Client discretion

Bermuda offshore wind: LCOE assessment

For Greenrock

August 2022

Document history

Revision	Description	Circulation classification	Authored	Checked	Approved	Date
1	For client	Client discretion	CDB	BAV	BAV	24 Aug 2022

Strictly confidential to XX Not to be circulated beyond the named persons or group within client.

Commercial in confidence Not to be circulated beyond client (or BVG Associates if no client specified).

Supplied under NDA Not to be circulated beyond client or other organisation party to a non-disclosure agreement (NDA) with the client (subject to any additional terms agreed with the client in [state details of agreement]).

Client discretion Circulation is at the discretion of the client (subject to any terms agreed with the client in [state details of agreement])

Unrestricted No restriction on circulation.

Note: Circulation classification may not be changed on a document. Only BVGA may issue a revised document with a revised circulation classification.

Copyright

Disclaimer

1. This document is intended for the sole use of the Client who has entered into a written agreement with BVG Associates Ltd or BVG Associates LLP (jointly referred to as "BVGA"). To the extent permitted by law, BVGA assumes no responsibility whether in contract, tort including without limitation negligence, or otherwise howsoever, to third parties (being persons other than the Client), and BVGA shall not be liable for any loss or damage whatsoever suffered by virtue of any act, omission or default (whether arising by negligence or otherwise) by BVGA or any of its employees, subcontractors or agents. A Circulation Classification permitting the Client to redistribute this document shall not thereby imply that BVGA has any liability to any recipient other than the Client.
2. This document is protected by copyright and may only be reproduced and circulated in accordance with the Circulation Classification and associated conditions stipulated in this document and/or in BVGA's written agreement with the Client. No part of this document may be disclosed in any public offering memorandum, prospectus or stock exchange listing, circular or announcement without the express and prior written consent of BVGA.
3. Except to the extent that checking or verification of information or data is expressly agreed within the written scope of its services, BVGA shall not be responsible in any way in connection with erroneous information or data provided to it by the Client or any third party, or for the effects of any such erroneous information or data whether or not contained or referred to in this document.

The views expressed in this report are those of BVG Associates. The content of this report does not necessarily reflect the views of Greenrock.

Executive summary

The purpose of this document is to help Bermuda reach net zero by providing a levelized cost of energy (LCOE) assessment of offshore wind. It was commissioned as follow up to our previous report *Bermuda offshore wind: Key publications review and priority actions,* dated April 2022, which suggested that one of the key uncertainties to address in considering whether offshore wind makes sense for Bermuda related to LCOE.[i]

Project assumptions

We assessed a project based on the following headline assumptions:

- Project rated power 60 megawatts (MW), with two variant configurations: ten 6 MW turbines or four 15 MW turbines
- Average wind speed (at 100 m height) 7.8 m/s
- Average water depth 20 m, and
- Commissioned in 2028.

Based on these headline assumptions and engagement with industry, we assessed LCOE using the following additional assumptions:

- Monopile foundations
- No offshore substation
- European supply chain rather than US
- Turbine variants suitable for hurricane (typhoon) (Class T) conditions are available for installation in 2028 (15 MW variants like this are in the market now; it is not certain that 6 MW variants like this will be available for installation in 2028)
- Installation process uses a single jack-up vessel for the installation of the monopiles and turbines
- The installation vessel transits from Europe to Bermuda unloaded, hence requiring transport vessels to bring the major components
- Components are transferred onto the jack-up either in a sheltered area or while the transport vessel is berthed in port, and
- The operator establishes a small team locally in Bermuda. Major repairs and major replacements require mobilising specialist teams and vessels to Bermuda at a high cost.

LCOE assessment

For each turbine configuration, the LCOE was assessed for three scenarios:

- 1 GW project in an established market (Europe)
- 60 MW project in an established market, and
- 60 MW project in Bermuda.

As shown in Figure 0.1, the 15 MW turbine configuration is cheaper for each scenario, though the 5% difference compared to the 6 MW turbine configuration in Bermuda is small enough to be within current uncertainty levels.

The LCOE of the lowest cost Bermuda project is about 2.9 times greater than a 1 GW project in an established market at $152 /MWh. The increase is about one-third due to project scale and two-thirds due to Bermuda's remote location.

---

[i] For an explanation of LCOE, and information of offshore wind technology and processes more generally, see https://guidetoanoffshorewindfarm.com/, including the *Wind farm costs* tab.

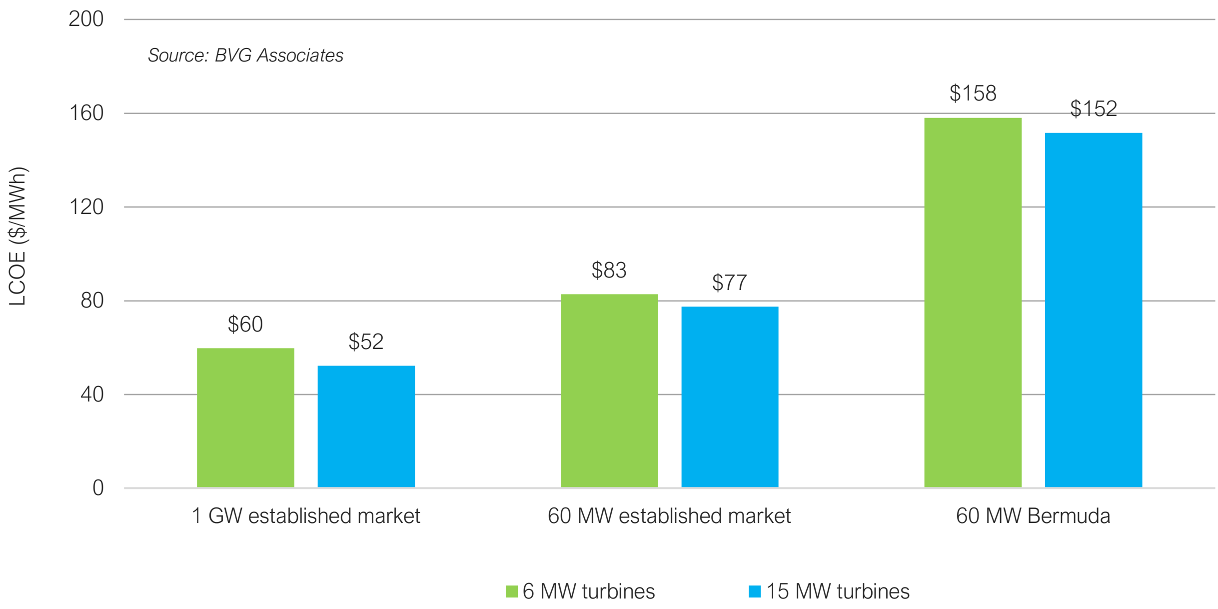

Figure 0.1 LCOE for each scenario.

These results are lower than presented in two previous Bermuda offshore wind LCOE studies. In 2014, the University of California estimated a mid-value LCOE of $261 /MWh, and in 2021, Ricardo estimated a range from $182 /MWh to $296 /MWh. [1, 2] A discussion of these analyses was provided in our previous report. The discrepancy largely comes from:

- Both previous studies only considering smaller turbines (3.6 MW and 5 MW).
- Both previous studies assuming a higher weighted average cost of capital (WACC) of 10%, compared to the 7.5% assumed in this study.
- University of California assuming a 20-year project lifetime (Ricardo did not state its assumption). This study assumes a 32-year lifetime which is expected to be typical for projects installed in 2028.
- A more detailed approach in this assessment, considering practicalities of delivering a small project in Bermuda, but using up-to-date costs.

Smaller turbines, a higher WACC, and a shorter lifetime all contribute to a higher LCOE. If using a WACC of 10% and a lifetime of 20 years for this study, whilst keeping cost and energy production unchanged, LCOE would increase to $199 /MWh for a project using 15 MW turbines.

Options

The industry engagement confirmed a conservative set of assumptions, with options with the potential to further reduce LCOE:

- The project could be used as an extension to a US East Coast project. This option could see savings from development, procurement of major components, installation, and operations, maintenance, and service (OMS).
- Chinese offshore wind turbines could be used and could come at a lower cost than European turbines, potentially as part of a market entry move. This could provide a LCOE reduction of 6% for the 15 MW turbine configuration.
- Wind turbines designed for low mean wind speed sites could significantly boost the energy production. This could provide a LCOE reduction of 11% for the 15 MW turbine configuration if such turbines are available in the market for installation in 2028.

- A turbine designed for lower mean wind speeds has a larger diameter rotor than a comparable design for higher mean wind speeds. Likewise, typically it will have a lower extreme storm design wind speed, which would make it more susceptible to hurricanes unless suitably reinforced (which is possible, but may not be available as an option for any given turbine). This is a natural impact of having longer blades.
    - There are large markets emerging, especially in East Asia, characterised by lower mean wind speeds and higher storm wind speeds than established markets, potentially similar to Bermuda. If turbines suited to these markets are designed, which is likely given the growing demand for offshore wind in such markets, then they will also be suitable for Bermuda.
    - There is no generic reason why a turbine with lower rated power will be more suitable for any particular mean wind (or storm wind speed) than a turbine with higher rated power. Suitability is set by the technical design parameters used when designing the turbine.
    - In almost all normal cases, turbines with higher rated power offer lower LCOE.
- Alternate installation processes such as using a local port or using the same heavy lift vessel both for the transportation and installation of the monopiles and turbines could lower LCOE by about 1%.
- Floating turbines could be used to remove the need for chartering a jack-up vessel to Bermuda. It is unlikely that integrated turbine-foundation packages could be towed across the Atlantic, so local final assembly would be needed. This would most likely need a large crane, meaning this option is unlikely to be cheaper. Future innovations may change this.

