Scottish Islands Renewable Project

Final Report

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1. EXECUTIVE SUMMARY

Context

DECC and the Scottish Government appointed Baringa Partners (incorporating Redpoint Energy) and TNEI to undertake an independent study to assess whether Scottish Island Renewables could make a cost effective contribution to meeting the UK's renewable energy targets and to determine whether any additional measures are required to bring these projects forward. This report summarises the outputs of this analysis.

Scottish Island renewable resource potential

Renewable resources from wind, wave and tidal on the Scottish Islands of the Western Isles, Orkney and Shetland are considerable, and renewable generation on the Scottish Islands could make a significant contribution to Scotland's and the UK's 2020 renewables targets, as well as playing an important role in longer term decarbonisation objectives. Of a total practical resource potential in excess of 80 TWh/yr (around 20% of current total GB electricity demand), our analysis suggests that with the appropriate policy support and regulatory environment an additional 4 TWh could be developed by 2020, and around 18.5 TWh by 2030 (representing approximately 1% and 5% of total GB electricity demand respectively). Longer term there could be even greater potential, particularly if the costs of marine renewables fall as should be expected with successful demonstration and commercialisation of these technologies on the islands.

Socio-economic and wider benefits of Scottish Island renewables

The development of renewable generation on the islands could also have significant benefits to the local economies, through direct, indirect and induced jobs. Our analysis suggests that by 2020 up to 392 full time equivalent jobs could be created on the Western Isles, 463 in Shetland, 416 in Orkney, and an additional 3,000 FTEs could be generated in the rest of Scotland and elsewhere in the UK. By 2030, the number of jobs created could increase to over 3,500 on the Western Isles, almost 2,900 in Shetland, and over 4,500 on Orkney, demonstrating the potential significance of the marine industry in the UK. The large numbers of jobs created on Orkney are associated with wave and tidal generation which would be labour intensive in the early years, providing the opportunity to develop local supply chains with the capability to export expertise if the industry takes off. Under our Central Scenario of an additional 6 GW[1] of Scottish Island renewables by 2030, which represents a credible deployment case assuming the necessary policy support and transmission capacity is in place, our analysis suggests that a further 29,000 FTEs could be created by 2030 elsewhere in the UK.

In terms of carbon and fuel savings, we estimate that up to 6.6 Mt CO_2 and 35 TWh of fuel savings (gas) could be realised by 2030 under our Central Scenario for Scottish Island renewable deployment.

The analysis also demonstrates that renewable generation and associated transmission links could provide further benefits related to local security of supply, whilst the diversity benefits of developing renewables on the islands (especially marine) could reduce the overall cost of intermittency on the GB system.

[1] Assuming an installed capacity of 2.4 GW of onshore wind, 2.0 GW of wave, 1.5 GW of tidal on the Scottish Islands by 2030

Key challenges

Given the remote locations, novel technologies and distances from the main centres of demand, the large scale deployment of renewables on the Scottish Islands faces a number of challenges. We have concluded that the key challenges are the following:

- The funding gap
- Grid access
- Availability of early stage funding for marine projects, and
- Potentially support for the supply chain

Of these, the first two are by far the most important and, as we discuss below, are interlinked. The Scottish Islands offer some of the best sites for renewables projects anywhere in the UK, and indeed Europe, due to the high winds, waves and tidal flows. As such, projects in these areas should produce significantly greater revenues than their mainland equivalents. Yet, due to the challenges outlined below, Scottish Island renewables projects, and onshore wind plant in particular, also incur comparatively higher costs which negate the benefits of the higher yields.

The funding gap

The cost challenges are associated with the remote locations and harsh operating conditions. For wind plant, we estimate that these factors increase the costs of construction by around 20%, and may, in some cases, more than double cost of operation. However, by far the biggest cost element is associated with the links required to connect the plant to the transmission system (since the output from the plant would be well in excess of local demands). The costs of constructing subsea cables between the islands and the mainland, and associated onshore reinforcements are very high. For example, the cost of the HVDC cable to Lewis alone is in excess of £700m. These transmission projects, and the associated onshore reinforcements that are required both on the islands and the mainland, are complex involving lengthy planning and engineering studies, and with their own environmental impacts.

The methodologies for calculating transmission charges are currently under review through the Project TransmiT/CMP213 process. However, it is likely that a significant proportion of the incremental costs of the transmission upgrades would be charged to island generators.

Taking into account the higher revenues and higher costs associated with island wind projects, our analysis suggests that in aggregate they are typically between around £19/MWh and £45/MWh more expensive on a levelised basis than their mainland equivalents[2], with Orkney and Shetland at the lower end (with levelised costs of £103/MWh and £106/MWh respectively[3]), and the Western Isles at the higher end (at £129/MWh[3]). A different outcome from the current review of transmission charging (for example, including a lower proportion of HVDC converter costs in the local charge component) could lower the difference with mainland projects to between £14/MWh and £36/MWh. Nonetheless, our analysis concludes that under current policy (0.9 ROCs/MWh) it is unlikely to be economic to develop further onshore wind projects on the islands as returns will not meet the required hurdle rates.

However, the costs of Scottish Islands onshore wind, with the exception of onshore wind on the Western Isles, are in the same range as several other forms of low carbon generation being considered by

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[2] Comparing our 'best estimate' LCoE for Scottish Islands onshore wind with DECC's central view for onshore wind> 5MW and using technology specific hurdle rates

[3] Assuming a 2020 commissioning and a technology specific hurdle rate

government including nuclear, biomass and imported renewables from Ireland[4], all currently estimated to be in the region of £85-£110/MWh. Compared to typical Round 3 offshore wind projects, and using DECC's technology specific hurdle rates, the Scottish Islands onshore wind projects are estimated to be £32/MWh-£58/MWh cheaper[5]. (Please note that the above figures vary depending in particular on the hurdle rate applied).

Given the limitations on resource potential for some of the cheaper forms of renewable generation, it is likely that, based on the current view of costs, significant volumes of £100/MWh+ generation will be required to meet the 2020 renewables targets and wider decarbonisation objectives. This, and the wider socio-economic benefits, could provide justification for bridging the funding gap for Scottish Islands wind, either through higher support levels or capped transmission charges. We have set out some policy alternatives in this report for achieving this, with some advantages and disadvantages for each.

Marine renewables are in an earlier stage of their evolution, and our analysis confirms that these technologies will continue to require financial support (and other forms of funding) at levels at or above those currently being offered (5 ROCs/MWh), if the industry is to develop into a world leader. There are significant opportunities for costs to come down through learning effects in the future.

Grid access

Together with the funding gap, grid access is the key challenge. There is little existing local grid network, and hence new projects are reliant on the proposed new transmission links. These links have been delayed, in part due to cost escalations (in the case of the Western Isles link) and in part due to lack of confidence in the needs cases given the uncertainty of whether projects will be able to afford the works required without visibility of any further potential financial support above that currently being offered. For some developers, particularly for smaller or community owned projects or those with new technologies, the grid access challenge is even greater since they are unable to underwrite the liabilities and associated security requirements needed to secure capacity on future transmission links. As a result these developers are dependent on 'anchor projects', such as large windfarms in the Western Isles or Shetland or large marine projects in Orkney, to underwrite new transmission investment, and hope that there is sufficient spare transmission capacity to accommodate their projects. Whilst these user commitment rules are doing what they are designed to do, which is to protect consumers from stranding of transmission assets associated with higher risk generation projects, they place potentially undue barriers to developers of new marine technologies. If the policy intent is to promote marine generation, having a regulatory regime that can create barriers may appear counter-productive, especially when compared to other countries where connections for emerging technologies are prioritised. For these reasons there may be grounds for pursuing measures that lower the risks of securing transmission capacity for certain classes of developers.

We have set out some options, and advantages and disadvantages of each in this report ranging from less onerous securities and liabilities, underwriting of securities and liabilities for marine, lower user commitment levels for needs cases to aggregation services for smaller generators. In addition, we have explored measures that could increase grid capacity on a transitional basis to mitigate the impact of delayed transmission links on the evolution of the marine industry, should this be required. Amongst

[4] For Irish import, LCoE input assumptions were based on information published by Greenwire and Mainstream. Available at: http://www.greenwire.ie/greenwire-project/frequently-asked-questions/ and http://www.energybridge.ie/development_process.asp. Assumed TNUoS of £40/kW/year.

[5] The DECC technology specific hurdle rates assume a higher rate for offshore wind than onshore wind given the greater risk factors. Applying a uniform 10% discount rate, the difference between Scottish Islands onshore wind and R3 offshore wind, would be between £2/MWh (Western Isles) and £29/MWh (Shetland).

others, these measures include changes on the demand side as well as options to displace or compensate existing generation.

Also in the report we have included some policy measures that could support early stage funding for marine projects and the development of the supply chain through capital grants, higher financial support levels or low cost debt.

Any potential intervention would have to comply with EU law, including the Third Energy Package and State Aid regulation, and may require changes to legislation. Hence, the implementation implications associated with any policy measure need to be carefully considered.

Conclusions

On the basis of our study, we have concluded that the costs of deploying renewables on a large scale on the Scottish Islands is high, and there are a number of technological and environmental challenges. However, onshore wind on the Scottish Islands is cost competitive with several other forms of low carbon generation and, particularly in the case of Orkney and Shetland, is significantly cheaper than Round 3 offshore wind. The development of renewables on the Scottish Islands would provide a number of socio-economic benefits, including the creation of local jobs, and there is an opportunity to establish Scotland as a world leader in marine technologies.

We have also concluded in our study that further renewable generation on the Scottish Islands will not be developed on any scale in the near term under current policy. The costs of connecting to the transmission system are too high, making it difficult for developers and the regulator acting on behalf of customers to commit to costly new transmission infrastructure. In turn, the lack of grid access deters new developers, particularly those not in a position to meet the financial commitments required to secure future grid capacity. Ongoing uncertainty will inevitably lead to delays meaning that, despite the potential, renewable generation on the Scottish Islands would only make a minimal contribution to 2020 renewables targets, and an opportunity to develop the UK as a world leader in marine renewables could be lost.

Government will need to weigh up the costs and benefits of renewable generation on the Scottish Islands against other sources of electricity, as set out in this report and elsewhere, and in particular considering the impact on the local economies and communities, and importantly on wider GB consumers. Should the political commitment be there for Scottish Islands renewables to be a key contributor to Scottish and UK 2020 renewable strategies and beyond, then a co-ordinated policy and regulatory response will be required urgently[6], incorporating some of the measures outlined in this report.

[6] This is particularly the case for the Western Isles given the status of tendering for the transmission link, where decisions are required by July 2013.

2. INTRODUCTION

2.1. Context

The UK Government has agreed an ambitious target of meeting 15% of the UK's energy needs from renewable sources by 2020, which requires about 30% of UK electricity to come from renewables by this date. The Scottish Government policy is to generate the equivalent of 100% of Scotland's gross annual electricity consumption from renewable sources by 2020. In order to achieve such a substantial deployment of low carbon energy in this timeframe, the Governments have established a policy framework to support investment in renewable generation.

Renewable projects on the Scottish Islands have the potential to be an important contributor to meeting the UK's and Scottish Government's renewable energy targets. With one of the world's strongest tides peaking at four meters per second[7], record wave heights off the coast of over 40ft[8] and high wind yields year round (with some sites achieving capacity factors of 50% or more), the Scottish Islands' desirability for wind, wave and tidal projects is evident.

Furthermore, the exploitation of the renewable generation resources on the islands has the potential to deliver socio-economic benefits to the islands, to Scotland and the wider UK, particularly if the country is able to establish itself as a leader in marine renewable technologies with the associated export opportunities. Security of supply on the islands would also be enhanced creating further value to the local communities and businesses.

However, a number of stakeholders have expressed concerns that these projects are not coming forward quickly enough, in large part due to the lack of grid capacity and the high transmission costs associated with the links required to connect the Islands to the mainland transmission network. There are also a number of other practical and logistical challenges in developing generation and transmission projects in remote locations.

For onshore wind projects on the Islands, the question is whether the higher wind yields compared to onshore wind farms on the mainland, and the lower construction and maintenance costs when compared to offshore wind projects connecting further south, can outweigh the additional transmission costs, or whether additional support is required to develop these projects. Of particular relevant in this context is the Directive 2001/77/EC which requires Member States to ensure that transmission and distribution fees do not discriminate against peripheral regions, such as islands[9].

For wave and tidal projects, the challenges are somewhat different in that the technologies are yet to be proven on a large and commercial scale. For marine generation, support is required to test new technologies and to develop them to a commercial scale. Development and construction finance, the necessary financial support regime and, again, grid access are the key issues holding back the rapid deployment of these projects.

[7] http://www.guardian.co.uk/environment/2012/aug/28/orkney-green-energy-wave-power

[8] http://www.bbc.co.uk/news/uk-scotland-highlands-islands-21339819

[9] "Member States shall ensure that the charging of transmission and distribution fees does not discriminate against electricity from renewable energy sources, including in particular electricity from renewable energy sources produced in peripheral regions, such as island regions and regions of low population density" Article 16, Item 7, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009. See also: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=Oj:L:2009:140:0016:0062:en:PDF

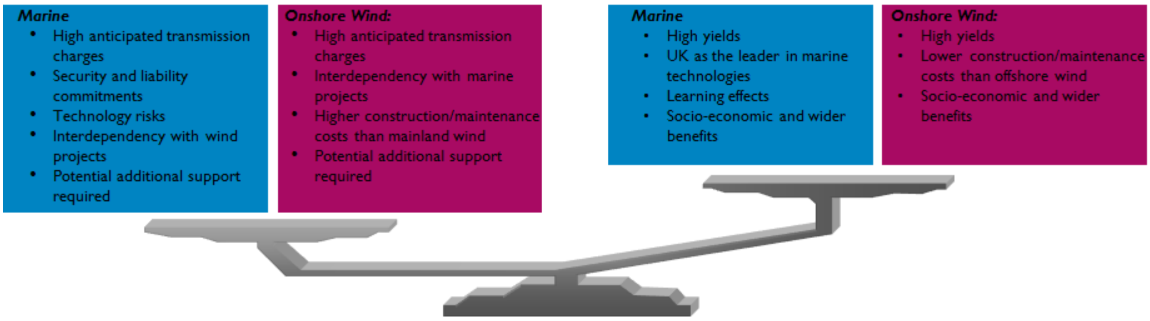


Figure 1 – Key questions for SI renewable projects (illustration only)

In this context, DECC and the Scottish Government appointed Baringa Partners (incorporating Redpoint Energy) and TNEI to undertake an independent study in order to assess the relative costs and benefits of Scottish Island Renewable projects, and to determine whether any additional measures are required to bring these projects forward, and what form these may take.

2.2. Objectives

In order to assist the consideration of further measures to support the development of Scottish Islands renewables, this study aims to answer the following specific questions:

- To what extent can renewable generation on the Scottish Islands make a cost effective contribution to meeting renewables and decarbonisation targets?
- How does the levelised cost of renewables on the Scottish Islands compare to other forms of generation which are expected to contribute to the target?
- Is the current Renewables Obligation and proposed Contracts for Differences policy framework for renewable generation likely to deliver generation on the Scottish islands? What measures would bring such generation forward at what cost?
- Are there other factors beyond the current level of project and transmission costs that justify particular support for renewables on the Scottish Islands, including:
    - social and economic impacts; and
    - long term advantages for marine energy
- What are the relative advantages and disadvantages of alternative policy interventions to further support renewable electricity generation on the Scottish Islands?

A Steering Group comprising of representatives from DECC, the Scottish Government, the Island Councils and Charitable Trusts, Highlands and Islands Enterprise, National Grid Electricity Transmission (NGET) , Scottish Hydro Electric Transmission Limited (SHE-T) and Ofgem was created in order to oversee this study.

2.3. Approach

The study was split into four phases as outlined in Figure 2 below.

Figure 2 - Approach

The objective of Phase 1 was to review the existing analysis on the resource potential and cost of renewable energy projects on the Scottish Islands. Baringa and TNEI then gathered further evidence and carried out over thirty stakeholder interviews on the Western Isles, Shetland and Orkney in late February/ early March 2013 (please refer to the Appendix for a detailed list of all interviewees). The interviews explored the key drivers for cost/revenue differences, any perceived barriers to deployment, the associated socio-economic benefits as well as any potential mitigating actions or lessons learned. In addition, developers were asked to provide key project cost data on a confidential basis in order to allow Baringa/TNEI to assess the typical levelised cost of energy (LCoE) for renewable generation on the Scottish Islands.

In Phase 2, Baringa/TNEI, in conjunction with DECC, modelled LCoE for all Scottish Island and comparator projects from DECC published projects. The LCoE calculations used DECC's model and assumptions, with the exception of assumptions for the Scottish Islands gathered during the course of this study. The purpose of these calculations was to assess where Scottish Islands projects sit within the merit order of other low carbon alternatives given that their relative rank drives potential returns and economic viability for these projects and determines the level of support they may require.

In Phase 3, Baringa/TNEI assessed the socio-economic benefits that these projects would bring as well as the wider impacts Scottish Islands projects would have. A bottom-up view of project specific data was compared and contrasted with top-down analyses in order to derive the number of direct/indirect employment opportunities. The security of supply benefits and learning benefits for marine technologies were also assessed during this phase.

Finally, the study concluded with an outline of potential policy options to address the key barriers to deployment that were raised during the stakeholder interviews, identified in the literature review or a result of the levelised cost analysis.

2.3.1. LCoE modelling methodology

In order to compare the costs of generating electricity from Scottish Island renewables with other forms of generation we used a levelised cost approach using DECC's model and underlying assumptions. LCoE is defined as the net present value of total capital and operating costs of a plant divided by the net present value of the net electricity generated by the plant over its operating life. For further information on how levelised costs are calculated and DECC's Levelised Cost Model, please refer to Annex 2: Calculating Levelised Costs of DECC (2012) 'Electricity Generation Costs'[10].

Cost and expected generation data of Scottish Island projects were aggregated for each of the Scottish Islands in order to calculate a 'best estimate' LCoE for Orkney, Shetland and Western Isles onshore wind projects. The aggregated capex, opex and expected generation data was then provided to DECC to calculate LCoEs using the DECC model[10]. Please note that the assumptions used for the 'best estimate'

[10] DECC (2012). *Electricity Generation Costs.* Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65713/6883-electricity-generation-costs.pdf

calculations were based on the data received from developers and the commentary provided during the stakeholder interviews. These costs do not represent any specific existing or planned project on any of the Scottish Islands, nor an arithmetic average or median of data received. For onshore wind, the figures represent our 'best estimates' of a typical project on the Scottish Islands taking into consideration the range of cost data we received, the projects' stages of development, the developers' confidence in the cost forecasts as well as information gathered during the stakeholder interviews. For more information about our 'best estimate' LCoE for each island, please refer to Appendix A.3.

Due to the limited number of data points received for Scottish Island wave and tidal projects, cost and generation data provided to DECC for these projects was based on the RenewableUK 'Channelling the Energy'[17] study. The latter was quoted by several developers during our interviews and was considered to provide a fair representation of their expected cost ranges.

LCoE for all other technologies referred to in this report except Scottish Island wind, Irish wind and wave and tidal are based on DECC's published view of costs and all are calculated using the DECC LCoE model.

2.3.2. Socio-economic methodology

The socio-economic benefits have been captured by calculating potential Full Time Equivalent (FTE) employment figures. The FTE calculation includes direct employment, indirect employment (such as employment generated in business that serve the new sectors) and induced employment (jobs created through income being spent and re-spent in the broader economy). Additional forms of job creation have also been included, such as Community Fund payments, lease rental payments and crofting compensation payments.

The FTE figures have been calculated on a project basis from information contained in Environmental Impact Statements or similar planning documentation and from estimates given directly from developers. The total FTE figures for each island group (Western Isles, Orkney and Shetland), Scotland and the UK have been compared with figures derived from using RenewableUK's estimate for UK FTEs/MW for wind and marine projects.

The wider social benefits have also been discussed qualitatively, such as the impact on declining population, potential to reduce fuel poverty and benefit in developing a UK marine energy industry.

2.4. Structure of the report

Section 2 summarises the opportunities and challenges for Scottish Islands projects outlining the resource potential for renewable projects versus the current project status of all wind, wave and tidal projects.

The results of the LCoE modelling are presented in Section 3, and the key drivers for cost, revenue and risk differences for Scottish Island projects discussed during the stakeholder interviews presented in Section 4.

The socio-economic benefits and wider impacts of Scottish Island renewable projects are discussed in Sections 5 and 6.

Section 7 outlines the key policy options to address the challenges identified for Scottish Island renewables.

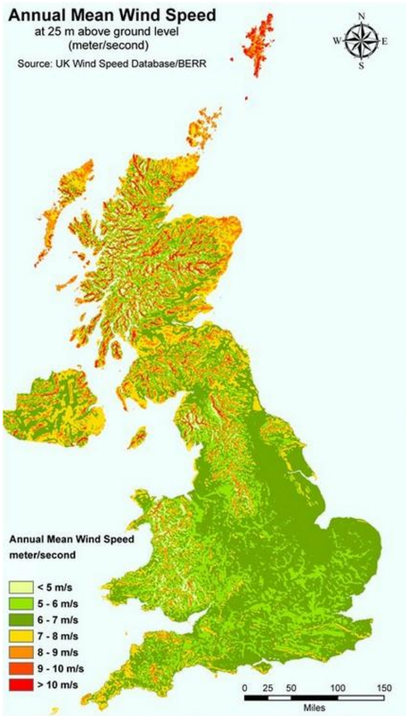
Finally, Section 8 presents the conclusions of the Scottish Islands Renewable study.

3. OPPORTUNITIES AND CHALLENGES

3.1. Scottish Islands renewable resource potential

With a total practical resource potential estimated at 2.8 GW for onshore wind, 5.6 GW for wave energy and 4.5 GW for tidal energy, the Scottish Islands offer a unique opportunity for renewable energy developers. Compared to only 55 MW of installed capacity installed to date, the scale of the untapped resource is significant.

3.1.1. Scottish Island onshore wind resource potential



With 4.65 GW[11] of operational capacity installed to date, onshore wind is already the single most deployed renewable electricity technology in the UK[12]. With a further annual growth rate of around 13% anticipated over the next decade, the UK Renewable Energy Roadmap sets out an ambition that sees this capacity increase to around 13 GW by 2020. This pipeline of new projects is distributed across the UK. However, the majority is expected to be installed in Scotland due to the high wind yields found in the northern part of the country.

With average annual mean wind speeds of >10m/s, the Scottish Islands offer a unique opportunity for developers to reap offshore wind yields on onshore sites. The operational Burradale wind farm on Shetland with a recorded capacity factor of around 52%, one of the highest for wind farms in Europe, is an example of the exceptional wind resource available on the Islands.

A further advantage of the Scottish Islands' wind resource is that the wind energy output is relatively uncorrelated to other UK wind sites, diversifying the effect of intermittency and increasing the value of the energy generated (see Section 4.5.6 for more details).

