GARRAD
HASSAN

OFFSHORE WIND
Economies of scale, engineering resource and load factors

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APPENDIX 1 CAPITAL COST BUDGET BREAKDOWN

1 INTRODUCTION

The UK Dept of Trade and Industry and the Carbon Trust (DTI & CT) have contracted Garrad Hassan and Partners (GH) to carry out a review of specific subjects pertaining to the future development of offshore wind power in the UK.

The scope of the work defined by DTI & CT [1.1] requires appraisal of:

1. Economics of offshore wind power;
2. Available engineering resource for the offshore wind industry; and
3. Achievable load factors for UK offshore projects.

The findings of the review are reported in individual sections below, each being prefaced by more specific definition of the objectives.

2 ECONOMICS OF OFFSHORE WIND

2.1 Objectives

The objectives of this work were to provide a supported opinion on:

- Capital costs for current (e.g. UK Round 1) offshore wind projects, broken down by major constituent parts – see Section 2.2;

- Annual operation and maintenance (O&M) costs for current (e.g. UK Round 1) offshore wind projects, broken down by major constituent parts – see Section 2.3;

- Expected capital and O&M costs for next generation (e.g. UK Round 2) offshore wind projects – see Section 2.4; and

- Anticipated long-term trends in these costs – see Section 2.5.

2.2 Current capital costs

2.2.1 Approach

There have only been thirteen offshore wind farms constructed to date which gives a very limited reference for estimation of current or future costs. Added to that, many of the existing projects are very much of a demonstration nature and have limited relevance to the current crop of projects.

In 2002 and 2003, five projects have been built which form the primary reference, although not all have published costs and none have done so in explicit detail. Added to those, two further UK Round 1 projects have been open-tendered. GH has managed both of those tender competitions which facilitates some of the insights presented here although specific project data is confidential.

The aim of this section is to provide a summary of costs for the current generation of projects, namely UK Round 1 and similar, constructed or to be constructed, in the time period 2003 to 2005.

2.2.2 Reference costs

Several previous projects have published their capital cost data and these are summarised in Table 2.1. The costs of the early projects were collated as part of the CA-OWEE project in which GH was a partner [2.1]. Others have been sourced as referenced in the notes to the table. Insofar as is possible, these have been made comparable by inclusion of grid connection costs. However, many of the costs have significant uncertainty associated with them in regard to the exact scope associated with them and the risk allocation.

Project name	Rated power [MW]	Date installed	Capital cost [€M]	Specific capital cost [£M/MW]
Vindeby	4.95	1991	10.25	1.45
Lely (Ijsselmeer)	2.00	1994	4.5	1.58
Tuno Knob	5.00	1995	10.35	1.45
Dronton / Irene Vorrink (Ijsselmeer)	16.80	1996-97	20.5	0.85
Bockstigen	2.50	1997	4.7	1.32
Blyth	4.00	2000	6.32	1.11
Utgrunden (Oland) [1]	10.00	2000	13.9	0.97
Middelgrunden [2]	40.00	2000-01	51.3	0.90
Horns Rev [3]	160.00	2001-03 [5]	300.0	1.31
Samsoe	23.00	2002-03	35.0	1.07
North Hoyle	60.00	2003 [5]	105.7	1.23
Nysted	158.4	2003 [5]	268.8	1.19
Scroby Sands	60.00	2003-04 [5]	107.1	1.25

Notes 1 Confidential – figures shown are based on budget costs and possible rating of 10.5MW, not 10MW restriction.

2 Derived from figures published for half the project owned by Middelgrunden Co-operative, with estimate added for grid connection

3 Verbally advised by Techwise July 2002, including grid connection. Vestas have announced that turbine supply contract price is DKK 1 Bn (€134M).

4 Based on exchange rates: €1 = £0.70 = DKK7.44

5 Works still underway – not necessarily final costs.

Table 2.1 Published total technical capital costs for offshore wind farms

As Table 2.1 clearly shows, there is only a limited database on which to base any cost estimate and in fact many of the projects shown there are far from representative. For instance, the early Danish and Dutch projects (1997 and earlier) were demonstration projects. They were also located in very sheltered waters, with much less weather delay risk than in the Irish or North Sea. Moreover, the wind turbines used were much smaller than those planned for future use.

The Horns Rev, North Hoyle, Nysted and Scroby Sands wind farms are much more representative of the current generation of projects in terms of turbine size and project nature and are considered the best cost references.

The current cost position appears to be at around £1.1 – 1.3M/MW. However, caution is advised in characterising wind power costs on a per MW basis as the energy output per MW is a function not just of site parameters but also of technical concept.

Notwithstanding the project-specific factors described, it is useful to observe the trend of dropping capital costs over time which is also very much a feature of onshore wind farm developments. However, there is a clear step-up in this trend after 2000, representing the move to more demanding sites and closer to commercial conditions.

2.2.3 Cost model

To gain an insight into the component costs and how those may vary in the future, GH has assembled a simple budgetary model, Appendix 1. This has made a wide range of assumptions but GH are of the opinion that, insofar as a typical project exists, it represents a reasonable breakdown of the costs associated with a typical UK Round 1 offshore wind farm.

The resultant breakdown is shown in Figure 2.1.

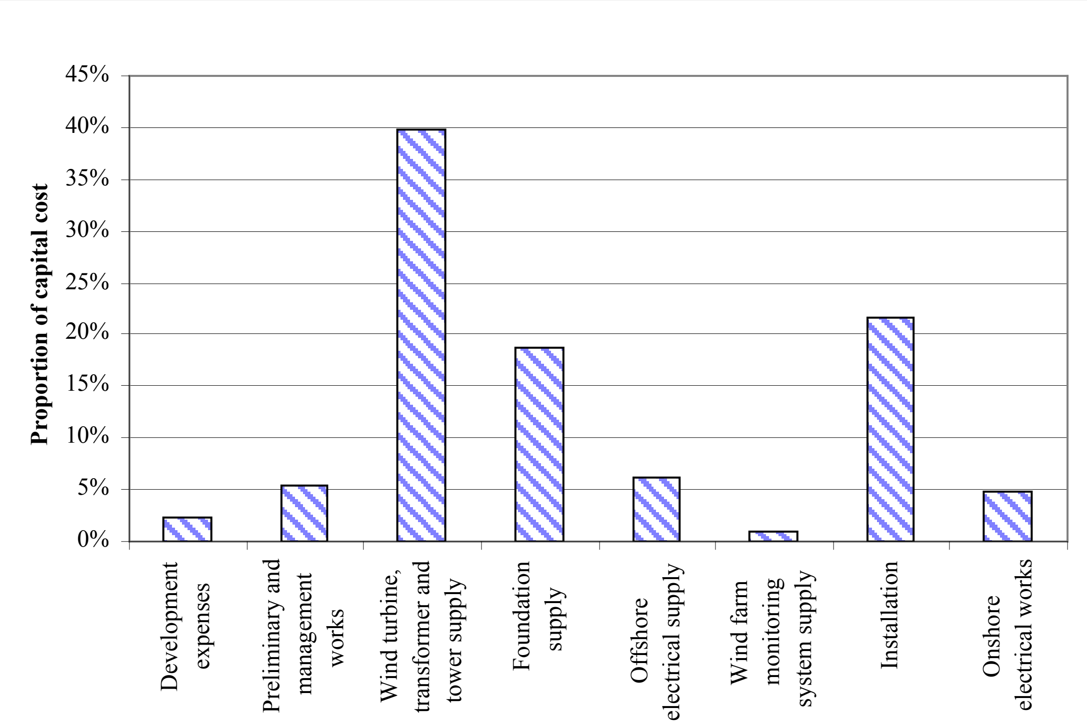

Figure 2.1 Typical breakdown of capital costs (UK Round 1)

The breakdown presented in Figure 2.1 agrees adequately well with GH experience on commercial projects for UK Round 1 offshore.