Contents

List of figures

List of tables

1. Introduction

1.1. Background

Greenrock is seeking to support the decarbonisation of Bermuda's electricity supplies within a timeframe that remains within a 1.5C carbon budget.

Based on previous renewable energy resource and technology assessments, offshore wind has consistently been identified as the most critical mature renewable energy technology to achieve decarbonisation of the electricity sector.

Greenrock has welcomed the progress made by the Bermuda Government to date considering offshore wind as a key potential element of a sustainable, low carbon energy system for Bermuda. It seeks now to help accelerate progress through bringing in global experience of the technology, costs and practicalities of offshore wind, recognising that:

- Offshore wind costs have been falling rapidly and are projected to continue falling, in relative terms compared to traditional forms of electricity generation
- The scale of technology and market continues to grow
- Bermuda has specific characteristics (in terms of size of market, location and available facilities) that need to be addressed, and
- Knowledge about how to progress offshore wind in Bermuda is naturally limited.

Bermuda has a typical power consumption of 50 to 100 megawatts (MW). Historically, Bermuda has used fossil fuels to generate most its electricity but also uses some small-scale renewables with about 13 MW of solar photovoltaic (PV). It does not have the available landside area to meet its electricity demand with onshore renewables – there is space for approximately 84 MW of solar PV which would meet a quarter of electricity demand. Offshore wind, however, presents an opportunity for Bermuda to vastly increase its share of renewable energy generation, with a relatively small 60 MW installation able to meet about 40% of electricity demand.

1.2. Purpose

The purpose of this document is to provide a comprehensive levelized cost of energy (LCOE) analysis recommended in the report *Bermuda offshore wind: Key publications review and priority actions,* dated April 2022, with key factors such as project scale and installation logistics accounted for. Engagement with developers, installers, and turbine suppliers defined how a project would be executed. These engagements also explored possible alternate options, such as the use of floating foundations.

2. Methodology

2.1. Overview

This assessment evaluates the LCOE of an offshore wind project in Bermuda. Site assumptions were based on viable offshore wind sites put forward in two previous studies relating to offshore wind in Bermuda. Project execution assumptions were defined through engagement with developers, installation contractors, and turbine suppliers.

LCOE was assessed across three scenarios:

- Project with rated power of 1 GW in an established market (Europe),
- Project with rated power of 60 MW in an established market, and
- Project with rated power of 60 MW in Bermuda.

LCOE results are given for each scenario to show the extent that each factor, project size or location, influences cost.

The option of using floating foundations was explored as a means of bypassing the need for an expensive jack-up vessel.

2.2. Site assumptions

The Bermuda project is assumed to have a rated power of 60 MW, use monopile foundations, have no offshore substation, and be commissioned in 2028. Two configurations were considered – four 15 MW turbines or ten 6 MW turbines.

The 15 MW turbines represent the average size of offshore turbines expected to be installed in 2028. Experience to date is that in most offshore wind markets, using the largest available turbine offers the lowest LCOE solution.

The 6 MW turbines are representative of the largest onshore turbines expected to be in the market at that time, marinized for offshore use. Turbines of such size are already uncompetitive for most offshore wind sites, but they may have a role in close-to-shore projects due to their smaller visual scale, and may offer installation cost savings on remote sites due to the avoidance of high-cost state-of-the-art installation vessels.

A set of site parameters were selected for the purpose of evaluating LCOE. These represent several viable sites put forward in two separate publications which aimed to evaluate the LCOE of offshore wind energy in Bermuda:

- *Offshore wind energy in the context of multiple ocean uses on the Bermuda platform*, dated March 2014, authored for Government of Bermuda by MSc Students at University of California, Santa Barbara[1], and
- *Assessment of the Offshore Wind Potential in Bermuda*, dated August 2021, authored for Regulatory Authority of Bermuda by Ricardo[2].

These parameters can be seen in Table 2.1.

Table 2.1 Site parameters for the three scenarios.

Parameter	1 GW project in an established market	60 MW project in an established market	60 MW project in Bermuda
Average wind speed @ 100 m (m/s)	9.5	9.5	7.8
Average water depth (m)	20		
Distance from construction port (km)	40	40	6,000
Distance from operations port (km)	20		
Maintenance and service vessel strategy	Crew transfer vessel		
Offshore export length (km)	20 (14 km straight-line distance, with 40% added to minimise environmental impact of cable routing)		
Onshore export length (km)	2		
Number of offshore substations	2	0	0

2.3. Project execution assumptions

There are various routes to execute a project in Bermuda, each with different risk and cost. To better understand how the project would be approached, two global offshore wind project developers, two leading offshore turbine suppliers, and five leading engineer-procure-construct contractors were interviewed. Based on these interviews a conservative set of assumptions were used, with options to potentially further reduce LCOE noted.

2.4. LCOE assessment

Costs were calculated for a 1 GW project in an established market using BVGA's in-house LCOE model. The model is continually updated as insights are gained either through consultancy work or when there are major industry announcements such as auction results. Data sources and the validation process for updating the model can be found in Appendix A.

We then adjusted these costs to account for a much smaller project and then such a project in Bermuda. We made these adjustments through a combination of:

- Industry experience through assessing costs of projects of different sizes
- Quantitative input during engagement with senior industry staff, and
- Bottom-up cost modelling (for example of installation processes).

All costs are in end of 2021 US$. As the costs of certain commodities such as steel, copper, fuel, and electricity are in flux and not expected to change at the same rate of inflation, premiums were added to account for the higher prices of these commodities in the future.

3. Results

3.1. Overview

A summary of the LCOEs for the various scenarios are shown in Figure 3.1. The Bermuda LCOEs are $158 /MWh and $152 /MWh for the 6 MW and 15 MW turbine configurations, respectively. The 6 MW turbine configuration was anticipated to see significant savings during installation due to a cheaper jack-up vessel. This option requires double the number of transport vessels and a lengthier installation period, putting it on par with the 15 MW installation costs.

The LCOE of the cheapest Bermuda project is about 2.9 times greater than a 1 GW project in an established market. This high LCOE is due to two primary reasons:

- Project size: a 60 MW project is far smaller in scale than other commercial-scale projects. Projects in 2028 are likely to be 1 GW and above as developers seek to maximise the benefits of economies of scale.
- Project location: Bermuda is approximately 6,000 km from the major European markets. Components and an installation workforce need to be transported over long distances.

The increase is about one-third due to project scale and two-thirds due to Bermuda's remote location.

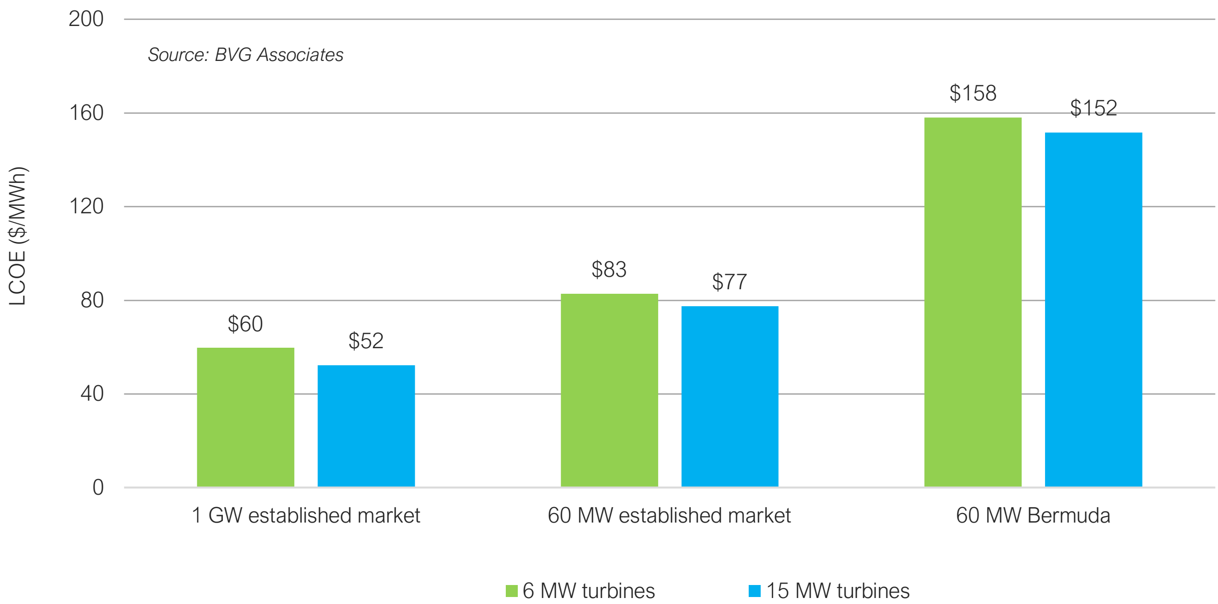

Figure 3.1 LCOE for each scenario.

These results are lower than presented in two previous Bermuda offshore wind LCOE studies. In 2014, the University of California estimated a mid-value LCOE of $261 /MWh, and in 2021, Ricardo estimated a range from $182 /MWh to $296 /MWh. A discussion of these analyses was provided in our previous report. The discrepancy largely comes from:

- Both previous studies only considering smaller turbines (3.6 MW and 5 MW).
- Both previous studies assuming a higher weighted average cost of capital (WACC) of 10%, compared to the 7.5% assumed in this study.
- University of California assuming a 20-year project lifetime (Ricardo did not state its assumption). This study assumes a 32-year lifetime which is expected to be typical for projects installed in 2028.
- The more detailed approach used in this study, considering practicalities of delivering a small project in Bermuda, but using up-to-date costs.