In terms of the total practical resource potential, the Aquatera[13], Garrad Hassan[14], and Npower Renewables[15] studies estimate the scale and distribution of onshore wind capacity across the Western Isles, Shetland and Orkney as follows (whereby 'practical' in this context follows the Carbon Trust definition of the total resource after taking into account realistic locations, cost of energy as well as locational and environmental constraints):

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[11] DUKES (2012). Avaiable at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65881/5949-dukes-2012-exc-cover.pdf

[12] DECC (2011). UK Renewable Energy Roadmap. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48128/2167-uk-renewable-energy-roadmap.pdf

[13] Aquatera (2005). Renewable energy resource assessment for Orkney & Shetland. Available at: http://www.see.ed.ac.uk/~ibryden1/REE/2007%20material/rera-study-report-sections-summary-rev-2.pdf

[14] Npower renewables (unknown). Future Prospects for the Western Isles from Marine Energy. Available at; http://www.susplan.eu/fileadmin/susplan/documents/presentations/WS_Stornoway/SUSPLAN_Robertson_Future_Prospects_Western_Isles_Marine_Energy.pdf

[15] Garrad Hasan (2002). Western Isles Renewable Energy Study. Available at: http://www.scotland.gov.uk/Resource/Doc/1086/0041184.pdf

	Orkney Islands	Shetland Islands	Western Isles
Onshore wind	Up to 900 GWh/year or 256MW	Up to 7 TWh/year or 1,980 MW	Up to 1.7 TWh/year[16] or 550 MW (assumption)
Source	*Aquatera 2005*[13]	*Aquatera 2005*[13]	*Assumption of 550 MW at 35% load factor*

Table 1 – Total practical resource potential (onshore wind)

Please note that the above figures represent the practical potential resource and are not a forecast of deployment. To illustrate the potential socio-economic benefits discussed in more detail in Section 5, we have created an illustrative credible 'central scenario' of potential wind, wave and tidal deployment rates on the Scottish Islands by 2020, 2025 and 2030 assuming the necessary policy support is in place and marine technologies become established (please refer to Section 3.3 for more details).

3.1.2. Scottish Island wave and tidal resource potential

With its large coastal exposure to the Atlantic the UK, and Scotland in particular, has some of the best wave and tidal resources found anywhere in the world. With more project leases granted than anywhere else in the world, world leading testing infrastructure, including the European Marine Energy Centre (EMEC) on Orkney, to support deployment and a concentration of project and technology developers, the UK is in pole position to become a world leader in marine energy[17].

Several studies have analysed the resource potential of the UK waters for wave and tidal generation. All show that there is sufficient primary energy potential to meet all of the country's electricity demands from marine renewables. Where the studies differ is on the proportion of the resource that can practically be harnessed.

Wave

In its 2012 'UK wave energy resource study', the Carbon Trust estimates that the 'total resource incident on our shores is around 230 TWh/yr with the majority found in the deeper offshore parts of the UK's Exclusive Economic Zone'[18]. In terms of location, 'the most attractive sites for offshore devices are tens of kilometres offshore, both in Cornwall and off the North and West Coasts of Scotland. Sheltering from Ireland reduces the wave energy resource in the Irish Sea and the energy levels in the North Sea are significantly lower than in the west'[18]. Taking into account the cost of energy at different locations in the UK waters, the Carbon Trust concludes that between 32 TWh and 42 TWh could practically and economically be extracted from UK waters per year which equates to an installed capacity of roughly 10 to 13 GW[18].

In comparison, in its 'UK Wave and Tidal Key Resource Areas'[19] project The Crown Estate published indicative annual energy figures from wave generation of 69 TWh/yr equating to an installed capacity of

[16] Assuming 550 MW of wind in Western Isles at 35% load factor based on planning data

[17] RenewableUK (2010). Channelling the Energy. Available at: http://www.marinerenewables.ca/wp-content/uploads/2012/11/Channelling-the-Energy-A-Way-Forward-for-the-UK-Wave-Tidal-Industry-Towards-2020.pdf

[18] Carbon Trust (2012). UK wave energy resource. Available at: http://www.carbontrust.com/media/202649/ctc816-uk-wave-energy-resource.pdf.

[19] The Crown Estate (2012). UK Wave and Tidal Key Resource Areas Project. Available at: http://www.thecrownestate.co.uk/media/355255/uk-wave-and-tidal-key-resource-areas-project.pdf

27 GW. Similarly, in terms of resource distribution, The Crown Estate concluded that the Scottish waters offer the majority of the UK's wave resource (46 TWh/yr equating to 18 GW in terms of installed capacity)[19]. However, it is important to note that these figures represent an unconstrained view not taking into account existing sea uses, sensitivities or environmental factors which in practice would limit deployment.

Finally, the Energy and Climate Change Select Committee quotes a practical wave resource size of 40-50TWh/yr[20] based on constrained resource analysis.

Tidal

The practical tidal stream resource has previously been estimated at 116TWh[20] but more recent assessments of the practical and economic resource produced significantly lower figures. The Carbon Trust's 2011 study on 'UK Tidal Current Resource & Economics' concluded that the total practical resource amounts to 10.3 TWh/yr in a pessimistic, 20.6 TWh/yr in a base and 30.0 TWh/yr in an optimistic scenario[21].

All marine

The above figures represent only a selection of the various estimates of the size of the marine resource that is available in the UK. What is evident is that while ranges differ, the size of the opportunity is immense.

By way of illustration, 50 TWh/yr of practical wave resource combined with 21 TWh/yr of practical and economically feasible tidal generation would equate to around 20% of current UK electricity demand[22]. Such a level of deployment would align with figures quoted in DECC's Renewable Energy Roadmap which states that between 200 and 300 MW of wave and tidal stream generation capacity may be able to be deployed by 2020, and at the higher end of the range, up to 27 GWs by 2050[23].

The Scottish Islands are uniquely positioned to capture both exceptional wave resource and significant tidal resource as illustrated in the Figure 3 graphic from The Crown Estate.

Figure 3 shows the distribution of wave, tidal stream and tidal range energy resource across the UK. It becomes evident that Orkney offers significant tidal stream capacity whereas the Western Isles in particular as well as Orkney and Shetland experience unparalleled wave resources when compared to the rest of the UK.

[20] Energy and Climate Change Select Committee (2012). Energy and Climate Change - Eleventh Report. The Future of Marine Renewables in the UK. Available at: http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/1624/162405.htm#a2

[21] Carbon Trust (2011). UK Tidal Current Resource & Economics. Available at: http://www.carbontrust.com/media/77264/ctc799_uk_tidal_current_resource_and_economics.pdf

[22] Carbon Trust (2011). Accelerating marine energy. Available at: http://www.carbontrust.com/media/5675/ctc797.pdf

[23] DECC (2013). Wave and tidal energy: part of the UK's energy mix. Available at: https://www.gov.uk/wave-and-tidal-energy-part-of-the-uks-energy-mix

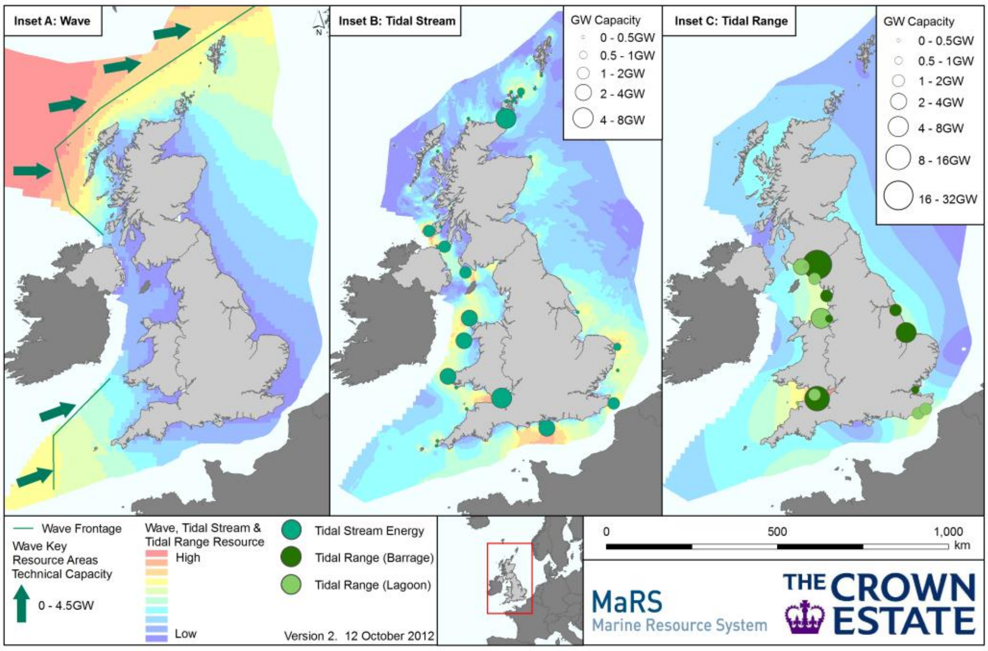

Figure 3 – Wave, tidal stream and tidal range resource potential (The Crown Estate)

The Aquatera[13], Garrad Hassan[15], and Npower Renewables[14] studies give further insight into the distribution and scale of the practical renewable resource for each of the Scottish Islands as illustrated in Table 2 below.

	Orkney Islands	Shetland Islands	Western Isles
Wave	350-800 GWh/year 101-226 MW	1.2-2.1 TWh/year 347-596.2 MW	16.8 TWh/year 4.8 GW (technically extractable)
Tidal	5-12 TWh/year 1,462-3,571 MW	900 GWh/year 248 MW	2 TWh/year 685 MW
Total	Up to 12.8 TWh/year or Up to 3,797 MW	Up to 3 TWh/year or Up to 844 MW	18.8 TWh/year 5,485 MW (technically extractable – NOT practically extractable)
Source	*Aquatera 2005[13]*	*Aquatera 2005[13]*	*Garrad Hassan[15] &, Npower Renewables[14]*

Table 2 - Total practical resource potential (wave and tidal)

As mentioned above for onshore wind, these figures represent the practical potential resource and are not a forecast of deployment. Our central scenario provides a credible deployment outcome assuming the necessary policy support is in place and marine technologies become established (please refer to Section 3.3 for more details).

3.2. Grid Access

The Scottish Islands groups considered currently have either very limited grid connections to the mainland or none at all, so connections for renewable energy are limited by the local load demands and balancing of island systems until large transmission infrastructure projects are constructed.

There are a number of different terms that relate to the 'firmness' of user commitment and grid access which we refer to in this report:

- Contractually firm – this relates to projects that have applied for and accepted a grid connection offer and their project has been included in planned network reinforcements. Contractually non-firm projects are those that have not applied for or accepted a grid offer and therefore when they do come to apply their application will have to be considered in relation to local network access issues and wider and enabling works in the mainland system.

- Technically firm – this relates to the technical design of the system. All of the island connections have been designed using single circuit, which are technically non-firm solutions, to minimise the infrastructure that needs to be built.

- Commercially firm – this relates to the project's access to the system in the event of a fault or outage, or wider transmission constraint. Most of the developers have chosen to accept a commercially non-firm connection which means they would be constrained off in the event of an outage on the local assets without financial compensation. By selecting a single circuit design, but with greater risk of outages, the generator benefits from lower TNUoS charges. Under the Connect and Manage regime generators are commercially firm from the Main Interconnected Transmission System (MITS) substation onwards even if wider works are still required to ensure the mainland system complies with the security and quality of supply standard (SQSS), meaning they can bid for compensation via the Balancing Mechanism to be curtailed to alleviate transmission constraints on the MITS.

- Managed - this relates to the fact that some developers have been offered and accepted a connection offer that allows them to be curtailed via active network management systems to alleviate local constraints in the event of low load or high generation.

SHE-T, as the local transmission owner, has undertaken studies to consider the most efficient and economic infrastructure to enable the renewable generation to connect. It has only taken into account those projects that have applied for and accepted connection offers, although it has allowed for some oversizing for example in a larger HVDC connection to Shetland than currently contracted. If further anticipatory investment was considered then alternative infrastructure plans may be considered but at the greater risk of stranding.

SHE-T's planned links are shown in Figure 4. Those relating directly to the Scottish Islands (6, 7 and 9) are discussed further below. There are existing cables to Orkney but they are distribution system cables operating at 33kV and so are not shown on this map.

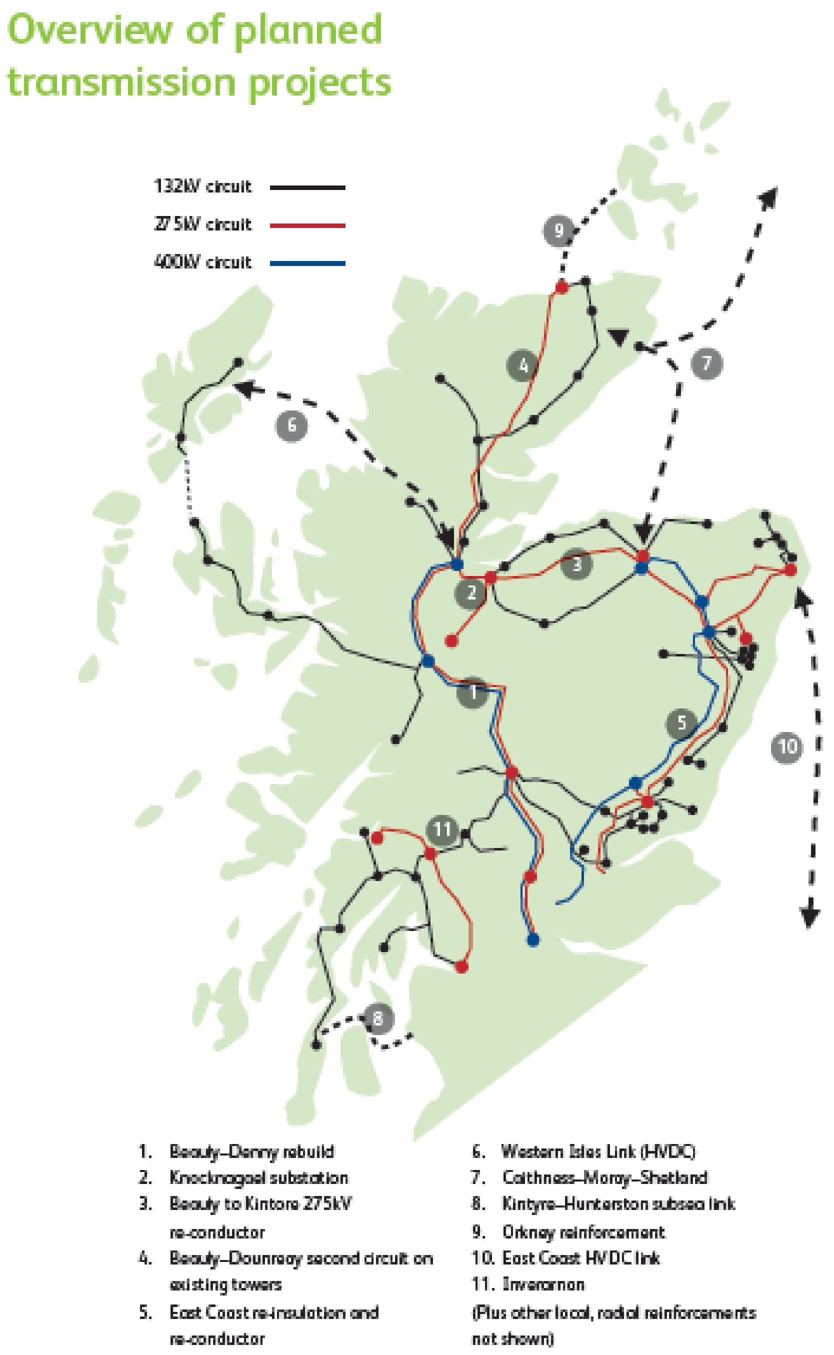

Figure 4 – SHE-T Transmission Projects Map[13]

Western Isles

There is an existing single circuit connection to the Western Isles at 33kV via the Isle of Skye but this connection is only rated at 20MW/23MVA. There is a local demand that varies between 7.5MVA and 31MVA and there is 7MW of generation already connected (excluding standby diesel plant). Studies by SHE-T have confirmed that up to 37 MW of generation could connect prior to the HVDC link being installed.

The proposed connection upgrades are as follows:

- **Western Isles HVDC Link – Planned Completion Date: October 2016**[24]

This 156 km Link comprises a 76 km section of subsea cable (single cable) and an 80 km section of onshore cable (two cables to be laid to allow for future capacity without additional disturbance to the sensitive environment). The new 450 MW HVDC link would be connected to the existing Stornoway Grid substation via a new 132kV circuit which is being developed as part of the Lewis Infrastructure project. The project is unique due in part to the high soil thermal resistivity of the onshore route as well as stringent environmental installation restrictions. It has been triggered solely by connection applications from renewable generation wishing to locate on the Western Isles.

Projects that have made grid applications, have committed to securities and liabilities and are progressing within their project development timescale and so would receive contractually firm access on the link are:

- Beinn Mhor Power (GdF Suez): 133 MW
- Muaithebheal (Uisenis Power Limited): 150 MW
- Tolsta (2020 Renewables): 39 MW
- Siadar Lewis Wave (Aquamarine): 40 MW
- Distributed Generation (various): 46 MW

If all the above projects were to go ahead, there would be approximately 42 MW of capacity left on the cable, but there may be additional managed capacity available dependent on constraints analysis. For further non-managed access to be made available an additional HVDC converter will be required on the Western Isles and at Beauly and an additional subsea cable. (Please note that all of the aforementioned projects are dependent on the new HVDC link to be installed; none of them are guaranteed without the additional transmission infrastructure or additional funding that may be required to make them economic.)

This link was originally planned for 2015 but recent announcements by SHE-T on supply chain and delivery issues have delayed the project. The project may be pushed back further by a delay in submission of the 'needs case' to Ofgem (originally due by 1 March 2013) as SHE-T did not have sufficient confidence in the commitment by developers on the Western Isles to their projects and the affordability thereof, in the light of policy uncertainty with respect to transmission charging and renewables support. As this delay may impact on the tendering timescales for the transmission project it could have a significant impact on the timings and costs, which in turn could impact on the financial viability of some of the generation projects. Further delays may affect the participation of projects, and the need to re-tender for the link, which will put some doubt on a 2016 completion date.
The budgeted anticipated cost of the HVDC link is £705m and this covers the costs for the subsea and onshore cables, the converter stations including the associated AC works, but not additional infrastructure on Lewis. These costs have increased substantially during the tender stage (previously believed to have

[24] Note that depending on the timing of the submission of the 'needs case' this target date may slip.

been estimated around £450m) and these we believe are mostly due to the high thermal resistivity issues on the onshore cable.

- **Lewis Infrastructure – Planned Completion Date: October 2017**

This link with a capacity of 180MVA and a length of approximately 25 – 30 km depending on the final route selection will provide access to the Western Isles HVDC Link for Tolsta, Siadar Wave and embedded generators located at the Stornoway Grid Supply Point.

The cost is still unknown and could vary between £50m and £90m dependent on final design solution (latest estimate was quoted as 'no less than £75m'[34]). The final design will be determined following detailed site investigation works, and so the full cost of the grid connections for the developers remains unknown at present.

These works were originally planned for 2015 but have been delayed to 2017. This means that the projects in the Stornoway area (Tolsta, Siadar and Distributed Generation) will not be able to connect until the end of 2017 at the earliest although Tolsta and Siadar have always had a connection date of 2017.

In addition to the Western Isles HVDC Link and Lewis Infrastructure works, further project specific works are required to connect the generators to either Gravir or Stornoway. The associated costs (up to £12.5m for the Siadar Lewis Wave connection to Stornoway) will be included in the individual developer's security and liability payment and use of system charge calculations.

They are anticipated to be completed between 2016 and 2017.

Orkney

The existing Orkney 33kV connections are rated at 20MVA and 32MVA. Local demand varies between 8.7 MW and 33 MW. There is already 26.9 MW of generation connected with commercially firm connections (16.4 MW renewables and 10.5 MW at the Flotta oil terminal). There is an additional 19.4 MW of inter-tripped (commercially non-firm) generation, 5 MW of micro-generation and 25.9 MW of generation connected under an active network management Registered Power Zone (RPZ) scheme (commercially non-firm and managed).

There is a total of 66.7 MW of renewable generation already connected and managed on Orkney and some of this generation is curtailed on a regular basis because the amount of installed generation is high compared to the local demand and grid connection capacity. All developers (even micro-generation) currently waiting for a connection will be required to wait until further action is taken and any network upgrades are completed. The current timescales for the planned works would mean that they would be waiting until at least April 2018.

A lithium ion energy demonstration project with a maximum power output capacity of 2 MW is currently being installed at the Kirkwall Power Station. The objective of the project is to demonstrate stabilisation of the power supply and management of exports on the existing 33kV connection.

The proposed connection upgrades are as follows:

- **Orkney AC Link (including Orkney substation) – Planned Completion Date: April 2018**

This 73 km link comprises a 70 km section of subsea cable and a 3 km section of onshore cable, both single circuit. It will provide contractually firm grid access for 180 MW of wave and tidal projects that have applied for and provided security for a grid connection. They are:

  - SSE Renewables (SSER): Phase 1 - 130 MW
  - SP Renewables (SPR): 49.9 MW

There will be no non-managed access available for other projects and although larger and higher voltage cables have been considered by SHETL/NGET, they have not been progressed as there was no defined need (no other developers have requested connections) and there is no available transmission capacity on the mainland.

The projects that have not submitted connection applications (and hence will need to consider commercially non-firm and managed access or wait until further reinforcements are complete) are Fairwind, smaller scale wind projects, EON, Scotrenewables and other SSER/SPR projects.
This AC link was originally planned for 2015 but recent announcements by SHE-T on supply chain and delivery issues have delayed the project. The NGET and SHE-T view is that the impact of this delay on the customers with signed connection offers is relatively low as most of these projects are only seeking limited exports between 2015 and 2017 due to delays in marine technology development. It will delay capacity being made available for other projects that as yet have not applied for grid connection or embedded generators.

The budget anticipated cost is £230m and this covers the costs for the subsea and onshore cables, the onshore substation and the 20 km, 132kV cross island link and associated substation works. The costs will be confirmed prior to submission of the Needs case to Ofgem in Q3/Q4 2013 and the Technical case in Q1/Q2 2014.

- **Orkney HVDC Link – Planned Completion Date: October 2020 at the earliest**

This 600 MW, 120 km link comprises a 70 km section of subsea cable and a 50 km section of onshore cable, both single circuit. It will provide grid access for the second stage of wave and tidal projects that have already submitted connection applications and additional generation that may look to connect. They are:

  - SSE Renewables: Phase 2 - 320MW

The link is anticipated to have a capacity of 600 MW so an additional 280 MW of capacity will be made available for further wind, wave and tidal projects and although it is currently planned for 2020 it may be later, and will be subject to the deployment of the currently contracted generation.

The budget anticipated cost is £500m and this cost only covers works between Orkney and the HVDC switching station at Spittal in Caithness. Further investment is likely to be required from Spittal southwards potentially as a 1200 MW HVDC Link to Peterhead. These costs have not been included here.

The case for this HVDC Link is currently dependent on the commitment from (and therefore the commercial success of) the existing contracted marine developers. Until this is established it is unlikely that the HVDC Link will be taken forward without further applications from other interested developers.

Shetland

There is no grid connection between Shetland and Mainland Scotland. There are two large fossil fuel based generators on the islands (67 MW at Lerwick Power Station and 100 MW at the Sullom Voe oil and gas terminal which currently exports, at most, 22 MW to the Shetland system). Local demand varies between 12 MVA and 43 MVA. There is already a 3 MW windfarm (Burradale) and small distributed wind connected with firm connections.

The current mix of generating plant is not sufficiently flexible to cope with much additional intermittent renewable generation whilst maintaining network system stability. This is particularly true during the summer where the low demand on the islands makes it very difficult to accommodate any further renewable generation.[25] Similarly to the situation for Orkney, it is now not possible for new generation to obtain a connection.

The planned Northern Isles New Energy Solutions (NINES) project will allow an additional 10 MW of wind to connect through a wind to heat scheme[26] using innovative domestic and district thermal storage technology. There is very limited capacity available for further generation and projects will need to wait for the planned connection upgrades to obtain a grid connection. The tidal turbine prototype project from Nova Innovation is connecting through the NINES project, using the generation locally for an ice machine to supply local fishing boats.

The proposed connection upgrades are as follows:

- **Shetland HVDC Link – Planned Completion Date: November 2018**

This 600 MW, 297 km link comprises a 284 km section of subsea cable and a 13 km section of onshore cable, both single circuit. It will provide grid access for Viking Energy, the only generator to have applied for and provided security for a grid connection. This link was originally planned for 2016 but recent announcements by SHE-T on supply chain and delivery issues have delayed the project.

