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Guidelines regarding the variation of infrastructure requirements with scale of deployment

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Guidelines regarding the variation of infrastructure requirements with scale of deployment

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Summary

There have been many studies of the possible variation of economic viability (in particular on the cost of electricity per kWh and the specific capital cost) with cumulative installed capacity of marine energy. Typically the learning curve approach has been employed using progress ratios inferred from other sectors. Although of some use for long term policy decisions, learning curve studies of marine energy systems do not provide a basis for understanding how the cost of a particular technology may vary with deployment site and with the installed capacity at a particular site. To understand how the economic viability of a technology may vary between individual projects, it is important to consider how the cost structure of a project can vary with scale of deployment. Since it is beyond the scope of this project to address the design- and cost- of individual devices, the focus of this task has been on evaluation of the essential infrastructure requirements associated with different types of marine energy device. The main design options for mooring systems and bed-mounted structures for both wave-devices and tidal stream devices have been identified in deliverables 7.3.1 and 7.3.2. This report summarises the main findings from earlier deliverables regarding the suitability of mooring and support structure options for array deployment and provides a summary of the processes which are expected to cause changes of infrastructure requirements due to change of project scale.

1 INTRODUCTION

To understand how marine energy systems may contribute to future electricity supplies it is important to predict how costs may change as the industry moves from demonstrator schemes to large-scale deployments. This requires consideration of the change of economic viability due to:

i) Increased project scale: e.g. to understand how the estimated cost of a pre-commercial project (Order 1-10 MW installed capacity) relates to a commercial scale project (for example; an installed capacity of 100 MW or greater).

ii) Increased development of the technology which may occur due to a variety of factors including Research & Development and learning from experience of either the technology or the sector.

In many studies of marine energy economics (EPRI, 2004 and Carbon Trust, 2006 amongst many others) it has been assumed that the cost of electricity will fall with the cumulative installed capacity. This approach is based on the assumption that increased experience of designing and using a technology reduces its cost and is referred to as an experience curve. Details of the approach are given in various texts (Junginger, 2004; IEA, 2006) but essentially the approach assumes that, for each doubling of cumulative installed capacity, costs fall to a percentage of those in the reference year by a factor defined as the progress ratio. In general, progress ratios in the range 85 – 90% have been applied to the cost of energy from marine energy systems (Carbon Trust, 2006; EPRI, 2004). Since there is no data on which to base marine energy learning curves, these progress ratios have typically been based on those observed for a range of other industry sectors, with particular reliance on data drawn from the wind industry. Progress ratios for the installed cost of onshore wind have been reported as 92 – 94% (Neij et al. 2008) although variations are observed across states (90–96% for several EU states; Neij et al. 2003) and with sample and data size (77 – 85% globally, Junginger et al. 2005), 82-92% observed by McDonald and Schrattenholzer, 2001). Progress ratios for the unit cost of electricity from wind energy (e.g. €/kWh) are generally lower (~82 %, Neij et al 2008) since they account for reductions of both installed cost and operating cost as well as increased performance.

Whilst the learning rate approach is of some use for predicting general trends across a sector, many studies caution the use of this approach, particularly for emerging technologies. A recent example of learning curve limitations is given by the UK offshore wind sector - although costs were expected to fall from 2007 to 2010 (Ernst & Young, 2007) they have risen (Ernst & Young, 2009). This cost increase seems to have occurred due to several factors including a doubling of average capital costs and 65% increase in operating costs over a five year period. In this case, cost increases appear to be driven by supply chain constraints and (to a lesser extent) real changes of exchange rates (ODE 2007; Boccard et al. 2009). Principal concerns associated with the application of learning curves are:

- Progress ratios are difficult to transfer between industry sectors (IEA, 2006)
- Progress ratios estimated from historic data are uncertain. Even when the same set of turbine cost data is employed, the learning rate can vary between 1.8-7.9% depending on econometric assumptions (Soderholm and Sundqvist, 2007) so sensitivity ranges are recommended (Neij et al 2008 recommends 2%).
- Progress ratios are time-varying and so it has been suggested that extrapolations should not be made beyond two orders of magnitude from the supporting data (IEA, 2000).
- The cumulative installed capacity at which cost reduction due to experience commences remains unclear. In a study focused on the investment required for marine energy learning (Jeffrey, 2008) it is noted that experience does not lead to cost reductions until the installed capacity of a single technology type is greater than around 100MW.