Smaller turbines, a higher WACC, and a shorter lifetime all contribute to a higher LCOE. If using a WACC of 10% and a lifetime of 20 years for this study, whilst keeping cost and energy production unchanged, LCOE would increase to $199 /MWh for a project using 15 MW turbines.

Cost breakdowns and significant extra detail is provided in Appendix B.

The sensitivity of LCOE to CAPEX, OPEX, annual energy production (AEP), project lifetime and WACC is shown in Figure 3.2 for the Bermuda project using 15 MW turbines. As always, LCOE is particularly sensitive to AEP, reinforcing the point that using turbines suited to lower wind conditions would be advantageous, discussed later. The main driver of annual energy production is mean wind speed. There remains uncertainty about the wind resource in Bermuda, as to date, the most thorough assessment has used a global dataset. Although developed specifically to support wind projects and proved to be relatively reliable in many locations, a key way to increase bankability will be to conduct a multi-year on-site wind measurement campaign, typically using a floating lidar.

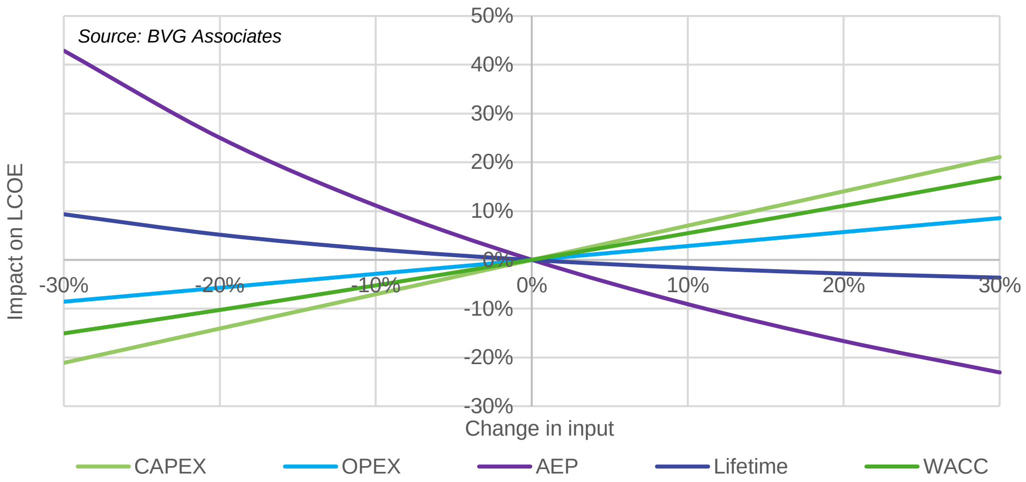

Figure 3.2 Sensitivity of LCOE to key project inputs.

3.2. Project execution assumptions

Assumptions are broken down by cost element.

3.2.1 Project development

- The project is developer-led from a European base as a stand-alone project. It is anticipated that the additional cost and inefficiency of using the US supply chain will offset the benefit of being closer to Bermuda.

3.2.2 Turbines and balance of plant

- Both turbine variants (6 MW and 15 MW) are sourced from European supply.
- Although Bermuda would benefit from turbines designed for low-wind sites (hence with larger rotor than standard), a standard turbine rotor diameter of 224 m is assumed for the 15 MW offshore turbine (specific rating 380 W/m^2). It is uncertain whether a global market will materialise for large offshore turbines designed for lower-wind sites by 2028.
- A relatively larger 164 m diameter rotor compared to rated power, better suited for medium-wind sites, is assumed for the 6 MW turbines used in Bermuda. This rotor diameter is typical of the standard offering already available from suppliers (specific rating 284 W/m^2). For high-wind established sites, a 158 m diameter rotor is assumed.

- The turbines modelled are assumed suitable for hurricane (typhoon) risk areas, hence we have added cost to cover necessary design changes. This does not necessarily mean that such turbines will be available in the market for installation in 2028.
    - The offshore turbines with highest rated power in use as of 2022 already have typhoon certified (Class T) variants.[ii] Bermuda's wind climate, with low mean wind speeds and high peak wind speeds, is not unique. It is similar to the wind climate of the Asian-Pacific. It is likely that future 15 MW offshore turbines will be Class T if they are to be used in North America and the Asia-Pacific markets. The statistical severity of hurricanes in Bermuda is still to be fully evaluated compared to wind turbine design parameters.[iii]
    - It is less certain whether 6 MW Class T turbines will be available in the market in 2028.

Offshore turbine rated power, rotor diameter, suitability and availability in the market

Wind turbine suppliers seek to optimise products for different markets they serve, balancing cost, energy production and other drivers. Key parameters are:

- Rotor diameter. The diameter (normally in m) of the circle swept by the rotor as the blades rotate. From this is derived the rotor swept area, the area of the circle swept by the rotor as the blades rotate.
- Rated power. The maximum power (normally in MW) that the wind turbine can provide. This is when the wind speed is relatively high.
- Specific rating. A measure of the relative rated power of the turbine compared to the size of the rotor (normally in MW per m²). It is calculated by dividing the rated power by the rotor swept area.

Typically, regarding optimum rotor diameter:

- Increasing the diameter of a turbine means it produces more energy, but it also adds cost.
- The same is true for turbine rated power, but it tends to be less effective to do this for sites with lower mean wind speeds than to increase the size of the rotor.
- In effect, for a turbine with a given rated power, the optimum rotor diameter tends to be larger for a site with lower mean wind speed.

Typically, regarding optimum rated power:

- Assuming the same specific rating, increasing the rated power decreases LCOE. This is because costs (especially of foundations and installation) do not increase as fast as the extra energy production. It is why we have seen such an increase in turbine size and reduction in LCOE in offshore wind in recent years.
- There is no driver to use turbines with lower rated power on sites with lower mean wind speeds or higher storm wind speeds. Suitability is set by the technical design parameters used when designing the turbine.

The impact of designing to withstand storms:

- All conventional wind turbines stop generating power as the wind speed increases, but before it gets to an extreme level. This is because it would add more cost to design the turbine so that it could carry on generating than is justified by the additional energy that it would produce under these rare conditions.
- All wind turbines are designed to withstand storms. It costs more to design a turbine to withstand more severe storms.

[ii] A standard offshore wind turbine typically is designed to withstand extreme 3-second gusts of 70 m/s (250 km/h). Class T turbines designed to withstand extreme 3-second gusts of 80 m/s (almost 290 km/h) are now available, though these are not variants designed for lower mean wind speed sites.

[iii] Nominally, Bermuda expects up to category 4 strength storms. Using the Saffir–Simpson scale, this corresponds to a maximum 1-minute mean wind speed at 10 m height of 70 m/s, which in turn corresponds approximately to a 3-second gust wind speed of 72 to 78 m/s at 10 m height.[iii] A peak gust of 74 m/s (unknown averaging period) was recorded in Hurricane Fabian in 2003, along with a peak 10-miunute mean wind speed of 53 m/s at 68 m height.[iii] A wind turbine should be designed to withstand the anticipated 50-year return period, 3-second gust at hub (rotor centre) height.

- Often, turbines designed for sites with lower mean speeds (hence with relatively larger rotors) are designed to withstand lower extreme winds (hence saving cost) because such sites often have lower extreme winds.

Availability in the market:

- Bermuda, and an increasing number of other emerging wind markets, have lower mean wind speeds and higher extreme wind speeds than established markets. As the wind industry grows, more suppliers will develop products for such markets. Before this happens, the choice available for such conditions is to use a turbine designed to withstand the extreme wind speeds, that may not have optimum design to minimise LCOE on sites with lower mean wind speeds. This is what we have modelled.

The above is summarised In Figure 3.3.

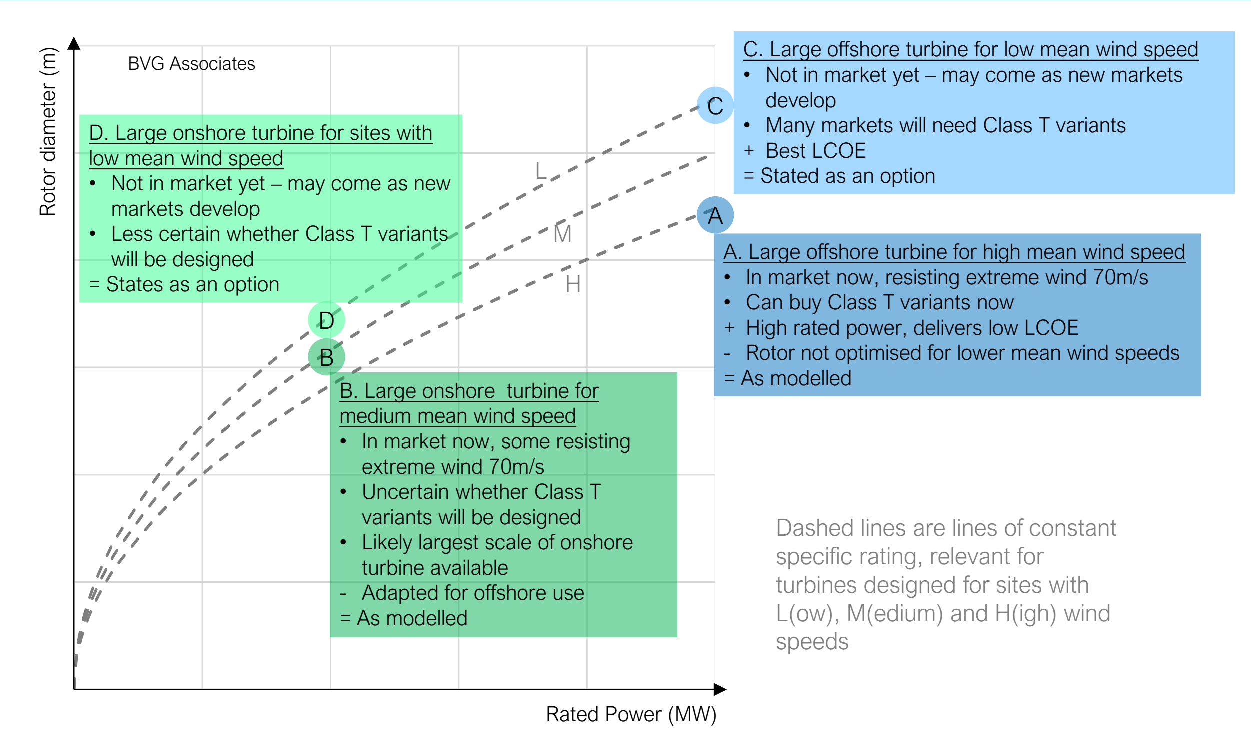

Figure 3.3 Offshore turbine rated power, rotor diameter, suitability and availability in the market.