This project will provide contractually firm grid access for:

  - Viking: 412 MW

The link is anticipated to have a capacity of 600 MW and so an additional 188 MW of capacity for other projects may be made available, although the Shetland connections for these projects have not been planned or costed as they have not submitted connection applications. The other known potential projects are Aegir (10 MW), Enertrag (100 MW+), North Yell Windfarm (40 MW). It should be noted that in the absence of further user commitment, building a 600 MW link with only 412 MW of contracted generation would require a level of anticipatory investment that Ofgem would need to approve following receipt of a needs case.

The budget anticipated cost is £520m and this cost only covers works between Kergord on Shetland and Caithness (at a location near Spittal). The link forms part of a three terminal HVDC system covering Shetland - Caithness – Moray. SHE-T is currently assessing tender returns, a more accurate breakdown of costs will be available when they are complete.

25 Scottish Hydro Electric Power Distribution Proposals for the development of the Integrated Plan for Shetland

26 Please refer to the following for more details: http://www.shetlandtimes.co.uk/2012/02/21/trustees-agree-to-3-6-million-expansion-in-district-heating-scheme-for-330-new-properties ; http://www.shetlandtimes.co.uk/2011/12/09/chance-to-invest-7-million-in-nines-wind-turbines; http://www.shetnews.co.uk/news/4677-wind-to-heat-helps-district-heating-scheme-to-expand

3.3. Central deployment scenario

Figure 5 summarises the status of the new generation projects for each of the Island Groups. Not including existing generation that is already connected to the distribution networks, Figure 5 shows the scale of the projects with firm or non-firm capacity on the planned transmission links as well as an estimate of the realistically deployed resource by 2030 as explained further below.

As can be seen, the project pipeline in the Western Isles and Shetland is dominated by onshore wind along with a few smaller scale wave and tidal projects. The Shetland new generation capacity is dominated by the Viking windfarm, whereas the Western Isles is a combination of medium to large onshore wind projects. In contrast, Orkney's project pipeline is driven mainly by large scale wave and tidal projects with smaller quantities of onshore wind.

In the context of the 2020 renewables target, the figure suggests that available transmission capacity will be the constraining factor for the Western Isles, notwithstanding whether additional financial support will be required and available. For Orkney though, there is a considerable degree of uncertainty surrounding technical maturity and timing to commercial viability of marine generation.

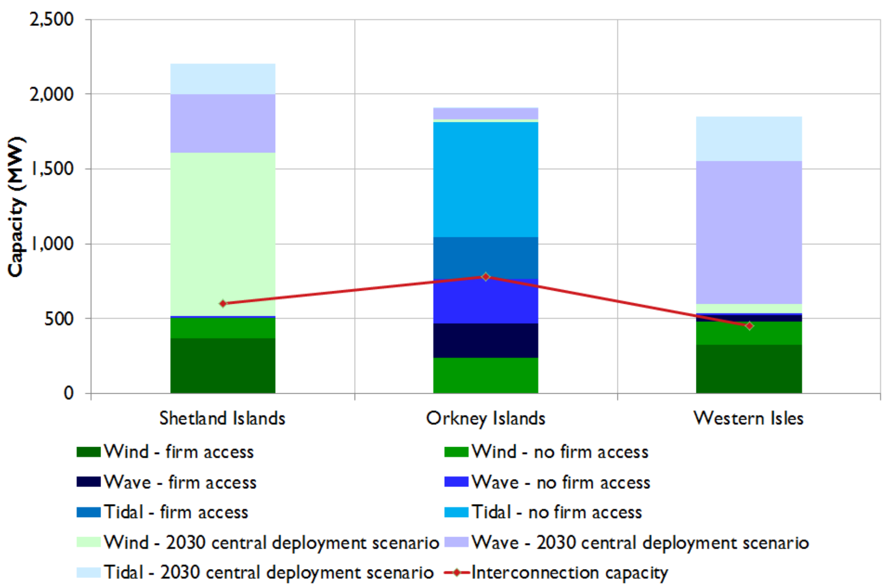

Figure 5 – Contractually firm, non-firm and practical resource potential as per the central scenario[27]

Based on the review of publically available estimates of resource potential (see Section 3.1), our stakeholder interviews as well as the current project pipeline of existing projects with firm or non-firm capacity on the transmission links, we have defined a credible central scenario for wind, wave and tidal deployment for the Scottish Islands in 2020, 2025 and 2030.

Please note that while these figures are meant to represent a realistic deployment scenario assuming that the necessary policy support is in place, they are not to be interpreted as a forecast or a maximum deployment limit. Instead, we use this scenario to illustrate in particular the potential socio-economic benefits by 2020, 2025 and 2030 (see Section 5).

[27] Showing transmission capacity of both the AC and HVDC link for Orkney

Installed Capacity (MW)	2020	2025	2030
Orkney – Onshore Wind	40	256	256
Shetland – Onshore Wind	600	1,200	1,600
Western Isles – Onshore Wind	400	550	550

Table 3 – Assumed installed capacity in the Scottish Islands – Onshore Wind

Installed Capacity (MW)	2020	2025	2030
Orkney – Wave	47	349	600
Shetland – Wave	0	100	400
Western Isles – Wave	50	5,00	1,000

Table 4 – Assumed installed capacity in the Scottish Islands – Wave

Installed Capacity (MW)	2020	2025	2030
Orkney – Tidal	93	310	1,000
Shetland – Tidal	0	100	200
Western Isles– Tidal	0	200	300

Table 5 – Assumed installed capacity in the Scottish Islands – Tidal

We have not included any offshore wind in our central scenario although there are opportunities around Orkney.

3.4. Key challenges

Table 6 provides an overview of the key challenges Scottish Islands Renewable projects are facing currently. Section 4 explores each of these challenges in turn and discusses both the drivers as well as the impact on revenue, cost or risk.

#	Category	Key challenges	Impact	Section
Revenue				
1	Capacity Factors	While high, the expected capacity factors are more uncertain for wave and tidal projects given the relative lack of operational data. For wind however, high capacity factors on the Scottish Islands are the key benefits.	High	4.3.2
2	RO vs. CfD	The recent delay of the transmission cable for the Western Isles may limit developers' choices between the RO and CfD support regimes.	Medium	4.3.3
Cost				
3	Development costs	Evidence suggests that development costs are marginally higher due to the difficult environmental conditions (especially with regard to protection of red throated diver, whimbrels and eagles), complex terrain, crofting rights and higher land costs.	Low	4.4.1
4	Construction costs	Evidence suggests that construction costs are higher due to the remote location/access, lack of infrastructure, adverse weather, higher wind speeds and scarcity of labour and material.	Medium	4.4.2
5	Transmission costs	The high transmission costs, particularly for the Western Isles, result in high transmission charges under the current charging methodologies. This is a major driver of higher costs for the Scottish Island projects.	High	4.4.3
6	Operational costs	Evidence suggests that higher wind speeds, the import requirements for skilled labour, higher community benefit payments and higher insurance costs also result in higher operational costs.	Low	4.4.3
Risks				
7	Grid access	Recently announced delays to transmission links may have an adverse effect on project timings. A number of wind, wave and tidal projects have not yet secured capacity on the planned transmission links, in part due to the security and liability requirements. Access may only be available on a commercially non-firm and managed basis.	High	4.5.1
8	Grid charging	The CMP213 Workgroup Consultation is currently reviewing TNUoS charging arrangements which may have an impact on	High	4.5.2

		the way the wider locational and local circuit tariff elements of Transmission Network Use of System (TNUoS) are calculated. Uncertainty as to the methodology and scale of TNUoS, as well as the overall level of charges, is a key concern for generators. The scale of transmission capex, which has recently been estimated to be greater than £700m in the case of the Western Isles, is the second key dimension influencing the level of transmission charges and is adding to the uncertainty faced by generators.		
9	Grid availability	Single circuit connections and HVDC technology increase grid availability risks, leading to higher insurance costs. However, single circuit connections do reduce the transmission charges paid by generators.	Medium	4.5.3
10	Dependency on wider grid works	The planned Scottish Islands links are dependent on other onshore reinforcements before grid access is possible.	Medium	4.5.4
11	Security and liability requirements	The scale and timing of security and liability payments is a challenge, particularly for wave and tidal as well as smaller scale/ community owned wind projects.	Medium	4.5.5
12	Loss of diversity benefit under CfD regime	Generators may not be able to capture the diversity benefits that Scottish Island wind farms offer under the design of intermittent CfDs as these will be settled against Day Ahead power prices.	Low/Medium	4.5.6
13	Currency and commodity price risks	Given the uncertainty surrounding the timing of island transmission infrastructure, developers cannot hedge against currency and commodity price risks making project costs more uncertain.	Low	4.5.7
14	Technology risks	Technology risks remain a key concern for developers, particular for wave and tidal.	Medium	4.5.8

Table 6 – Key challenges for renewable generators on the Scottish Islands

4. KEY DRIVERS FOR COST AND REVENUE DIFFERENCES

4.1. Summary LCoE modelling results

As described in Section 2, one of the key aims of this study is to benchmark the costs of Scottish Islands renewable generation with equivalent projects on the mainland, and other forms of generation more generally. For the purposes of this study the following power generation technologies have been considered:

- Gas – CCGT;
- Nuclear - EPWR FOAK;
- Coal - ASC with FGD;
- Biomass Conversion;
- Dedicated biomass 5-50MW;
- Dedicated biomass >50MW;
- Onshore >5 MW UK;
- Offshore wind Round 2 and Scottish Territorial Waters (STW);
- Offshore Round 3;
- Solar 250-5000kW;
- Imported wind from Ireland (based on Baringa estimates[28]);

Figure 6 shows estimated LCoEs for project commissioning in 2020. For each technology, we show a low, central and high LCoE scenario based on DECC's published view of costs (incorporating 'low' and 'high' pre-development and capital costs)[10].

For Scottish Island onshore wind, the LCoE presented in this and the following sections were informed by data gathered through the interview stages on the project. This encompasses a diverse range of projects at various stages of development. Based on the data we received, we calculated our 'best estimate' of LCoE for these projects. In this context it is important to note that while the majority of developers believed that there are genuine reasons for cost differences which they reflected in the cost estimates submitted to the project team, some interviewees thought that these were negligible. However, we noted that in general projects that were more advanced believed that the cost differences would be greater, and since these developers are already in advanced stages of discussions with suppliers, we have placed greater weight on the cost data provided by these developers. Our 'best estimate' reflects this weighting. As a result, the 'best estimate' does not represent any specific existing or planned project on any of the Scottish Islands, nor an arithmetic average or median. For onshore wind, the figures represent our 'best estimates' of a typical project on the Scottish Islands taking into consideration the range of cost data we received, the projects' stage of development, the developers' confidence in the cost forecasts as well as information gathered during the stakeholder interviews. For more details with regard to the input assumptions for the 'best estimate' calculations, please refer to Section 2.3.1 and Section A.3 in the Appendix.

Figure 6 compares all technologies using a uniform 10% discount rate across all technologies (in line with the approach used in reports produced by DECC and other organisations). These estimates may be viewed as neutral in terms of financing and risk when comparing across technologies. In contrast, Figure 7 shows all renewables at DECC's technology specific hurdle rates (and commissioning in 2020), which are designed to reflect the different risks associated with different technologies. For example, the DECC technology specific hurdle rates are higher for offshore wind than onshore wind.

[28] For Irish import, LCoE input assumptions were based on information published by Greenwire and Mainstream. Available at: http://www.greenwire.ie/greenwire-project/frequently-asked-questions/ and http://www.energybridge.ie/development_process.asp. Assumed TNUoS of £40/kW/year.

Modelling results using a uniform 10% discount rate

As can be seen in Figure 6, our best estimates for LCoE for onshore wind projects commissioning in 2020 on Orkney and Shetland (using a 10% discount rate) are around £110/MWh and £112/MWh respectively. Please note that there remains some uncertainty regarding transmission charges prior to the conclusion of the CMP213 process. One key uncertainty in the future transmission charging methodology is the treatment of HVDC converter costs. For our central case we have assumed that 100% of converter costs are included in the transmission charges. The impact on LCoE of including, say only 30% of converter costs is illustrated in more detail below (see modelling results using technology specific hurdle rates). At £137/MWh, onshore wind on the Western Isles is significantly higher than onshore wind on Shetland and Orkney. This is mainly due to the combination of less favourable yields and higher transmission charges (the drivers for these cost differences are explored in more detail in Section 4.3). Note that the expected LCoE for Western Isles wind has shifted dramatically over the past twelve months with the escalation in costs for the HVDC link. Such significant changes in costs are less likely for the Orkney and Shetland links, but some cost escalation is possible. Differences in LCoE expectations between Orkney/Shetland and the Western Isles could narrow as a result but the wind yields on the latter means that LCoE will likely always be higher.

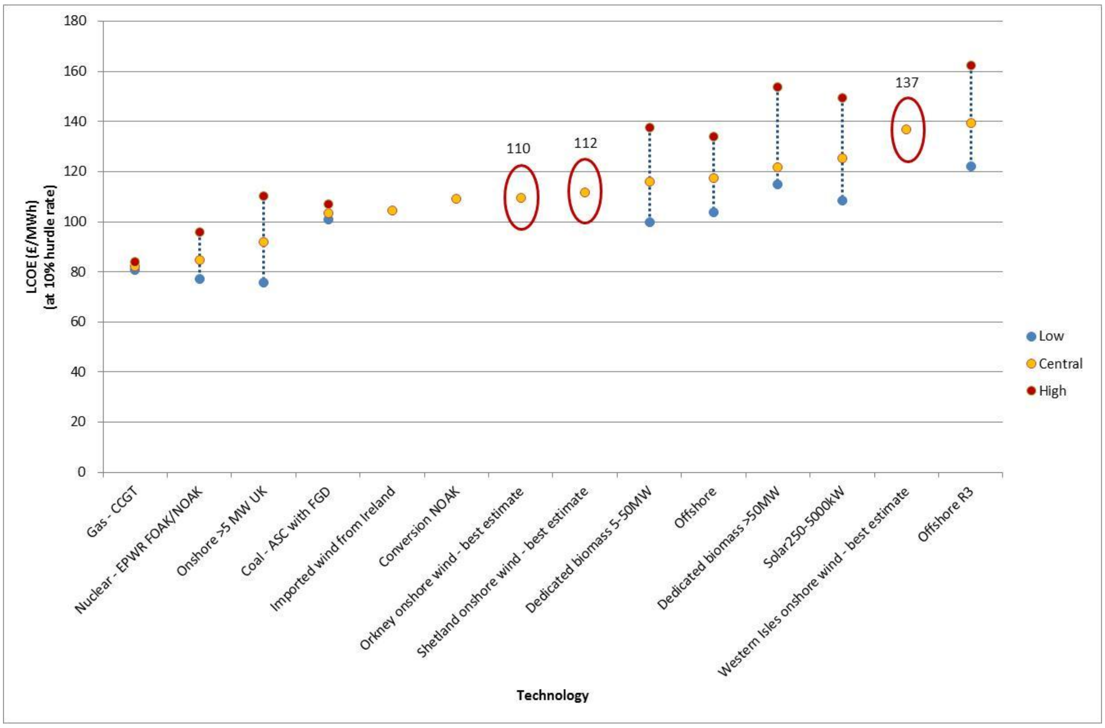

Figure 6 – LCoE modelling results showing 'best estimate' for SI projects and LCoE ranges based on DECC's published view on costs and using 10% discount rate for projects commissioning in 2020

At £92/MWh under the Central scenario (and assuming a 10% discount rate), LCoE for other UK onshore wind >5MW is estimated to be £18/MWh cheaper than onshore wind on Orkney and £20/MWh cheaper than on Shetland. That said, LCoE estimates for onshore wind >5MW may still vary quite substantially (between £76-£110/MWh) depending mostly on capacity factors.

The costs of onshore wind on Orkney and Shetland are in the range of costs of several other low carbon alternatives including dedicated biomass and Round 1 and Round 2 offshore wind, and are broadly similar to the costs of importing wind energy from Ireland (estimated at £105/MWh). They would appear to be higher than DECC's range of nuclear costs (£77/MWh - £96/MWh).

Offshore wind LCoE is estimated between £104-£134/MWh for Round 2 and STW sites (around £118/MWh under the Central scenario) and between £122-£162/MWh for Round 3 sites (around £139/MWh under the Central scenario). Hence, onshore wind on Shetland and Orkney is cheaper than offshore wind, and the cost on the Western Isles is similar to Round 3 offshore wind.

Modelling results using published technology specific hurdle rates

Using DECC's technology specific hurdle rates which are less than 10% for onshore wind but greater than 10% for offshore wind, LCoE for Orkney, Shetland and Western Isles onshore wind reduces to £103/MWh, £106/MWh and £129/MWh respectively (commissioning in 2020) compared to £84/MWh for a typical UK onshore wind site.

Similarly to the above, onshore wind on Orkney and Shetland compares favourably with imported wind from Ireland, biomass conversions (estimated at £95/MWh and £110/MWh respectively under the central scenario) and Round 2/STW offshore wind (around £121/MWh under the central scenario).

Importantly however, Western Isles onshore wind is estimated to be £31/MWh cheaper than Round 3 offshore wind under the central scenario when applying technology specific hurdle rates and Shetland and Orkney are £57/MWh and £55/MWh cheaper respectively.

As stated above, please note that these estimates are based on inclusion of 100% of the HVDC converter costs in the transmission charges. If, say only 30% was included, the LCoE of Orkney and Shetland onshore wind is estimated to reduce to £98/MWh and £103/MWh under central assumptions of transmission capital costs (see also Section 4.5.2). Similarly, under the same assumptions, LCoE of Western Isles onshore would be closer to £120/MWh (see Section 4.5.2 for more details).

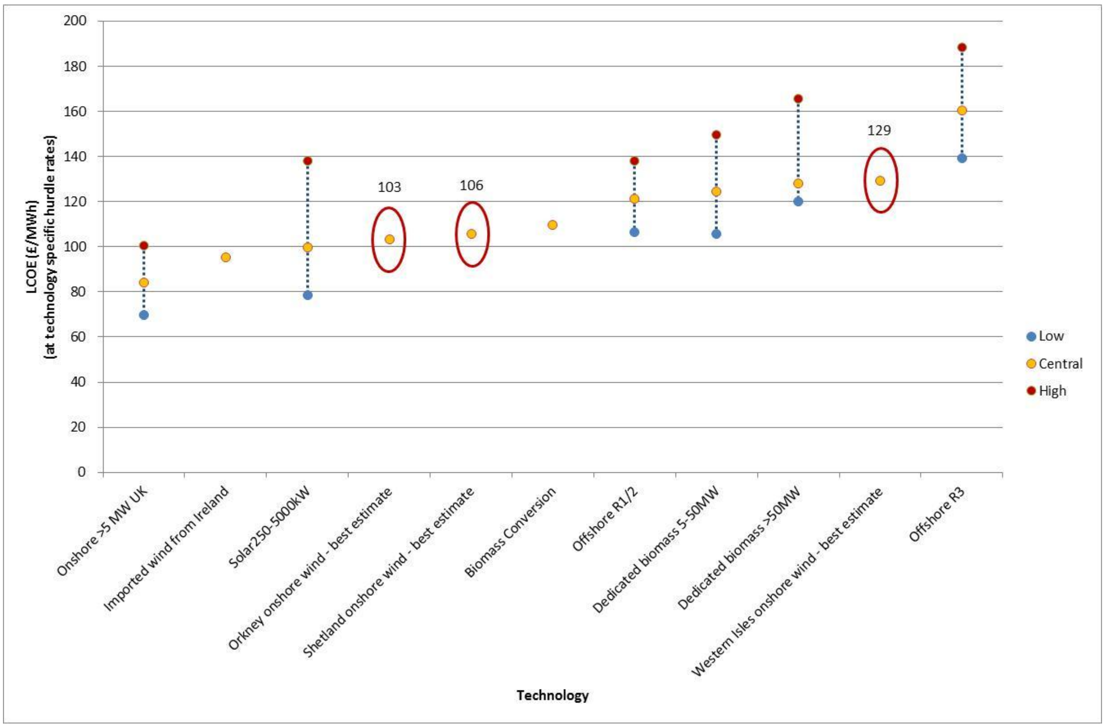

Figure 7 – LCoE modelling results showing 'best estimate' for SI projects and LCoE ranges based on DECC's view of costs and using DECC's technology specific hurdle rates for projects commissioning in 2020

Apart from LCoE changing due to different levels of transmission charging, Table 7 below shows the impact on LCoE of adding 1% to DECC's onshore wind technology specific hurdle rates. Each 1% increase adds around £5/MWh to the LCoE.

LCoE (£/MWh)	Best estimate	+1%
Onshore Wind Orkney	103	108
Onshore Wind Shetland	106	110
Onshore Wind Western Isles	129	135

Table 7 – Hurdle rate sensitivity on LCoE (£/MWh) for Central capex and 100% converter costs (2020 commissioning)

Figure 8 below shows the range of LCoE for marine projects becoming operational in 2020, using DECC's technology specific hurdle rates.

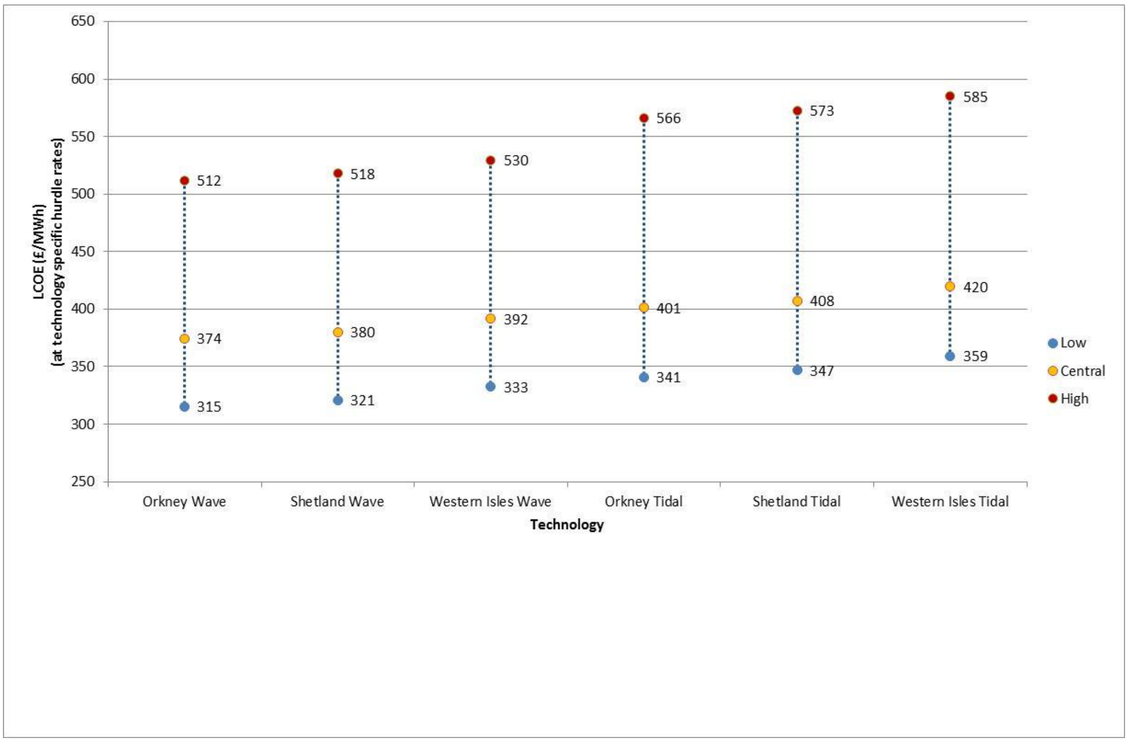

Figure 8 – LCoE modelling results showing for wave and tidal using DECC's technology specific hurdle rates and projects commissioning in 2020 (based on RenewableUK cost data)

As wave and tidal remain commercially unproven power generation technologies, very significant variations have been observed in the calculated LCoE estimates.