Aside from the limitations noted above, the experience curve approach does not facilitate comparison between different types of marine energy technology since estimates are generally made for an industry sector. An alternative to the top-down industry-wide approach of experience curves is to apply a bottom-up analysis to the costs associated with representative projects of increasing scale. This requires more detailed understanding of the cost breakdown for a particular technology and so is difficult to apply at an early stage. However, for any electricity generating technology, economic viability (based on a discounted measure such as the levelised cost of electricity or net present value) can only be improved through one of three main mechanisms: increase of revenue or reduction of either capital or operating costs (see Equimar D7.1.1). (Note that, discounted measures of economic viability will also reduce with reduction of the perceived risk (see Equimar D7.2.1) but this aspect is not considered further at this stage.) Estimates of cost reductions or performance increase can therefore inform estimates of change of economic viability. Since it is impractical to consider the costs associated with device manufacture, one part of the capital cost – station keeping infrastructure – is considered in this report. Issues associated with the change of operating requirements with scale of deployment are discussed in EQUIMAR Deliverable 7.4.1 and performance improvement is considered in EQUIMAR Deliverable 7.5.

The cost of both station-keeping and inter-array electrical equipment will depend on the number of devices to be installed, their configuration within an array and the inter-device spacing. Station-keeping systems vary with device type but typically either comprise a mooring for floating devices or support structure for bed-mounted devices. Deliverable 7.1.1 identifies the following components of infrastructure costs:

Installation costs

Expected to strongly influence the deployment site due to both the distance to shore and the type of bed-conditions. Although this cost may be device specific, there are likely to be similarities for types between particular typologies of devices. For example, most of the offshore floating wave energy converters currently being developed could be towed to the deployment site through the use of vessels generally operating for offshore oil and gas industry. Costs associated with these vessels, however, might be changing depending on demand. The Marine Energy Challenge (Carbon Trust, 2006) used long-term average rates for estimation of these costs and additionally considered the possibility in the future to obtain lowest rates for long-term operations (large scale farms will require several units to be installed and therefore a large number or vessels or a long hiring period). Carbon Trust estimates installation cost as 13% for a typical wave device and only 2% for a tidal stream device. Developers with experience of deployed devices estimate station-keeping costs represent 15 – 35% of capital cost (Figure 5.1 Deliverable 7.1.1) but these costs are expected to reduce by 5 – 20% (Figure 5.3, Deliverable 7.1.1).

Station-keeping costs

Include all the components required to hold the device in place. Depending on the design, the structure of the device might effectively work itself as station-keeping element. Horizontal axis tidal turbines are typically installed on a monopile that represents also the main structure of the device. For offshore floating converters, moorings are usually separate systems that allow the device to move independently within a limited range and are required to prevent drifting of the device. Design of foundations and moorings has been common practice for decades in offshore oil and gas extraction and therefore many standards on mooring design criteria are available and cost accounting procedures of mooring systems have been defined. However, the difference of the scale of the projects implies choices that would not be cost-effective at all if applied to marine renewables. Moreover typical safety coefficients defined for the offshore industry are generally quite conservative. Carbon trust estimates tidal stream structure as 39% of total capital cost. Developers with experience of deployed devices estimate station-keeping costs represent 2.5 – 25% of capital cost (Figure 5.1 Deliverable 7.3.1).

The purpose of this report is to provide an overview of the main findings from infrastructure studies presented in Deliverables 7.3.1 to 7.3.2 as related to arrays of marine energy devices. First, a brief review is given of the infrastructure requirements of the main device types and the variation of these requirements with scale of deployment is discussed. This provides information on the site conditions for which alternative support structures are suitable. Subsequently, processes by which the costs of infrastructure and the cost to install infrastructure may be affected by scale of deployment are discussed. In this section, the processes of cost reduction are considered in terms of scale of deployment, experience of deployment and time dependency. Indicative estimates of quantitative change of cost are noted where this information is available. The information presented is intended to summarise design considerations that should be made when estimating (or comparing) the economics of projects of different scale.