This breakdown has been used in later sections to project future cost scenarios.

2.2.4 Summary

Reference data for offshore wind farms is scant but it appears that capital costs are of the order £1.1-1.3M per MW installed for the current generation of projects. The approximate breakdown of this cost for a "typical" UK Round 1 site is shown in Figure 2.1.

2.3 Current O&M costs

The data on operational costs for offshore wind farms is even more sparse than that for capital costs. The first project which could sensibly serve as a reference is Horns Rev and it has not yet completed a year of full operation. All earlier projects are either too small or too favourably-located (e.g. in very sheltered waters) to be a useful reference.

The major uncertainty in assessing costs for operation and maintenance is the level of unscheduled maintenance required, and in particular the extent to which large marine plant must be mobilised to effect repairs. The turbine contractors offer a wide range of views in terms of budget figures and commercial offers.

GH consider that the cost is best represented on a per turbine basis and recommend that for current generation projects, a figure of £70,000 per turbine per annum be assumed. This figure can be assumed to include:

- Wind farm scheduled and unscheduled maintenance
- Owner's operating costs
- Insurances

However, it does not include for lease payments to Crown Estate or Transmission Network Use of System charges.

The figure of £70,000 per turbine is consistent with the figures seen by GH in commercial projects albeit that on this particular point, contractors range widely in price and presumably cost estimation. This is presumably due mainly to uncertainty in the level of unscheduled maintenance cost offshore. However, there is also wide variance from contractor to contractor and project to project for onshore projects in part due to different accounting of warranty costs.

It is considered that to forecast future trends in operating costs for offshore wind farms is pure speculation and it is recommended that this assumption is held constant. However, it is certainly the opinion of GH that scale and learning will yield some reduction by 2008.

2.4 Next generation capital costs

2.4.1 Approach

The approach adopted to extrapolate from the costs given in Section 2.3 is as follows. Each of the cost areas itemised in Figure 2.1 has been considered, as regards the effect on cost, for the following factors:

- "Learning" how to work more efficiently
- Project scale
- Wind turbine scale

The aim has been to estimate cost for a nominal UK Round 2 project installed in 2008.

2.4.2 Cost-change factors

There has been work carried out on "Progress Ratios" in many industries to capture the potential for cost reduction in new technology, including some specifically carried out for the overall renewable power and onshore wind industry [2.2, 2.3].

In brief, a "Progress Ratio" is normally defined as the cost reduction due to doubling of production of a piece technology. There is significant consensus that the onshore wind sector has seen a Progress Ratio of around 90% in recent years – each doubling of cumulative megawatts produced and installed has seen a 10% reduction in capital cost and consequently in energy price. Over the past decade this has been consistent with a 3% year on year reduction in energy cost from wind.

There are some issues to be addressed in using this Progress Ratio approach for offshore wind:

- There is a substantial proportion of the cost which is unrelated to onshore wind, namely the marine installation and foundation works.

- Some of the offshore cost elements are very immature and may be subject to much better progress on costs than a ratio of 90% would indicate. However, the sites are also changing and the nature of sites in UK Round 2 are likely to be quite different to those in Round 1 in terms of geology, exposure, marine plant required and contractors involved.

- The scale of the next generation projects (up to 1GW) is much larger than previous UK wind projects. Whereas existing projects have almost without exception been accommodated on the distributions systems, projects of the 1GW scale clearly will not. The costs of modifying the NGT system to connect such projects may be well in excess of the level implied by simple scaling, making cost-sharing arrangements and the level of government intervention of vital importance.

- The location of offshore wind farms remote from populations will effectively remove non-technical constraints such as noise nuisance and visual intrusion. In the long-term this will result in significant cost efficiencies in offshore-specific designs although that process has just begun and will be ongoing in designs deployed in 2008.

The use of Progress Ratio also requires as input an assumption of accumulated capacity deployed both offshore and in respect of the turbines at least, onshore. GH are of the view that less than 200MW offshore wind construction will occur globally in 2004 and that 2005 to 2007 will see construction of around 1GW per annum globally. As regards the onshore wind power market, it is reasonable to consider that it will double in size over the next five years from its current size of approximately 35GW.

The Progress Ratio of 90% quoted above would typically capture all the factors listed in Section 2.4.1 and this approach has been used in the long-term projections of Section 2.5.

However, in the shorter term, the following approach has been used to attempt to arrive at a more accurate estimate of the capital cost reduction which is achievable. This approach uses the cost breakdown and the market forecasts and targets defined. The possibility for cost change has been itemised in Table 2.2 for each area of cost as follows:

- Highly favourable
- Favourable
- Neutral
- Unfavourable
- Highly unfavourable

Justification for the above assessment, specifically in relation to the major cost items, is given in Table 2.2.

By way of scenario, some estimates of capital cost reduction have been placed on the above subjective categories to demonstrate the effect on overall project (per MW) costs. These are represented in Table 2.3.

Table 2.2 Subjective assessment of scope for capital cost (per MW) reduction.

Cost item	Cost change possibility	Comments
Development expenses	Highly favourable	Scale and learning effects considerable
Preliminary and management works	Highly favourable	Scale and learning effects considerable
Wind turbine, transformer and tower supply	Favourable	*Scale effect:* As the turbines are currently onshore designs, considerable economies of scale already exist and future designs have to improve on that baseline. This limits the scope for cost improvements, due to both scale of unit and production volume, to that from a relatively mature product. *Learning effect:* Modification of the currently-proposed designs to reflect offshore conditions should yield some reduction in capital and operating costs by 2008, as well as improved availability. The next generation offshore designs which will be marketed in the 2007 – 2010 period will continue this trend.
Foundation supply	Favourable	*Scale effect:* There should be limited saving in per MW costs from increase in unit size. The saving due to volume production should be substantial as many of the current suppliers have historically supplied the oil and gas sector, which involves relatively small batch sizes. New suppliers and new production approaches should yield significant savings. *Learning effect:* The evolution of new concepts such as suction caissons and Arup's Wind Ace should push down the relative capital costs on sites such as those in UK Round 1 and also play a role in making more demanding sites economically viable.

Table 2.2 Subjective assessment of scope for capital cost (per MW) reduction.