The costs of developing a typical 10 MW wave project on the Scottish Islands commissioning in 2020 have been calculated to be in the range of £315-£530/MWh, with cost estimates for a typical project of around £374-392/MWh. This compares with a cost estimate of between £341 - £585/MWh for tidal projects with £401-£420/MWh representative of a typical project.

These very significant LCoE variations for wave and tidal projects demonstrate the uncertainty facing investors in these technologies which are as of yet commercially unproven. We discuss potential for learning and cost reductions in more detail in Section 6.1.2.

The above figures are based on the cost estimates made by the RenewableUK 'Channelling the Energy' study[17]. We are unable to base our costs estimates on cost data received by developers due to the limited number of data points we received. In order not compromise commercial confidentiality, we have chosen to display the publically available industry average here only. The differences in LCoE between Shetland, Orkney and the Western Isles are a function of differing levels of TNUoS only.

4.2. LCoE modelling results by Island (onshore wind)

Figure 9, Figure 10 and Figure 11 show LCoE for onshore wind by Island Group and compare the cost components to the Central UK onshore wind LCoE of £84/MWh. Note that these calculations have been undertaken using DECC's technology specific hurdle rates.

Orkney:

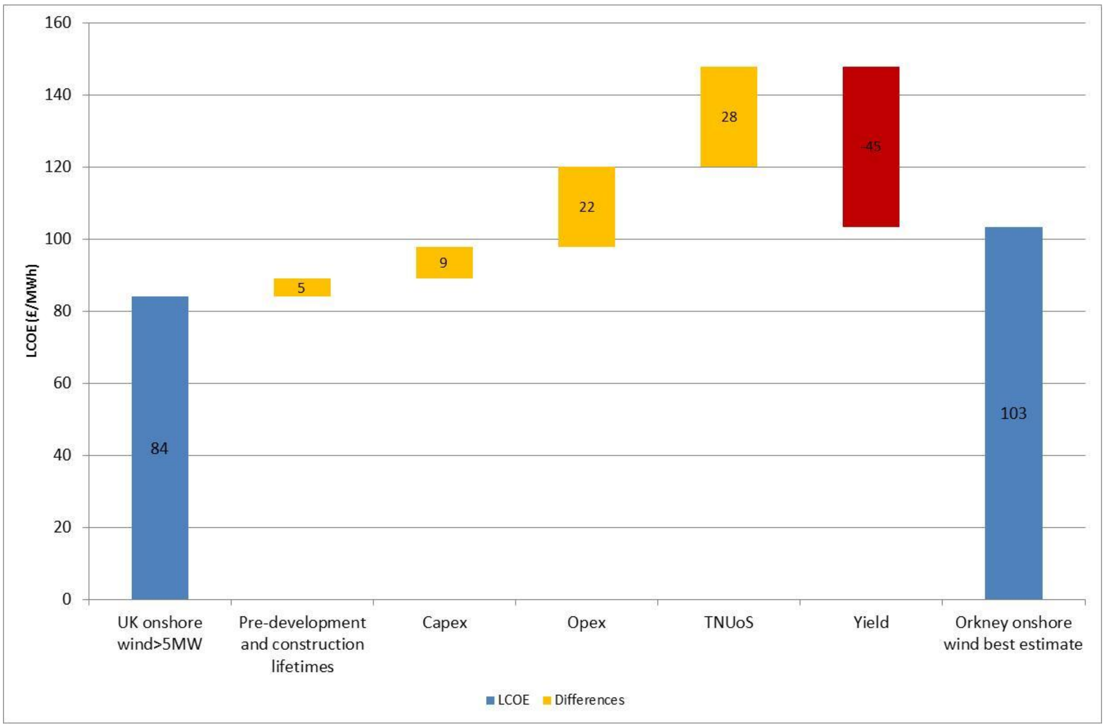

Figure 9 – Orkney: Onshore wind LCoE waterfall chart at technology specific hurdle rates and for projects commissioning in 2020

For Orkney, the waterfall chart highlights that there is a genuine cost difference between a typical Orkney wind project and the average UK onshore wind farm[29]. Longer pre-development/construction times and higher capex, opex and TNUoS charges add £5/MWh, £9/MWh, £22/MWh and £28/MWh respectively to the average onshore wind costs (in LCoE terms). However, the higher yields are able to compensate for most of these costs (illustrated by a reduction of £45/MWh) with the overall delta coming to £19/MWh. The reasons for these differences, from a revenue and cost perspective, are explained in more detail in Section 4.4.

Shetland:

At £106/MWh, LCoE for a typical Shetland onshore wind project is comparable to that of Orkney. There was little evidence to suggest that development or construction costs are significantly different between

[29] Note we did receive information from developers that suggested lower costs for some projects. What we show here is our best estimate for a typical project on Orkney.

the Islands.   We assess opex to be slightly higher, and TNUoS would be greater. The higher yields would result in an even bigger saving versus a typical mainland project. In aggregate an estimated LCoE of £106/MWh is similar to Orkney.

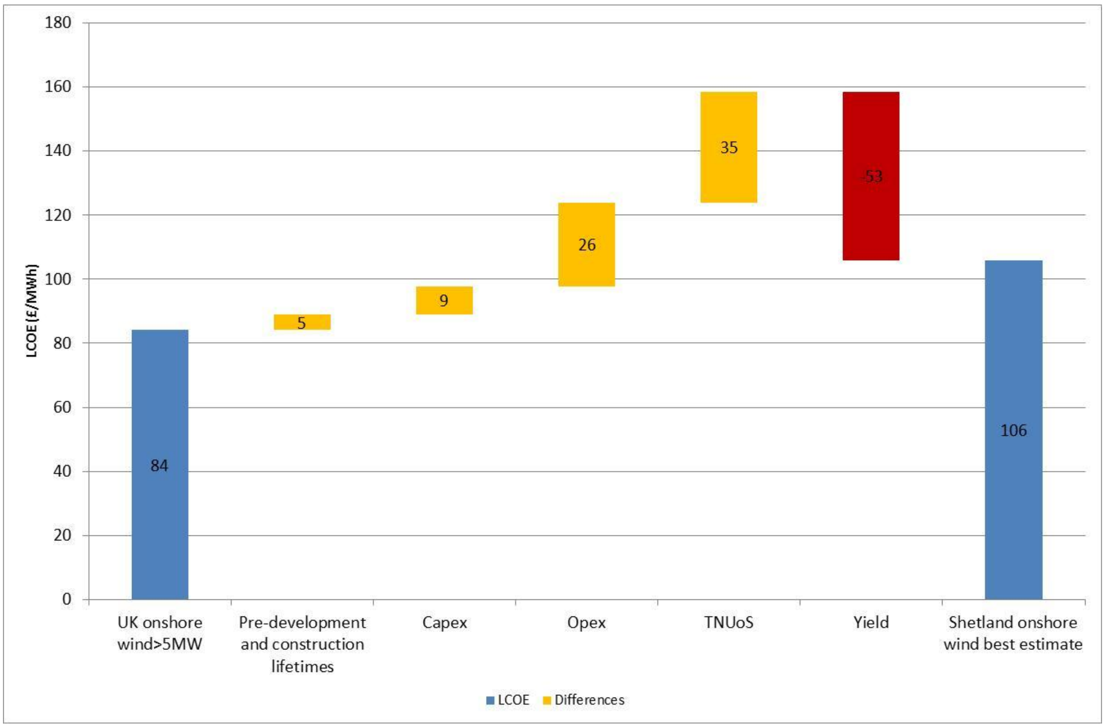

Figure 10 – Shetland: LCoE waterfall chart at technology specific hurdle rates and for projects commissioning in 2020

Western Isles:

Onshore wind projects on the Western Isles, while still competitive with some other low carbon alternatives as shown above, face a higher LCoE than onshore wind on Shetland and Orkney. The latter is mainly a function of higher TNUoS charges and lower yields. As a result, LCoE for onshore wind projects is estimated to be around £130/MWh.

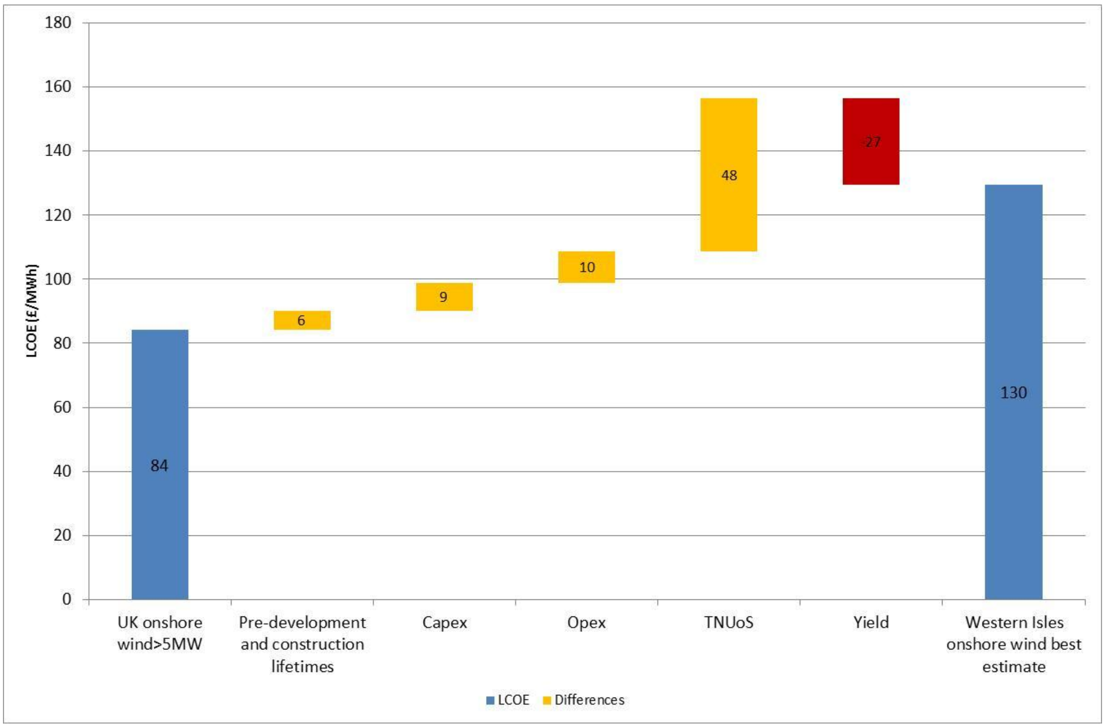

Figure 11 – Western Isles: LCoE waterfall chart at technology specific hurdle rates and for projects commissioning in 2020

4.3. Key drivers for revenue differences

In this section we go into further detail on what drives the revenue differences between Scottish Islands renewables and comparable projects on the mainland. In the next section we explore the drivers of the cost differences.

4.3.1. Wind yields

As described in Section 3.1.1 above, Scotland is one of the windiest regions in Europe, with the Scottish Islands offering particularly high wind yields year round. While the average onshore wind capacity factor in England and Wales is approximately in the region of 27% - 29%, and 30% on the Scottish Mainland, the Scottish Islands offer capacity factors above 35% - a fact which constitutes the single most important driver for higher revenue streams of Scottish Island versus mainland projects. The fundamental question faced by onshore wind developers is whether the increase in yields outweighs the higher development, construction and operational costs (particularly transmission charges) over the lifetime of their project.

Table 8 below provides an overview of the ranges of wind yields interviewees are expecting on the Western Isles, Shetland and Orkney. Given the uncertainty associated with these figures, we have refrained from presenting an average and are showing the full range of capacity factors we have received.

	Western Isles	*Shetland*	*Orkney*
Expected capacity factor	35%-41%	43%-50%	42%-44%

Table 8 - Expected capacity factors for onshore wind (based on stakeholder interviews)

The above results broadly align with the figures reported by IPA in its 2008 report of 'The relative economics of wind farm projects in the Scottish Islands'[30] which stated expected capacity factors of 35% for the Western Isles, 49% for Shetland and 49% for Orkney.

Generally speaking, capacity factors seem to be highest on Shetland and Orkney with the Western Isles experiencing somewhat lower yields. The latter is evidenced in the waterfall charts above with yields 'reducing' LCoE differences by £53/MWh in Shetland, £45/MWh in Orkney and £27/MWh in the Western Isles.

4.3.2. Wave and tidal yields

Given the relative immaturity of the technology and lack of operational data, there is a much higher degree of uncertainty associated with the expected capacity factors for wave and tidal projects. The generally accepted industry-estimated yields are shown in Table 9 below.

Despite the wider range for tidal projects, interviewees stated that, generally speaking, they thought tidal yields were more certain than wave yields given that tidal technology was slightly more advanced in terms of its stage in the development process.

	Wave	*Tidal*
Expected capacity factor	30-35%	26-35%

Table 9 - Expected capacity factors for wave & tidal (based on RenewableUK 'Channelling the Energy' report)

Marine developers require a sea-bed lease in order to develop their projects. In 2008, The Crown Estate announced plans to hold a leasing competition in the Pentland Firth and Orkney waters and subsequently entered into agreements for lease for projects with a potential capacity of up to 1600 MW[31]. The Pentland Firth and Orkney waters were the first area in the UK to be made available for commercial scale development of wave and tidal projects and are believed to be the largest development of its kind worldwide[31]. As such, while expected yields were undoubtedly a key driver for the selection of this area, it concentrated developers' efforts in this area rather than, for example, Shetland or the Western Isles.

4.3.3. Support regimes

The Electricity Market Reform (EMR) will introduce Contracts for Differences (CfDs) as a primary support mechanism for renewables from 2017. Developers will be able to choose between the current RO scheme and the new CfD scheme during a transitional period between 2014 and 2017.

Interviewees expressed particular concerns about the recent delay of the Western Isles transmission link (see also Sections 3.2 and 4.4.3) and the impact thereof on the choice of support mechanisms available to them. Prior to the recent announcement by SHE-T to delay the submission of the needs case to Ofgem[32], the planned operational date for the Western Isles link was October 1st 2016. With a time window of only six months at most between the two deadlines, developers fear they may involuntarily be caught in the new regime or face lower ROC bandings due to delays that are not in their control.

[30] IPA (2008). The Relative Economics of Wind Farm Projects in Scottish Islands. Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/39275/file46739.pdf

[31] The Crown Estate (2013). Pentland Firth and Orkney waters. http://www.thecrownestate.co.uk/energy-infrastructure/wave-and-tidal/pentland-firth-and-orkney-waters/

[32] SSE (2013). Electricity Transmission Link Update. Available at http://www.sse.com/WesternIsles/ProjectDocuments/:

4.4. Key drivers for cost differences

Having outlined the scale of cost difference between Scottish Island wind projects and Central UK onshore wind above, the purpose of this section is to highlight the drivers for such cost differences. This is based on our review of existing evidence as well as our stakeholder evidence sessions on the individual Islands. We show the key drivers contributing to cost differences, their impact and the project phase they are likely to occur in.

In addition to known differences in cost, developers highlighted significant differences in risk which will be further explored in Section 4.5.

4.4.1. Development

Cost driver	Impact
Environmental conditions/ complex terrain	▶ The complex environmental conditions presented on the Scottish Islands are perceived to lead to longer survey periods and consequently to longer planning timelines and higher development costs. ▶ More specifically, developers quoted examples of bird survey costs (e.g. for the red throated diver, whimbrels and eagles) and peat probing costs. ▶ One frequently cited example in this context was SSE's withdrawal from its Pairc wind farm at South Lochs on Lewis. 'The risk of killing protected golden and sea eagles as well as affecting divers was too great' SSE was quoted[33].
Crofting rights and land costs	▶ Several developers highlighted that the number of crofters they needed to engage with added another layer of complexity and in some instances added as much as twelve months to their project timelines. ▶ Others anticipated that apart from higher legal costs relating to crofting rights, land costs would also be significantly higher.
Community engagement and benefits	▶ Developers felt that there is generally a higher level of community support and engagement on the Scottish Islands than on the mainland thus facilitating project development. ▶ Developers also stressed the importance of the work by the Island Councils as well as other public/private industry bodies which encouraged and facilitated project developments. ▶ However, developers also highlighted that community benefit payments were higher on the Scottish Islands than on the mainland (see Section 4.4.3 below).

[33] Hebrides News (2012). SSE drops plans for Pairc windfarm . Available at: http://www.hebrides-news.com/sse_drops_pairc_windfarm_8812.html

Planning permission	▶ In line with a high level of community support, developers also spoke favourably of the local planning regime and almost uniformly agreed that getting planning permission on the Scottish Islands was generally easier than in other parts of the UK, particularly when compared to England.

Table 10 – Drivers of increase development costs

4.4.2. Construction

Cost driver	Impact
Location and access	▶ Several developers anticipated higher transport costs relating to the need to deliver a lot of the components by sea rather than by road due the nature of the island location as well as poor road infrastructure. ▶ Also, remote locations require more infrastructure needing to be built in terms of site access roads, ports and beach landing facilities. ▶ That said, while most interviewees stressed the higher costs due to the remote location and lack of existing infrastructure, one developer thought access by sea would be cheaper overall. ▶ While overall, location and access appear to contribute to higher costs, this is very site specific.
High wind speeds/ adverse weather	▶ The adverse weather conditions, high wind speeds, complex terrain and environmental constraints (e.g. bird mating seasons) reduce construction productivity in terms of the time window available to erect turbines in particular. This is perceived to lead to longer construction periods and consequently higher construction costs. ▶ Some developers stated that this delay could add as much as 1-2 years to their construction period. ▶ Higher wind speeds also require stronger components (i.e. a higher turbine IEC class requirement) which increase turbine costs.
Scarcity of labour and material	▶ Related to the above points about location and access is the requirement for developers to source a proportion of specialist labour and materials from the mainland which increases construction costs.

Table 11 – Drivers of increase construction costs

4.4.3. Operation

Cost driver	Impact
Capital costs for transmission link	▶ The cost of the transmission links and the associated transmission charges (explored in more detailed in Section 4.5.2) were by far the top concerns for developers interviewed. ▶ In November 2012, SHE-T issued a statement on the progress of the Western Isles transmission project[34]. In this statement, SHE-T announced that following contractual negotiations with the preferred supplier of the HVDC link the total costs and delivery programme agreed in October 2010 would need to be substantially altered. ▶ The total cost of the HVDC link (excluding the associated infrastructure on Lewis) was estimated to amount to at least £700m. The cost for the infrastructure on Lewis was quoted as no less than £75m. ▶ In addition, SHE-T estimated a delay of at least 12 months to the overall programme with 'a real potential it could be later'. ▶ SHE-T stated that this project is unique due in part to the split of subsea and onshore cable, but also because of the high soil thermal resistivity of the onshore route. ▶ Developers were particularly concerned about: o The impact of these costs on transmission charges (see Section 4.5.2). o The volatility of these costs (see Section 4.5.2) and the total possible maximum costs. o The reasons for the cost increase which they felt they had little visibility of (whether the cost increase related to increases in commodity prices, installation costs, resource costs or technical/environmental complexity etc.). o The resulting delay caused to renewable projects on the Western Isles. o The risk that the transmission link may be cancelled altogether as projects start to 'drop out' in light of the above announcements. o The impact on the cost estimates and timelines for the Orkney and Shetland transmission links. ▶ Overall, the uncertainty associated with the timing and costs of the transmission cable was already quoted as one of the main reasons for project developers to abandon their projects on the Western Isles. ▶ The Siadar Wave Energy Project on the Isles of Lewis, a joint venture between Npower Renewables and Voith Hydro Wavegen, was cancelled in late 2012. The continuous delays of the transmission

[34] SSE (2012). Western Isles Update November 2012. Available at http://www.sse.com/WesternIsles/ProjectDocuments/:

	cable and the uncertainty around transmission charges were quoted in the local press as amongst the main reasons for the withdrawal.[35] [36] ▶ Another example illustrating the scale of the challenge is Statkraft's withdrawal from their eight onshore wind sites in Orkney (totalling 165 MW in capacity) in March 2009. In an interview with the project team, Statkraft quoted escalating transmission charges (which back then were estimated to amount to £62/kW/year) as their main reason for selling their stakes in their JVs with Fairwind.
Insurance costs	▶ There is a higher risk of grid failure due to being on a lengthy radial single circuit link. As a result, developers anticipate lower availability due to forced outages and maintenance of the single cable. ▶ Based on our stakeholder interviews, the latter may add significant extra insurance costs, in the region of £10-15/kW p.a., equivalent to around £4/MWh, when compared to mainland projects. ▶ Together with the capital costs for the transmission link, insurance costs appear to be a key driver for cost differences for projects on the Scottish Islands. ▶ See Section 4.5.3 for more details.
High wind speeds/ higher load factor	▶ Developers generally anticipate higher turbine maintenance costs due to high wind speeds/ high turbulence environment as well as higher cost of extended warranties. ▶ In addition to a higher frequency of repairs, maintenance costs are also expected to be higher due to specialist equipment and components needing to be brought in from the mainland. ▶ One developer estimated turbine maintenance costs to be >10% higher than on the mainland, another indicated that this would be as much as 30%. A third developer quoted an increase in opex due to higher running hours of £20/kW p.a., equivalent to >£5/MWh, when compared to a mainland project. ▶ Related to the above is the expectation of a shorter economic/ operational lifetime due to high load.
Location and access	▶ In addition to the points raised for location and access in the development and construction phase, developers expect greater equipment down time in the remote island locations in view of the difficulty in getting trained staff and specialist equipment (such as cranes or blades) to site.
Community benefit payments	▶ The final driver impacting a developer's operational costs is the scale of benefit that has been agreed to be payable to the relevant community. ▶ Payment and ownership arrangements vary from project to project

[35] Subseaworldnews (2012). UK: Siadar Wave Energy Project Cancelled. Available at: http://subseaworldnews.com/2012/12/21/uk-siadar-wave-energy-project-cancelled/

[36] Offshorewind.biz (2012). Scottish Wave Energy Project Cancelled. Available at: http://www.offshorewind.biz/2012/12/21/scottish-wave-energy-project-cancelled/

	but given the relative importance of renewable projects for the Scottish Islands, several interviewees believed that these payments were generally higher in these areas than elsewhere in Scotland, England or Wales. ▶ One developer quoted that community benefit payments amount to£7,000/MW for an onshore wind project on the Scottish Islands in comparison to 2,000/MW on the mainland.

Table 12 – Drivers of increase operational costs

4.5. Key drivers for risk differences

4.5.1. Grid access risks

As discussed in Section 3.2, there are a number of grid upgrades required to enable any significant level of generation to connect in the Scottish Islands. It should be noted that in addition to these specific local upgrades, access is only available to the wider network on the mainland subject to additional further reinforcements being undertaken or network management via the Connect and Manage regime.

The grid upgrades have only taken into account projects that have applied for and accepted connection offers. On the Western Isles and Orkney there are likely to be further projects that are not able to connect before 2020 or will only be able to connect with a commercially non-firm and managed connection.

In order to secure access projects need to apply for a connection offer and commit to liabilities and securities as discussed in Section 4.5.5. These can be extremely high at a time where project finance and consenting risks are still present and have discouraged a number of projects from applying or accepting their connection offers thus making it difficult for the NETSO to anticipate the capacity that wishes to connect.

The identified projects that are not contracted on the existing networks and planned links are as shown in Table 13 below. Second and third phases of large tidal and wave projects have not been included here since these are unlikely to be looking for grid access before 2020.