2 MOORINGS FOR ARRAYS OF DEVICES

2.1.1 General considerations for array installations

(i) The acceptable size of surface and subsea footprint. This is absolutely key in determining the mooring configuration. Given "unlimited" space the choice would be for either a simple catenary or compliant system which will provide the most well understood and load accepting configurations. However the need to produce a particular density of machines will then have a strong influence on mooring requirements which could radically increase costs as higher load capacity is required in the legs for smaller footprints.

(ii) The loading criterion will affect the dimensions and arrangement of a mooring configuration and is fundamentally related to the site conditions (wave, current and wind) AND the device characteristics. For example, PELAMIS is designed to particularly "shed" the higher loads from extreme wave as a principle of operation. The mooring configuration will also be affected by any "directional" properties of the device that will produce particular directional loading states that has to be considered in the mooring design. The degree of redundancy must be considered carefully. Although there is not the same degree of health and safety concerns within a MEC array, the consequence for the array of a single device becoming detached could be serious.

(iii) A key cost reduction philosophy for array deployment would be to reduce the number of components/installation requirements as array number increases. The sharing of each anchor point to connect to several lines could be considered. This has advantages in minimising the number of installation points. It may also provide a reduction in overall loading on the anchor point. This arrangement would require a piled anchor connection and be more complex to install. A second method of minimising sea bed attachments and anchors points might be to provide compliant (surface) connections between a number of devices in the array. This would have a high degree of novelty. There has been a large amount of analysis on two body, tanker-tanker or tanker-calm mooring analysis but the multi-body dynamics for multiple linked devices would be uncertain.

(iv) The response of the umbilical due to device motions is a key concern when designing the mooring. Methodologies that would allow "de-coupling" of the umbilical or, perhaps, shared umbilical arrangements could result in reduced costs for umbilical/mooring arrangements.

(v) Quick release connection/disconnection systems would reduce maintenance and servicing costs within a large array, but should be weighted against the general survivability/availability criterion.

2.1.2 Array system costs

This will depend on the allowable footprint but indicates the approximate magnitudes. In general as the allowable offset of the device is increased the total cost will decrease.

(i) chain and lines (50 -70% of costs) is the largest cost factor. Note cost of anchors is dependent on required holding power and weight and this is sensitive to subsurface geotechnical conditions. For example – sand is better than clay with cost of anchors being approximately 25% for clay deployment. The capital cost of a driven pile is considerably less (around 40% of equivalent capability anchors) BUT installation costs for piles are much higher (vessels types time and spreads). For suction piles both the capital cost and installation cost increase.

(ii) connectors (shackles etc)

(iii) buoys and clump weights

2.1.3 Array installation costs

Cost of installation is heavily dependent on two factors:

(i) the need for specialist vessels and

(ii) the time required to install.

These are both driven by the complexity of the system (e.g. system with wire rope, chain, synthetic fibre, mid line buoy, etc), the water depth and the available installation vessel. Furthermore consideration must be given to the installation of a single or multiple devices.

For single (small number of machines) all of the "standard" mooring methods could be appropriate. It is unlikely that for these numbers the footprint would be of great concern with regards the use of sea space. The prime consideration would be to ensure that the umbilical was adequately protected from undue motion and fatigue loading.

It is likely that the catenary with spring buoy would be most attractive. This is because of the better loading characteristics (though care is needed to consider the effects of the survival conditions of overly compliant systems). The major advantage would be in deployment of the device/maintenance of the device. The inclusion of a surface line has the following benefits, (i) greater ease of connecting during installation and disconnection for removal of the device; and (ii) failure of an individual line is relatively simple to repair (a failure of a simple catenary would imply recovery of the end from the sea bed).

For larger arrays (multiple devices systematically arranged) the use of sea space becomes more important and the footprint of both the device and the seabed spread has to be included in the mooring design that will effects installation methodology.

- Pure catenary would require larger sea space. Installation is well understood and so installation costs might be expected to be least for a pure catenary.
- Catenray & spring buoy would reduce the footprint somewhat but add to the complexity of the mooring. For a large array this could be very expensive in terms of time of installation and maintenance. Note that a decrease in the footprint will generally lead to an increase of costs through the requirement for higher load bearing capacity of the chain/wire. Installation costs would be higher due to the greater complexity requiring more specialist handling and installation equipment. The multiplicative factor of a large array will make this more important.
- It is for this case that the tension leg mooring might have a long-term benefit. It could provide the ability to minimise footprint whilst providing enough compliancy to minimise static loading. The main barrier to this in terms of cost would be the need to provide vertical hold anchors. This would imply specialist (DP) vessels and so installation costs and uncertainty high. This may also provide a design solution for floating tidal turbines for deeper waters. The use of more compliant moorings (and resulting motions) may have highly adverse effects on the efficiency of floating tidal devices.