3.2.3 Installation

- A single jack-up is assumed to carry out the installation of turbines and foundations to minimise the additional mobilisation costs of multiple vessels. The jack-up returns to Europe for conversion from monopile to turbine sea fastenings and equipment. The 15 MW turbine configuration requires a state-of-the-art vessel while the 6 MW turbine configuration utilises a small older vessel that may have greater availability around this timeframe.
- The jack-up transits to Bermuda unladen. Transport vessels bring monopiles and then turbines to Bermuda. The jack-up transfers components onto its deck in a sheltered lagoon area or when the transport vessel is berthed in port. The jack-up then transits to site for installation.
- Array cable (including for export) is installed by an older cable lay vessel due to the relatively short length of cable that needs to be installed. This is optimal as a smaller vessel can also do nearshore installation, removing the need for a second vessel.

3.2.4 Operation, maintenance and service

- The operator establishes a small team locally for general operations and much of the planned maintenance. Local vessels are used as required as crew transfer vessels.
- Major repairs require teams coming to Bermuda at additional cost.
- Major replacements require bringing specialist vessels to Bermuda.
- Turbine availability is increased by the scale of the farm and lower mean wind speeds[iv]. This allows the operator to navigate weather windows more easily as planned maintenance campaigns are short.
- Turbine availability is decreased by long wait times for major repairs and major replacements as specialist teams and vessels need to be mobilised to Bermuda. These types of failures can sometimes be predicted, meaning some work can be done reduce downtime.

3.3. Additional industry insights

Additional insights captured during engagement included:

- Developers are generally interested in delivering the project, despite its scale. Each is likely to look for an innovation or strategic angle (such as a tester for a small-scale hydrogen project or novel floater design) or higher return than standard, as effort per MW installed is much increased and all expect their teams to be busy over the next decade.
- An experienced developer is likely to be required to keep turbine supplier interest, as they find it more efficient to work with experienced clients.
- As an ongoing pipeline of offshore wind projects is unlikely, it is improbable that many project developers will invest in getting to understand the market. The most likely way to get some level of competition will be for Government (or some other entity) to commission early survey and development work, then offer the project to market on a revenue per MWh basis, possibly with scope wider than just wind farm supply. Developers prefer a non-competitive process with bilateral negotiation with Government or offtaker.
- Installers generally want as large a portion of the installation contract as they can handle. The full engineering, procurement, construction, and installation contract is preferred, especially for smaller projects.
- A monopile order would be easy enough to fulfil with similar premiums to turbines expected for an order of this size. Tower factories suited to manufacturing towers for 15 MW turbines could also potentially supply the monopiles for smaller 6 MW turbines.
- The supply of cables should be straightforward with no small-order premium. The export cable(s) connecting the wind farm to shore will be the same design as the array cables that connect turbines together, as no offshore substation is required due to the short distance to shore.

[iv] Availability is a standard measure of the fraction of time a wind turbine is fault-free and available to generate power, independent of whether the wind conditions are suitable for operation. Typical offshore wind farms in established markets have availability of about 95%, meaning that on average, each turbine is unavailable to generate for 5% of the time.

4. Options for potential LCOE reduction

The industry engagements gave insight into how an offshore wind project in Bermuda should be executed, with options to potentially further reduce LCOE discussed below.

4.1. Development

Combining with a larger project. A developer could use Bermuda as an extension to an East Coast US project. The US would likely be more costly for a stand-alone project, but it may be offer lower LCOE if there is the possibility to add to an existing large US project. There would need to be the right circumstances for this option, such as a willing developer and installer working on a project around the Carolinas or Virginia at the right time and with suitable technology. This option would reduce mobilisation costs during installation and give installers more flexibility. It could also reduce some of the premium due to the small project, but not all, as a certain amount of the engineering design is site specific. The exact effect on LCOE is difficult to quantify without a full cost analysis.

Combining with an energy system project. Developers also showed interest in combining the offshore wind project with a similar small-scale green hydrogen generation demonstration project, replacing use of fossil. As 60 MW makes up a large portion of Bermuda's electricity demand, there would be times when generation is above demand. With no external grid link, Bermuda will need an energy storage solution to manage any surplus electricity. Existing fossil fuel powered generating plants could be retrofitted to generate electricity via hydrogen.

4.2. Turbines and balance of plant

Chinese supply. Chinese suppliers are keen to get a foothold in European and Americas markets. They may provide discounted prices (no premiums) to do so, potentially reducing LCOE by $9 /MWh or 6%.

Turbines designed for low-wind sites. 15 MW turbines with large rotors suited for low mean wind speed sites (such as Bermuda) may be available for use by 2028. These could offer a significant increase in annual energy production and an associated decrease in LCOE of up to about $16 /MWh or 11%. It may be that this option may be first available through the use of Chinese turbines, increasing the potential LCOE reduction. It will be important to ensure any turbines used are designed to withstand extreme wind speeds in Bermuda.

4.3. Installation

Using a Bermudan port. In this option, transport vessel would unload components at a local port or cruise terminal. These are unlikely to have the bearing capacity necessary to support turbines. Using a Bermudan port would allow installers to navigate weather windows more easily. It would also reduce the time that transport vessels would be required on site. A port assessment would be required, and potentially port upgrades, before this could be considered a viable option.

Using a heavy lift vessel for installation. A heavy lift vessel could potentially carry both foundations and turbines from Europe to the site and install directly. This would remove the need for transport vessels and the transferring of components from vessel to vessel, reducing LCOE by $2 /MWh. This is a non-standard practice that has not been well demonstrated.

Alternate cable installation. Cable installation was assumed to use an indirect route to shore. Environmental sensitivities such as the coral environment of the sea bed likely require a sub-optimal cable route and non-standard installation practices to minimise the environmental impacts. If the sea bed environment is more favourable than expected, cable will be quicker to install and use a more direct route, lowering LCOE by up to about $2 /MWh.

4.4. Floating

Floating turbines provide the opportunity for Bermuda to overcome the costly installation process of fixed-bottom turbines by removing the need for expensive jack-up vessels on site. Turbines could be fully assembled onto the floating foundations at a suitable port in the US and towed to site using anchor handling tugs. While the process of towing the turbines 1,200 km would be long and slow, the cost of such vessels in minimal compared to jack-ups. While there is opportunity to lower LCOE, the option comes at great uncertainty and risk. Towing for a such a long period of time puts the vessels and turbines at risk of unpredictable weather. There is also significant uncertainty with how the unplanned service of floating turbines requiring major component exchange would be handled in Bermuda.

Developers and installation contractors were hesitant to confirm that fully integrated turbine-foundation packages could be towed to Bermuda from either the US or Europe.

Preferred installation methods were proposed, all of which involved assembling turbines onto foundations in Bermuda. This would likely require either a jack-up vessel or a large landside crane to be transported to Bermuda. Both would be costly and would negate the cost saving potential from a cheaper installation process.

The operation, planned maintenance, and unplanned service of floating turbines raises additional uncertainties and risks – a suitable port may be required for tow-in maintenance which Bermuda may not have.

If the turbines cannot be towed from the US or Europe, then floating is likely not a feasible option given current technology.

These assumptions are based on the floating technology of today. Innovations such as self-installing nacelles may change this outlook[v].

[v] A range of solutions are being developed, for example see https://sensewind.com/technology/.

Appendix A LCOE model

Introduction

The original BVGA LCOE model was created in 2012 as part of work for The Crown Estate (TCE). This was based on engagement with 56 companies in the European offshore wind supply chain. The engagement was focused on players with track record in the industry, rather than innovators from outside of the sector. Then as now, a top-down overview analysis was used to moderate and validate the bottom-up approach of innovation estimation. Our LCOE model is continually updated as we gain insights either through our consultancy work or when there are major industry announcements such as auction results.

This section describes the function and scope of the BVGA offshore wind LCOE model and its ongoing validation.

Framework

We define a site with a range of variables that can vary spatially:

- Wind speed
- Water depth
- Significant wave height (on occasion – impact is often second-order)
- Distance to construction port
- Distance to operation port
- Offshore grid distance
- Onshore grid distance
- Plus variables that typically are fixed for a given modelling activity:
- FID or installation date
- Turbine rated power and rotor diameter
- Project rated power
- WACC
- Project lifetime
- Project spend profile, and
- Technology constraints, such as forcing use of a given foundation type, operation, maintenance and service strategy or transmission solution.

