechanical disc brakes can be positioned on either the low speed or high speed shaft. (see section E Safety Systems).

The function of the main bearing is to transfer the rotor weight and rotor thrust to the bedplate, allowing rotational motion of the low speed shaft.

The low speed shaft transfers rotary motion and may house the brake disc. Its length is often chosen to obtain a good balance of weights on the tower top. It often includes elastomeric couplings to absorb shock energy and to introduce damping

The second bearing ensures good alignment on the gearbox input shaft.

The gearbox steps up the rotational speed from the rotor to the generator. For large wind turbines driving standard generators these are usually 3 stage gearboxes with epicyclic first and second stages, and parallel shaft third stage. The epicyclic design gives a lighter, more compact design than the parallel shaft design for the same torque and speed rating.

The high speed shaft connects the gearbox output shaft to the generator input shaft. It often carries the main operational brake disc and it often carries flexible couplings to correct for any misalignment between the gearbox and generator.

The generator in a geared system runs at one or two of the standard speeds of either 1500, 1000 or 750 rpm and generates electrical power at a frequency of 50Hz. These generators have 4,6 and 8 poles respectively.

Induction generators are also known as asynchronous generators. They use reactive power to induce an electromagnetic field in the generator rotor. The driving torque produces power in the stator windings as the rotor is driven slightly above synchronous speed.

Reactive power must be supplied from outside the generator. For land-based machines this is the most common type of generator because they are cheap and reliable. The reactive power for starting is supplied by the electricity network (grid) which also supplies the fixed frequency which fixes the rotation speed (see section C variable speed operation). During operation, reactive power is often supplied by power factor correction capacitors.

Synchronous generators provide their own magnetising current using an exciter. They can generate power from startup without any outside supply of reactive power. The frequency of the voltage is determined by their rotational speed. They are used extensively for stand-alone wind turbines operating in diesel grids. For operation on large networks they must be synchronised with the grid frequency during start up.

Advantages
- Good accessibility for maintenance
- Standard industrial components may be available

Disadvantages
- The heaviest solution
- Gearboxes for large wind turbines may be outside manufacturers standard torque range.

4.2.2 Integral drive train (compact drive train)
The term integral drive train coves many variations of design of the geared system. All of these seek to reduce the overall, weight and cost of the modular system described earlier.

In some series produced small and medium scale wind turbines drive train development has moved towards the use of integrated drive trains, in which functions of support and gearing are integrated. The functions of first rotor shaft bearing and main gearbox bearing can be integrated, when a parallel gearbox is being used. The generator can be attached directly to the high speed shaft, giving rise to very compact and lightweight drive trains. In particular a large proportion of the bedplate weight can be avoided. This option is more difficult to engineer with epicyclic gears, which are the first stage gears required for megawatt class turbines. In such a transmission system the first (solar) wheel must be able to adjust to the loads received from the planet wheels and is not built to cope with shear loads in the shaft. Hence the weight of the rotor must be supported at the shaft in other ways.

Of turbines in the megawatt class several machines use partial integration, in which the drive train is designed in a very compact way even though it is built in a modular form. This leads to a lightweight solution, but entails the penalty of difficult access (Vestas V63, Bonus 750kW).

In the present MW designs there is a clear tendency to compact and lightweight drive trains. With this approach it is important to choose the load paths so that the rotating parts of the structure transfer only torques but do not carry bending moments (Nordic, WEG, etc.).

Advantages
- lower weight
- lower cost possible by combining functions in one component
- reduced bedplate and tower loads

Disadvantages
- access for maintenance more difficult
- special components must be manufactured
- modules to be replaced are physically larger than in the 'modular' design

4.3 Direct drive/gearless operation

Directly driving a generator from the wind turbine rotor without the need for a gearbox is an attractive option. The gearbox is an expensive item needing regular maintenance.

The main components of a direct drive or gearless system are a rotor support bearing and a generator. Direct drive generators are being developed in a number of forms. Two manufacturers, Enercon and Lagerwey make wind turbines at utility scale using this concept.

Direct drive is usually combined with variable speed operation (see section C) which combines the necessity of using power electronics to operate a reasonably sized generator with the advantage of extra energy obtained using variable speed operation.

Direct drive generators have a large number of poles arranged around a large radius. The Enercon E-40 has 84 poles and 6 phases, a rotor with field windings and grid connection through a frequency converter.