2.1.4 Overall economic considerations for array installations

For the installation of multiple devices in an array layout the choice of a mooring configuration may not be based necessarily purely on the capital, installation and operation costs to account for the overall economics of the array. Economic factors must consider the wave energy available and the extent to which this can be harvested. A wider spread for the same devices will reduce the number that can be installed in a given area. To achieve an economical arrangement that is profitable, devices may have to be more closely packed, demanding specific mooring configurations. (A devices that generates high power per m^2 of sea surface area may typically have a larger mooring spread. Alternatively a device which produces less power per m^2 must be "packed" more closely.) There may be no straight forward "generic" assumption that can be made as to how closely devices may situated, requiring a detailed understanding of the design capacity of each specific device.

3 SUPPORT STRUCTURES FOR ARRAYS OF DEVICES

3.1 SURFACE DEVICES (WAVE DEVICES)

A review of alternative support structure concepts for an array of closely spaced wave devices is given in report 7.3.1 (ODE, 2009) and the main concept types are summarised in Table 3.1. Primary findings are:

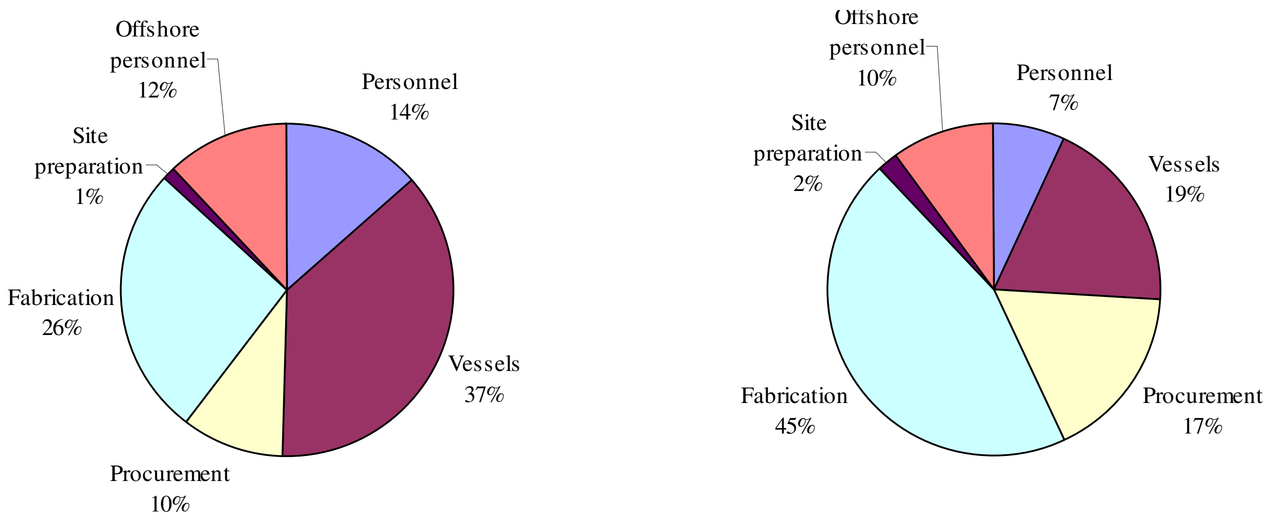
- Dolphin pile supported structures only suitable in water depths less than 20 m. (similar to 25 m suggested by Talisman, 2007 for offshore wind).
- Structure design strongly influenced by lateral load transferred from floats to supporting platform and design for full lateral restraint of horizontal load on all wave energy devices is impractical.
- Alternative float-over configurations must be tailored to specific designs and are sensitive to environmental conditions.
- Platform installation cost typically represents 20 – 25% of the total cost of the facility and are typically determined by the primary installation vessel employed for the work rather than by the structure itself.