Renewable Project	Islands	Project Capacity (MW)	Type of project
Pelamis Bernera wave	Western Isles	10	Wave
Druim Leathann Wind	Western Isles	42	Onshore Wind
Stornoway Wind Farm - Lewis wind farm	Western Isles	129.6	Onshore Wind
Vattenfall Shetland Aegir wave	Shetland Islands	10	Wave
Beawfield wind farm	Shetland Islands	104	Onshore Wind
Hunda/ Littlequoy	Orkney Islands	5	Onshore Wind
Hammars Hill B	Orkney Islands	9.9	Onshore Wind
Spurness Wind Farm Repowering	Orkney Islands	10	Onshore Wind
Pelamis Farr Point wave	Orkney Islands	10	Wave
Lashy Sound (phase 1)	Orkney Islands	10	Tidal
E-on wave Orkney South (phase 1)	Orkney Islands	10	Wave
E-on wave Orkney Middle south	Orkney Islands	10	Wave
Small Project Clusters (<5MW)	Orkney Islands	15	Onshore Wind
Fara	Orkney Islands	21	Onshore Wind
Ness of Duncansby	Orkney Islands	30	Tidal
Brough Ness (phase 1)	Orkney Islands	33	Tidal
Multiple projects - Future Electric / Fairwind	Orkney Islands	175	Onshore Wind
Inner Sound	Orkney Islands	400	Tidal

Table 13 – Projects that are not contracted in the planned links

The 188 MW of spare capacity on the Shetland Link would allow the Aegir and Beawfield projects to connect, for example, subject to capacity being available in the wider mainland network.

Analysis presented by Orkney Renewable Energy Forum (OREF) based on work carried out by the International Centre for Island Technology, Heriot-Watt University, suggests that on Orkney 30% more capacity could be connected than the size of the transmission infrastructure due to the diversity of the wave, wind and tidal resource. Therefore, it may be possible to apply this concept on all the Island Groups and allow some additional non-contracted projects to connect on a commercially non-firm and managed basis.

The latter may enable some additional capacity to connect on The Western Isles including the 10 MW Pelamis Bernera Wave Project but as most of the contracted generation is onshore wind then there would not be sufficient capacity to connect the 129.6 MW Lewis Windfarm, assuming that all projects with accepted connection offers go ahead, and studies would need to be done to assess the capacity constraints for connecting the 42 MW Druim Leathann Windfarm.

If the diversification benefit can be proven, this could make approximately 54 MW of capacity available on the new AC link for wind on Orkney but would require active management of the system. This would allow most of the small distributed wind projects to connect but not the wave, tidal or large Future Electric / Fairwind wind projects. These would need to wait until the HVDC connection is available in 2020-2025.

In addition to the major infrastructure links that are planned, many of the generators would still need to invest in local distribution upgrades. For example, Scotrenewables will need to include costs for connections from its proposed tidal array to a grid interface point for the AC connector, provided capacity can be found for it to connect, or on the HVDC link when it is built later.

4.5.2. Grid charging risks

In May 2012, the Gas and Electricity Markets Authority directed NGET to raise a modification proposal to the Connection and Use of System Code (CUSC) to ensure that the transmission charging methodology:

- 'better reflects the costs imposed by different types of generators on the electricity transmission system;
- takes account of the development of HVDC circuits that will run parallel to the AC transmission network; and
- takes account of the island connections comprised of sub-sea cable technology, such as those being considered in Scotland'[37]

This followed on from Ofgem's Project Transmit Significant Code Review which assessed the costs and benefits of the status quo, improving the Investment Cost Related Pricing (ICRP) methodology or moving to a regime of fully socialised transmission charges. The latter approach would have radically changed the economics of the Scottish Island projects by significantly reducing transmission charges, but the Authority ruled this out as it was seen to have disproportionate cost to consumers, exacerbate the regional pattern of fuel poverty and stray into areas of Government policy. Instead it directed the CUSC panel to consider options based on an improved ICRP approach.

The subsequent CMP213 Workgroup Consultation[37] was published in December 2012. The Workgroup Consultation document sets out a number of issues in respect of calculating TNUoS on an improved ICRP basis. For details, please refer to the Workgroup Consultation document[38].
The total charge that a user may potentially be subject to on the islands comprises a local circuit charge, local substation charge, wider locational element and residual element. Typically the wider locational tariff and the residual tariff are together referred to as the wider tariff.

While there are a number of different considerations in the charging methodology that remain open, it is the expansion factor driving the local circuit charge that will have the most significant impact on TNUoS charges for the Scottish Islands. The two key uncertainties within the expansion factor are the scale of transmission capital costs and the charging of HVDC converter stations (at either 30%, 50% or 100%). In addition, it is yet to be decided whether all Islands will be treated specifically or the same in terms of the methodology applied.

Pending the decision on the charging methodology, and recognising the uncertainties surrounding the expansion factors, National Grid provided the project team with a range of potential local circuit tariff charges projects on the Western Isles, Shetland and Orkney could face. Table 14, Table 15 and Table 16 include the outputs of this analysis as part of an overall projection of island TNUoS charges. These estimates also include the wider, residual and local substation tariff components that make up TNUoS.

Depending on the scale of transmission capex and the charging of converter stations, TNUoS charges could range from £101-£135/kW/yr for the Western Isles, £85-£115/kW/yr for Shetland and £56-£81/kW/yr for Orkney (AC cable).

[37] CMP213 Project TransmiT TNUoS Developments, Stage 02: Workgroup Consultation, National Grid, 7 December 2012; http://www.nationalgrid.com/NR/rdonlyres/869AF29F-0CBE-4189-97D5-562CBD01AD86/44194/GuidetooffshoreTNUoStariffs.pdf

[38] The CMP213 CA Consultation will open, subject to Panel agreement on 10th April.

Potential TNUoS ranges (£/kW/yr)	30% converter - low capex	50% converter - low capex	100% converter - low capex
Western Isles (Oct-16)	£100.96	£107.73	£124.64
Shetland Islands (Nov-18)	£85.41	£87.95	£94.29
Orkney Islands AC (Apr-18)	£55.70	£55.70	£55.70
Orkney Islands HVDC (2025)	£54.13	£59.21	£71.89

Table 14 - TNUoS ranges under low transmission capex

Potential TNUoS ranges (£/kW/yr)	30% converter - central capex	50% converter - central capex	100% converter - central capex
Western Isles (Oct-16)	£101.34	£109.36	£129.39
Shetland Islands (Nov-18)	£86.11	£89.12	£96.63
Orkney Islands AC (Apr-18)	£68.55	£68.55	£68.55
Orkney Islands HVDC (2025)	£58.90	£64.91	£79.93

Table 15 - TNUoS ranges under central transmission capex

Potential TNUoS ranges (£/kW/yr)	30% converter - high capex	50% converter - high capex	100% converter - high capex
Western Isles (Oct-16)	£102.04	£111.51	£135.19
Shetland Islands (Nov-18)	£102.17	£105.72	£114.60
Orkney Islands AC (Apr-18)	£81.40	£81.40	£81.40
Orkney Islands HVDC (2025)	£63.90	£71.00	£88.76

Table 16 - TNUoS ranges under high transmission capex

Table 17 illustrates the components of the total tariff that may be faced by island generators, including the wider zonal charge (including residual) and local substation elements. The calculations also include an illustration of the contribution to the local circuit tariff that may arise from the use of on-island local circuits. These may vary by project but are generally small in the context of the total tariff. For comparison, the current range of local tariffs is from approximately -£1/kW/yr to +£6/kW/yr. For a detailed breakdown of TNUoS components for each of the above scenarios, please refer to Section A.4 in the Appendix.

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)[39]	Local substation tariff	Total
Western Isles (Oct-16)	102.51	25.42	1.29	0.17	**129.39**
Shetland Islands (Nov-18)	71.04	25.42	0.00	0.17	**96.63**
Orkney Islands AC (Apr-18)	42.96	25.42	0.00	0.17	**68.55**
Orkney Islands HVDC (2025)	54.34	25.42	0.00	0.17	**79.93**

Table 17 - TNUoS ranges under central transmission capex and 100% converter costs (£/kW/yr)

Given the earliest the Authority could make a decision on the above proposals is expected to be September 2013, generators face significant uncertainty as the exact methodology and amount they will be charged in TNUoS. Coupled with escalating costs for the transmission links, TNUoS is considered the biggest uncertainty and cause for concern for developers.

While generators generally refrained from sharing an 'acceptable' level of TNUoS, it is evident that a significant increase in these charges may render projects commercially unviable under current levels of financial support and may deter developers from pursuing projects altogether.

The impact of different outcomes in terms of the charging of converter stations and scale of transmission capex on the LCoE of onshore wind projects in the Island Groups is illustrated in Table 18, Table 19 and Table 20 below.

TNUoS impact on LCoE (£/MWh)	Low transmission capex	Central transmission capex	High transmission capex
30% converter costs	96	98	99
50% converter costs	98	99	101
100% converter costs	101	103	106

Table 18 - Orkney onshore wind - TNUoS impact on LCoE (2020 commissioning)

TNUoS impact on LCoE (£/MWh)	Low transmission capex	Central transmission capex	High transmission capex
30% converter costs	103	103	107
50% converter costs	103	104	108
100% converter costs	105	106	110

Table 19 - Shetland onshore wind - TNUoS impact on LCoE (2020 commissioning)

TNUoS impact on LCoE (£/MWh)	Low transmission capex	Central transmission capex	High transmission capex
30% converter costs	120	120	120
50% converter costs	122	123	124
100% converter costs	128	129	131

Table 20 – Western Isles onshore wind - TNUoS impact on LCoE (2020 commissioning)

[39] Based on information currently available from SHE-T, we have assumed that limited local transmission infrastructure is required to connect a typical project to the transmission cables in Orkney and Shetland. Hence, the local circuit tariff on island shows '0' for Shetland and Orkney. In some cases additional reinforcements may be required to distribution networks depending on connection points. Please refer to Appendix A.4 for detailed input assumptions used to calculate local circuit tariff (on island).

4.5.3. Grid availability risks

Prior to the new transmission links, renewable generation projects on the Scottish islands can only be offered managed connections (if at all) with the potential to be curtailed in the event of circuit outages or low demand / high generation. On Orkney there is an Active Network Management (ANM) scheme but because of an unexpected level of small embedded and non-managed generation connecting some of the generation connecting under this ANM scheme have had very high levels of curtailment. There is a similar scheme planned for Shetland and some of the projects involved have also reported high levels of expected curtailment. This has had a substantial impact on projects like Hammers Hill on Orkney which have experienced greater levels of curtailment than they might have anticipated when they made financial investment decisions. This adds a further risk to projects which are already faced with other significant risks in the development.

There is an alternative scheme in place on The Western Isles, where a 'Connect and Manage' derogation is in place at present which facilitates the connection of distributed generation on a commercially firm basis ahead of the HVDC Link.

Outages and 'Connect and Manage'

Contracted generation connecting as part of the planned transmission infrastructure upgrades will still only be offered technically non-firm connections with constraints dependent on the single circuit connections from the Islands to the closest MITS substation. In the case of Western Isles this will be Beauly, for Orkney AC it will be Beauly and Shin and for Shetland it will be Blackhillock. Any transmission assets up to the MITS entry point is considered as local works, and anything beyond the MITS entry point is wider works. The developers could choose a commercially firm connection if they were to pay a security factor of 1.8 on the local assets in the TNUoS calculation. If there are outages or congestion beyond the MITS points then the generation may still be constrained, although in that case they can bid for compensation under the Connect and Manage regime.

The location of the MITS impacts on TNUoS charges and available compensation for curtailment, and could also have an impact on levels of securities and liabilities. For example, a re-definition of the MITS substation, especially in relation to the HVDC multi-terminal asset at Spittal could move the MITS point to Sinclair's Bay. The net effect on TNUoS charges for generators on Shetland would be small since any savings in local asset charges may be offset by a higher wider charge. The generators would, however, be less exposed to outage risk at the Spittal switching station, since this would no longer be treated as enabling works under the Connect and Manage definition. Any impact on the level of securities and liabilities for Shetland generators would depend on whether the Spittal switching station and Caithness-Moray HVDC cable were de-classified as attributable works for the user commitment definition given that they would be now be part of the MITS.

Single Circuit Risks

The transmission owner, SHE-T, has determined that the most efficient and economic connections for these islands is a single circuit, technically non-firm connection to reduce the infrastructure that needs to be built and paid for. Developers are, however, able to choose if their connection will be commercially firm or non-firm. If they were to choose a commercially firm connection, they would incur higher TNUoS charges (based on a security factor of 1.0 rather than 1.8) on the local asset, but they would be compensated for all circuit outages. Instead developers have generally chosen to insure their projects (either through insurance products or self-insure) against the risk of single circuit failures which is a key contributor to higher opex costs for Scottish Island versus mainland projects. However, the lower availability/higher insurance costs are still considered to be a more economic solution than paying for a commercially firm connection or double circuit.

Grid Technology Risk

The technology for the Orkney HVAC link is proven with many project references and a number of suppliers and installation contractors to choose from.

However, the HVDC technology used for the Western isles HVDC link and the Shetland HVDC Link are relatively new with only a few project references and a limited number of suppliers at this time - although it is expected that a number of new entrants will enter the market in the near future. HVDC has many advantages for long cable connections as it requires less cable to carry the same power, has lower electrical losses and needs less reactive compensation but it does need converter stations. For the Shetland connection there is no choice other than to use HVDC technology since the distances are beyond the technical capability of a HVAC cable.

In addition to the above and the single circuit risk, there is an additional technology risk relating to the proposed Shetland design as it is a three–terminal link. This has not been installed anywhere else in the world although similar schemes are being considered, designed and planned elsewhere. This additional technology risk will impact on the economics on the generation projects and will be a factor in the final investment decisions of the developers.

4.5.4. Dependency on wider grid works in Scotland

The planned Scottish Islands links are also dependent on other onshore reinforcements before access to the grid is possible as these reinforcements are required to deliver wider infrastructure reinforcements. In order to avoid network constraints, this could therefore mean that island connections are timed to align with onshore reinforcements being available. The majority of the reinforcements are shown on the map in Section 3.2. Some of them have been delayed because of supply chain, consenting or other reasons. Those that are now planned to be completed in 2018 are noted here[40]:

- Part of Upgrade 7 - Dounreay - Spittal 275kV Reinforcement
    - Required to increase the connection capacity for generation in Orkney and Caithness
    - Completion Date: 31 October 2016
    - New Completion Date: 31 October 2018

- Upgrade 5 - East Coast 400kV Upgrade (re-insulation)
    - Required to increase the connection capacity for generation in all areas of the Highlands and Islands
    - Original Completion Date: 31 November 2016
    - New Completion Date: 20 April 2018

- Part of Upgrade 7 - Blackhillock Substation
    - Required to allow the HVDC schemes from Spittal and Shetland to connect, delivering additional network capacity to transport power from ~7GW of new contracted generation projects
    - Original Completion Date: 31 March 2016
    - New Completion Date: 31 January 2018
    - This reinforcement has been delayed by outstanding land issues and outage planning. The consents for the overhead lines have not yet been obtained.

[40] Summary of the Impact of the SHE Transmission programme changes – 20 December 2012. NGET

- Part of Upgrade 7 - Spittal Substation
    - Required to allow the generation in Caithness and Orkney to connect to the HVDC scheme
    - Original Completion Date: 23 March 2016
    - New Completion Date: 30 June 2018
    - There are issues around outstanding Bird Surveys for this substation and concerns about the supply chain for the required HVDC technology.

- Upgrade 10 – Eastern HVDC Link
    - Required to provide an increased transmission boundary capacity for renewable generation in the Highland and Islands and Offshore Wind.
    - Expected Completion Date: 2019

In addition to these onshore works, that have a direct impact on the Scottish Island Projects, there are also another eight infrastructure projects in the SHE-T area that were planned for completion in 2014 – 2016 and have been delayed by 2 -4 years with the majority now expected to be completed in 2018. Hence, some interviewees expressed concern that these dates may slip further as skilled engineering, supply chain and financing constraints impact on the projects.

4.5.5. Security and liability requirements

User commitment rules place financial liabilities on generators to reduce the risk of transmission asset stranding for transmission operators and ultimately consumers. To address the associated credit risk, generators are also required to post securities against a portion of their liabilities. Ofgem can within its duties approve a degree of additional capacity on the grounds of anticipatory investment, which may not be secured by specific generators, but may have been identified by the TO to promote future consumers' interest and environmental objectives.

In the past the liabilities for transmission project costs were shared across the contracted generators as incurred up until the generation was connected and started to pay TNUoS. This was called the Final Sums methodology. Generators had to provide securities for 100% of their liabilities, and those liabilities covered all of the TO's potential risk. If developers dropped out then the liabilities for other developers would increase accordingly.

To reduce the uncertainty and volatility in liabilities and securities, National Grid introduced two interim arrangements: first reducing the works requiring security under Final Sums to just local assets; second allowing users to opt for an interim generic user commitment methodology based on a multiple of their transmission charge. Subsequently, CMP192 (Arrangements for Enduring Generation User Commitment) replaced these two interim arrangements with a new methodology, for the first time enshrining the user commitment process in the CUSC.

Figure 12 below shows how liabilities, split between wider and attributable local works, escalate in the run up to the commissioning date.

Related securities are overlaid in red, noting that the percentage required reduces within four years of commissioning (the point when liabilities step up) and again after the project can demonstrate that key consents have been achieved.

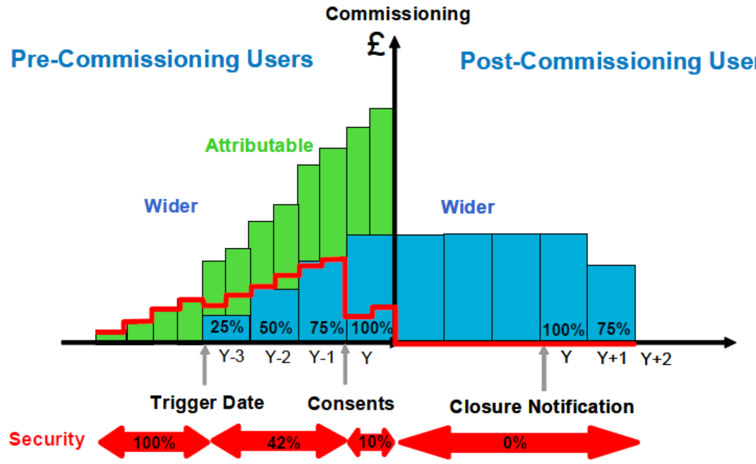

Figure 12 – Securities and Liabilities Timeline

The introduction of user commitment arrangements into the CUSC has helped Scottish generators in four ways:

- The developer can choose between actual and fixed costs so they have a clear view of the impact over the timeline of their project development.
- The securities are not the full amount of the liabilities so companies do not have to put up such significant sums in security although the full liabilities will have to be reflected in the projects balance sheet.
- The wider zonal liabilities have been split across demand and generation customers and are published so that customers can assess this element.
- The attributable liabilities can be reduced by consideration of reuse factors and strategic investment factors.

For the projects considered on the Scottish Islands these securities and liabilities can be a significant financial risk as the levels of liabilities anticipated for these island projects are extremely high and the securities are also significant. For marine project developers, their own project risks are also extremely high within the period of Y-3 to Y1.

The exact liabilities that a project would incur are difficult to define exactly when project costs and timelines are unknown. However, using data provided by SHE-T and National Grid, and the assumption that the reuse factor used is one third, and the strategic investment factor is based on the full capacity of the link being used and shared across all parties, we have made some estimates of typical securities and liabilities levels for island generators.

This has been shown for a 40 MW project connecting in four different locations (assuming that each project has chosen the Fixed approach for its attributable liability):

- On Shetland, connecting into the HVDC converter station (Figure 13)
- On Lewis, connecting into the Stornoway substation via a 132kV overhead line (Figure 14)
- On Orkney, connecting into the 132kV cable close to the landing point (Figure 15)
- At Gills Bay (on the mainland), connecting into the new substation that will be connected to Thurso South by two single circuit, 44km, 132kV wood pole trident lines (Figure 16)[41 42]

[41] Gills Bay CMS Roadshow Exhibition Board. SSE

[42] *www.**sse**.com/uploadedFiles/.../**GillsBay**ExhibitionJune2011.pdf*

It should be noted that the treatment of the second land cable for the Western Isles project would have an impact on the security and liabilities as well as the TNUoS payments. Here, the full cost of the project has been included but if the second cable was not included in the calculations for the contracted projects, it could reduce liabilities by up to 12% and securities by up to 9%.

The time at which the generator achieves key consents and hence when the security goes to 10% can vary. For these comparisons it is assumed that it is in year Y.

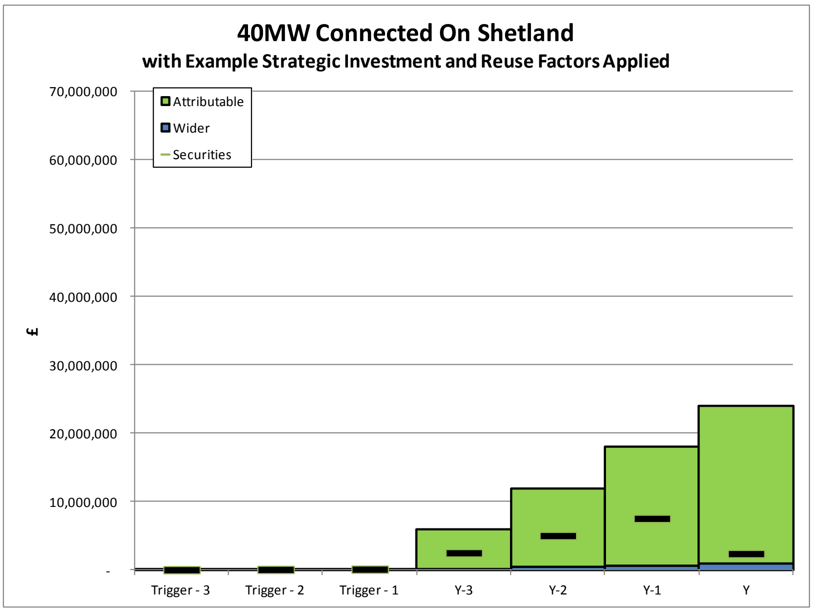

Figure 13 - Example of Security and Liability Requirements for 40MW on Shetland

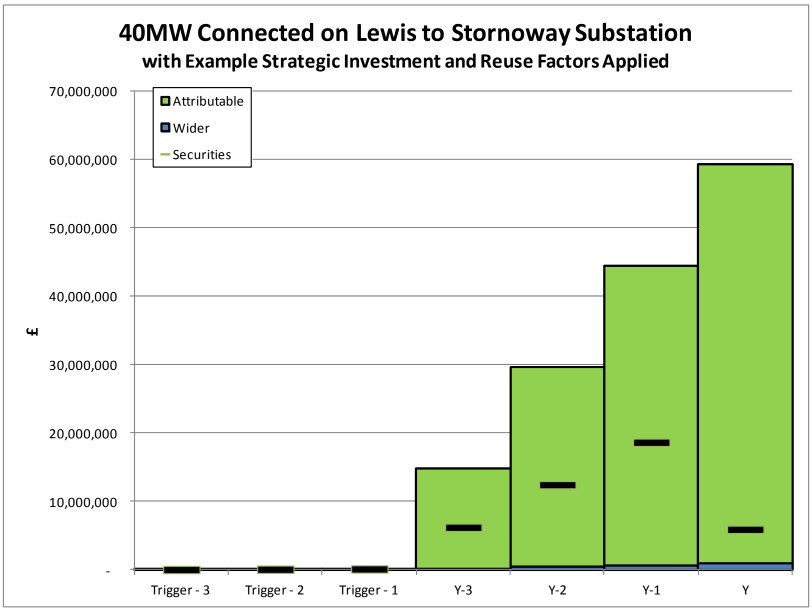

Figure 14 - Example of Security and Liability Requirements for 40MW on Lewis

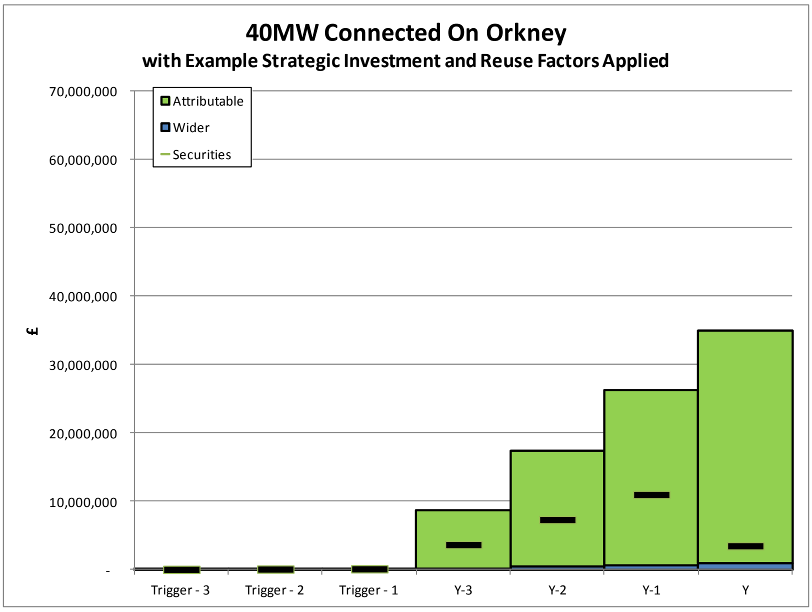

Figure 15 - Example of Security and Liability Requirements for 40MW on Orkney

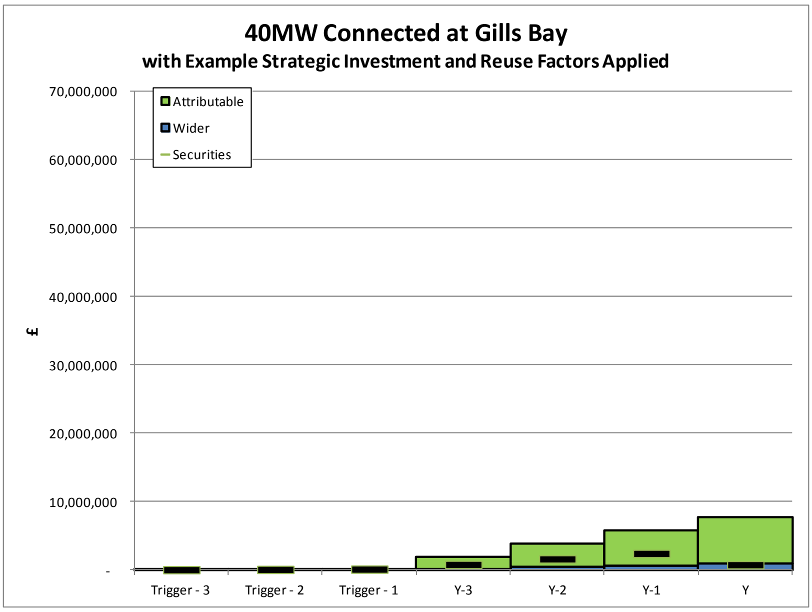

Figure 16 - Example of Security and Liability Requirements for 40MW at Gills Bay, Caithness

It can be seen that for the example project connecting on Lewis into the Stornoway substation, securities of up to £18m are required in year Y-1 when the project may not yet have consent in place and is yet to receive financial close.