Other options for direct drive which are being considered are permanent magnet generators and switched reluctance generators, both in the development stage.

Advantages
- eliminates the gearbox, a high cost item
- offers promise of lower maintenance cost
- enables very compact design
- needs only one or two drive train bearings
- higher efficiency than a combined gearbox/generator system
- in combination with variable speed operation, higher energy capture than conventional fixed speed operation

Disadvantages
- special large generators must be purpose built
- must be used in combination with frequency converter involving power electronics
- large production runs required to obtain economies of scale in generator manufacture
- generator cannot be fully encapsulated against corrosive environmental impact.

5. Safety system options

5.1 Certification requirements

The certification bodies and the international standard IEC 1400-1 all insist that wind turbines be equipped with two independent safety systems each capable of bringing the turbine to rest from a number of potential operational and extreme conditions.

Most wind turbines at utility scale utilise use aerodynamic systems as the primary safety system and one mechanical system as a secondary system to fulfil this criterion. One turbine manufacturer, Tacke relies on 2 independent mechanical braking systems to perform these tasks.

5.2 Aerodynamic brakes stall regulated turbines

These normally consist of tipbrakes which can be activated automatically in a rotor overspeed condition through centrifugal force, or can be operated by control signals acting on the tips. The tips are usually designed to be fail-safe, operating by spring force when the hydraulic or mechanical power which is needed to re-set them is removed. (Actuation is dealt with below) Some small turbines (Atlantic Orient) use electro magnetic latches to hold centrifugally activated tip plates in place.

5.3 Aerodynamic brakes - pitch regulated turbines

Active pitch regulated turbines use the blade pitch mechanism to ‘ feather’ the blades when the turbine needs to be brought to rest.

5.4 Mechanical brakes

Mechanical brakes are normally disc brakes, with spring applied, hydraulically or pneumatically held-off callipers. In early stall-regulated machines, a brake was positioned on the low speed shaft. With increased experience, the brakes are now positioned on the high speed shaft, enabling disc size to be significantly reduced but with the disadvantage of having full braking torque transferred through the gear teeth in the gearbox.

5.5 Yaw controlled braking

One turbine, the GAMMA60, uses active yaw control to move the rotor out of the wind in order to bring the rotor to rest. This requires a very high yawing rate and imposes large gyroscopic loads on the rotor. This is overcome in the GAMMA 60 by using a teetered rotor.

5.6 Electrodynamic braking

This concept is currently undergoing a revival since its use in the 1980’s on Californian wind farms. It uses an extra electrical load imposed on the generator to reduce rotor speed. The technology is simple, using contactor relays, capacitors and dump load resistors to impose the extra load on the generator. Because at low speeds the electromagnetic field collapses, this system will only work down to about 20% of rotor speed. A parking brake is required to bring the rotor fully to rest.

6. FLEXIBLE CONCEPT OPTIONS

6.1 Overall concept

Flexible design concepts can be compared with a stiff concept such as the ‘traditional’ Danish three blade, stall regulated, induction generator concept which has served the wind industry so well.

Flexible options use the properties of components or sub-systems to reduce unwanted loads on the machine. The aim is to produce a lighter, cheaper wind turbine.

This section deals with the rotor concepts involved in ‘flexible’ design. The soft/flexible drive train options have been dealt with in variable speed and variable slip concepts elsewhere in the Appendix (section C).

6.2 Flexible blade concepts

Flexible blades are those which bend significantly in a flap wise direction. This sheds loads at high windspeeds and has been successfully employed by Carter wind turbines for many years. It is proposed for the ‘Ultimate Wind Turbine’ concept. This also includes self twisting blades eliminating the use of on active pitch control. By tailoring of the angle of attack of the flow, aerodynamic loads are reduced by increasing flapwise binding.

Advantages

- reduced bending moments at blade roots
- coning action reduces powers at high windspeeds

Disadvantages

- narrow frequency band of operation may restrict use in variable speed applications
- for full span pitch control the requirements for torsional stiffness and flapping flexibility conflict.

6.3 Teeter blade concepts

A number of two blade designs used fixed hubs, such as Nedwind and Windmaster, (NL) Näsudden I, II and III (S). Teeter is the name applied to the action of a two blade wind turbine hinged at its centre point. Many two blade machined such as the WEG MS3, MS4 (UK), the MOD2 and MOD5 (US), Carter (US), Gamma 60 (I) and the Maglarp (S) turbine have used this method. It reduces the different loading experienced at the hub as the two blades rotate in the wind field. The different loading on the blade comes from wind shear (change in windspeed with height), yawed flow, tower shadow, and coriolis force (gyroscopic force) from yaw motions.