Cost item	Cost change possibility	Comments
Offshore electrical supply	Unfavourable	*Scale effect:* Limited savings in relative costs on-site, due to larger unit and project size. Significant increase in European production volumes for submarine cable should yield some unit rate saving but other electrical components are from mature supply chains. Assuming larger R2 sites are significantly further offshore the savings are anticipated to be counteracted by the additional cost of connecting back to shore. *Learning effect:* Minimal – mature technologies.
Wind farm monitoring system supply	Favourable	
Installation	Favourable – Highly favourable	*Scale effect:* Effect of increased unit size will give significant per MW capital cost reduction. Increased project and industry scale will give substantial savings due to experience gained, utilisation of more optimal installation plant and reduction in effect of fixed costs such as mobilisation. Impact moderated somewhat by more demanding nature of some of the deeper, farther offshore R2 sites. *Learning effect:* Speed of installation and contingency requirement expected to reduce dramatically as experience is gained. For example the approximately 50% reduction in installation time was achieved between first 10 and last 10 units at Horns Rev (80 units overall).
Onshore electrical works	Favourable - Highly unfavourable	Highly site-specific

Table 2.3 Example scenarios for capital cost (per MW) reduction.

Item	**Cost change possibility**	**Base Case**	**Low progress**	**High progress**	**NGT cost +**	**NGT cost -**	**High progress on installation cost**
Development expenses	Highly favourable	50%	50%	50%	50%	50%	50%
Preliminary and management works	Highly favourable	50%	50%	50%	50%	50%	50%
Wind turbine, transformer and tower supply	Favourable	85%	95%	75%	85%	85%	85%
Foundation supply	Favourable	85%	95%	75%	85%	85%	85%
Offshore electrical supply	Unfavourable	115%	115%	115%	115%	115%	115%
Wind farm monitoring system supply	Favourable	85%	95%	75%	85%	85%	85%
Installation	Favourable	85%	95%	75%	85%	85%	50%
Onshore electrical works	Favourable - Highly unfavourable	110%	110%	110%	200%	90%	110%
Cost per MW vs. UK Round 1		85%	93%	77%	90%	84%	77%

For the purpose of the Base Case scenario, “Favourable” has been modelled as 15% capital cost reduction, “Unfavourable” as 15% increase, “Highly favourable” as a halving of cost and “Highly unfavourable” as a doubling of cost. This has resulted in an estimate of capital cost at 85% of the per MW current costs.

Low and High variants on this base case have been used to show the potential effect of low or high levels of experience. The resultant range is a capital cost range of 77% to 93% of the per MW current costs.

Two further scenarios have been used to explore the impact of grid connection costs – resulting in a range of 84% to 90% of the per MW current costs.

A final scenario has been used to explore the impact of high progress with cost reduction in marine installation – resulting in an estimate for capital cost of 77% of the per MW current costs.

A factor not considered in the above is currency exchange rate, to which the turbine supply element is particularly sensitive. For example, the capital cost of UK Round 1 projects has increased by over 10% in sterling terms since mid-2002.

2.4.3 Summary

The scenarios presented above can only be indicative, however, based on the assessment conducted capital costs can be expected to reduce by around 15% over the next 5 years on a per MW basis. There is also considered to be more scope for higher reductions than for lower reductions, in particular for the marine installation activities.

2.5 Long-term cost trends

DTI & CT have requested that GH provide an opinion on the long-term trends expected for capital costs in offshore wind power.

As described above, the offshore wind power industry may be assumed to be partly influenced by the degree to which cost reduction remains achievable in onshore wind. Tables 2.4 and 2.5 demonstrate this with reference to onshore and offshore wind power, respectively.

In both tables, the ISET [2.3] Progress Rate of 92% has been used (basis - cost per MW for each doubling of MW cumulative capacity).

Approximate growth rates are shown to 2020 for both on-shore and offshore. These have been selected to be lower than industry expectations, which results in a conservative view on cost reductions. So, for the next few years, the growth rates for the two sectors have been set so as to agree broadly with project plans (see [2.4] for offshore projects). For the remaining years, they are closer to very conservative projections from the IEA, than to industry estimations published by BTM Consult and GH’s own view. All figures in Tables 2.4 and 2.5 are on a global basis.

From these tables, it may be interpreted that savings in capital cost (per MW) of offshore wind over a 20 year timescale can be anticipated to fall by up to 40 % compared to today’s figures.

It should be noted that the 2008 projections shown here differ from those in Section 2.4 which used a more detailed approach.

	Onshore wind power [GW] Annual installations	 Cumulative	Progress Ratio (2003 basis)
2003	6	35	100%
2004	6	41	98%
2005	7	47	96%
2006	7	54	95%
2007	7	61	93%
2008	8	68	92%
2009	8	76	91%
2010	8	84	89%
2011	9	92	88%
2012	9	101	87%
2013	10	110	86%
2014	10	120	85%
2015	11	131	84%
2016	11	141	84%
2017	12	153	83%
2018	12	164	82%
2019	13	177	81%
2020	14	190	81%

Annual deployment growth rate (nominal assumption) 5%

Table 2.4 Progress Ratio projection – onshore wind.

	Offshore wind power [GW]		Progress Ratio
	Annual installations	Cumulative	(2003 basis)
2003	0.4	0.5	100%
2004	0.5	0.9	93%
2005	0.6	1.4	88%
2006	0.7	2.0	84%
2007	0.8	2.6	81%
2008	1.0	3.5	78%
2009	1.2	4.5	76%
2010	1.4	5.7	73%
2011	1.7	7.1	71%
2012	2.1	8.8	69%
2013	2.5	10.9	67%
2014	3.0	13.4	66%
2015	3.6	16.3	64%
2016	4.3	19.9	62%
2017	5.1	24.2	61%
2018	6.2	29.3	59%
2019	7.4	35.5	58%
2020	8.9	42.9	57%

Annual deployment growth rate (nominal assumption)	20%

Table 2.5 Progress Ratio projection – offshore wind.

3 AVAILABLE ENGINEERING RESOURCE

3.1 Objectives

The objectives of this work were to provide a supported opinion on whether engineering resource is likely to constrain future offshore wind development, specifically:

- Identifying construction timescale issues based on experience to date – see Section 3.2;
- Identification of critical parts of the engineering supply chain – see Section 3.3;

The critical time frame for supply chain issues has been defined by DTI & CT as 2008 and shortly after. The basis for this is assumed to be to determine the capability of the industry to deliver UK Round 2 projects. However, from a practical viewpoint, consideration of supply chain issues far beyond that point is considered so speculative as to be of little value in any event.

It is stressed here that consideration has been restricted to the engineering supply chain although other obstacles may be of equal or greater importance. For instance the achievement of consent for all works, particularly high voltage grid connection infrastructure, is vital. Also, the availability of finance will to some degree be restricted by the degree to which technical risks are mitigated by field experience – that may also be a restricting factor but is not one which is considered here.

The supply chain considered here is not restricted to the UK or Europe, the issue of UK content being the subject of a separate study [3.1].

3.2 Construction timescales

DTI & CT ask in their work scope if "*existing companies will have the resources, skills and time required to install in excess of 1 GW per year from 2008, given the annual window for construction in the North Sea*." This section examines the time element of this question, and takes it to include construction in the Irish Sea and Thames Estuary as well.

From the limited experience to-date of construction of commercial-scale offshore wind farms, the fastest construction times have been achieved at the newest Danish projects. In good weather conditions, per vessel, a full turbine, including the pile, has been installed in less than a day. Table 3.1 below compares some approximate statistics for Horns Rev and North Hoyle wind farms. This is a superficial examination, and does not include additional timescales for cable laying (which would typically not be a critical path activity) and commissioning (which should again largely happen in parallel to the main construction works).