The maximum liabilities and securities for the compared projects are shown in Table 21.

Location of Project	Maximum Liabilities	Maximum Securities
Shetland	£24 million	£7.5 million
Lewis (Stornoway)	£60 million	£19 million
Orkney	£35 million	£11 million
Gills Bay	£8 million	£2.5 million

Table 21 - Comparison of Grid Costs for 40MW Example Project

It can be seen that from these figures, the location of the project significantly impacts the connection costs and therefore the security and liabilities that the projects have to commit to in advance. Securities and liabilities for the example project on the Scottish Islands are significantly greater than an equivalent example at Gills Bay on the mainland.

4.5.6. Loss of diversity benefits under the CfD policy framework

One key advantage of marine renewables, and to a degree wind located in geographically remote locations, is that its output is less correlated with wind generation on the mainland. This helps to diversify the intermittency effect and should allow a greater proportion of renewables to be accommodated within the electricity system all other things being equal.

The benefit accrues both in terms of better utilisation of grid infrastructure, as evidenced by the work undertaken by Heriot Watt University, and in terms of balancing supply and demand nationally. The island renewables generator should be able to benefit through reduced network charges and better 'price capture'. By the latter, we mean the average price that the island generator will receive for its output, which should steadily improve relative to wind plant on the mainland since its periods of highest output will not correspond to the same extent with periods of lowest price.

For example, in Redpoint's report for the British Wind Energy Association (now RenewableUK)[43], it was estimated that marine projects may be able to capture as high as £14/MWh more (more than 30% more in relative terms) for their output relative to a wind generator in a power system that is heavily dominated by wind[44]. With respect to wind generators in remote locations, analysis presented below suggests that a wind plant located in Shetland should be able to capture a power price of up to 3% higher by 2020 and up to 4% higher by 2030 relative to the average Scottish Mainland wind plant.

Under the Renewables Obligation, which is a premium support mechanism, generators are exposed to wholesale electricity prices and hence the diversity benefit should accrue to the generator (or its offtaker) through the improved price capture. However, under the proposals for intermittent CfDs with EMR the benefit would be 'sterilised' since the contracts are settled with reference to a day-ahead price, making plant largely indifferent to the market price when they are generating (notwithstanding residual balancing risk).

Figure 17 shows the location of installed wind generators in the UK as taken from the UK Wind Energy Database (UKWED)[45]. The anticipated increase in wind penetration in the UK will have a significant impact

[43] http://www.redpointenergy.co.uk/images/uploads/BWEA_Redpoint_Report.pdf

[44] Wind generation was assumed to equal 30% of total demand for that scenario (120TWh out of a total of 400TWh).

[45] UK Wind Energy Database. Accessible from: http://www.renewableuk.com/en/renewable-energy/wind-energy/uk-wind-energy-database/index.cfm

on the level and shape of power prices as considerable amounts of inflexible, low short-run marginal cost generation enters the system. As a result, the correlation between the power output from wind generators located across different sites in the UK along with the correlation between wind generation and system demand will become increasingly important from a market as well as system dispatch point of view. For the purposes of this study we analysed the wind speed correlation co-efficient[46] based on 1970-2012 wind speed data from the following areas in GB:

- Orkney Islands
- Shetland Islands
- Western Isles
- North Scotland – Onshore (near Inverness)
- South Scotland – Onshore (near Glasgow)
- North West England and North West Wales – Onshore (near Chester)
- Midlands and North East England – Onshore (near York)
- South West England and South West Wales – Onshore (near Bristol)
- East England – Offshore
- Irish Sea – Offshore
- Scotland– Offshore (between the Moray Firth and Firth of Forth R3 sites)

The calculated correlation co-efficients can be found in Section A.5 in the Appendix.

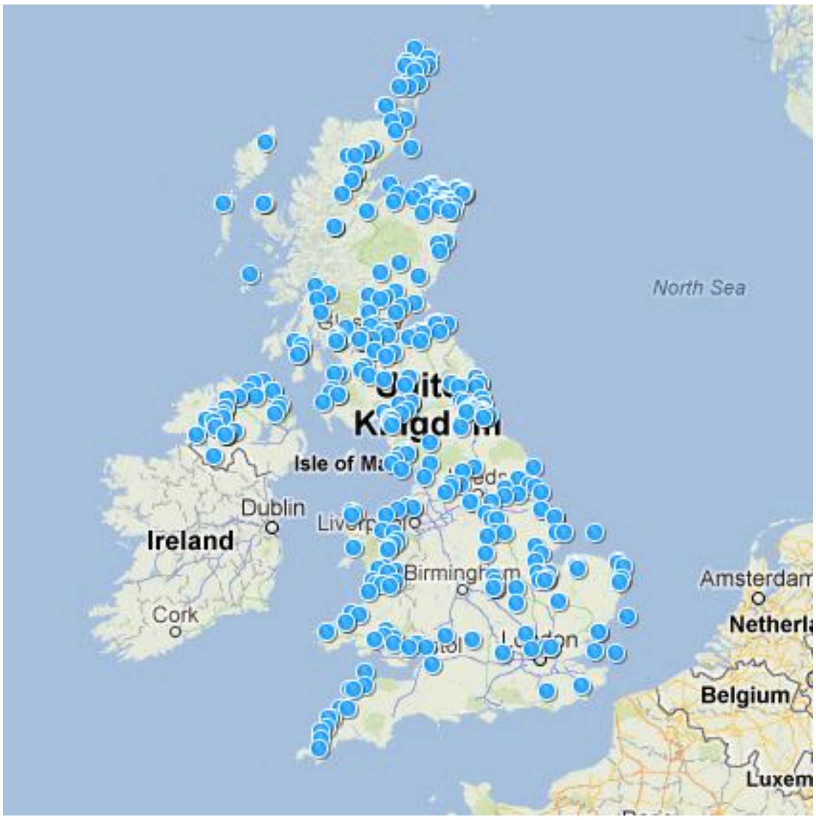

Figure 17 - Location of operating wind plant in the UK (taken from the UK Wind Energy Database)

[46] The correlation coefficient is used to determine the relationship between two properties (say x and y). The equation for the correlation coefficient we used is given by: $Correl(X,Y) = \frac{\sum(x-\bar{x})(y-\bar{y})}{\sqrt{\sum(x-\bar{x})^2\sum(y-\bar{y})^2}}$ where $\bar{x}$ and $\bar{y}$ are the sample means AVERAGE(x) and AVERAGE(y).

We then used a power market simulation tool (PLEXOS) to derive the 2020, 2025 and 2030 market prices that different onshore and offshore wind plant would be able to achieve in the wholesale market assuming 2012 GB wind speed data and demand shape[47] and excluding any transmission constraints. We used the latest fossil fuel[48] and carbon prices[49] from DECC (October 2012) and we assumed that the following wind capacity was operational under the three modelled years[50].

Installed Wind Capacity (MW)	2020	2025	2030
Orkney	40	256	256
Shetland	600	1,200	1,600
Western Isles	400	550	550
North Scotland – Onshore	3,000	3,600	3,600
South Scotland – Onshore	5,000	5,500	5,500
North West England and North West Wales - Onshore	2,300	2,450	2,900
Midlands and North East England - Onshore	1,500	2,000	2,500
South West England and South West Wales - Onshore	500	700	900
East England – Offshore	5,100	6,000	8,500
Irish Sea – Offshore	3,150	5,500	5,500
Scotland– Offshore	2,000	3,500	5,000

Table 22 – Installed wind capacity (MW) assumed for the diversity analysis

The prices captured by the various modelled onshore wind plant are shown in the Table 23 below. It can be seen that onshore wind plant in the Shetland Islands offer the greatest diversity benefits, followed by onshore wind plant in the Western Isles and then Orkney Islands. For 2020, for example, with 13.3 GW of onshore wind plant and 10.3 GW of offshore wind plant on the system, the market price achieved by an onshore wind plant in the Shetland Islands could be almost £2/MWh higher (roughly 3% of baseload price) compared to a typical Scottish onshore or offshore wind plant. By 2030 this could be as high as £3/MWh (more than 4% of baseload price) further illustrating the diversity benefits that onshore wind plant in the Scottish Islands offer.

Market Price Achieved – Wind (£/MWh)	2020	2025	2030
Shetland	63.3	65.9	65.6
Western Isles	63.0	65.5	64.8
Orkney	62.4	65.1	64.3
South England and South Wales - Onshore	61.7	64.3	64.1
North England and North Wales - Onshore	61.2	63.8	63.1
North Scotland – Onshore	61.7	64.3	63.0
Midlands and North East England - Onshore	61.0	63.7	63.0
South Scotland – Onshore	61.4	64.1	62.9
East England – Offshore	61.2	63.7	62.8
Irish Sea – Offshore	61.5	63.7	62.8
Scotland– Offshore	61.3	64.0	62.5

[47] The shape of demand is based on 2012 historic data however overall demand is uplifted to take into account the latest DECC demand projections.

[48] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65698/6658-decc-fossil-fuel-price-projections.pdf

[49] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/41797/6664-carbon-values-used-in-deccs-emission-projections-.pdf

[50] Note the capacities shown here are for the purposes of this example and are not predictions of the likely capacity of renewable generation on the Scottish Islands.

Baseload price	64.0	66.7	67.2

Table 23 – Market Price Achieved – Wind (£/MWh)

4.5.7. Currency and commodity price risks

Given the uncertainty surrounding the exact timing of the transmission infrastructure investments in particular, developers are not in a position to place orders for turbines, materials or associated works or to hedge their exposure to any change in the underlying commodity or currency fluctuations. As a result, developers have less certainty surrounding their project costs relative to equivalent projects on the mainland.

4.5.8. Technology risk – wave/tidal

Wave and tidal technology is still at an early stage of development and has yet to prove its commercial viability. There is a vast array of technologies being tested with both expected yields and costs being still highly uncertain as evidenced by the wide range of LCoE estimates in Section 4.1.

To foster advances in wave and tidal technologies, the European Marine Energy Centre (EMEC) was founded in 2003. Based in Orkney, it provides developers with purpose-built, accredited open-sea testing facilities. 'With 14 full-scale test berths, there have been more grid-connected marine energy converters deployed at EMEC than any other single site in the world, with developers attracted from around the globe.'[51] EMEC also operates 'two scale test sites where smaller scale devices, or those at an earlier stage in their development, can gain real sea experience in less challenging conditions than those experienced at the full-scale wave and tidal test sites'.

While EMEC's facilities and services continue to facilitate marine energy in the UK, it is acknowledged that technical and commercial feasibility at commercial scale is still a number of years away.

[51] EMEC (2013). About us. Available at: http://www.emec.org.uk/about-us/#loaded

4.6. Impact of cost and risk differences

The wide range of LCoE outcomes for the Scottish Islands is reflective of the uncertainty and levels of risk associated with these projects. If developers do not feel confident that their projects will be commercially viable given the higher inherent risks, this may lead to delays or ultimately to potential cancellations of renewable projects on the Islands. In summary, the key risks are:

- ***Construction delays:*** Due to the harsh weather conditions coupled with complex environmental terrain, construction windows tend to be limited thus extending the overall construction period and increasing construction costs.
- ***Operational availability:*** While higher yields are a key advantage for onshore wind projects on the Scottish Islands, harsher weather conditions and the remote location may also result in longer unavailability periods and higher maintenance costs.
- ***Grid access timing:*** The recent announcement by SHE-T to defer the needs case submission to Ofgem for the Western Isles has compounded concerns that the transmission links, not just for the Western Isles, will be delayed further thus exposing developers to further risks.
- ***Grid operational availability:*** SHE-T has designed a system which uses single circuit technically non-firm connections to reduce the infrastructure that needs to be built and paid for. Generators have chosen commercially non-firm connections to reduce the amount of TNUoS they are liable for. As such, generators are exposed to the risk of single circuit failures – although these are insurable to a degree.
- ***TNUoS uncertainty:*** One of the biggest challenges for developers is the uncertainty and scale of transmission charges due to uncertainty in transmission capex and in the near term the outcome of the Project TransmiT/CMP213 process.
- ***Support mechanisms:*** As a result of the above, projects are running the risk of being delayed which may inhibit developers' ability to qualify for the RO regime, whereas details of the replacement CfD mechanisms, crucially the strike price, are currently not known.
- ***Technology risk:*** In the case of marine, technology risk remains the key challenge which will require substantially more equity funding until it can be economically deployed at commercial scale, thus pushing up the costs of capital.

5. SOCIO-ECONOMIC BENEFITS

5.1.1. Local benefits

Methodology

There is a wide range of potential socio-economic benefits from the deployment of renewable generation on the Scottish Islands, including direct jobs associated with the construction and operation of the plant themselves, additional jobs in the supply chain and the payment of community benefits that can be invested on the islands.

For ease of comparison we have attempted to capture these socio-economic benefits in terms of potential Full Time Equivalent (FTE) employment on the islands and in Scotland and the UK more widely. In addition local communities may benefit financially from stakes in the projects, although since this is project-specific we have not attempted to quantify this benefit. Although we are focusing on the quantifiable benefits in terms of increased economic activity on the islands, we should not ignore the wider social benefits that are associated with reduced emigration and maintaining vibrant local communities, especially on the Western Isles where alternative employment opportunities are more limited.

The potential Full Time Equivalent (FTE) direct, indirect and induced jobs have been calculated for the planned renewable energy projects on the Western Isles, Orkney and Shetland. An outline of the methodology is given as follows:

- For each project, the Environmental Statement (ES) containing the Environmental Impact Assessment (EIA) or other similar planning documentation has been reviewed. If published data is not available, developers have been contacted directly for information.
- Where there is a socio-economic analysis, this has been reviewed and analysed in detail in order to compile:
    - Projections of direct, indirect and induced jobs associated with each project;
    - Details of the socio-economic effects of the community benefits package;
    - Other socio-economic factors such as crofting compensation payments and lease rental payments.
- With regard to the assessment of job creations, these have been analysed as FTE jobs. The additional socio-economic benefits such as community benefit fund payments have also been analysed and converted to FTE jobs, and these have been added to the total FTE jobs.
- Due to the nature of the projects, some jobs will be available for the construction period only whereas others will be for the full life time of the project. Therefore, the FTEs have been calibrated by calculating these as permanent full-time equivalents based on HM Treasury convention. One permanent FTE job is the equivalent of ten person years of employment. For example, if 140 people are estimated to be required for a construction time period of 2.5 years, the number of permanent FTEs is calculated to be 140/10×2.5 = 35. This approach has been applied to all FTE figures quoted in this section.
- Please note that FTE figures refer to potential jobs associated with the relevant projects whereby these jobs may be newly created or displaced from other geographies or industries.
- Some of the socio-economic analyses have been carried out for projects where the size of the project has subsequently been reduced. In this instance, the numbers of FTEs have been reduced by the proportion of the reduction of the project scale.
- For the smaller capacity projects, there is often no detailed assessment of job creation and other socio-economic benefits. Therefore, an FTE/MW figure has been derived for the summation of known projects, and applied to these smaller projects to give a total upper sensitivity for FTEs produced.

- Indirect and Induced Multipliers: These have been calculated for onshore wind from multipliers provided for the Stornoway Wind Farm project. A detailed assessment was available for this project, and multipliers were given for activities such as construction and grid. The following multipliers were therefore calculated:
  - 1.2 for indirect and induced employment generation from manufacture and construction in Western Isles (and assumed same for Orkney/Shetland);
  - 2.0 for indirect and induced employment generation from manufacture and construction in Scotland;
  - 1.44 for indirect and induced employment generation from operation in Western Isles (and assumed same for Orkney/Shetland);
  - 4.15 for indirect and induced employment generation from operation in Scotland.
- Lower, middle and upper scenarios have been calculated for the marine projects as both Aquamarine and Pelamis gave ranges for their estimates.

It should also be noted that indirect employment is generated in businesses that supply goods and services to sectors that have seen direct job increases. Induced jobs are those associated with the income (wages) being spent and re-spent through the broader economy, e.g. on food and entertainment. Forms of job creation other than through construction and operation/maintenance have been considered for wind farm projects, relating primarily to additional payments into communities. This has included Community Fund payments, lease rental payments and crofting compensation payments.

For Community Funds, distinction is made between capital spend (i.e. money which is spent on community/regeneration projects) and revenue spend (i.e. money which is spent on the wages of staff who manage the fund). Only larger projects tend to have a project specific fund, with the majority of projects simply paying into the Council operated fund. As such, the contribution of the majority of projects tends to be entirely spent on capital projects.

We assume that £35,000 of revenue spend supports one full time job each year and also that the job would last for twenty five years (the duration of the operation of the wind farm). We assume that £80,000 of capital spend results in one job for a year[52]. Details relating to £/MW contribution have been sought, and where these are not available, assumptions have been made based on similar projects' contributions.

With all of the above in mind, the £/MW and the capacity of the project have been used to calculate the approximate annual payments, and these have then been used to calculate direct jobs associated with the revenue spend and capital spend. Appropriate multipliers have then been applied to calculate annual indirect and induced job creation.

A similar approach has been taken when calculating the jobs associated with lease payments to land owners (where appropriate) and crofting compensation payments (where appropriate). We assume, for example, that 46% of crofting compensation payments are retained, and that £66,667 of spend supports one agricultural job for a year[52].

A "top down" approach has also been applied to sense check the results of the FTE analysis. For this, figures obtained from RenewableUK for FTEs/MW for wind and marine have been applied[66]. However, the methodology used to calculate these figures is different from that adopted above. For example, because the build out rate is reasonably constant across the UK, the ten person year convention is not adopted. Also, direct and indirect employment is included, but not induced. Finally, the marine predictions for Orkney, Shetland and the Western Isles are based on Pelamis' and Aquamarine's assessments for 10 MW

[52] Impact of Community Benefit Payments (2005). *Western Isles Development Trust.*

and 40 MW installations respectively and therefore these may not take into account economies of scale as deployment rates for marine increase. However, the RenewableUK analysis is based on marine projections of 1.3 – 2 GW. Results based on the top down approach are provided in Appendix A.6.

Western Isles

The Western Isles has a number of strengths regarding current and future economic regeneration including public services, tourism, community land ownership, Harris Tweed and of course abundant renewable energy resource. However, the area also faces significant challenges such as a declining and ageing population, a high proportion of the workforce employed in the public sector, contraction of traditional industries such as fishing and fuel poverty[53]. Within the last one hundred years, the population of the Western Isles has declined by approximately 43% to 26,100 in 2011[54]. The population is predicted to decline by a further 11% between 2010 and 2035[53]. The demographics of the population are also changing, with pensioners currently making up 25% of the population, projected to rise to 35% by 2035[53]. The Western Isles has a significantly lower gross weekly pay of £438.30 compared with the average for Scotland (£498.30) and Great Britain (£508.00)[55].

The Western Isles also has the highest fuel poverty level in the UK, with 58% of households in fuel poverty compared with the national average of 28%. A household is said to be in fuel poverty if more than 10% of its disposable income is spent on household fuel use.

The number of residents in employment in the Western Isles by industry is given in Table 24. It can be seen that the percentage of residents employed in the public sector is higher than in Scotland as a whole. The percentage of residents employed in some traditional industries such as fishing is also higher in the Western Isles.

Industry	No. of Residents in Employment	Outer Hebrides % of Total	Scotland % of Total
Manufacturing	600	6.1	8.7
Construction	800	7.2	5.9
Services	8,500	81.0	81.9
Distribution, hotels & restaurants	*2,100*	*19.9*	*22.2*
Transport and Communications	*600*	*5.9*	*5.1*
Finance, IT, other business activities	*1,000*	*9.6*	*19.1*
Public admin, education and health	*4,500*	*42.6*	*30.0*
Other services	*300*	*3.0*	*5.4*
Tourism-related	900	8.5	8.9
Total	**10,800**	**100**	**100**

Table 24 - Distribution of Western Isles employee jobs, 2008[55]

Due to the declining population, reduction in the working population and decrease in public spending it was predicted in 2008 that 1,200 new FTE jobs will be required in the Western Isles by 2020 to maintain

[53] Outer Hebrides Community Planning Partnership (2012). *Economic regeneration strategy to 2020*. Available at: *http://outerhebridescommercegroup.wordpress.com/2012/10/30/economic-regeneration-strategy-to-2020/*

[54] European Commission (2012). *Economic regeneration strategy to 2020*. Available at: *http://outerhebridescommercegroup.wordpress.com/2012/10/30/economic-regeneration-strategy-to-2020/*

[55] Nomis official labour market statistics (2008). *Labour Market Profile Eilean Siar.* Available at https://www.nomisweb.co.uk/reports/lmp/la/2038432126/report.aspx

current employment levels[56]. This was identified as a minimum strategic objective and it was recommended that a more ambitious target of 2,000 jobs should be used.

Table 25 summarises the assumed additional renewables capacity in the Western Isles from our Central Scenario. Our analysis suggests that almost 400 FTEs could be created on the Western Isles by 2020, over 2000 FTEs by 2025 and over 3500 FTEs by 2030 (please refer to Appendix A.6 for more details as to how these figures were calculated)[57]. However, these numbers are partly driven by high FTE/MW for wind and tidal projects, and as scale is achieved for these projects the numbers of FTEs per MW is likely to fall.