Table 3.1: Summary of options for support structures for surface devices (Equimar D7.3.1)

	Monopiles	Braced Monopiles	Piled Lattice	Gravity-Based	Semi-Sub
Soil	Sand, Clay, Weak Rock. No rocks (driven piles)			Sand or Clay. Adequate shear & bearing pressure	Suitable for drag- or pile-anchors
Depth	< 10 m	< 15 m	< 50 m	> 50 m but column diameter and ballast increased	< 40
Tidal Range	n/a			n/a	n/a
Fabrication	Rolled steel (up to 100 mm thick), Diameters up to 6.5 m		Standard offshore jacket techniques	Requires dry dock with > 10 m draft	Standard semi-sub techniques
Foundation Install	Driven piles	Driven raked piles	Heavy lift vessel	Bed excavation & preparation.	Anchor handling
Topside Install	Float-over barge		Heavy lift vessel	Heavy lift vessel	Float-over barge
(+)	Cheap fabrication	Cheap fabrication High lateral capacity Simple installation	Compact, standard offshore structure	Low skilled fabrication Long life	Straightforward installation & removal
(–)	Specialist installation vessel Depth limited by lateral capacity < 10 m depth	Depth limited by installation < 15 m depth	Joint fabrication can be expensive	Dry dock Bed preparation Low moment resistance Decommissioning	Typically only competitive in deep water or for liquid storage (ODE)

Following the concept review, a detailed design was conducted of two support structures which differed in terms of water depth and number of wave devices installed. These were are a structure supporting 10 wave devices in a 5 x 2 configuration suitable for water depths up to 20 m and a structure supporting 25 wave devices in a 5 x 5 configuration in water depths up to 40 m. For both cases, representative bed conditions are assumed to estimate pile dimensions and a contingency provided for any additional piling cost. Dimensions of each structure were selected to allow installation by different classes of offshore vessel. Capital and installation costs were obtained based on calculated dimensions, and installation requirements. From the capital cost estimate for two different types of structure the specific capital cost breakdown for a single supporting structure can be obtained as illustrated in Figure 3.1. For both structures, these cost breakdowns include all line items listed in Sections 9.3.1 and 9.3.2 of [xx] except for preliminary design work.

In both cases the major components of capital cost are procurement (based on raw material costs), fabrication and vessel rates. Procurement & Fabrication costs are based on steelwork weights obtained from structural design and appropriate rates obtained by ODE. As with moorings, the cost of support structures is heavily dependent on the type of vessel employed and the duration of vessel use. For both configurations, the installation schedule is estimated as two weeks due to the requirement to meet a mid-summer installation window at a typical site. Within vessel costs, mobilisation & demobilisation costs and costs associated with offshore support vessels represent 50% of vessel cost for 5 x 5 platform and 60% of vessel cost for 5 x 2 platform. Deployment of multiple platforms at the same site would see these costs incurred only once for the site. For installation of 200 generating devices (8 No. 5 x 5 platforms or 20 No. 5 x 2 platforms), representing an installed capacity of 100 MW (approx), this provides a reduction in vessel rates of approximately 50% relative to costs for installation of a single platform. If these costs are halved the total capital cost would be reduced by 5% or 11 % respectively. Whilst this study only compares a small number of designs it provides an indication of the relative magnitude of the major costs associated with this type of structure and allows preliminary estimates of cost changes to be made.



(a): 5 x 2 array (b) 5 x 5 array

Figure 3.1: Breakdown of specific capital cost for wave device support structure based on design and estimates by ODE (Section 9.3.1 of ODE, 2009). Total structure cost of 4.35£k/kW approx. excludes one-off preliminary design work.

3.2 Sub-surface devices (Tidal Stream Devices)

The foundation systems presented in report Equimar Deliverable 7.3.2(b) are the three main technologies that are currently in use for horizontal axis tidal stream devices. Differences between the three tidal stream foundation technologies are summarised as follows:

- **Gravity based foundations** are suitable for deep water and characterised by low installation costs. However, a long schedule of installation and maintenance makes the technology unsuitable for large-scale developments.
- **Mid-weight tripod anchored foundations** are suitable for deep water and characterised by low maintenance costs and a complex installation procedure. This technology is presently suitable for medium-scale farms and, would be suitable for large farms if rapid installation and maintenance strategies are developed.
- **Mono/Multi-pile foundations** are suitable for water depths to 30 m (approx.) and are characterised by straightforward maintenance. Presently the technology is too expensive for early-farms but a reduction of installation costs is expected as the scale of the farm increases so should become suitable for large-scale farms.