		North Hoyle	**Horns Rev**
No. Turbines		30	80**
Vessels*	Monopiles	Excalibur (Seacore)	Buzzard (2 monopiles/trip)
	Turbines	Excalibur (Seacore), MEB-JB1 with feeder vessel Annegret	Ocean Hanne and Ocean Addy (both A2Sea)
Installation	Monopiles	Early April 2003 – End July 2003 (~122 days)	Mid March 2002 – 1st August 2002 (~ 137 days)
	Turbines	Late June 2003 - Mid December 2003? (~183days)	Beg. May 2002 – End August 2002 (~ 122 days)
Installation rate	Monopiles	4 days per monopile / 4 days per vessel per turbine	1.7 days per turbine / 1.7 days per vessel per turbine
	Turbines	6.1 days per turbine / 12.2 days per vessel per turbine	1.5 days per turbine / 3 days per vessel per turbine
	Project	9.1 days per turbine	2.1 days per turbine

* also separate vessels for transition pieces and cable installation, not included here for simplicity

** also piles for offshore transformer, installation began Sept 2001.

Table 3.1 Installation timescales

"In excess of 1 GW per year" translates to, say, installation of 300 turbines per annum spread over four distinct locations. Tentatively, to construct at this rate would require between four construction supply chains (based on Horns Rev construction performance) and sixteen (based on North Hoyle construction performance). The constituent parts of a construction supply chain at site are, broadly:

- Main installation vessel for foundations
- Main installation vessel for turbines (which may be the same vessel as for the foundations)
- Cable lay vessel
- Anchor handling tugs
- Personnel movement and site utility boats
- Shuttle vessels for plant

- Staging port

The critical components of from this list are addressed in more detail in Section 3.3.

Given the difficult circumstances of North Hoyle, notably (in GH's opinion) ground conditions, the North Hoyle installation rate can be seen as a fairly pessimistic example. Moreover, there is significant scope for improvement in these rates and indeed (from discussions with the involved parties), GH are aware that during the course of Horns Rev construction the installation rate improved dramatically.

From GH's knowledge and experience of offshore construction, the following observations can be made in terms of improving timescales:

- Weather: this is obviously a factor and the conditions experienced at the two projects are understood to have been quite typical for those locations through the main construction activities shown in Table 3.1.

- Site selection: some locations are simply more difficult and time-consuming to construct than others, for instance due to ground obstructions or environmental restrictions on working.

- Project planning and timely delivery of components and vessels: to maximise fair weather construction windows, detailed marine planning needs to evolve for future projects and there is considered to be substantial scope for improvement.

- Vessels: a vessel that can ferry the maximum number of components, jack-up and install in the minimum amount of time is clearly desirable. North Hoyle suffered from the non-arrival of the Mayflower vessel, and instead utilised a variety of vessels not ideally suited to the task. The use of more vessels undertaking the same task in parallel also speeds up installation, but there will be a limit to this depending on the capability and size of the harbour facilities.

- Cable-laying: properly planned and managed using appropriate equipment, this should not be a critical path activity but in the absence of those, it can become so.

- Access: to turbines at a variety of stages is required up to completion of commissioning. The health and safety issues associated with different access methods may be unresolved, which can be a source of delay. A major factor for recent projects has been the extension of commissioning into the winter season has which presented serious difficulties for reaching final completion of construction in the absence of a safe and effective personnel transfer system.

Implications for Round 2 are:

- Timely delivery is much more likely with those who can demonstrate an understanding of these issues, preferably through experience.

- R1 has already shown the importance of early anticipation of engineering needs. Government can influence the ability of suppliers to respond positively, and on time, to project needs. This can be through positive market signals (giving companies the confidence to invest in new equipment), and diversification and start-up support.

- An installation rate of 1 GW per annum will require (by tentative estimate) four to sixteen construction site supply chains implying, in either case, need for increased installation capacity (see Section 3.3) and improved productivity.

3.3 Critical links in the engineering supply chain

The following sections address this issue by breaking down the offshore wind industry into its key components:

3.3.1 Wind turbines

For projects out to 2008, it is considered that the wind turbines used will be derivatives of the models which have emerged as prototypes in the past year and in the very near future. These have rated powers approximately in the range 2.5 MW to 4 MW.

As the onshore global wind turbine supply industry during the next decade is seen as being an order of magnitude larger than the offshore sector (see Tables 2.4 and 2.5 for instance), turbine supply is only seen as a potentially critical factor in those areas where the offshore designs differ markedly from onshore designs.

In projects installed to date, the turbines used have been very subtly modified onshore designs, however, future offshore turbines are seen as being more specifically designed for the offshore market. The most obvious areas of difference from a manufacturing viewpoint are seen as a matter of scale rather than concept. These are not seen as introducing demands on the manufacturing industry more onerous than that due to the onshore market.

Additionally, marinisation features will be increasingly added to address:

- Corrosion protection;
- Environmental protection;
- Access to the turbine (e.g. heli-decks, craneage);
- Condition monitoring; and
- Remote diagnosis and control.

While these represent innovations and evolution of design, they are not seen as critical in terms of engineering or manufacture.

Additionally, the scale of the proposed offshore developments means that the wind turbines and wind farms will have to be compliant with the emerging NGT Grid Code. Both the Grid Code (and similar instruments throughout Europe) and wind turbine electrical design is evolving and it is anticipated that efficient grid integration will require:

- Evolution of wind turbine electrical designs to make them more “grid-friendly” in terms of power quality, voltage control, power factor control and fault level, as well as more resistant to grid faults;
- Active grid management measures to accommodate large quantities of induction-based renewable generation; and

- Moderation of the Grid Code as applied to renewables.

The issue of grid integration is seen as a key area of technical and institutional development but it is not seen as presenting a supply bottleneck.

3.3.2 Wind turbine towers

All offshore wind turbines installed have favoured tapered tubular steel towers, and the lattice type is unlikely to feature in the future offshore market. The principal reasons for the exclusion of lattice towers are seen as maintenance requirements.

Tubular steel towers are usually manufactured in sections to assist handling, transportation and installation operations - each section is finally bolted together via internal flanges. The largest offshore turbine which is currently offered commercially is the GE Wind Energy 3.6 MW which is designed to provide 3.6 MW maximum electrical power. For the offshore version of this machine, the tower will be manufactured in two thin-wall sections approximately 40m in length, with maximum diameter of 5.5m.

The tower designs required will be little different from those required onshore in the 2008-2010 timeframe and therefore the same argument as applied above to the turbine applies.

3.3.3 Wind turbine foundations

Most recent offshore wind turbines are fixed to the seabed using a single steel pile (or *monopile*). The alternatives to monopiles are generally considered to be: gravity base foundations or tripod subsea structures – see Figure 3.1.

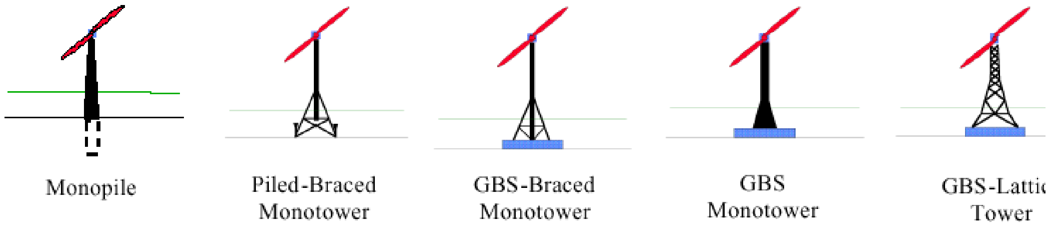

Figure 3.1 Support structures for offshore wind turbines

Over the next decade, monopiles and gravity base structure (GBS) foundations are anticipated to remain important with the additional introduction of braced space frame concepts for deeper water and larger turbines and also the introduction of other concepts such as suction caissons.