From these variables and using the model setup in Figure A.4.1, we output the element values and the LCOE for the sites specified. We can also look at the impact that individual or groups of innovations have.

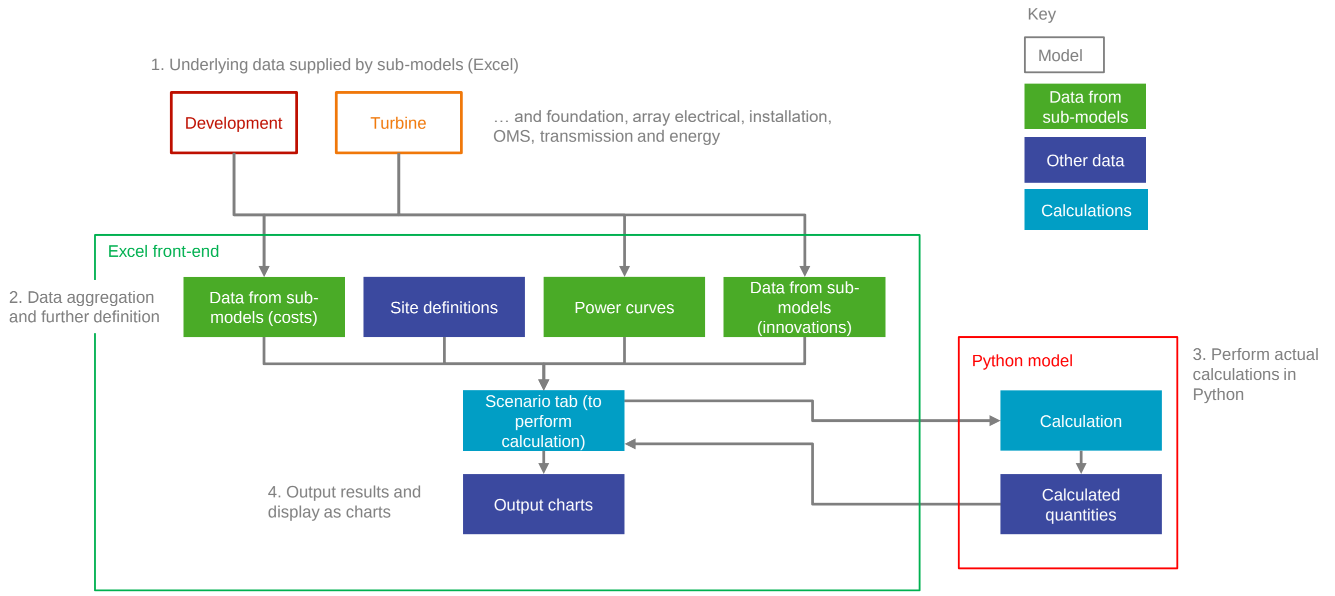

Figure A.4.1 Model framework.

We calculate LCOE in stages as shown in Figure A.2 . Project size and geographical region adjustments are applied after the other characteristics.

To assess LCOE and element values over a region in GIS format (rather than as a long list of sites), we specify turbine and project rated power, FID date, WACC, lifetime, foundation type (monopile, jacket or floating), CTV or SOV and HVAC or HVDC. The model front-end then interacts with the GIS data to produce a GIS output.

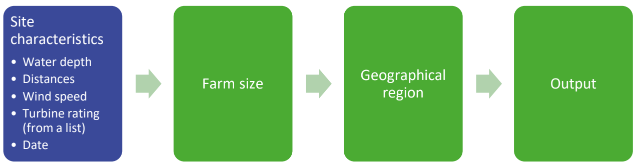

Figure A.2 Modelling process.

Model validation

The original BVGA LCOE model was created in 2012 as part of work for The Crown Estate (TCE) in the UK. This was based on engagement with 56 companies in the European offshore wind supply chain. The engagement was focused on players with track record in the industry, rather than innovators from outside of the sector.

A top-down overview analysis was used to moderate and validate the bottom-up approach of innovation estimation. Workshop discussion was used to validate the results. The report was then peer reviewed in sections so that at least two reviewers with expertise in the area under review had input into each section.

The model is continually updated as we gain insights either through our consultancy work or when there are major industry announcements such as auction results.

Our ongoing review process is shown in Figure A.3.

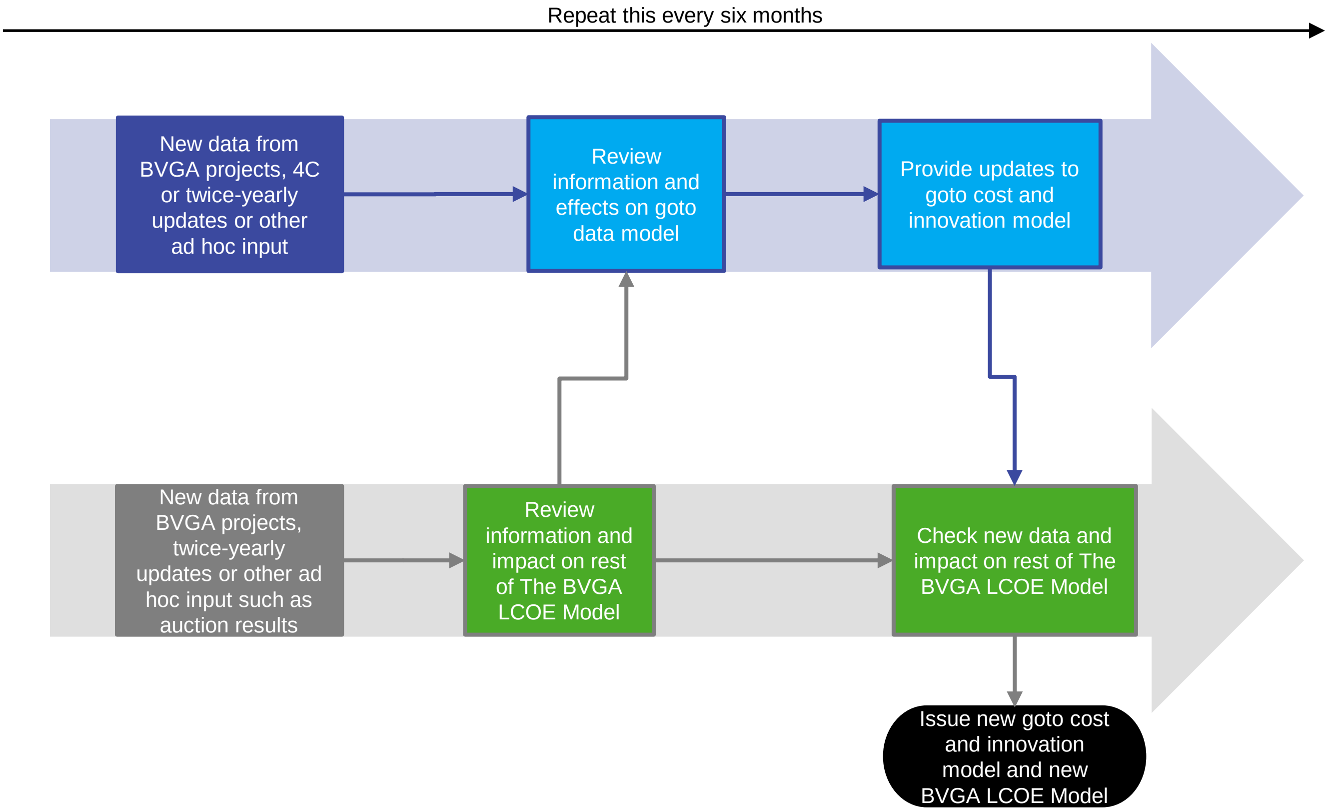

Figure A.3 Procedure for incorporating new information.

Variable Definitions

We use the following element definitions:

- Turbine rated power (MW)
- Project rated power (farm size) (MW)
- Water depth (m), average over the project, depth from lowest annual tide (LAT)
- Distance to construction port (km), distance from centre (centroid) of wind farm to construction port, taking into account vessel path restrictions
- Distance to operations port (km), distance from centre (centroid) of wind farm to operations port, taking into account vessel path restrictions
- Distance to grid (offshore) (km), distance from edge of wind farm to shore, taking into account transmission cable path restrictions. This is not length of cable, which often has some slack in it. It is length of cable route.
- Distance to grid (onshore) (km), distance from shore landing to onshore substation taking into account transmission cable path restrictions. This is not length of cable, which often has some slack in it. It is length of cable route.
- Wind speed (m/s) at 100m height above mean sea level (MSL)
- Rotor diameter (m), and
- Hub height (m) above mean high water spring (MHWS).

Data sources and validation

We keep an internal record of data sources and validation for each cost element, including our method of deriving annual energy production considering a range of losses, including the impact of project size and density.

We have validated aspects of our models against many 10s of different published reports over time.

LCOE definition, cost and energy assumptions

Levelized Cost of Energy

Levelized cost of energy (or LCOE) is defined as the revenue required (from whatever source) to earn a rate of return on investment equal to the discount rate (also referred to as weighted average cost of capital or WACC) over the life of the wind farm. Tax and inflation are not modelled. The technical definition is:

$$LCOE = \frac{\sum_{t=-5}^{n+1} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=-5}^{n+1} \frac{E_t}{(1+r)^t}}$$

Where:

I_t Investment expenditure in year t

M_t Operations and maintenance expenditure in year t

E_t Energy generation in year t

r Discount rate; and

n Lifetime of the project in years.