Table 3.2: Summary of support structure options for sub-surface devices

	Large Gravity-based foundation	Mid-weight anchored structure	Mono-pile structure
Installation Costs	Cheap	Cheap	Expensive
Maintenance Costs	Expensive	Medium	Cheap
Installation Time	Long	Short	Short
MaintenanceTime	Long	Short	Short
Installation Logistics	Float over	Mid-weight lift	Heavy-lift
Maintenance Logistics	Heavy-lift	Mid-weight lift	Small vessel
Large-scale farm development	Difficult	Possible	Feasible
Visual Impact	Immersed	Immersed	Surface piercing

The table above represents a summary of the suitability of the three main foundation technologies for tidal stream support structures as detailed in Equimar D7.3.2(b).

3.3 Overall considerations for arrays of supporting structures

As with moored devices and structure-supported wave devices, an important consideration is the suitability of the bed connection technology to the site conditions. Principal parameters are the water depth and type of bed condition. Mono-pile type foundations are expected to become uneconomic for water depths greater than 30 m (also In addition, the selection of support structure type and dimensions is governed by vessel requirements. Vessels that allow installation of multiple support structures during a single visit to the site are expected to provide opportunities for capital cost reduction.

4 INFRASTRUCTURE COST CHANGES

As discussed in Section 1, many studies report estimates of cost reduction rates for either the installed capital cost, or levelised cost of electricity, based on the cumulative production (or capacity) of an entire industry sector. This provides limited information on the change of costs that could occur between projects that employ similar technologies but at different scales of deployment. An alternative approach is to conduct an engineering analysis of how the costs of individual components of cost may change. Sections 2 to 4 summarise the infrastructure types and configurations that are suitable for different site conditions and indicates that some concepts are more suited to large-scale deployment. For different scales of deployment, costs may change due to only a small number of factors: principally change of procurement costs (or rates) and efficiency of installation processes such that vessel time is reduced. Cost changes due to change of scale of deployment will, to some extent, be caused by experience (of manufacturing and installation respectively) but these cost changes require investment and time to occur. Processes by which capital costs may change due to scale of deployment (i.e. between projects that are developed at the same time) and due to increased experience (i.e. between projects that are developed at different times) are discussed below.

Cost Changes related to scale of deployment

For marine energy project cost estimates, a percentage reduction of unit cost has typically been assumed to represent bulk orders (Boud & Thorpe, 2003; IEA, 2005; Carbon Trust, 2006), and additional costs for construction of mass fabrication facilities have sometimes been considered (Atkins, 1992). The magnitude of the percentage change employed is typically based on expert estimates but values are not widely reported. Reviews and predictions of cost changes in the offshore wind sector (Garrad Hassan, 2003; ODE, 2007; Ernst & Young, 2009) suggest that the following costs may change due to change of deployment scale:

Supply of Station-Keeping Structure: Limited reductions of foundation cost (e.g. €/MW) are expected due to volume production. For offshore wind this is expected to yield cost reductions estimated at 15% although this is partly attributed to increased unit size, i.e. increased swept area and hence capacity of individual turbines, (Garrad Hassan, 2003; Boccard et al., 2009). A comparison of 1 and 5 MW wind turbines indicates 10% reduction of levelised cost using the larger capacity turbines (Kaltschmitt et al. 2007, Table 7.3 p.369 referenced by Boccard 2009). For tidal stream devices, similar mechanisms may occur since increase of swept area increases performance. Alternatively, the number of devices on a single support structure may be increased. However, for wave devices, power output per mooring (or per support structure) will only be improved by installation of multiple generating units on the same mooring (or support structure) since power output is not a function of device dimension. A study of the maximum capacity and power output of wave devices is given in Deliverable 7.5. Savings due to volume production should be possible due to standardisation (Batten et al 2007) particularly since this has not previously been possible for companies which traditionally supplied relatively small batch sizes to the oil & gas sector (Garrad Hassan, 2003). Marine energy device developers with offshore experience suggest that station-keeping costs could reduce by up to 20% although small increases of cost could also occur with increasing scale of deployment (Figure 5.3, Deliverable 7.1.1).