Suction caissons have been widely used in the oil and gas industry for many years. At present the wind industry and academia are researching and developing this technology for use in offshore wind farms with suitable seabed conditions, i.e. sandy or soft clay soils.

There are some other novel ideas being proposed such as telescopic towers anchored by suction caissons which may prove to be viable, but realisation of this technology in commercially competitive projects is someway off for the present.

The potential supply issues for each of these are seen as follows:

Monopile:

- Plate steel supply (40 to 70mm thick)
- Rolling and fabrication facility

GBS structures:

- Concrete supply
- Reinforced steel supply
- Accessible fabrication locations

Frame structures:

- Fabrication facility

Suction caissons structures:

- Fabrication facility

Taking each of these in turn in terms of criticality:

Plate steel
The supply of plate steel is not anticipated as a bottleneck. Nearly 50% of steel production in Europe is from recycled scrap, and the total size of the world steel market is more than sufficient to absorb the volumes implied here. Indeed, offshore wind energy could offer a welcome market for suppliers suffering from a recent drop in the utilisation of steel in heavy engineering, and from previous years of oversupply.

Rolling
There are currently only a handful of companies with the equipment required to roll the large diameter monopiles, but many more with the capability for towers. Diversification to both towers and monopiles from related activities such as manufacture of pressure vessels and oil tanks is reasonably straightforward, and therefore this is not considered an onerous bottleneck.

Fabrication facility
Because of the size of the monopiles, rolling and fabrication will almost certainly take place in the same facility. The space required for rolling, fabrication and shipping to the customer lends itself to either purpose-built facilities close to sea access, or to utilisation of former boat, oil and gas and other former heavy engineering facilities. On a European scale, this is unlikely to be a bottleneck. If there is a desire to carry out all fabrication in the UK, it may require some regeneration of old ports.

An example of this already underway is Arnish on the Isle of Lewis, a former oil and gas construction yard which is in the process of regeneration for tower and foundation fabrication by Cambrian Engineering. Such a dockside fabrication facility does not necessarily need to be in the vicinity of the site as once loaded aboard a ship, distance to site (or the staging port for site) has a relatively low cost impact.

In the foreseeable future we are likely to see the steady utilisation of steel monopile foundations for offshore wind farms sited in shallow water with good geotechnical soil conditions. As the number of these suitable sites become a rarity, and technological developments advance, alternative foundations will feature in the exploitation of sites previously considered uneconomic. The transition from monopile to, say, subsea tripod manufacture is unlikely to be a painful process for current monopile suppliers given the fabricated and tubular nature of steel tripods.

The fabrication expertise for each of the various designs is pre-existing in oil, gas and other heavy engineering industries in UK and Europe as well as in the lower cost Asian economies.

3.3.4 Submarine cable

Manufacture of submarine power cables is a specialist activity. At present there are four well-known submarine cable manufacturers in Europe or close proximity to Europe. They are:

- Nexans
- AEI (TT Electronics)
- ABB
- Pirelli

All companies are relatively large multi-national operations with offices and manufacturing facilities throughout Europe, and all specialise in the manufacture of power cables except for ABB who encompass the power system plant in general. There are other manufacturers around the world such as Hitachi in Japan, and Olex in Australia. The demand for manufacture of subsea power cables has historically been relatively low. Coupled with the specialised manufacturing requirements and the need to be able to manufacture cables with a high integrity in very long continuous lengths (several or tens of kilometres) means that manufacturers tend to have one specific manufacturing facility rather than multiple facilities in different locations. In addition, not all manufacturers supply cables across the range of voltages that may be seen. For example, AEI (TTE) does not manufacture 132kV (+) cables but do supply cables at voltages up to 36kV.

Manufacture of cables for offshore wind farms can take several days or weeks, and orders need to be placed well in advance to ensure a timely manufacturing slot. With considerable demand the current facilities could be heavily worked, although with year round manufacture (and storage) this will probably not be an issue. Manufacturers have not indicated to date any anticipated supply problems. The worst outcome of high demand is therefore likely to be that preferred manufacturers may not be available, and therefore preferred specifications and the lowest prices will not be guaranteed. Projects may need to purchase submarine cables from whoever can meet the demand. Expansion of existing manufacturing facilities should be possible within timescales of several years if manufacturers consider the market justifies it.

As noted earlier, not all cable manufacturers have the capability to supply submarine cables across the voltage range. The largest volume demand for cables is likely to be in the 36kV rating bracket where cables of this type are known to offer the most economic selection for array (turbine to turbine) cabling. All manufacturers offer this voltage range.

Higher voltage cables are more specialised as observed above. Demand for these cables is likely to be much smaller as they will only be used for transmission to shore or to a major offshore transmission substation. There are unlikely to be supply issues at voltages up to 150/170kV for such cables (in the UK 132kV).

The highest voltage solid submarine AC cables currently in supply are of the 150/170kV range, although ABB claim to be able to make “solid” XLPE cable up to 245kV. Demand and the technical and manufacturing capability for solid cables above this does not at present exist, and it is necessary to use oil-filled cable or similar. Oil-filled cable is not likely to be acceptable on environmental grounds and it is not clear whether solid higher voltage cables will be developed in the near future. This is an issue, since higher transmission voltages may be required for Round 2 offshore projects and offshore transmission substations are under consideration. In the UK, transmission usually implies voltages of 275kV and 400kV.

If suitable cables are not available at these higher voltages then engineering solutions using lower voltage cables are certainly possible, although they may not be optimal. This is therefore likely to be a nuisance rather than an impediment.

New entrants to this market are unlikely.

Summary
The high volume demand for subsea cable may stretch existing manufacturing facilities close to its limits, particularly in the under 36kV cable range, which will be used for turbine interconnection. Higher voltage cables will be less in demand, but it is not clear whether the capability to manufacture transmission voltage cables will exist and this may force less than optimal solutions to be used.

3.3.5 Offshore substations and collection systems

Offshore electrical plant is required at the turbines and for offshore substations. Round 2 projects are anticipated to require offshore substations due to their size and likely distance offshore.

Electrical plant in turbines (apart from that supplied with the turbine) is limited to switchgear and in some cases transformers. Suppliers for such plant are plentiful and spread throughout the world. No issues are anticipated with supply of plant in these cases. Suppliers include all the large electrical plant manufacturers of ABB, Siemens, Alstom and General Electric, as well as numerous smaller and more specialised switchgear and transformer manufacturers such as Ormazabal, Schneider, and Pauwels.

Offshore substations are more complex and require skilled design and engineering. Key plant items in offshore substations will include:

- Transformers (36/132kV, 36/275kV, 132/275kV and 132/400kV are most likely).
- 36kV switchgear.
- Higher voltage switchgear (132kV, 275kV and 400kV).
- Reactors, back-up generators, control and protection equipment.