Generation Projection	2020	2025	2030
Wind (MW)	400	550	550
Wave (MW)	50	500	1,000
Tidal (MW)	0	200	300
Total (MW)	**450**	**1,250**	**1,850**

Table 25 – Central generation scenario for the Western Isles

[56] European Commission (2012). *Economic regeneration strategy to 2020*. Available at: *http://outerhebridescommercegroup.wordpress.com/2012/10/30/economic-regeneration-strategy-to-2020/*

[57] Note we have not attempted to estimate the FTEs for the construction of new transmission infrastructure although this would significantly promote economic activity in Northern Scotland.

		Western Isles				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	Scale (MW)	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	
Wind	400	110.2	24.5	102.7	33.2	102.8	190.3	0.0	91.8	23.8	18.3	1.7
Wave	50	72.5	14.5	25.7	8.5	90.1	144.5	2.8	81.3	3.6	7.3	9.0
Tidal	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	450	***183***	***39***	***128***	***42***	***193***	***335***	***3***	***173***	***27***	***26***	2.6
Total		***392***				***704***				***53***		

Table 26 – Number of FTEs for Western Isles Generation (Central Scenario, 2020)

		Western Isles				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	Scale (MW)	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	
Wind	550	151.5	33.7	141.1	45.6	141.3	261.7	0.0	126.2	32.8	25.1	1.7
Wave	1000	725.0	145.0	257.0	85.1	901.3	1445.0	28.0	812.7	36.3	72.5	9.0
Tidal	250	290.0	58.0	102.8	34.0	360.5	578.0	11.2	325.1	14.5	29.0	9.0
Sub-Total	1800	***1166***	***237***	***501***	***165***	***1403***	***2285***	***39***	***1264***	***84***	***127***	6.8
Total		***2069***				***4991***				***210***		

Table 27 – Number of FTEs for Western Isles Generation (Central Scenario, 2025)

		Western Isles				Rest of Scotland				Rest of UK		
		Construction		**O & M**		**Construction**		**O & M**		**Construction**		**Total/ MW**
Sector	**Scale (MW)**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	
Wind	500	151.5	33.7	141.1	45.6	141.3	261.7	0.0	126.2	32.8	25.1	1.7
Wave	2200	1450.0	290.0	514.0	170.2	1802.5	2890.0	56.0	1625.3	72.5	145.0	9.0
Tidal	500	435.0	87.0	154.2	51.0	540.8	867.0	16.8	487.6	21.8	43.5	9.0
Sub-Total	3200	***2036***	***411***	***809***	***267***	***2485***	***4019***	***73***	***2239***	***127***	***214***	7.9
Total		***3523***				***8815***				***341***		

Table 28 – Number of FTEs for Western Isles Generation (Central Scenario, 2030)

Using the top down approach, the equivalent figures for FTEs in the Western Isles are 760 in 2020, rising to nearly 10,000 in 2030, so somewhat higher than using the bottom up approach and illustrating the uncertainty associated with these calculations. Further details are provided in Appendix A.6.

It is very clear from both approaches that marine projects have the potential to develop significantly more socio-economic benefit than onshore wind projects. This is due to the potential for more of the job functions (such as construction and manufacture) to be located in the area. However, it should be noted that FTEs have been estimated for 10 MW projects, and as the costs of marine generation decline fewer FTEs per MW may be created.

The potential for the marine renewable industry to generate socio-economic benefits for the UK is investigated further in Section 6.1.1.

Shetland

Shetland has a population that is increasing slightly (an increase of just over 1% between 2001 and 2009) and its unemployment rate is below the rate for the Highlands and Islands[58] as a whole. Shetland's economic activity is high compared with Highlands and Islands and Scotland, largely due to the Sullom Voe Oil Terminal and oil and gas revenues. It can be seen from Table 29 that Shetland has a lower percentage of the population in the public sector than the average for Scotland. In addition, Shetland has a higher gross weekly pay of £546.10 compared with the average for Scotland (£498.30) and Great Britain (£508.00)[59].

Industry	No. of Residents in Employment	Shetland % of Total	Scotland % of Total
Manufacturing	900	7.8	8.7
Construction	900	8.1	5.9
Services	8,800	75.9	81.9
Distribution, hotels & restaurants	*2,200*	*18.8*	*22.2*
Transport & communications	*1,400*	*12.3*	*5.1*
Finance, IT, other business activities	*900*	*8.0*	*19.1*
Public admin, education & health	*2,900*	*25.3*	*30.0*
Other services	*1,300*	*11.5*	*5.4*
Tourism-related	1,300	10.9	8.9
Total	**11,700**	**100**	**100**

Table 29 – Distribution of Shetland employee jobs, 2008[59]

Shetland has a renewable energy strategy in order to:

- Maximise the potential of Shetland's significant renewable energy resources;
- Diversify the economy from one primarily supported from the oil and gas and fishing industries;
- Reduce the community's high dependence on fossil fuels[60].

Due to Shetland's remote location there are limited opportunities for diversification of the economy and therefore utilisation of its natural resources for renewable energy generation is very important in this regard. Both the fishing industry and oil and gas industries are cyclical and dependent on macro-economic factors. Therefore, diversification of the economy is important. It can also help the community to offset rising oil and gas prices and hence reduce community fuel costs. Fuel poverty is also an issue for Shetland, with approximately 35% of households in Shetland living in fuel poverty compared with a national average of 28%.

Shetland's proposed interconnector is driven by the Viking wind farm project which is currently proposed to have a capacity of 412 MW. However, the currently proposed transmission link would provide capacity for 600 MW of generation, with the additional generation yet to be determined. The Crown Estate has

[58] Highlands and Islands Enterprise (2011). *Area Profile for Shetland.* Available at: www.hie.co.uk.

[59] Nomis official labour market statistics (2008). *Labour Market Profile Shetland Islands.* Available at https://www.nomisweb.co.uk/reports/lmp/la/2038432147/printable.aspx

[60] Shetland Islands Council (2009). *Renewable Energy Development in Shetland: Strategy and Action Plan*. Available at: *www.shetland.gov.uk*.

currently not leased any large areas for wave or tidal projects, but it is assumed that this could change if grid connection was available.

An approach similar to that adopted for the Western Isles has been used for assessing economic benefits in Orkney and Shetland. However, detailed information was available for fewer projects than for the Western Isles. Detailed analysis was available for Viking and information has been obtained directly from Pelamis and Aquamarine for their marine projects. These figures have been applied to our Central Scenario for deployment for 2020, 2025 and 2030 given in Table 30. The outcomes are shown in Table 31, Table 32 and Table 33.

Our analysis suggests that around 460 FTEs could be created on Shetland by 2020, around 1500 FTEs by 2025 and nearly 3000 FTEs by 2030 (please refer to Appendix A.6 for more details as to how these figures were calculated).

Generation Projection	2020	2025	2030
Wind (MW)	600	1200	1600
Wave (MW)	0	100	400
Tidal (MW)	0	100	200
Total (MW)	**600**	**1,400**	**2,200**

Table 30 – Central generation scenario for Shetland

		Shetland				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	Scale (MW)	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	
Wind	500	145.1	92.3	147.0	78.4	282.5	139.4	207.4	114.1	204.4	93.1	2.5
Wave	2200	0	0	0	0	0	0	0	0	0	0	0
Tidal	500	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	3200	***145***	***92***	***147***	***78***	***283***	***139***	***207***	***114***	***204***	***93***	2.5
Total		***463***				***744***				***298***		

Table 31 - Number of FTEs for Shetland Generation (Central Scenario, 2020)

		Shetland				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	Scale (MW)	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	
Wind	500	290.2	184.6	294.1	156.8	565.1	278.9	414.9	228.2	408.8	186.2	2.5
Wave	2200	145.0	29.0	76.0	25.1	180.6	278.5	8.4	240.7	18.1	36.3	10.4
Tidal	500	145.0	29.0	76.0	25.1	180.6	278.5	8.4	240.7	18.1	36.3	10.4
Sub-Total	3200	***580***	***243***	***446***	***207***	***926***	***836***	***432***	***710***	***445***	***259***	4.5
Total		***1476***				***2903***				***704***		

Table 32 - Number of FTEs for Shetland Generation (Central Scenario, 2025)

		Shetland				Rest of Scotland				Rest of UK		
		Construction		**O & M**		**Construction**		**O & M**		**Construction**		**Total/ MW**
Sector	**Scale (MW)**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	
Wind	500	386.9	246.1	392.1	209.0	753.4	371.8	553.2	304.2	545.1	248.2	2.5
Wave	2200	580.0	116.0	304.0	100.3	722.5	1114.0	33.5	962.9	72.5	145.0	10.4
Tidal	500	290.0	58.0	152.0	50.1	361.3	557.0	16.8	481.4	36.3	72.5	10.4
Sub-Total	3200	***1257***	***420***	***848***	***359***	***1837***	***2043***	***603***	***1749***	***654***	***466***	4.3
Total		***2885***				***6232***				***1120***		

Table 33 - Number of FTEs for Shetland Generation (Central Scenario, 2030)

Using the top down approach, the equivalent figures for FTEs in Shetland are 600 in 2020, rising to nearly 6000 in 2030, so again somewhat higher than using the bottom up approach. Further details are provided in Appendix A.6.

Orkney

Orkney's population rose 3.9% between 2001 and 2009 and unemployment is below the rate for the Highlands and Islands as a whole. Orkney has a tendency towards an ageing population with a similar structure to the Highlands and Islands average[61]. A higher proportion of workers are employed in the public sector than in other sectors. Orkney has a slightly lower gross weekly pay of £480.90 compared with the average for Scotland (£498.30) and Great Britain (£508.00)[62]

Industry	No. of Residents in Employment	Orkney % of Total	Scotland % of Total
Manufacturing	500	5.5	8.7
Construction	900	9.2	5.9
Services	7,200	76.8	81.9
Distribution, hotels & restaurants	*2,100*	*22.8*	*22.2*
Transport & communications	*900*	*9.8*	*5.1*
Finance, IT, other business activities	*600*	*6.0*	*19.1*
Public admin, education & health	*3,200*	*34.4*	*30.0*
Other services	*400*	*3.8*	*5.4*
Tourism-related	1000	11.1	8.9
Total	**9,300**	**100**	**100**

Table 34 – Distribution of Orkney employee jobs, 2008

Like Shetland, Orkney has a sustainable energy strategy. The key objectives of Orkney's renewable energy strategy are as follows[63]:

- To ensure Orkney has a secure and affordable energy supply to meet its future needs;
- To develop its extensive renewable energy resources to benefit the local economy and local communities;
- To reduce its carbon footprint.

In Orkney, fuel poverty is a particular concern, being the second highest in Scotland. This is partly due to Orkney's cold, wet and windy climate. In Orkney, the fuel poverty rate is over 50% compared with the Shetland fuel poverty rate of 35% - both of which are above the national average for Scotland. The Scottish Government has a number of objectives in order to eradicate fuel poverty and one key objective is the utilisation of renewable energy on Orkney.

These figures have been applied to our Central generation scenarios for 2020, 2025 and 2030 given in Table 35.

In Orkney, the number of potential FTEs has been assessed by using the figures obtained from Aquamarine and Pelamis. The figures obtained for Viking have been applied to onshore wind on Orkney as there is no

[61] Highlands and Islands Enterprise (2011). Area Profile for Orkney. Available at: *www.hie.co.uk.*

[62] Nomis official labour market statistics (2008). *Labour Market Profile Orkney Islands.* Available at https://www.nomisweb.co.uk/reports/lmp/la/2038432143/report.aspx

[63] Orkney Islands Council (2009). A sustainable energy strategy for Orkney. Available at: *www.orkney.gov.uk*

additional information. The outcomes for 2020, 2025 and 2030 are given in Table 36, Table 37 and Table 38.

Based on the Central Scenario deployment shown in Table 35, our analysis suggests that around 420 FTEs could be created on Orkney by 2020, around 2,000 FTEs by 2025 and around 4,600 FTEs by 2030 (please refer to Appendix A.6 for more details as to how these figures were calculated).

Generation Projection	2020	2025	2030
Wind (MW)	40	256	256
Wave (MW)	47	349	600
Tidal (MW)	93	310	1000
Total (MW)	180	915	1,856

Table 35 - Central generation scenario Orkney

		Orkney				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	**Scale (MW)**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	
Wind	500	9.7	6.2	9.8	5.2	18.8	9.3	13.8	7.6	13.6	6.2	2.5
Wave	2200	68.2	13.6	35.7	11.8	84.9	130.9	3.9	113.1	8.5	17.0	10.4
Tidal	500	134.9	27.0	70.7	23.3	168.0	259.0	7.8	223.9	16.9	33.7	10.4
Sub-Total	3200	***213***	***47***	***116***	***40***	***272***	***399***	***26***	***345***	***39***	***57***	8.6
Total		***416***				***1041***				***96***		

Table 36 - Number of FTEs for Orkney Generation (2020 Scenario)

		Orkney				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	**Scale (MW)**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	**Direct**	**Indirect**	
Wind	500	61.9	39.4	62.7	33.4	120.5	59.5	88.5	48.7	87.2	39.7	2.5
Wave	2200	506.1	101.2	265.2	87.5	630.4	972.0	29.2	840.1	63.3	126.5	10.4
Tidal	500	449.5	89.9	235.6	77.7	559.9	863.4	26.0	746.2	56.2	112.4	10.4
Sub-Total	3200	***1017***	***230***	***564***	***199***	***1311***	***1895***	***144***	***1635***	***207***	***279***	***8.9***
Total		***2010***				***4984***				***485***		

Table 37 - Number of FTEs for Orkney Generation (2025 Scenario)

		Orkney				Rest of Scotland				Rest of UK		
		Construction		O & M		Construction		O & M		Construction		Total/ MW
Sector	Scale (MW)	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	
Wind	500	61.9	39.4	62.7	33.4	120.5	59.5	88.5	48.7	87.2	39.7	2.5
Wave	2200	870.0	174.0	456.0	150.4	1083.8	1671.0	50.3	1444.3	108.8	217.5	10.4
Tidal	500	1450.0	290.0	760.0	250.7	1806.3	2785.0	83.8	2407.2	181.3	362.5	10.4
Sub-Total	3200	***2382***	***503***	***1279***	***434***	***3011***	***4515***	***223***	***3900***	***377***	***620***	***9.6***
Total		***4599***				***11649***				***997***		

Table 38 - Number of FTEs for Orkney Generation (2030 Scenario)

Using the top down approach, the equivalent figures for FTEs in Orkney are around 1,050 in 2020, rising to nearly 12,000 in 2030, so again somewhat higher than using the bottom up approach. Further details are provided in Appendix A.6.

5.1.2. Summary of socio-economic benefits

The potential FTEs that could be generated from renewable energy projects in 2020 are summarised in the table below. The additional FTEs for the Scottish Islands have been plotted versus the total current employment figures in Figure 18. Although the predicted 2020 capacity is lower for Orkney than for Shetland and the Western Isles, much of this capacity is predicted to be wave and tidal which has much higher values for FTE/MW. It should be borne in mind that once an industry of this scale has developed, FTE/MW values may decrease.

In addition, if it is assumed that UK renewable energy targets are met, FTEs created for wind projects will be primarily shifting of jobs from other areas to the islands. However, the connections are creating a new industry for marine generations, and hence these will primarily be new jobs created.

	Capacity Assumption (MW)	Scottish Islands	Rest of Scotland	Rest of UK	Total
Western Isles	450	392	704	**53**	**1,599**
Shetland	600	463	744	**298**	**2,105**
Orkney	180	416	1,041	**96**	**1,733**
Total	***1,230***	***1,271***	***2,489***	***447***	***4,205***

Table 39 – Summary of Potential FTE Creation by 2020

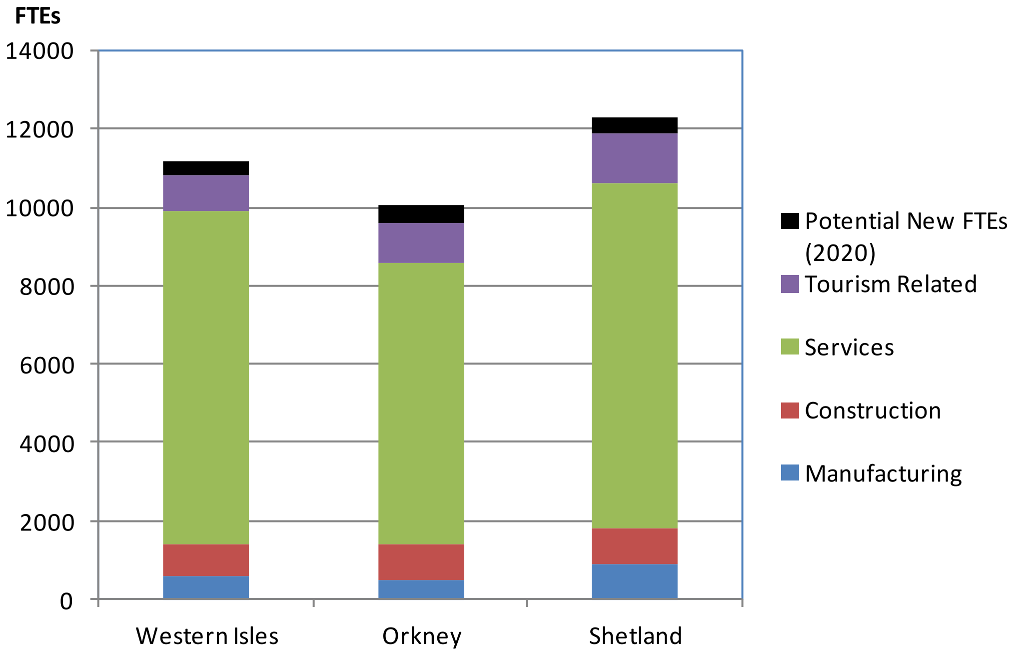

Figure 18 - Potential new FTEs versus current employment figures (2020)

6. WIDER BENEFITS

6.1.1. Potential Wider Benefits to UK Marine Energy Industry

The potential socio-economic benefits to the UK of developing a UK-based marine energy (i.e. wave and tidal) industry have been assessed by a number of bodies and organisations. Whilst there is a range of differing opinions regarding the levels of job creation, there is a general consensus that if a successful marine industry is developed in the UK it could lead to significant numbers of direct jobs in a range of job functions, e.g. planning and development, design and manufacturing, construction and installation, operations and maintenance and support services.

There is also general consensus that the UK has lost out in terms of its onshore wind industry to countries such as Denmark, and the opportunity for significant job creation by this industry has been lost. This is investigated in more detail in the section below.

RenewableUK has provided a view on potential socio-economic benefits for a high growth scenario for marine renewables for 2020, 2035 and 2050[64], with a summary shown in Table 40. These figures are based on deployment Scenario 3 in The Offshore Valuation[65] This scenario gives a wave deployment of 14 GW and tidal deployment of 31 GW by 2050.

	2020	2035	2050
Annual Value to UK	£3.7bn	£6.1bn	£5.9bn
Number of Individuals Directly Employed (FTEs)	10,000	19,500	19,000
UK Share of Domestic Market	80%	71%	60%
UK Share of Export Market	22%	14%	9%
Gross Value Added	£530m	£800m	£770m

Table 40 - Socio-economic impacts from developing a UK Marine Energy Industry

The following points should be noted from Table 40:

- The annual value is the total capital and operating cost spend on domestic goods and services. Financing costs and interest charges are not included.
- Jobs are FTEs and exclude indirect and induced jobs.
- Gross Value Added (GVA) is calculated from number of direct jobs multiplied by an estimate of GVA to employee ratio for engineering industries.
- The decline from 2035 to 2050 is due to UK deployment reducing from 2.3 GW per annum to 1.3 GW per annum.

It can be seen that 10,000 Full Time Equivalent jobs (FTEs) are predicted for 2020, rising to 19,500 FTEs in 2035. However, it should be noted that RenewableUK also predicted approximately 5,000 FTEs for a low growth scenario by 2020 and 7,000 FTEs for a medium growth scenario by 2020[66]. In addition, a further RenewableUK study[67] notes that the Scottish Government predicted 7,000 FTEs to be created in a marine

64 RenewableUK (2010). *Channelling the Energy: A Way Forward for the UK Wave & Tidal Industry Towards 2020*. Available at: http://www.renewableuk.com/en/publications/index.cfm/Wave-and-Tidal-Channelling-the-Energy.

65 Public Interest Research Centre (2010). *The Offshore Valuation.*

66 RenewableUK (2011). *Working for a Green Britain: Vol 2: Future Employment and Skills in the UK Wind and Marine Industries*. Available at: http://www.renewableuk.com/en/publications/reports.cfm/Working-for-a-Green-Britain-Volume-2.

67 RenewableUK (2010). *Marine Renewable Energy: State of the industry report.* Available at: http://www.renewableuk.com/en/publications/reports.cfm/year/2011/.

industry by 2020, but a study by Bain and Company predicted only 2,100 jobs in the UK by 2020[68]. The figure from Bain and Company is based on an annual deployment of 1.4GW/annum.

There is therefore a range of published estimates, but nonetheless there is a consistent view that an industry cluster could be created with significant job potential and much of this could be centred in Scotland. In addition, as noted above, these job estimates are FTEs only and these would lead to further indirect and induced job creation.

6.1.2. Likely Cost Reductions from Marine Technologies

As experience in marine generation increases and scale also increases, cost of energy for marine generation is predicted to fall. Analysis from the Carbon Trust[69] predicts that both wave and tidal generation costs will fall significantly as global deployment increases, as shown in Figure 19 and Figure 20. It is therefore essential that global deployment rates are achieved and for the UK this is only possible if the areas in which there are good marine resources have grid connection to enable sufficient generation to be exported. Orkney and Caithness alone could achieve 1.6 GW of primarily marine generation by 2020/2021, and if this were achieved this would significantly accelerate marine generation cost reduction.

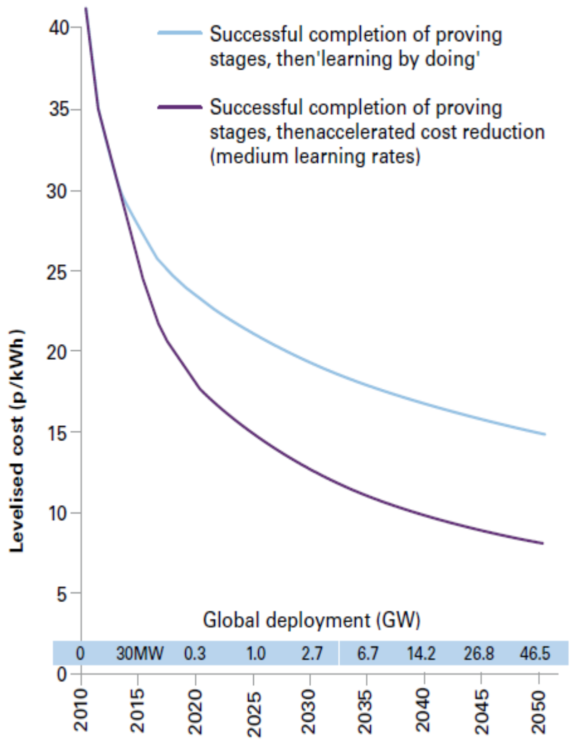

Figure 19 – Predicted levelised cost reduction for wave energy[64]

[68] Bain & Company (2008), *Employment opportunities and challenges in the context of rapid industry growth.* Available at: http://www.bain.com/publications/articles/employment-opportunities-and-challenges-in-the-context-of-rapid-industry-growth.aspx.