Advantages

- reduced bending moment on the blade roots and hub
- requires lighter hub structure

Disadvantages

- requires teeter hinge and optionally, dampers

6.4 Hinged blade concepts

This is similar to teetering, but it can be used on 3 blade turbines. As well as eliminating blade root bending moments in the hinge direction, it enables coning of the rotor to take place, either passive, as in the Südwind (DE) turbines and Lagerwey (NL) turbines or actively as in the proposed Garrad Hassan Cone 450 (UK) design. Coning also enables the rotor to have a larger swept area at low winds and reduced in area at higher windspeeds. This utilises the generator more effectively.

Advantages

- reduces in-plane blade root bending moment to zero
- allows passive or active coning

Disadvantages

- extra hinges and mechanism
- dynamically more complex than fixed blades.
- Spring or active system required to keep the blades in parking position at low speed (startup)

Appendix B: Future wind turbine design concepts for offshore application

1. Introduction

In the main text certain ‘base cases‘ for the development of OWECS, broadly representative of the state of current technology, have been identified. Combinations of the base cases for each of the subsystems will allow investigation of the range of interactions between the factors that influence the cost of offshore wind energy. It is not practical, however, to evaluate one important interaction by this methodology, specifically that relating the design of the turbine, the operation and maintenance solution and their influence on the energy costs.

In this appendix a ‘forward looking’ approach will be taken to investigate how relatively radical changes in design might influence energy costs, for example the effect that any improvements in turbine reliability might have on the energy costs of an OWECS. Five possible ‘concept lines’ along which the development of future wind turbines for offshore application might progress have been identified:

- Base case
- Disposable wind turbine
- Reduced failure wind turbine (“Robust 1”)
- Easy maintenance wind turbine (“Robust 2”)
- Advanced lightweight wind turbine

Each concept represents a different compromise between the desirable features. Some designs attempt to minimise the amount of maintenance required, some focus on simplifying and therefore reducing the costs of maintenance, while others neglect maintenance altogether aiming to maximise the energy yield.

The concepts are intended to represent something of what the ‘next generation’ of OWECS turbines might look like. Each, therefore, is described in relation to a base case that is a fictitious machine. The discussion will be limited to reviewing the development concepts, and attempting to make some entirely qualitative comparisons and projections.

2. Base case

2.1 Concept description

The base case machine is intended to be comparable to current state of the art 1 MW capacity and greater commercially available turbines, that have been subject to limited marinisation for offshore use.
Proposed characteristics
A failure schedule for the base case has been synthesised from data for a number of commercially successful modern wind turbines in the 500 kW and above range.

- Preventative maintenance carried out every half a year
- Corrective maintenance performed according to 6 failure classes as in table B-1.

Type of failure	Events/year	Repair time (hours)	Heavy lifting equipment required?
Blades / heavy component	0.44	24	yes
Gearbox, etc.	0.14	48	no
Electronics/control	0.29	48	no
Hydraulics	0.22	24	no
Electrics	0.37	16	no
Others	0.33	4	no

Table B-1: Failure schedule for the base case concept

3. 'Disposable' wind turbine

3.1 Concept description

The primary goal underlying a disposable no-maintenance concept is the production of the lowest capital cost machine consistent with a predictable lifespan. No provision would be made for any maintenance at all, not even onshore, allowing the adoption of a very tightly integrated component arrangement. This concept has been formulated with a view for use with a no-maintenance strategy, where failed machines would be abandoned and no attempt made at repair, other than perhaps replacement of the whole nacelle. This has two implications. Certainly failures should be minimised. Yet, it should be recognised that failures are going to occur, and that to minimise wasted investment, a low capital cost turbine is essential.

In view of the need to minimise costs, there would be little room for sophistication in a disposable machine, unless it brought substantial reliability benefits. Thus in general, more recent innovations designed primarily to increase energy capture, such as variable speed would not be applicable. Relative simplifications, the use of a direct drive and power electronics being an example, would have a role to play, and in many instances would sit very well with the highly integrated design. In essence a disposable machine would be an extremely well conceived, but predominantly conventional design.