A value for LCOE for a specific year (annual LCOE) can be calculated by setting the value of t to the year in question.

Financing cost is the equivalent CAPEX needed under zero-WACC conditions to produce the same LCOE as is calculated with non-zero WACC.

Element definitions

Definitions of the scope of each element that makes up LCOE are summarised in Table A.1, written for fixed projects. We hold similar for floating.

Table A.1 Definitions of the scope of each element.

Type	Element	Definition	Unit
DEVEX	Development (generation asset)	Development, consenting and project management work paid for by the developer up to WCD. Includes: • Internal and external activities such as environmental and wildlife surveys, met ocean surveys, met mast (including installation), geophysical, geotechnical and hydrological services and engineering (pre-FEED) and planning studies. • Consenting services • Further site investigations and surveys after FID • Engineering (FEED) studies • Environmental monitoring during construction • Project management (work undertaken or contracted by the developer up to WCD) • Other administrative and professional services such as accountancy and legal advice • Any reservation payments to suppliers • Development costs of transmission system Excludes: • Construction phase insurance • Suppliers own project management	$/MW
CAPEX	Turbine and tower	Includes: • Payment to wind turbine manufacturer for the supply of: o Rotor, including blades, hub and pitch system o Nacelle, including bearing, gearbox, generator, yaw system, the electrical system to the array cables, control systems, etc. o Tower • Assembly thereof • Delivery to nearest port to supplier • Warranty • The wind turbine supplier aspects of commissioning costs Excludes: • Turbine OPEX • RD&D costs	$/MW

Type	Element	Definition	Unit
	Foundations	Includes: • Payment to suppliers for the supply of the support structure comprising the foundation (including any piles, transition piece and secondary steel work such as J-tubes and personnel access ladders and platforms) • Delivery to nearest port to supplier • Warranty Excludes: • Tower • Foundation OPEX • RD&D costs	$/MW
	Array electrical	Includes: • Delivery to nearest port to supplier • Warranty Excludes: • Operation, maintenance and service costs • RD&D costs	$/MW
	Installation	Includes: • All installation work for turbines • All installation work for support structures • All installation work for array cables (including burial where appropriate) • Sea fastening and grillage for the installation vessel • Project management and contractor risk for the vessel operator • Transportation of all components from each supplier's nearest port • Pre-assembly work completed before components are taken to site • Commissioning work for all but turbine (including snagging post WCD) • Scour protection (for support structure and cable array) • Subsea cable protection mats etc., as required • Offshore logistics: weather forecasting, additional crew transfer vessels and marine co-ordination. • Shared wind-farm infrastructure such as marker buoys. Excludes: • Installation of offshore substation/transmission assets	$/MW

Type	Element	Definition	Unit
	Insurance and contingency (generation asset)	Includes: • Construction phase insurance cover, from start of construction until operation start, including all construction risks & third party • Construction contingency • Other CAPEX contingency • Contingency and insurance for the transmission asset	$/MW
	Transmission	Includes: • Payment to manufacturer for the supply of onshore and offshore export cables and onshore and offshore substations • Installation of onshore and offshore substations and onshore and offshore export cables • Warranty Excludes: • Development of transmission system • Insurance and contingency for the transmission asset	$/MW
OPEX	Operation, maintenance and service for the generating assets – planned and unplanned	Includes: • Operation and planned (routine) maintenance, unplanned service (in response to faults; may be either proactive or reactive), operations phase insurance and other OPEX. • Starts once first turbine is commissioned. Operation and planned maintenance includes: • Operational costs relating to the day-to-day control of the wind farm (including CAPEX on operations base as an equivalent rent) • Condition monitoring • Planned preventative maintenance, health and safety inspections Unplanned service includes: • Reactive service in response to unplanned systems failure in the turbine or electrical systems. Operations phase insurance: • Operations phase insurance takes the form of a new operational “all risks” policy and issues such as substation outages, design faults and collision risk become more significant as damages could result in wind farm outage. Insurance during operation is typically renegotiated on an annual basis. Other OPEX covers fixed cost elements that are unaffected by technology innovations, including: • Contributions to community funds • Monitoring of the local environmental impact of the wind farm	$/MW/year

Type	Element	Definition	Unit
	Transmission operation, maintenance and service for the transmission assets	Using the timing and other definitions above, includes: • Planned maintenance, unplanned service, operations phase insurance and other OPEX of transmission assets • Grid use charges	$/MW/year
	Site rent	Includes: • Site rent/sea bed leasing costs	
DECEX	Decommissioning (generation asset)	Includes: • Planning work and design of any additional equipment for decommissioning required to meet legal obligations. • Further environmental work and monitoring. • Removal of the turbine • Removal of the foundation • Removal of the array cables (where applicable)	$/MW
	Decommissioning (transmission asset)	Includes: • Planning work and design of any additional equipment for decommissioning required to meet legal obligations. • Decommissioning of the transmission asset	$/MW
AEP	Net AEP (annual energy production)	AEP averaged over the wind farm life at the offshore metering point at entry to offshore substation. Accounts for any improvements in early years and degradation in later years. Includes: • Aerodynamic array losses within the wind farm • Losses due to unavailability of the wind turbines, foundations and grid • Electrical array losses • Losses due to blockage effect, and • Other losses, including from cut-in/cut-out hysteresis, power curve degradation, power performance loss and blade degradation. Excludes: • External wake effects from neighbouring wind farms, and • Losses due to icing effects, curtailment and wind speed inter-annual variability. • Losses from transmission system	MWh/MW/yr
Financing cost	Weighted average cost of capital (WACC)	The discount rate is made up of finance cost from debt and equity, weighted by their contributions to give a WACC.	-

Model assumptions

Standard wind farm assumptions for 1 GW project in established market installed in 2028 are provided below.

General

- Turbines are spaced at nine rotor diameters (downwind) and six rotor diameters (across-wind) in a rectangle
- A wind farm design is used that is certificated for an operational life of 32 years
- The lowest point of the rotor sweep is at least 22 metres above mean high water spring
- The development and construction costs are funded entirely by the project developer, and
- A multi-contract approach is used to contracting for construction.

Meteorological regime

- A wind shear exponent of 0.12
- Rayleigh wind speed distribution
- A mean annual average temperature of 10°C
- An air density of 1.225 kg/m3
- The tidal range is 4 m
- The Hs of 1.8 m is never exceeded on more than 25% of the days at the sites furthest from shore site, and
- No storm surge is considered.

Turbine

- The turbine is certified to Class IA to international offshore wind turbine design standard IEC 61400-3, so designed to withstand 5-second gusts of 70 m/s.
- The baseline turbines have low-ratio gearboxes and mid speed, mid-voltage AC generators, with a 158 m diameter rotor and a rated power of 6 MW, or diameter of 224 m and a rated power of 15 MW.

Support structure

- Ground conditions are "typical", that is, most relevant to North Sea zones, namely 10 m dense sand on 15 m stiff clay, only occasionally with locations with lower bearing pressure, the presence of boulders or significant gradients.

Array Cables

- The array cable assumption is that a three core 66 kV AC on fully flexible strings is used, that is, with provision to isolate an individual turbine.

Transmission

- Transmission costs are incurred as CAPEX and OPEX where appropriate. This treatment of transmission costs reflects the actual costs of building and operating, rather than the costs incurred by the asset owner.
- HVAC connections are generally assumed for sites up to 130 km from shore.
- HVDC connections are generally assumed further than 130 km from shore.

Installation

- Installation is carried out sequentially by the foundation, array cable, then the pre-assembled tower and turbine together.
- A single jack-up is used to install monopiles and transition pieces.
- Two jack-ups are used for jacket installation and pre-piling, collecting components from the installation port.
- Array cables are installed via J-tubes, with separate cable lay and survey and burial.

- A jack-up vessel collects components from the installation port for turbine installation.
- Decommissioning reverses the assembly process to result in installation taking one year. Piles are cut off at a depth below the sea bed, which is unlikely to lead to uncovering and typically cables are pulled out. All removed equipment will be transported to Europe for recycling / scrapping. Environmental monitoring is conducted at the end. The residual value and cost of scrapping is ignored, which is a conservative assumption.

Operation, maintenance and service

- Nearshore access is by service operation vessels (SOVs) or crew transfer vessels (CTVs). Jack-ups are used for major component replacement.
- Transmission OPEX covers both maintenance costs and grid charges.

Appendix B LCOE breakdown

The justification for cost changes and energy production between a 1 GW project in an established market and a 60 MW project in Bermuda are shown in Table B.1 and Table B.2 for the 6 MW and 15 MW turbine configurations, respectively.

Table B.3 shows the assumed parameters used in the LCOE calculations for each scenario. A WACC of 5.05% has been used for the established market projects which reflects trends in these markets. A WACC of 7.5% has been used for Bermuda. The higher WACC reflects the increased risk of a single project in a new market, coupled with the fact that the project is so small. This is lower than the 10% used for previous Bermuda LCOE studies discussed in the main text. A WACC of 10% is likely too high for a project installed in 2028, as the project would be carried out by an experienced developer and installation contractor, thereby limiting risk for debt and equity providers. A lifetime of about 32 years has been used for all projects. Project lifespans have been increasing as the industry matures due to more durable and reliable designs, and better maintenance practices. More CAPEX spend has been shifted into later years for the 60 MW projects compared to the 1 GW project, as turbine procurement and installation make up a larger proportion of spend.

The full cost breakdowns across each scenario for both turbine rated power configurations are shown in Table B.4 and Table B.5.

Per MW costs for each cost element within each scenario are shown in Figure B.1 and Figure B.2.