As noted above, 36kV switchgear suppliers are plentiful and no issues should be met with switchgear and associated plant at this voltage level. The key items are the transformers and higher voltage switchgear, where the number of manufacturers is more limited.

Manufacturers are largely limited to the large electrical engineering companies ABB, Siemens, Alstom and General Electric. There are also a few specialist manufacturers who produce large transformers and higher voltage switchgear, e.g. Temini in Turkey. Most of the large electrical manufacturers have facilities to manufacture plant in more than one location and although manufacturing timescales for such plant can be quite long (e.g. 6-8 months for a 132/33kV transformer), demand will not be high enough to create supply problems.

In addition, the specialist design skills for substations also lie with the large manufacturing companies and a number of consultants, and the demand for design skills is not expected to outstrip current capabilities.

New entrants to this market are possible, but since the market is already largely "over-supplied" are unlikely.

The supporting structures for offshore substations are in no way extraordinary being similar in terms of supply chain capability to a turbine foundation or a Minimum Facilities Platform as commonly used in the UK oil and gas industry.

Summary
GH does not consider there likely to be any supply problems with offshore substations and other electrical plant. There is already a large supply industry with healthy competition at all levels.

3.3.6 Onshore electrical works

Onshore electrical plant for substations and grid extension works is largely similar to that required offshore, e.g. transformers, switchgear, reactors, back-up generators, control and protection equipment, and overhead lines and underground cable. The supply issues are also similar to the offshore plant and it can be concluded that there are no critical items in the supply chain.

The most significant issue for onshore works is likely to be the planning permissions and the timescales required for high voltage infrastructure works. Recent experience in the UK has shown that extension of the transmission system via overhead lines could take 5-10 years mainly due to planning delays.

3.3.7 Construction ports

Offshore wind farm construction has specific requirements in terms of the base port as regards proximity to site, accessibility for construction vessels and quayside lay-down areas. For the UK Round 2 zones, the main options for established commercial construction ports are seen as :

- Northwest England Zone:
    - Belfast
    - Stranraer
    - Workington
    - Barrow
    - Heysham
    - Fleetwood
    - Liverpool
    - Mostyn
    - Holyhead
    - Rosslare

- Thames Estuary Zone:
    - Gt Yarmouth
    - Lowestoft
    - Harwich / Felixstowe
    - Thamesport

- Wash Zone:
    - Immingham
    - Hull

Grimsby
Kings Lynn
Lowestoft

It is assumed here that the Round 2 development will be spread approximately evenly between the three zones. Of the above, the only obvious bottleneck is the Thames Estuary Zone where there are few options in the estuary itself. Development of entirely new ports (e.g. T-jetties) is possible as is regeneration or modification of existing facilities. Indeed, for specific sites, these may be favoured options in the other zones as well.

The use of custom-built vessels, such as Mayflower Resolution and even larger offshore Dynamically Positioned (DP) and semi-submersibles (see below), with significant on-board deck space, facilities and accommodation, may take the pressure off port availability.

3.3.8 Turbine and foundation installation

There are a variety of options for the vessels to undertake installation works on the wind turbines and foundations, as listed below with their main technical, commercial and availability characteristics summarised. Also addressed below are the piling and drilling equipment.

The review below is based on the GH Market Survey of suitable marine plant [3.2] and is approximately ordered according to capability and cost.

- Inshore floating barges
  - very cheap day rate but very weather sensitive, slow and unsuitable for all but most sheltered UK sites e.g. Inner Thames
  - many options, little utilised already

- Inshore jack-up and spud-raising vessels
  - relatively cheap day rate but weather sensitive, slow and unsuitable for larger sites farther offshore
  - limited existing options, largely utilised already
  - new-build possible within project timescale

- Custom-built installation vessels (e.g. Mayflower Resolution):
  - capable for all but deepest sites
  - much higher day rate than inshore vessels
  - less weather sensitive than inshore vessels and faster installation rate
  - less dependence on local ports
  - following investment decision, new-build possible within 2 yrs (“same again” contracts) or 3 yrs (new design), investment decision very dependent on firmness of market

- Modified large installation vessels (e.g. A2Sea):
  - compromise in terms of cost and technical capability between inshore jack-up and custom-built installation vessel
  - following investment decision, new-build possible within 1 yr (“same again” contracts) or 2 yrs (new design), investment decision very dependent on firmness of market
  - plentiful supply of base vessels

- Offshore DP installation vessels:
  - capable for all but shallow sites (e.g. <20m)
  - much higher day rate than alternatives above
  - faster installation rate than vessels above, similar weather sensitivity for lifting operations
  - some options have limited on-board storage limited so staging required
  - many options (i.e. 20-30 vessels) in use by oil and gas industry, mostly stationed in Middle East, West Africa and Gulf of Mexico

- Offshore heavy lift vessels and semi-submersibles (some of which are DP):
  - capable for all but shallow sites (e.g. <25m)
  - much higher day rate than alternatives above
  - faster installation rate than most of vessels and very little weather sensitivity for lifting operations
  - ample on-board accommodation and storage
  - limited options in use in oil and gas industry (i.e. 5-10 vessels)

- Pile driving hammers:
  - two major suppliers (Menck and IHC) of hammers suitable for large diameter piles
  - increased size of designs over next 5-7 years will require incremental size increase
  - not a critical time or engineering constraint

- Large diameter drills:
  - only one established European contractor (Seacore) but no serious barriers to new market entrants
  - increased size of designs over next 5-7 years will require incremental size increase
  - not a critical time or engineering constraint

The installation vessel availability is summarised in Table 3.2. The categorisation of these vessels is somewhat subjective but that categorisation has been made to allow the problem at hand to be addressed.

Vessel type	Indicative current availability	Expansion possibility	Likely role in installing 1 GW/annum in UK
Inshore floating barges	Practically unlimited	No expansion necessary, some project-specific modification	Very limited role on most-sheltered sites only
Inshore jack-up and spud-raising vessels	Approx. 10 to 20 based in Europe	Readily expanded in project timescale	Limited role - sheltered and /or shallow sites only
Custom-built installation vessels	Only one built so far, several others designed but their construction not yet contracted	Considerable expansion possible in a 3 to 5 year timeframe given a stable environment in which to make major investment decisions	Major part of a solution on sites of all types except the very deepest
Modified large installation vessels	Approx. 2 to 5 based in Europe	Considerable expansion possible in a 2 to 4 year timeframe given a stable environment in which to make major investment decisions	Major part of a solution on most sites of all but deepest and most exposed sites
Offshore DP	Approx. 20 to 30, mostly based outside Europe	Expansion unlikely but mobilisation of a small number to Europe possible in the presence of a solid order book of 1 to 2 years of work	Major part of a solution on deepest and most exposed sites
Offshore heavy lift vessels and semi-submersibles	Approx. 5 to 10 worldwide	None, but “fly-by” usage may be practical i.e. during lulls in normal higher value work.	Possible minor role on deepest and most exposed sites

Table 3.2 Summary of installation vessel options

It is considered that a combination of the following measures is essential to achieve target 1 GW/annum installation required by DTI:

- upgrade of existing inshore vessels;

- new custom-build of vessels;
- new conversions of existing vessels; and
- development potential redeployment and modification of existing offshore DP, heavy lift and semi-submersible for larger sites far offshore.