Disposable machines would have to be very carefully designed, to ensure that the expected lives of all their components are very similar. Combining components with different lives would unnecessarily increase the capital cost. It is pointless having a generator with a twenty year life if the drive shaft is likely to fail after five years. In addition, it would be important for the variance of the expected component lives to be tightly controlled.

3.2 Proposed characteristics

Maintenance

- Preventive: none specified or possible
- Corrective: failures would occur at a rate comparable to that of the base case (with up to 20% increases or decreases in the failure rate being considered). No corrective maintenance is possible, other than replacement of the whole turbine.

Capital cost

- Reduced compared to base case

4. Reduced failure wind turbine ("Robust 1")

4.1 Concept description

The objective of the reduced failure turbine is to reduce the failure rate by improving the engineering of the machine. This improvement in reliability would necessitate a substantial increase in the machine capital cost. Such a turbine would probably be based heavily on an existing design, in an effort to avoid the unexpected troubles that are often associated with the adoption of totally new technology. The reduced failure concept would represent much more of an incremental development of existing technology than any of the other ideas.

Aside from ensuring that all components were sufficiently strong that they would not fail unnecessarily, a number of steps could be taken to improve failure rates. As an example, self lubricating bearings would help reduce bearing failures. Further reliability improvements might also be possible by replacing failure prone components with simpler, more robust alternatives such as using direct drive rather than a gear box and passive rather than active stall power control.

Other steps that could be taken include:

- Redundancy in major systems, such that any individual failures would not cause failure of the whole machine. Redundancy would be much easier to achieve in electronic/electrical systems rather than mechanical systems, for example it is physically impractical to have redundant blades or drive shafts, but it is relatively simple to have redundant electronic rectifiers, transformers. This, therefore, would tend to favour machine designs with fewer mechanical components (i.e. direct drive).

- On-line monitoring and control, designed to enable remote correction of as many problems as possible. This would prevent minor faults from halting energy production, making visits to the turbine necessary.

- A sealed nacelle with a controlled climate (through for example air conditioning) would prevent damaging salt water from reaching the internal components and increase the life of the machinery.

- In general the machine would be constructed of heavy, overspecified components.

4.2 Proposed characteristics

Maintenance

- Preventive maintenance: As for base case
- Corrective maintenance: Reduced number of failures compared to base case.
  Repair times the same as for the base case.

Capital costs

- Increased compared to base case

5. Easy maintenance wind turbine ("Robust 2")

5.1 Concept description

The underlying idea behind the easy maintenance turbine is to reduce the time and costs associated with offshore maintenance operations. No particular attempt is made to reduce the incidences of failure, but rather facilities are incorporated within the turbine to simplify rectification of failed machines. There are two ways in which OWECS turbines could be designed to achieve this.

Firstly, maintenance facilities could be constructed as an integral part of the design. Incorporating lifting gear into the nacelle for example would make a whole range of operations practical without any requirement for external equipment. Inevitably, this would have a detrimental effect on the overall capital cost of the plant and the capacity of the gear would have decided with this in mind. It should also be remembered that for very large operations, such as blade exchanges, external lifting equipment would still be needed.

A second way to reduce maintenance times would be through the use of a highly modular design that allows failed sub-systems to be quickly swapped. Thus, rather than perform extensive diagnostics attempting to locate the precise cause of a failure, followed by extensive work to access the failed component, workers would simply swap whole sub-assemblies. There is scope for taking this approach even further in the original design, by omitting large components for smaller, more easily replaced alternatives. A case in point might be eliminating a large gearbox by employing a direct drive machine with power electronics for converting the produced electricity into a form compatible with the external power grid.

Easy maintenance designs would benefit greatly from remote condition monitoring techniques. The early detection of a developing fault might enable its correction while still in the 'light-maintenance' category. In a strictly conventional machine, without condition monitoring, damage might accumulate undetected until a major failure occurred.

5.2 Proposed characteristics

Maintenance

- Preventive maintenance: As for base case, possibly reduced

Corrective maintenance: Same number of failures as for base case, but repair times reduced by approximately a half.

Capital cost

- Increased capital cost compared to base case

6. Advanced lightweight wind turbine

6.1 Concept description

An alternative approach to offshore design is to neglect maintenance as a main driver, and attempt only to optimise the balance between the machine capital cost and performance. The design criteria are then very similar to those underlying the advanced, flexible turbine concepts proposed by many forward looking on-shore studies.