Installation of Station-Keeping Structure: Increased project scale is expected to yield substantial savings due to improved utilisation of installation plant and reduction of fixed costs, such as mobilisation, per installed MW or device. Cost reductions of the order of 50% are expected for offshore wind (Garrad Hassan, 2003, Table 2.2). Developers with experience of deployed devices estimate installation cost reductions of the order of 5 – 20% (Figure 5.3, Deliverable 7.1.1). However, impact of installation cost reductions may be moderated by the more demanding nature of deeper, farther offshore sites and by the variation of vessel rates which tend to be a function of vessel supply and demand (ODE, 2007). A model for wind-turbine vessel installation rates proposed by ODE (2007) assumes rates are proportional to planned number of installation operations during the year of deployment which suggests that costs can increase during the early, rapid deployment of a technology if similar vessels are required for multiple sites. For offshore wind, increased unit size is expected to yield significant per MW capital cost reduction by reducing the number of installation tasks required for a given installed capacity.

Cost changes related to time

Change of material procurement costs are likely to be important (Batten et al. 2007), particularly for structure supported devices for which, similar to offshore wind, a major fraction of the capital cost will be associated with unit cost of steel (Section 3.1). Historic trends of market prices are publicly available (e.g. steel price from CRU[1] and Copper price from Kitco[2]). Predicted trends for material prices vary depending on source but may significantly influence predicted project cost. For steel, ODE (2007) suggest a 60% increase of steel price from 2007 to 2020 whereas Ernst & Young (2009) assume prices reduce to 2013 and maintain steady at the long-run average from 2014). Similarly, labour Ernst & Young (2009) analyse historic trends to predict linear growth of labour rate to 2015, a 5% increase of commodity prices by 2012 and an assumed constant exchange rate.

Cost changes related to experience of the technology

As detailed in Section 1, capital costs for most new technologies are expected to reduce with learning due to increase of cumulative installed capacity. For support structures, it is expected that existing concepts will be standardised and new concepts may emerge such that both procurement and installation costs are reduced. Such changes for offshore wind support structures are

[1] www.cruspi.com
[2] www.kitcometals.com

expected to yield cost reductions of up to 15 % (Garrad Hassan, 2003). There are significant opportunities for cost reduction due to improved installation methods. This may be caused by reduction of installation, mobilisation and contingency time and vessel customisation; reductions of up to 50% have been observed between early offshore wind farms (Garrad Hassan, 2003). Although support structure cost reductions due to accumulated experience and research and development may be large (estimated at 30% by ODE, 20007 for offshore wind) these cost changes will only be realised if the industry progresses.

5 INSTALLATION VESSELS

The foregoing review of infrastructure types for farms of wave- or tidal-stream devices indicates that a significant contribution to the installed cost of all marine energy projects is associated with the use of offshore vessels. The cost of vessel usage is dependent on both the type of vessel employed and the duration of vessel use. Whilst the type of vessel required is largely governed by the type of foundation selected, the duration of vessel usage will be dependent on the offshore work required and, to varying extents, on the design environment. This is a particularly important consideration for tidal stream sites where conditions suitable for installation and maintenance work are dependent on the joint occurrence of flow-speed and wave conditions. The sensitivity of the duration of vessel use to the wave and tidal regime at a deployment site is the topic of Deliverables 7.4.1 and 7.4.2 and is not discussed further at this stage.

6 SUMMARY

To facilitate comparison between alternative deployment marine energy projects it is necessary to consider the effect of site conditions on the station-keeping infrastructure employed and the effect of this on project cost. This report collates findings presented in earlier studies of the factors affecting the cost of marine energy device moorings (7.3.2), wave device support structures (7.3.1) and tidal stream device support structures (7.3.2b) with regard to the infrastructure required for an array of devices. Site conditions for which different types of station-keeping infrastructure may be appropriate are identified and factors which are expected to affect the cost of each option are discussed. For alternative projects that are installed at a similar time, differences in order size may result in different procurement costs and differences of deployment scale may allow more efficient installation scheduling. Reductions of vessel requirements are particularly important for sites that are located further from a suitable manufacturing site and port. For alternative projects that are installed at different times, time variation of material and labour costs must be considered in addition to expected changes due to accumulated experience of the technology.

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