Table B.1 Cost breakdown for 1 GW established market and 60 MW Bermuda project using 6 MW turbines.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
Development	99,795	717,150	• The change in farm size from 1 GW to 60 MW is responsible for 65% of the cost increase. The remaining 35% is from Bermudan factors. • A small project has proportionally much higher management and mobilisation costs per MW than a large project. • Surveys require mobilising specialist vessels and teams to Bermuda at additional cost. • New markets are more expensive as it is their first time going through processes.
Turbine	1,078,344	1,254,500	• The change in farm size from 1 GW to 60 MW is responsible for over 90% of the cost increase. The remaining under 10% is from Bermudan factors. • Ten 6 MW turbines is a reasonable order for turbines of this size for onshore use. There is a certain amount of engineering design work that is required that is specific to the wind farm (e.g., designing the turbine to fit onto several tower designs). These fixed costs are spread over fewer turbines than a larger project, so a premium of 10% is included, which also covers any changes needed to address hurricane risk.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
			• A larger-than-standard rotor is assumed to be used in Bermuda for the 6 MW turbines. The longer blades come at a higher cost, with other knock-on costs (for example on drive train) also included.
Tower	139,546	163,561	• The change in farm size from 1 GW to 60 MW is responsible for almost 90% of the cost increase. The remaining is from Bermudan factors. • There is the same small-order premium as for turbines. • Due to the longer blades for Bermuda than standard require a taller, more costly tower. • Note that although tower is modelled separately, it is sourced by the project developer from the turbine supplier.
Foundation	356,334	464,860	• The change in farm size from 1 GW to 60 MW is responsible for 90% of the cost increase. The remaining 10% is from Bermudan factors. • There is the same small-order premium as for turbines. • The higher-loaded rotor and taller tower for Bermuda drive a stronger and more costly foundation.
Array Electrical	52,349	69,208	• The change in farm size from 1 GW to 60 MW is responsible for 85% of the cost increase. The remaining 15% is from Bermudan factors. • A small project has proportionally higher delivery and administration costs per MW than a large project. • The longer blades for Bermuda require the turbines to be spaced further apart, meaning more array cable per turbine.
Installation	268,969	916,813	• The change in farm size from 1 GW to 60 MW is responsible for about 25% of the cost increase. The remaining 75% is from Bermudan factors. • A small project has proportionally much higher mobilisation costs per MW than a large project. Installation in Bermuda is costly due to chartering jack-up, transport, and cable lay vessels for a long period of time relative to the project size, however, a smaller jack-up is used for the 6 MW turbines that comes at 60% of the cost of a 15 MW jack-up. • Subsea cable installation is more costly as the installer needs to navigate sensitive coral environments, which could involve directional drilling or cutting and replacing sections of sea bed.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
			• Additional contingency included to account for weather delays.
Insurance and contingency	116,203	213,224	• 5% of CAPEX. Additional contingency is expected as the project carries additional risk. Much of the extra risk comes during installation phase through weather delays and any other local complications as the project is a first-of-a-kind in Bermuda.
Transmission	328,727	678,386	• The change in farm size from 1 GW to 60 MW is responsible for about 55% of the cost increase. The remaining 45% is from Bermudan factors. • A small project has proportionally higher installation and delivery costs per MW than a large project. • No offshore substation is used, but a more expensive onshore substation is required to "collect" two or more array strands. • Transportation of the main components of the onshore substation to Bermuda adds expense. • Export cable installation is more costly as the installer needs to navigate sensitive coral environments, which could involve directional drilling or cutting and replacing sections of sea bed. • An indirect route to shore for the export cable is assumed. About 40% more export cable is required than if a direct route was used. • Onshore installation works are more expensive due to higher cost of employment in Bermuda than established markets.
Planned operation and maintenance	34,202	85,383	• The change in farm size from 1 GW to 60 MW is responsible for about 60% of the cost increase. The remaining 40% is from Bermudan factors. • A small project has proportionally higher mobilisation and administration costs per MW and lower efficiency than a large project. • A premium of 10% was applied across the lifetime of planned maintenance to account for inefficiency. Planned maintenance is expected to be particularly inefficient in the early years of project, when LCOE is impacted the most. • Cost of employment is significantly higher than that of established European markets.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
Unplanned service	25,306	69,087	• The change in farm size from 1 GW to 60 MW is responsible for about 50% of the cost increase. The remaining 50% is from Bermudan factors. • A small project has proportionally higher mobilisation and administration costs per MW than a large project. • The same premium is applied as planned maintenance to account for expensive learning phase in early years of the project (applies to minor repairs). • Cost of employment is significantly higher than that of established European markets (applies to minor repairs). • Extra cost of chartering jack-up to Bermuda (estimated as 33% of major repairs and 71% of major replacements), although cheaper vessel can be used for 6 MW turbines. • Extra cost of bringing in suppliers and parts to Bermuda when needed (estimated as 67% of major repairs and 29% of major replacements).
Site rent	2,392	2,392	• Site rent scales with project rated power. • Uncertain how Bermuda will deal with site rent, assumed to be similar to established markets. • The Bermudan Government would have control over this aspect of cost. Increasing rent provides more revenue to Government but it is likely that the additional project cost would be passed on to consumers.
Transmission operational expenditure (OPEX)	20,240	35,571	• The change in farm size from 1 GW to 60 MW is responsible for about 70% of the cost increase. The remaining 30% is from Bermudan factors. • A small project has proportionally higher mobilisation costs per MW than a large project. • Uncertain how grid connection costs will be dealt with in Bermuda. Assumed to be similar cost to an established market. • Having no offshore substation to maintain reduces cost. • Additional costs to mobilise specialist labour to Bermuda. • Additional costs to mobilise specialist vessels to Bermuda (at the same premium to installation).
Decommission expenditure	174,830	595,928	• Calculated as 65% of installation cost.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
(DECEX) (generating)			
DECEX (transmission)	31,060	210,508	• Calculated as 65% of transmission install cost.
Net energy production	4,131 (MWh/MW/yr)	3,700 (MWh/MW/yr)	• Significantly reduced energy production from lower mean wind speeds in Bermuda (7.8 m/s vs 9.5 m/s). This lower production is the single largest contributor to the higher LCOE. • There is a notable reduction in aerodynamic array losses from fewer rows of turbines in the smaller farm (two rows rather than 13). This makes up for some of the lower energy production from the lower mean wind speed. Availability: • Small decrease in planned unavailability due to lower wind speeds and bigger weather windows. • Increase in unplanned unavailability from minor repairs as there would be a longer lead time to acquire a CTV and parts. • Large increase in unplanned unavailability from major repairs as lead time for mobilising vessels and specialist teams likely double that of established markets. It would take ~8 weeks to mobilise a vessel rather than the typical time of 3-4 weeks, for example.

Table B.2 Cost breakdown for 1 GW established market and 60 MW Bermuda project using 15 MW turbines.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
Development	99,795	717,150	• See Table B.1.
Turbine	1,161,768	1,579,297	• The change in farm size from 1 GW to 60 MW is responsible for all of the cost increase. • Four 15 MW turbines is an abnormally low number for an offshore wind order, so has large overheads associated with procurement and design. This is expected to add 30% to the cost, which also covers any changes needed to address hurricane risk.
Tower	109,520	148,880	• The change in farm size from 1 GW to 60 MW is responsible for all of the cost increase. • Same small-order premium as turbines.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
Foundation	256,290	385,784	• The change in farm size from 1 GW to 60 MW is responsible for all of the cost increase. • Same small-order premium as turbines.
Array Electrical	35,704	45,475	• The change in farm size from 1 GW to 60 MW is responsible for all of the cost increase. • A small project has proportionally higher delivery and administration costs per MW than a large project.
Installation	192,785	937,715	• The change in farm size from 1 GW to 60 MW is responsible for about 35% of the cost increase. The remaining 65% is from Bermudan factors. • A small project has proportionally higher mobilisation costs per MW than a large project. • Installation in Bermuda is costly due to chartering jack-up, transport, and cable lay vessels for a long period of time. The jack-up required for 15 MW turbines is about 70% more expensive than for 6 MW turbines. • Subsea cable installation is more costly as the installer needs to navigate sensitive coral environments, which could involve directional drilling or cutting and replacing sections of sea bed. • Additional contingency included to account for weather delays.
Insurance and contingency	109,229	226,773	• See Table B.1.
Transmission	328,727	721,153	• See Table B.1.
Planned operation and maintenance	25,401	63,411	• See Table B.1.
Unplanned service	21,958	65,885	• The change in farm size from 1 GW to 60 MW is responsible for about 40% of the cost increase. The remaining 60% is from Bermudan factors. • A small project has proportionally higher mobilisation and administration costs per MW than a large project. • Same reasoning as 6 MW turbine configuration but larger cost increase 15 MW turbines due to requiring more expensive jack-ups for major repairs and replacements.
Site rent	2,392	2,392	• See Table B.1.
Transmission OPEX	20,240	35,571	• See Table B.1.

Element	1 GW established market ($/MW unless stated)	60 MW Bermuda ($/MW unless stated)	Description
DECEX (generating)	125,310	609,515	• Calculated as 65% of installation cost.
DECEX (transmission)	31,060	215,844	• Calculated as 65% of transmission install cost.
Net energy production	4,283 (MWh/MW/yr)	3,853 (MWh/MW/yr)	• See Table B.1 for energy production and availability adjustments. • 15 MW turbine configuration has even lower wake losses than 6 MW turbine configuration due to a single row of four turbines (one row rather than eight for a 1 GW wind farm of 15 MW turbines).

Table B.3 Project parameters for LCOE calculations.