All these measures are possible in a 3 to 5 year timeframe provided that a firm market is developed for them.

3.3.9 Submarine cable installation

The vessel options for the submarine cable lay work are as follows :

- Low-powered anchored vessels:
  - cheapest day rate option
  - highly weather sensitive, slow and unsuitable for long runs
- Non-DP self-propelled vessels:
  - relatively low day rate
  - significantly weather sensitive
- DP vessels:
  - highest day rate
  - significantly less weather sensitive and faster

As for the main installation vessels, the eventual solution in a build-out which achieves a 1 GW/annum UK build rate, is expected to be a combination of all these options. There is one area where options are limited and that is in shallow water working close to the landfall point. However, it is possible to largely address that issue with land-based construction methods.

3.4 Summary

Table 3.3 summarises the main conclusions in each of the areas listed above.

Component	Anticipated bottlenecks (2008-2010)	Governmental actions required	Impact on 1 GW/annum objective assuming those actions are undertaken
Turbines	None specific to offshore	Stable environment for wind power generally	None
Towers and foundations supply	None	None	None
Submarine cable supply	Medium voltage (<36kV) submarine cable supply High voltage (>200kV) submarine cable supply	Stable investment environment with 3 to 5 year timeframe	None
Offshore substations	None specific to offshore	None	None
Onshore electrical works	High voltage infrastructure (consents - not technical)	Ensure maximum usage and possible upgrade of existing infrastructure; provide time for new-build; hasten consenting (if possible)	None
Construction ports	Thames Estuary Zone has only a few options. Development of new or existing facilities will likely be needed. New build (e.g. of a T-Jetty) may be a preferred option in any instance.	Stable investment environment with 3 to 5 year timeframe	None
Turbine and foundation installation	Requires investment over a 3 to 5 year timescale in : • upgrade of existing inshore vessels • new custom-build • conversions of existing vessels • potential redeployment and modification of existing offshore DP, heavy lift and semi-submersible for larger sites far offshore	Stable investment environment with 3 to 5 year timeframe	None
Submarine cable installation	There is one area where options are limited and that is in shallow water working close to the landfall point. However, it is possible to largely address that issue with land-based construction methods.	None	None

Table 3.2 Anticipated supply chain "bottlenecks" for construction of circa 1 GW/annum under UK Round 2.

4 LOAD FACTORS

4.1 Objectives

The objective of this work was to provide a supported opinion on the likely load factors for offshore wind power in the UK Round 1 and 2 offshore wind farms.

This is achieved below in two stages:

- Estimation of likely range of annual mean wind speeds;
- Derive corresponding load factors, including indicative wind farm losses; and
- Provide some actual data supporting these load factors.

4.2 Annual mean wind speed

The only published database which covers all UK waters including the coastal zone is that created by GH in conjunction with Germanischer Lloyd [4.1]. The database is prone to error for individual locations but as an ensemble average, it is considered a powerful tool. GH has also been able to validate the database against more recent predictions to refine it accordingly.

For this project, the GH database has been interrogated to obtain annual mean wind speed predictions for the UK Round 1 sites and for a range of points distributed in the three Round 2 search zones (including outside the 12 nautical mile limit). All wind speeds have been adjusted using a simple power law to 90m above mean sea level (AMSL) as that is seen as a likely average hub height for projects deployed over the next 5 years.

Based on this analysis, the offshore sites are considered to have annual mean wind speeds in the range 8.5 m/s to 9.5 m/s at 90 m AMSL. Round 2 sites, being typically further offshore, can be expected to have somewhat higher winds than the Round 1 sites, but there is only small variation predicted between overall wind speeds in the three Round 2 zones.

4.3 Net load factors

Wind farm net load factors have been calculated in three steps :

- Annual mean wind regime calculation at hub height at the site

  The annual mean wind speed figures derived as described in the previous section have been used, assuming a Rayleigh wind distribution and hub height 90m AMSL.

- Ideal energy output – a function of the above and the turbine power curve

  Power curves for two leading turbine options have been used (Vestas' V90 and GE 3.6MW).

- Deduction of wind farm losses

  Including for downtime, wake effects, transmission losses, etc., an overall loss figure of 20% has been assumed. The main losses are assumed as follows:

> Downtime: 7.5%. Onshore wind farms typically have 2 to 3% downtime after initial teething problems are resolved. Offshore, more downtime is expected due to access difficulties and resolution of the teething problems may be more extended. However, some contractors are offering to warrant downtime at around the 10% level for current offshore sites indicating that the industry will achieve a level somewhat better than that.
>
> Wake losses: 8%. This is a design decision trading off the usage of the site area against productivity but 8% losses are considered a robust assumption.
>
> Electrical transmission losses: 3%. This is a design decision trading off the capital cost against lifetime operating losses and 3% losses are considered a robust assumption.

The net load factors are presented as a function of annual mean wind speed in Table 4.1. There is some dependency on turbine technology and the average of the load factors for the two turbines mentioned has been presented.

Annual mean wind speed [m/s at hub height]	Net load factor
8.5	33%
9.0	36%
9.5	38%

Table 4.1 Estimated Net Load Factors – UK Offshore

GH has completed energy assessment of approximately 15 GW of wind power globally, both onshore and offshore. The above levels are seen as sensible working assumptions. Wind speeds offshore the UK are seen as being comparable to good hilltop sites in England and Wales and the load factor figures shown in Table 4.1 are considered somewhat lower than actually achieved on such sites, reflecting the higher loss assumptions made. The following section gives some supporting evidence to this.

4.4 Actual load factors

Production data from UK wind farms is rarely made available by owners but GH has sourced data from some example projects, in the UK and also, for reference, for the Middelgrunden Wind Farm, 3 km offshore Copenhagen in Denmark. The example projects have been selected as to represent a fair reflection of the range of load factors found in UK wind farms.

Project details	Net load factor	Comment
Delabole Wind Farm, Cornwall (4MW)	30 %	Elevation 240m AMSL, Cornwall, based on Nov 1991 to date (12 years). Source [4.2].
Burradale Wind Farm (4 MW)	51 %	Elevation 150m AMSL, Shetland, based on 2001 to 2003 (3 years). Source [4.3].
Middelgrunden Offshore Wind Farm (40MW)	29 %	Based on only full year since commissioned (2002). Source [4.4].

Table 4.2 Actual Example Net Load Factors

The context for this investigation is an assertion in a report by Incoteco (Denmark) ApS [4.5] that a typical of load factor for wind power onshore in western Denmark (quoted in [4.5] as 20%) may be applicable to UK offshore wind farms. This claim is considered entirely misleading for the following reasons:

- Western Denmark mostly has annual mean wind speeds of the range 6.0 m/s to 7.0 m/s at 50m height according to the European Wind Atlas [4.6]. Many of the turbines in Western Denmark are quite old with rather low hub heights so it is fair to assume that the average hub height is typically 50 m or possibly a little higher. Sites with annual mean wind speeds of 6 m/s to 7 m/s will typically yield load factors of 18% to 25%, consistent with the figure quoted by Incoteco [4.5].

- Onshore UK sites, although with underlying "flat-terrain" wind climates comparable to western Denmark, benefit substantially from the topography of the UK. The two UK examples of Table 4.2 show that even on quite low hills, substantial augmentation is observed.