Such an advanced design would seek to achieve good survivability offshore by alleviating high loadings through bending and compliance rather than resisting with pure strength. A particular example of this flexible technology would be the downwind 'coning' blade [B-1], which reduces loadings by 'folding up' at increased wind speeds. The folded-up blade presents a small cross-sectional area to the oncoming wind, thereby limiting the thrust force exerted on the support structure, and potentially allowing turbine operation at higher wind speeds than conventional designs allow.

Innovative control features can also serve to reduce loadings, by for example, fast 'active' yawing and rapid blade feathering to reduce the effects of gusts. Variable speed control systems can also have a role in load alleviation and improvement of the aerodynamic efficiency [B-2].

One recent example of a proposed design in this genre is the so called 'Ultimate Wind Turbine' [B-3]. Although formulated for onshore use, it has many qualities that would be attractive to the developers of offshore wind farms. The use of a flexible direct drive between the rotor and the generator would provide a lightweight, maintenance free teeter mechanism when combined with a highly flexible rotor. Similarly a variable speed control system would allow transient loadings to be easily absorbed while peak loads during storms could be accommodated by allowing the rotor almost to run free.

Ultimately, it is likely that production versions of lightweight machines will be reliable. It should be born in mind, though, that any ‘next-generation’ wind farm built using advanced technology would be relatively unproven. Experience shows that unproven wind farms are prone to failure, and thus an advanced turbine is likely to be less reliable than the base case.

Conventional opinion holds that lightweight machines are likely to be cheaper than their more ’robust’ counterparts. For a machine as advanced as that envisioned here, this seems unlikely. While certainly there will be reductions in the bulk of the components required, the cost of ’high-tech’ materials needed for their manufacture might well compensate for this. It is not safe to conclude that the capital costs of an advanced turbine will be substantially less than those of more conventional designs.

6.2 Proposed characteristics

Maintenance

- Preventive maintenance: Regular, every half a year (as for base case)
- Corrective maintenance: Approximately 20% increase in failure rate compared to base case, with no changes in the repair time.

Capital cost

- Comparable to base case

Other

- Increased energy yield (so long as the machine is fully functional).

7. Comparison of future concepts

The majority of attention will be focused on the ’hard’ features of each concept that directly affect the energy cost, that is the overall capital cost, the operation and maintenance cost and energy yield. If the ’pure’ economic results are close however, then the risk associated with each concept might be the deciding factor.

Figure B-1 gives a qualitative comparison of the major features of each concept. The distance of each box from the left hand side of the diagram represents the relative cost of each aspect of the relevant concept, whereas the length of the box indicates the uncertainty of that costs. The top bar attempts to indicate the ’risk’ of each concept, distance from the left being loosely proportional to the level of risk; it can be thought of as representing a monetary value for the risk, that could be added to the overall investment cost of aid in the comparison of the concepts. While the diagram is a helpful illustration of the ideas, it is important to remember that it reflects only one judgement of the merits of each concept, and is in no way based on any form of quantitative analysis.

The disposable design would be the cheapest scheme both in terms of overall capital cost and operational costs. This, indeed, is the whole basis of the concept. Thanks to the lack of sophistication within the machines, and that a fair proportion of the machines may spend a considerable quantity of time inoperable, having failed, then the disposable concept would undoubtedly provide the lowest energy production relative to the farm capacity at construction.