	1 GW project in an established market	60 MW project in an established market	60 MW project in Bermuda
WACC	5.05%	5.05%	7.5%
Project lifetime (years)	31.6	31.6	31.6
CAPEX spend in year -3	6%	6%	6%
CAPEX spend in year -2	10%	6%	6%
CAPEX spend in year -1	34%	13%	13%
CAPEX spend in year 0	50%	75%	75%

Table B.4 Full cost breakdown for each scenario for project using 6 MW turbines.

Element	1 GW established cost ($/MW unless stated)	60 MW established cost ($/MW unless stated)	60 MW Bermuda cost ($/MW)	Change in value from column 2 to column 3	Change in value from column 3 to column 4
Development	99,795	488,997	717,150	4.90	1.47
Turbine	1,078,344	1,240,370	1,254,500	1.15	1.01
Tower	139,546	160,513	163,561	1.15	1.02
Foundation	356,334	453,856	464,860	1.27	1.02
Array Electrical	52,349	66,676	69,208	1.27	1.04
Installation	268,969	429,804	916,813	1.60	2.13
Insurance and contingency	116,203	168,181	213,224	1.45	1.27
Transmission	328,727	523,410	678,386	1.59	1.30
Operation and planned maintenance	34,202	63,364	85,383	1.85	1.35
Unplanned service	25,306	46,883	69,087	1.85	1.47
Site rent	2,392	2,392	2,392	1.00	1.00
Transmission OPEX	20,240	31,203	35,571	1.54	1.14
DECEX (generating)	174,830	279,373	595,928	1.60	2.13
DECEX (transmission)	31,060	116,273	210,508	3.74	1.81
Net energy production	4,131 (MWh/MW/yr)	4,585 (MWh/MW/yr)	3,700 (MWh/MW/yr)	1.11	0.81

Table B.5 Full cost breakdown for each scenario for project using 15 MW turbines.

Element	1 GW established cost ($/MW unless stated)	60 MW established cost ($/MW unless stated)	60 MW Bermuda cost ($/MW unless stated)	Change in value from column 2 to column 3	Change in value from column 3 to column 4
Development	99,795	488,997	717,150	4.90	1.47
Turbine	1,161,768	1,579,297	1,579,297	1.36	1.00
Tower	109,520	148,880	148,880	1.36	1.00
Foundation	256,290	385,784	385,784	1.51	1.00
Array Electrical	35,704	45,475	45,475	1.27	1.00
Installation	192,785	446,014	937,715	2.31	2.10
Insurance and contingency	109,229	182,614	226,773	1.67	1.24
Transmission	328,727	557,829	721,153	1.70	1.29
Operation and planned maintenance	25,401	47,058	63,411	1.85	1.35
Unplanned service	21,958	40,680	65,885	1.85	1.62
Site rent	2,392	2,392	2,392	1.00	1.00
Transmission OPEX	20,240	31,203	35,571	1.54	1.14
DECEX (generating)	125,310	289,909	609,515	2.31	2.10
DECEX (transmission)	31,060	116,183	215,844	3.74	1.86
Net energy production	4,283 (MWh/MW/yr)	4,871 (MWh/MW/yr)	3,853 (MWh/MW/yr)	1.14	0.79

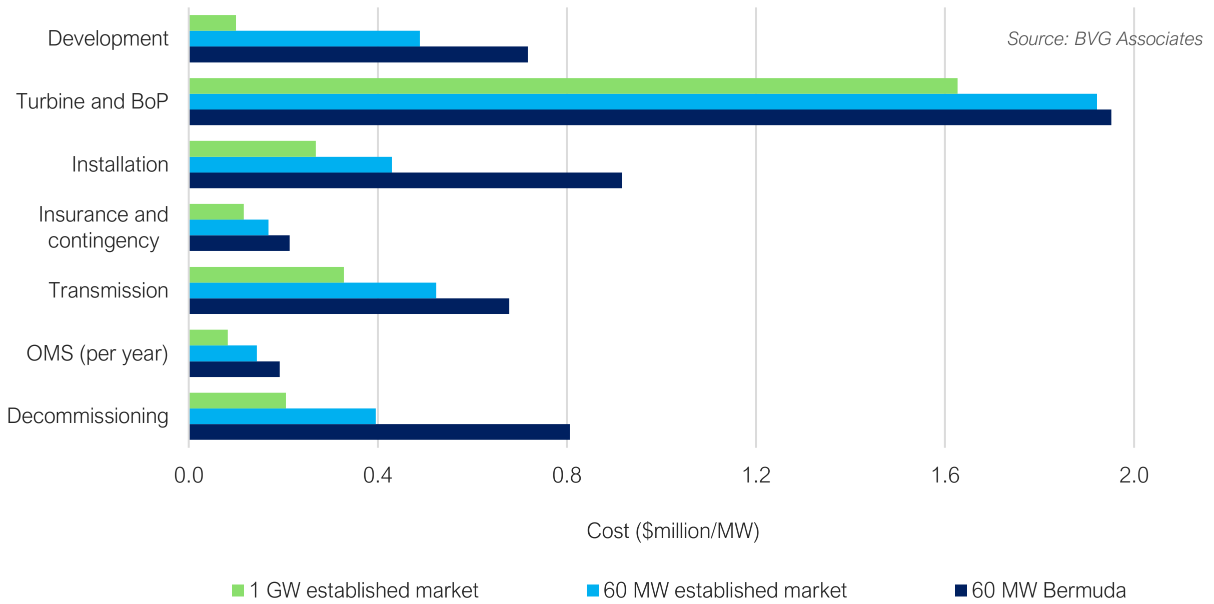

Figure B.1 Cost breakdown for project using 6 MW turbines.

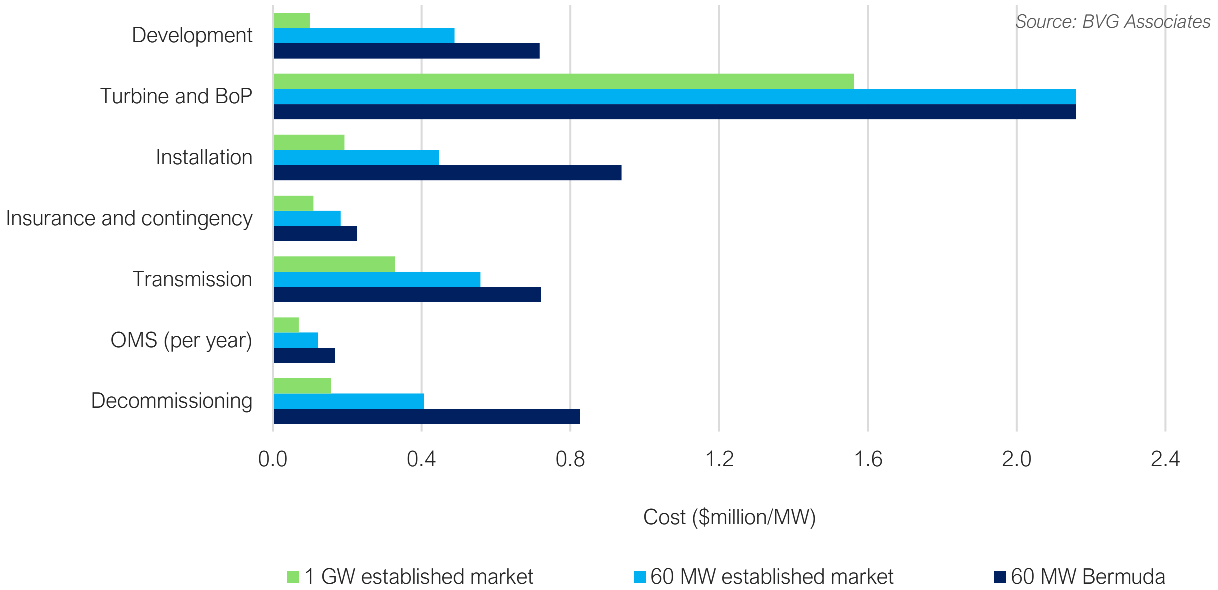

Figure B.2 Cost breakdown for project using 15 MW turbines.

About BVG Associates

BVG Associates is an independent renewable energy consultancy focussing on wind, wave and tidal, and energy systems. Our clients choose us when they want to do new things, think in new ways and solve tough problems. Our expertise covers the business, economics and technology of renewable energy generation systems. We're dedicated to helping our clients establish renewable energy generation as a major, responsible and cost-effective part of a sustainable global energy mix. Our knowledge, hands-on experience and industry understanding enables us to deliver you excellence in guiding your business and technologies to meet market needs.

- BVG Associates was formed in 2006 at the start of the offshore wind industry.
- We have a global client base, including customers of all sizes in Europe, North America, South America, Asia and Australia.
- Our highly experienced team has an average of over 10 years' experience in renewable energy.
- Most of our work is advising private clients investing in manufacturing, technology and renewable energy projects.
- We've also published many landmark reports on the future of the industry, cost of energy and supply chain.

References

[1] *Offshore wind energy in the context of multiple ocean uses on the Bermuda platform*, Alisan Amrhein, Darrell Gregg, Tinya Hoang, Rahul Madhusudanan, Casey O'Hara, University of California, Santa Barbara, March 2014, available online at https://bren.ucsb.edu/projects/offshore-wind-energy-context-multiple-ocean-uses-bermuda-platform.
[2] *Assessment of the Offshore Wind Potential in Bermuda*, Ricardo for Regulatory Authority of Bermuda, August 2021, available online at https://www.ra.bm/documents/bermuda-offshore-wind-public-report/.