- The annual mean wind speed increases significantly between flat level onshore terrain and sites at 10 km or more offshore. Additionally, modern offshore turbines will have higher heights than is typical in western Denmark. To illustrate this, consider the Middelgrunden Wind Farm load factor in Table 4.2. According to the European Wind Atlas [4.6], this area has annual mean wind speeds at 50m height of around 6 m/s implying wind power load factors of approximately 18 %. Middelgrunden by comparison appears at least 50% more productive, despite being only 3 km offshore and downwind of Copenhagen for prevailing winds.

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APPENDIX 1 CAPITAL COST BUDGET BREAKDOWN

I.1 Introduction

A development and construction budget has been assembled for a typical UK Round 1 project of 30 wind turbines, overall rated power approximately 100 MW to include:

- Pre-construction development and consenting
- Site survey works
- 30 wind turbine units including MV/LV transformers and switchgear, supplied to a UK load-out port
- 30 Wind turbine foundations supplied to a local staging port
- SCADA system
- 1 Instrumented meteorological mast and foundation
- Installation of the above
- Seabed preparation and scour protection for all foundations
- Supplied and installed 33 kV electrical cabling up to the shoreline and inland to a 132/33 kV substation at the grid connection point
- Construction management costs
- Contingency

In assembling this budget, GH has used information from an in-house database of unit rates for the industry and experience on UK Round 1 commercial projects. This pricing is purely indicative, for a “typical” project located approximately 10 km offshore in water depths of 5 to 15m LAT.

The attached table gives the breakdown of these budgetary costs and some key elements are elucidated upon below.

I.2 Development, site survey and preliminary works

Development cost estimates are based on discussions with active Round 1 developers

Typically site surveys will be two stage with the first being a relatively comprehensive set of geophysical and other surveys, budgeted at £250k. Further such work is envisaged to include additional boreholes or CPT tests at a sizeable sample of proposed wind turbine locations. An allowance of £500k is advised for this element.

For contractor’s construction project management, to include all administration, planning, project controls, reporting and E,H&S monitoring which would normally be within the remit of an EPC contractor, a typical budget of £2M is advised.

Construction insurance costs, notably CAR, are not yet well-established but a provisional sum of £2M is considered appropriate.

Similarly, the issue of finance costs is not at all well-defined as none of the UK Round 1 projects (nor any project globally) has yet acquired construction finance. Again, a provisional sum of £2m is considered appropriate for due diligence and arrangement fees.

I.3 Wind turbine supply

Budget costs for supply to a load-out port and for commissioning a 2.3MW to 3.6 MW model with MV/LV transformer, switchgear and tower to give hub height approximately 70 to 80m AMSL have been provided to GH in confidence by several turbine suppliers. These are relatively wide-ranging but have lead to an assumption of £1,600k per unit installed for a turbine in the middle of that size range.

II.4 Wind turbine foundations

For the purposes of the current note, it has been assumed that the support structure for the wind turbine (including pile and transition piece) will have a total mass of 500T based on GH project experience. The fabricated coated and delivered cost of structural steelwork of this nature including appurtenances such as ladders, cathodic protection and J-tubes is typically £1500/T.

II.5 Offshore cabling

The offshore electrical system and connection to shore has been assumed to consist of 33kV radial feeders, with three 33 kV cables running to shore. Total cable length has been estimated at 15,000m on the site and 30,000m for the connection to shore.

The cables used on-site are likely to be 500 mm^2 and/or 120mm^2 EPR or XLPE, in approximately equal proportions. Corresponding budget unit rates are, for the cable supplied to a local port, £175/m and £120/m, respectively.

The cables used for the connection to shore are likely to be 500 mm^2 EPR or XLPE with corresponding budget unit rate of £175/m.

II.6 SCADA system

Costs for SCADA systems are highly variable and it is advised that a suitable assumption for the purposes of the current note, excluding communications cabling (which are bundled with the electrical power cables) is £25k per turbine.

II.7 Meteorological mast

For a single meteorological mast, top height approximately 70-80 m AMSL, supplied to a local staging port, to include mast, instrumentation, foundation of approximately 100T, a budget figure of £250k is advised.

II.8 Installation

For the purposes of the current note, the following assumptions have been made:

- Use of a custom-built vessel such as Mayflower Resolution for transport of equipment from staging ports, installation of the foundations and wind turbines, based on budget day-rates for installation spread of £75k per day for foundation and turbine inst5allation works
- Mobilisation and demobilisation, total duration 10 days
- Load-out, transit time and installation time for foundations 4 days each
- Load-out, transit time and installation time for turbines 2 days each
- Cable burial at up to 3 m depth and reasonable seabed conditions (e.g. no rock-cutting) by typical cable-lay spreads, day-rate £45k, 100 days of working including cable-laying, burial, pull-ins, mobilisation and demobilisation
- Weather downtime allowance for all offshore working of 20%

II.9 Seabed preparation and scour protection

It is assumed that there is a requirement for localised levelling of the seabed and for scour protection to each of the foundation locations, subject to detailed design. Assuming the latter to be achieved through rock dumping, a budget of £100k per turbine foundation is advised.

II.10 Onshore electrical works

On-land, the works are budgeted as follows:

- 3 km onshore cabling

- Cost of connection to distribution system, £5m, based on discussions with UK Round 1 developers.

II.12 Total EPC costs and contingency

The attached table summarises the above costs, which total £1,200 per installed kW.

Item	Sub-item	Unit rate [£k]		UK Round 1 Project			
			Unit	Quantity	Cost [£k]	Subtotals [£k]	
Development expenses							
	PR	250	Project	1	250		
	Environmental Impact Assessment (incl. EIS)	1,000	Project	1	1,000		
	Consenting	250	Project	1	250		
	Wind monitoring	500	Project	1	500		
	Site surveys (geophys, etc.)	250	Project	1	250		
	Technical and commercial management	500	Project	1	500		
						2,750	2%
Preliminary and management works							
	Further site surveys	500	Project	1	500		
	Construction management	2,000	Project	1	2,000		
	Insurances	2,000	Project	1	2,000		
	Financing costs	2,000	Project	1	2,000		
						6,500	5%
Wind turbine, transformer and tower supply		1,600	Turbines	30	48,000	48,000	40%
Foundation supply		1.50	Ton. Steel	15000	22,500	22,500	19%
Offshore electrical supply							
	On-site 33kV submarine cables (incl. comms)	0.15	m	15000	2,213		
	Site-shore 33kV submarine cables (incl. comms)	0.18	m	30000	5,250		
	Offshore substation	5,000	substation	0	-		
						7,463	6%
Wind farm monitoring system supply							
	SCADA system	25	Turbines	30	750		
	Instrumented met mast and foundation	400	Mast	1	400		
						1,150	1%
Installation							
	Mob and demob	75	Days	10	750		
	Foundations and met mast	75	Days	120	9,000		
	Wind turbines	75	Days	60	4,500		
	Cable lay	45	Days	100	4,500		
	Seabed prep and scour protection	100	Turbines	30	3,000		
	Weather downtime	20%			4,350		
						26,100	22%
Onshore electrical works							
	Cabling	300	km	3	900		
	Grid Connection Agreement	5,000	Project	1	5,000		
						5,900	5%
Grand total						120,363	100%
Specific cost per installed MW						1,204	

Cost breakdown
Calc sheet rev B.xls
10/12/2003