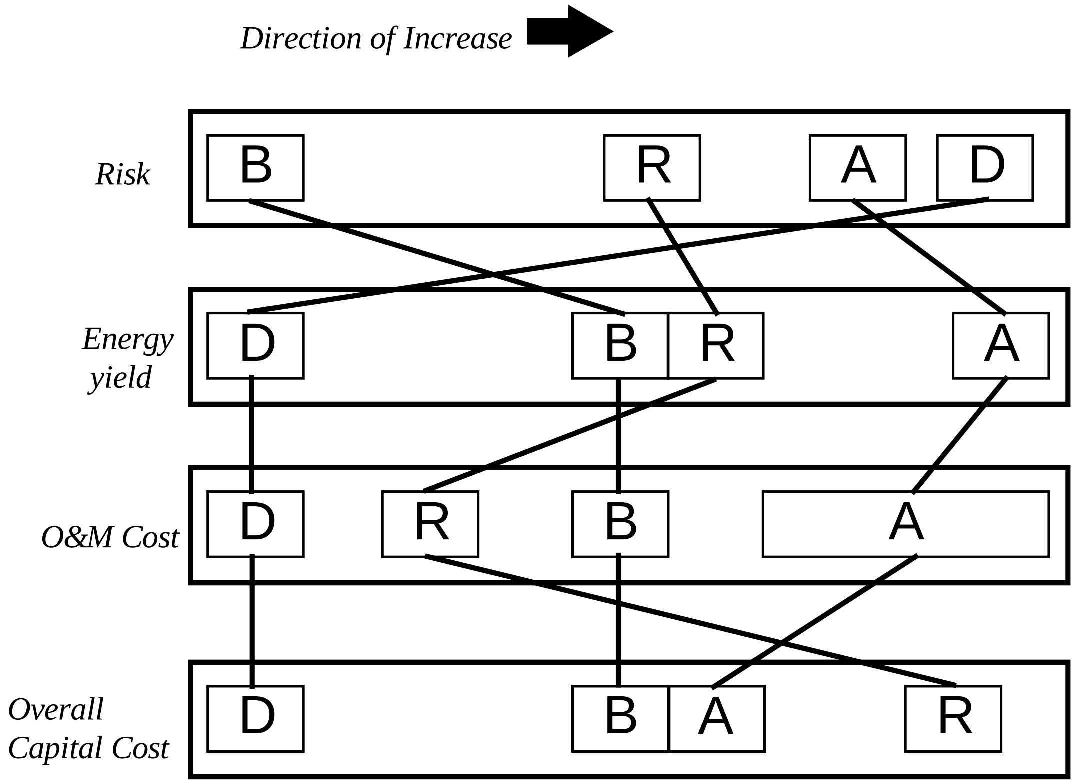

Figure B-1: Preliminary qualitative comparison of the perceived advantages and disadvantages of the proposed OWECS future development concepts.
(The letters should be interpreted as follows: B - Base case; D - Disposable machine; R - Robust (both types), A - Advanced lightweight.)

The disposable concept is likely to be very risky for the developer. The economics is dominated by achieving very low or even non-existent expenditure on O&M. The machines, therefore, must work. Any deficiencies that cause unexpectedly high failure rates will wreck the economic calculations in a devastating fashion.

The reduced failure rate (“robust 1”) design is at the opposite end of the capital cost scale from its disposable counterpart. Attempting to reduce failures would probably be an expensive exercise. It will never exhibit the absolute O&M economy that the disposable machine aims for though, since the capital tied up in each machine means that some action will have to be taken in the event of a failure - abandoning machines for the plant lifetime would represent a large wasted investment. In return for the extra expenditure, the long-life concept should return a considerably better energy with sophisticated design improving the performance of individual machines and excellent availability boosting the energy capture of the OWECS as a whole. Being essentially derived from current technology, the risk associated with a reduced failure rate machine is likely to be fairly low. Building machines adapted from tried and trusted designs must be safer than adopting radical innovations.

Easy maintenance (“robust 2”) designs would be at the expensive side of the capital cost spectrum thanks to the inbuilt maintenance facilities they would contain. The nature of the proposed maintenance is intended to keep O&M costs reasonably low, but they would still be significantly higher than for the disposable (i.e. no-maintenance) design. There would be some risk involved in designing an OWECS on these principles, but it would be towards the lower end of the range. Only very large design faults afflicting many of the machines would grossly upset the economics, by necessitating unplanned, expensive repairs.

It is difficult to speculate usefully about the economic features of an advanced lightweight machine. The most that can be said about the overall capital costs is that they are likely to be comparable to conventional machines. O&M costs are particularly difficult to evaluate, really the only sensible conclusion being that they will be more than for the no-maintenance machines. For the energy capture, things get a little easier; certainly the advanced concept should have by far the best energy capture. Also fairly clear is the risk involved with an advanced project - it would be considerable. The shear quantity of development work necessary to implement such a design would mean that the designers could not be sure from the outset that their concept would work.

The optimal choice of concept for OWECS depends to a large extent on the nature of the capital cost / O&M cost trade off, which is not well known. Figure B-2 shows diagrammatically a number of curves that might represent possible relationships between the capital cost and the O&M cost for an OWECS, if the energy yield is kept constant[1] . Any decision as to the best direction for future development - whether to increase or decrease capital costs in the hope of influencing the maintenance costs - depends both on which curve development will follow, and where on the curve current technology lies. If for example, current machines lie at point (1), then substantial excursions in the capital cost have only a limited influence on the O&M expense. Thus significant savings could be made in the investment costs without having too detrimental an effect on the O&M costs, and the most economic approach would be to minimise capital costs. At point (2) however, matters are quite different. Here, small changes in the capital cost have a large effect on the O&M cost. The most economic solution here is to increase the capital cost until such a point that the consummate decrease in O&M is no longer worthwhile. This point can only be determined by a quantitative investigation.

Effectively, each curve represents a different concept with a particular performance characteristic. Some point on each curve will produce a minimum overall cost design, representing the optimal trade off between investment and maintenance costs for that concept. This optimal point will be greatly affected by conditions outside the full control of the OWECS designer, particularly site characteristics, and the relative costs of maintenance and construction. To decide upon the best solution for a site it is first necessary to optimise the design of each concept (including the support structure, grid connection, array layout etc. as well as machine and operation and maintenance) and then compare the concepts on the basis of the economics.

[1] It is important that the energy yield is kept constant along each curve in this comparison. If this is not the case, then the diagram becomes meaningless since capital and maintenance costs could be varied almost independently. For example, the diagram assumes that, for any one curve/concept, substantial reductions in the capital cost will produce a fall in reliability and hence maintenance costs will have to rise to maintain the same energy production. Of course, it would be possible to leave the maintenance regime unchanged, and accept a lower availability and energy yield, but in this diagram that would mean switching to a different curve - accepting a reduction in energy yield is equivalent to changing the design goals for the OWECS, in other words changing the design concept (albeit slightly).

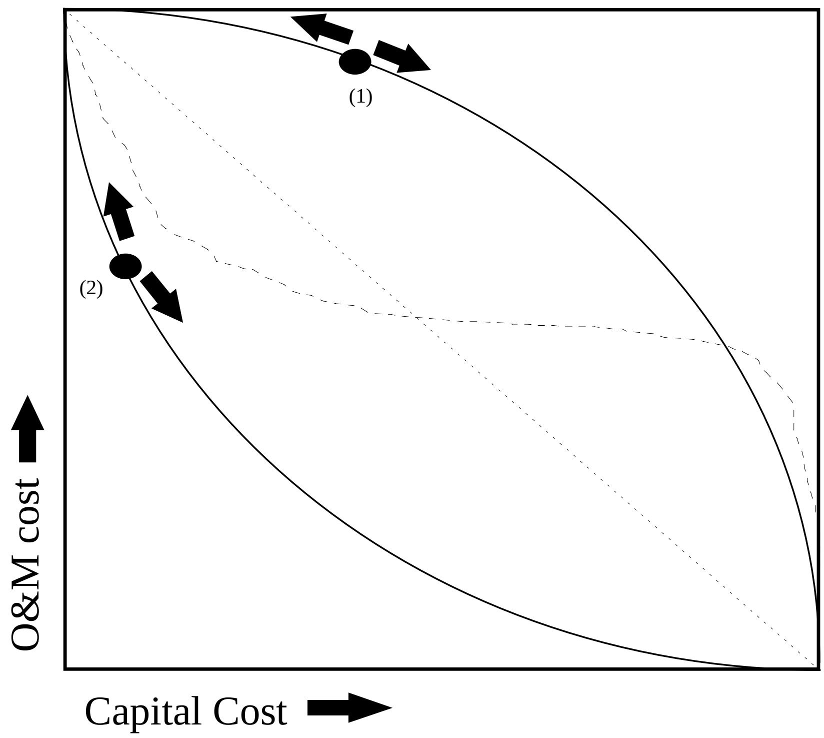

Figure B-2: Sketch graph to illustrate the trade off between operation and maintenance costs and capital costs for an OWECS
(Each curve represents a certain design concept with constant energy yield along each curve.)

References

[B-1] Jameson, P. et. al., Advanced Wind Turbine Design, Proc. EWEC ‘94, Volume II, p. 993ff

[B-2] Dijkstra, S. et. al., Control of Wind Turbine Systems to Reduce Vibrations and Fatigue Loading, Proc. EWEC ‘94, Volume I, p. 425ff.

[B-3] Jong, J.C. et. al., Design Study of the Ultimate Wind Turbine: A Minimum Cost and Minimum Maintenance Machine, Proc. EUWEC ‘96.