[69] Carbon Trust (2011). Accelerating marine energy: The potential for cost reduction – insights from the Carbon Trust Marine Energy Accelerator

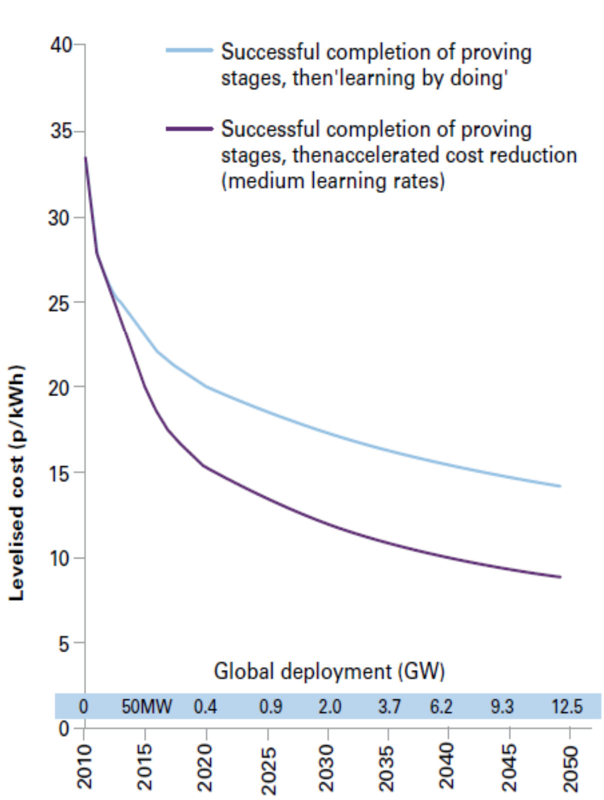

Figure 20 - Predicted levelised cost reduction for tidal energy[69]

Pelamis has predicted that costs will be reduced from £8m/MW for 1.5 MW generation capacity to £4m/MW for 50 MW generation capacity and then to £2.5m/MW for 500 MW of generation, for Pelamis' devices, as shown in Figure 21. The cost reductions are achieved from reductions in machining costs, innovation through new materials and increasing performance improvements meaning that the device size can fall. Due to economies of scale, labour and overheads fall significantly as scale increases.

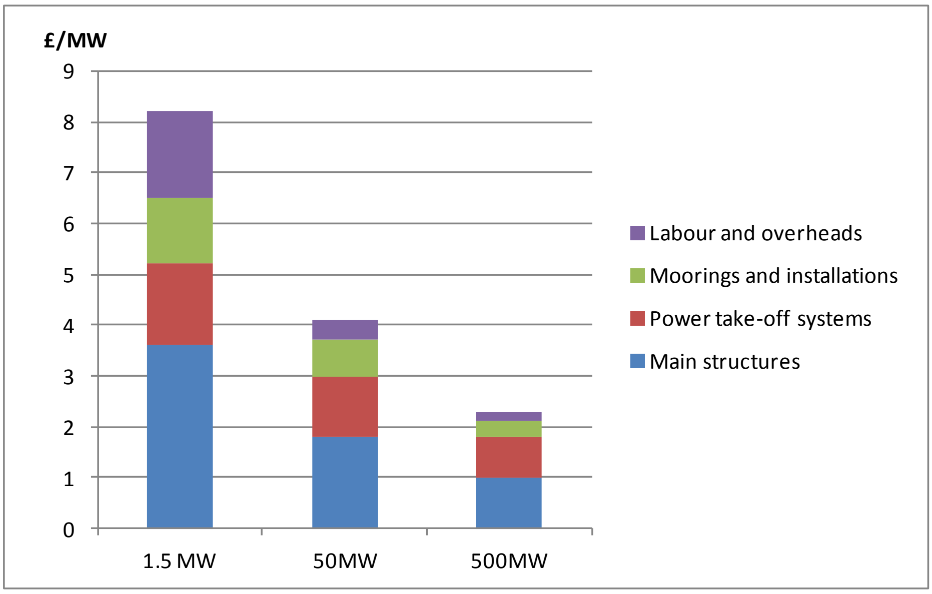

Figure 21 - Cost Reduction Profile for Pelamis Wave Device

CASE STUDY: Comparison with Onshore Wind Industry – Lessons from Denmark

There is general agreement in the industry that Denmark has achieved a greater market share and economic benefit from development of the onshore industry than that achieved by the UK. A number of reasons for this disparity are discussed by RenewableUK[64] but one key reason given is the difference in support to onshore wind made available in the two countries. Whilst similar investment was made in research and development, other incentives were provided five years earlier in Denmark than in the UK, hence accelerating the development of the industry. In addition, government support and policy was found to be consistent over 20 years. The Danish wind industry now has 28,000 FTEs and contributes €1.5 billion GVA to the Danish economy per annum[64] in 2010, compared with 8,600 FTEs and €0.6 million in the UK[70] in 2012. The difference between the total support made available for onshore wind in Denmark and in the UK is given in Table 41.

	Denmark (£ million)	UK (£ million)
Research & Development	122	141
Capital Grants	31	0
Production Incentives	615.4	240

Table 41 - Comparative wind industry public support made available in the UK and Denmark[64]

RenewableUK therefore concludes that consistent financial and political drivers are essential to securing long term socio-economic benefit. Whilst the UK does have political and financial support for the marine energy industry there is currently a lack of clarity going forward and hence there is a risk that long term socio-economic benefit will not be achieved for the UK. Furthermore, no special measures have been implemented within the regulatory regime around grid access and charging for marine technologies, whereas emerging technologies have in general not faced equivalent challenges in other countries. For example, it is interesting to note that in Denmark grid and infrastructure improvements were prioritised in order to enable connection of new onshore wind generation. In addition, Danish legislation gives wind power the highest priority of access to grid capacity[71].

The Western Isles, Orkney and Shetland have particularly strong wave and tidal resources, with the UK having 10% of the EU wave resource and 50% of the EU tidal resource[72]. The Western Isles has a particularly strong wave energy resource and is a key location for development of wave energy projects. Therefore, grid reinforcement will be required to develop demonstration projects in these areas. In terms of progressing marine demonstration projects, RenewableUK[64] makes the following recommendations:

- Market incentives are required to develop a viable industry (provided that technology can be demonstrated successfully);
- The support must be generous, consistent and long term.

The risk for the UK marine industry if these issues are not resolved is that the UK will not be able to maximise on the long term economic benefit, as has been seen in the onshore wind industry. In particular, the USA is currently developing a long term support structure for marine renewables as are other countries such as Canada, Spain, Ireland and Portugal[64]. The USA has established National Marine Renewable Energy Centres, and is delivering a clear policy to support renewable energy and has fewer issues regarding grid access and associated grid costs.

[70] RenewableUK (2012). *Onshore Wind: Direct & Wider Economic Impacts*. Available at: *http://www.renewableuk.com/en/publications/index.cfm/BiGGAR.*

[71] Legislative Council Secretariat (2006). *Wind Farms in Denmark.* Available at: www.legco.gov.hk/yr05-06/english/sec/library/0506in22e.pdf

[72] Pelamis Wave Power (2013). *Scottish Islands Renewable Project.* Provided at Western Isles Stakeholder Meetings

6.1.3. Fuel poverty

Fuel poverty is an issue for the Scottish Islands, particularly in Orkney and the Western Isles. Fuel poverty is defined as spending more than 10% of disposable income on household fuel. Whilst fuel prices are also high on Shetland, average wages are higher and hence the percentage of the population living in fuel poverty is lower than that for the Western Isles and Orkney. However, it is still higher than the national average for Scotland. The average percentage of the population living in fuel poverty is 28% for Scotland and this has risen in recent years due to increases in fuel prices, with the figure in 2002 being 13%.

	% of Population in Fuel Poverty	Ranking in Scotland
Western Isles	58	1
Shetland	35	6
Orkney	50	2

Table 42- Fuel poverty rankings

Due to the high and increasing costs of fossil fuels and carbon, one of the key ways to reduce fuel poverty is to promote the take-up of renewable energy, and in particular the installation of subsidised micro-renewables. It is now extremely difficult to connect any new generation in the Western Isles, Orkney or Shetland preventing new consumers from benefitting from feed-in tariffs which could contribute to a reduction in fuel poverty. Any spare grid capacity created by new transmission links could be beneficial in this respect.

6.1.4. Increasing security of supply

Whilst the Western Isles, Orkney and Shetland currently have adequate security of supply, development of new interconnectors for each area would provide benefits related to security of supply. These are described below.

The Western Isles are connected by a 20 MW single circuit of 243 km running from the Fort Augustus MITS substation to Skye, via subsea cable to Harris and then to Stornoway. This was established in 1990. Prior to this the supply was sourced primarily from diesel generators and the network was an island system. Peak island demand is approximately 27 MW and therefore local diesel generation (at Battery Point and Arnish) supplies the additional demand during the periods of maximum demand. These diesel generators are ageing and in addition the single circuit infrastructure does not provide preferred levels of security of supply. The additional planned interconnection would therefore provide greater security of supply for the Western Isles.

The Shetland Islands have no connection to the GB grid and therefore form an island system. The islands are supplied by Lerwick Power Station (LPS), (a 67 MW oil fired power station owned by SSE and operated by SHEPD), Sullom Voe Terminal (SVT) Power Station (with an installed capacity of 100 MW but currently exporting 22 MW maximum to Shetland), Burradale Wind Farm (3 MW privately owned wind farm) and a number of community wind generators. LPS combines diesel engines and gas turbine units resulting in a high cost of generation, and is also due to be replaced in the next few years, potentially by a 120 MW power station running on either Light Fuel Oil (LFO) or natural gas, or a combination. If natural gas is selected, a new pipeline would be required to connect the power station to the Sullom Voe terminal, whereas LFO would be delivered by ship and stored at the power station.[73]

[73] SSE (2012). *Replacing Lerwick Power Station: Securing Shetland's Future Electricity Supply*. Available at: *www.sse.com*.

In order to balance supply and demand on Shetland, LPS provides many ancillary services which places demands on the station. In addition, due to LPS' age, it is becoming more expensive to maintain and operate and difficult to maintain environmental compliance. It has recently been granted a number of derogations regarding environmental compliance, for example relaxing its emissions limits[74]. The SVT plant is also ageing and will require replacement or refurbishment. Although the Burradale Wind Farm operates at approximately a 50% capacity factor, and is one of the most productive wind farms in the world, it adds intermittency to the system which needs to be accommodated through flexibility of LPS. In addition to grid capacity, this limits the amount of additional renewable generation that can be connected prior to the transmission link.

Excluding SVT's industrial demand (which is met by on-site generation), the total island demand is in the range of 31 MW to 68 MW. The network is all at 33 kV or below.

The Shetland Northern Isles New Energy Solutions (NINES) project has looked at options for secure, environmentally compliant supply for Shetland compared with the cost of replacing LPS with a like-for-like power station[75] [76]. SHEPD states that even if a mainland HVDC link is constructed, due to the fact that the link will be a single circuit there must be an alternative means to maintain supply in the event of a fault to meet Engineering Recommendation P2/6 – Security of Supply. It also states that the Viking wind farm power generation will be less than the demand on Shetland for approximately 30% of the year.

The Integrated Plan for the Shetland Islands consists of Phase 1 (which was originally "NINES") and Phase 2 approaches. The broader aim of Phase 1 is to inform Phase 2 and the outcome from Phase 1 is to enable the peak capacity requirement for a replacement power station to be reduced by 20 MW. The following are key components of Phase 1:

- 1 MW battery at LPS: energised in September 2011 to facilitate connection of up to 400 kW renewables and for peak lopping
- Domestic demand side response and frequency response: advanced storage heating and water heating to be fitted in 750 homes (flexing up to 15 MW demand)
- Extension of Lerwick district heating scheme via a 4 MW electrical boiler
- Active Network Management (ANM) to connect increased renewable energy.

The aim of Phase 2 is to achieve the optimal solution with regard to replacement of LPS. For example, the aim of Phase 1 is to enable the capacity of the replacement LPS to be reduced from 67 MW to 48 MW.

If the Shetland HVDC interconnector was constructed, then LPS (or LPS replacement) would still be required in order to maintain security of supply. However, a number of benefits would be achieved:

- LPS would only be required to operate if the HVDC link was not available, and hence it would operate much less than currently. This would save on operating and maintenance costs and fuel costs which amounted to 29m in 2010-2011[77]
- 'In 2010-11, a third of this £29m was recovered directly from Shetland's customers through their electricity supply bills. The remainder was recovered from customers connected across SHEPD's

[74] Scottish Hydro Electric Power Distribution (2013). *Proposal for the development of the Integrated Plan for Shetland.* Available at www.ena-eng.org.

[75] Scottish Hydro Electric Power Distribution (2013). *Proposal for the development of the Integrated Plan for Shetland.* Available at www.ena-eng.org.

[76] IET (2011). *Shetland Northern Isles New Energy Solutions (NINES) Project Policy Submission.* Available at: *http://www.theiet.org/policy/submissions/s909.cfm.*

[77] Ofgem (2011). Shetland Northern Isles New Energy Solutions (NINES) Project Consultation

distribution network. SHEPD calculated that the additional cost of providing a supply on Shetland resulted in an average cost across all their customers of £27 per customer'.[77] In the presence of an interconnector, LPS would be required for much less of the time and hence the cost to the consumer would be reduced.

- It may be possible to replace LPS with a diesel facility rather than with a LFO or natural gas facility. Whilst a diesel power station is more expensive to operate than gas, it is cheaper to build and therefore could represent a considerable capital cost saving. With the interconnector plus LPS backup, the LPS would only be required to run occasionally, therefore operating and maintenance costs are much less of an issue.

Orkney is a Registered Power Zone (RPZ) and is connected by two 33 kV submarine cables rated at 20 MVA and 32 MVA. No new generation above the G83 limit of 3.7 kW is currently being allowed to connect. A number of options to alleviate this situation are currently being investigated. For example, it was originally thought that additional innovative measures working in conjunction with the Registered Power Zone (RPZ) such as dynamic line rating (DLR) could enable additional generation to connect. However, a risk of voltage instability has been identified by SSE which has delayed the implementation of DLR. The optimal solution would be the provision of a new Grid Supply Point but this would require the new 132 kV connection to be available. Increasing distributed generation is one of the key areas in which energy poverty can be improved and one of the reasons that the grid is now so constrained is because there has been a big take up of small generation connections in recent years. Curtailment levels of 4-8 times what were predicted from generation connection offers are being seen; for example one wind project is seeing curtailment levels of 70%. This means that business models that were built on much better availabilities are no longer valid. Clearly making capacity available for export of generation is critical for Orkney to achieve sustainable growth in renewable energy generation.

7. POLICY OPTIONS

7.1. Issues to be addressed

Our analysis suggests that the key issues that will need to be addressed to facilitate the large scale development of renewable generation on the Scottish Islands are:

- The funding gap
- Grid access
- Availability of early stage funding for marine projects, and
- Potentially support for the supply chain

Hence, the policies described in this section set out options for addressing each of these issues, and the potential advantages and disadvantages of each. In each area we set out a rationale for further measures but have not set out to make any policy recommendations with respect to the Governments' renewable generation strategies. Any potential intervention would have to comply with EU law, including the Third Energy Package and State Aid regulation, and may require changes to legislation. Hence, the implementation implications associated with any policy measure need to be carefully considered.

The issue of high transmission charging, we have considered as part of the funding gap and do not seek to explore the economic arguments around different transmission charging methodologies, since this is an area covered by independent economic regulation and not a policy option available to the Governments, other than a temporary cap than can be implemented in certain cases under Section 185 of the Energy Act 2004. Instead, we assume that the outcome of Project TransmiT/CMP 213 is a given, albeit uncertain.

Planning and consenting can be challenging in the Scottish Isles (particularly around bird habitats) but we did not find evidence that they were sufficiently more difficult here than in many other locations to justify specific measures to address these challenges.

In the course of our interviews, we heard concerns raised with respect to SHE-T's ability to deliver such a large transmission infrastructure programme within a very short space of time. We acknowledge the delivery risks associated with reliance on a single party but alternative TO models, including greater competition, were not within the scope of this study. Some interviewees also questioned whether there were lower cost options for building the transmission links to the islands. Detailed review of the technical configuration and costings of the proposed cable to the Western Isles, and future cables to Shetland and Orkney, were not within the scope of this study. To the extent that savings could be found, this would significantly improve the economics of the Scottish Island renewable projects.

7.2. Addressing fund gap for Scottish Islands wind

7.2.1. Rationale

Our study has confirmed that there is significant potential for the exploitation of renewable energy resources on the Scottish Islands, and the renewables industry could be a very significant contributor to the economies of the islands. We have also demonstrated that renewable generation and associated transmission links could boost local security of supply, whilst the diversity benefits of developing renewables on the islands (especially marine) could reduce the overall cost of intermittency on the GB system.

However, the analysis of levelised cost of energy suggests that further onshore wind projects, including those projects identified in this report as under development, which require costly new transmission infrastructure, would unlikely to be economic under current levels of support (0.9 ROCs/MWh) or a CfD strike set at an equivalent level[78]. The greater wind yields on the islands are likely not sufficient to outweigh the additional transmission costs (contingent on the outcome of the CMP213 process), particularly on the Western Isles.

We estimate that onshore wind projects are typically between £19-£45/MWh more expensive on a levelised basis on the islands than the average mainland project[79], with Shetland and Orkney at the lower end of this range (£19-£22/MWh) and Western Isles at the higher end (£45/MWh). Even with the most favourable outcome from the CMP213 process from the perspective of Scottish Islands generators we expect onshore wind on the islands to be £14-£36/MWh[80] more expensive on a levelised basis.

However, the costs of Scottish Island onshore wind, particularly at the lower end, are in the same regions as several other forms of low carbon generation being considered by government including nuclear, biomass and imported renewables from Ireland, all currently estimated to be around £85-£110/MWh. Compared to typical Round 3 offshore wind projects, the Scottish Islands wind projects are estimated to be around £32-£58/MWh cheaper currently.

Given the limitations on resource potential for some of the cheaper forms of renewable generation, the analysis suggests that Scottish Island wind could make a cost effective contribution to the 2020 renewables targets and wider decarbonisation objectives.

7.2.2. Options

a) Island specific support levels (wind)

One potential option for addressing the funding gap would be to establish financial support levels specific for Scottish Island projects, i.e. a specific ROC band or CfD strike price level. DECC currently has a process underway to set the CfD strike prices for renewable technologies for 2014/15 – 2018/19. The process and basis for setting those strike prices was published in Annex E of the EMR Policy Overview (November 2012)[1]. This option is therefore a departure from that. Consideration would need to be given to the eligibility criteria in order to avoid undue discrimination or create opportunities for windfall gains as well as the practical and legal implications of changing the planned approach at any time.
One option would be to make the support level only available to projects on named islands ie. the Western Isles, Orkney and Shetland. A more generic definition covers any onshore projects that require a local sub-sea connection asset more than a certain number of kilometres.

Based on our analysis we believe that support for Scottish Islands wind would need either 0.4-0.5 ROCs[81] more; which would be equivalent to an additional £19-22/MWh (in the case of Orkney and Shetland) in CfD strike price terms if they were to be set on the same basis to deliver the levels of deployment in our central scenario. Again, based on our analysis of the differences in LCoE, the Western Isles would require the equivalent of 1 additional ROC or a CfD strike price that is £45/MWh higher than the average for UK onshore wind. Under a more favourable outcome from CMP213 from the perspective of Scottish Islands generators these figures would drop to 0.3-0.4 ROCs and £14-19/MWh respectively for Orkney and

[78] Indicative values for strike prices are expected in Summer 2013 with the draft of the first EMR Delivery Plan.

[79] Assuming 2020 commissioning and technology specific hurdle rates

[80] Assuming 30% converter costs, central transmission capex and technology specific hurdle rates

[1] https://www.gov.uk/government/publications/electricity-market-reform-policy-overview--2

[81] Assuming a ROC value of £44 and comparing LCoE for Orkney and Shetland (£103/MWh and £106/MWh) against a mainland onshore wind project with a central LCoE of £84/MWh (simplified calculation).

Shetland (0.8 ROCs or £36/MWh for the Western Isles). (In addition, these figures assume DECC's technology specific hurdle rates, and would change if discount rates were higher or lower, and do not reflect other CfD design considerations.)

A further consideration would be whether to further sub-divide the support tranche according to Island Group. For example, we believe that wind projects on the Western Isles will require a greater level of support than those on Shetland and Orkney. A one size fits all approach risks on the one hand providing insufficient support for the Western Isles projects, but on the other hand excessive returns for projects on Shetland and Orkney.

A potential extension of sub-divided support levels would be for individual negotiation of CfDs between island wind developers and government. Such an option would be less accessible to smaller projects and hence it may be necessary to include a provision that CfDs must be offered on the same terms as individually negotiated contracts to subsequent projects for a defined period.

b) Cap on transmission charges

An alternative to providing higher levels of financial support for Scottish Island wind generators would be to reduce transmission charges. This could be enacted via Section 185 of the Energy Act 2004 which allows the Secretary of State to cap transmission charges for renewable generators in specified areas of GB until October 2024[82]. Such a cap would benefit island generators by reducing or eliminating the funding gap relative to onshore projects and removing TNUoS price risk; these costs would be transferred to electricity consumers.

Consideration would need be given as to what would be the appropriate level of cap. Our analysis suggests that a cap of £30/kW/yr would reduce the LCoE for onshore wind on Orkney and Shetland to around £90/MWh and make these projects potentially economic and on par with mainland onshore wind under current levels of financial support[83]. Caps at these levels would be equivalent to a financial subsidy for Scottish Islands wind generators of around £15/MWh. Marine technologies would also benefit from such a cap to a similar level (depending on capacity factor), but the impact in the context of the overall levels of financial support required would be relatively minimal. This subsidy would be paid for by consumers and other generators through a higher residual element in the TNUoS charge calculation.

A further question is how such a cap would be indexed. From a generator's perspective it would make sense if any cap was indexed in line with the inflation index of the support level – RPI in the case of RO plant, yet to be determined for CfD plant. Also, this option is currently only available until October 2034 which may limit its effectiveness.

c) Transmission charge indexation in CfDs

One potential downside of transmission charge caps (particularly if these are differentiated by Island Group) is that they neutralise the locational signal from transmission charging. Competition between projects on different Island Groups is reduced and, in extremis, generators may start to request connection offers in increasingly remote and costly locations.

[82] 'Section 185 of the Energy Act 2004 was amended by Section 25 of the Climate Change and Sustainable Energy Act 2006 to allow any scheme to run until October 2024' see https://www.gov.uk/electricity-network-delivery-and-access

[83] For the Western Isles, a cap at this level would reduce LCoE for a typical onshore wind project to around £96/MWh, which would unlikely to be economic at current levels of financial support.

A possible solution to this would be to include a term relating to TNUoS within the CfD indexation basket, for example, by increasing the CfD strike price by 25% of the cost of TNUoS exceeding £25/kW/yr. This would, however, be an even greater departure from the process underway to set the CfD strike prices as published in Annex E of the EMR Policy Overview. For the vast majority of plant operating under CfDs, whose TNUoS charges would be considerably less than £25/kW/yr, this term would have no impact. Only for plant located in regions of high TNUoS charges would this make a difference. Since the generator would still be exposed to a proportion of the higher transmission costs, developers would still be incentivised to some extent, all other things being equal, to seek out sites which require less costly transmission infrastructure, although that incentive would be weakened. Applying an approach such as this, not targeted specifically, has the potential for unintended consequences, including the underlying objective of the EMR to lead to competitive price discovery within and between technologies.

7.2.3. Summary

Table 43 below summarises the policy options for addressing the funding gap for Scottish Islands wind, with an assessment of the likely impact of each in terms of deployment of renewables capacity on the islands, the implementation requirement and the advantages and disadvantages of each option.

Policy option	Impact	Implementation	Advantages	Disadvantages
a) Island specific support	High	For CfDs – would have to be considered as part of the EMR strike price setting process.. For RO – would require emergency banding review (although may not be relevant given timing of island connections).	- Relatively simple	- Difficulty in establishing the correct definition of an island - Departure from current policy which is technology based and not location based - Likely practical and legal considerations given departure from current EMR strike price setting process already underway
b) TNUoS cap	High	At discretion of Secretary of State; needs to comply with EU law on competition, state aids and Third Energy Package	- Would be applied universally - Legislation already exists (Section 185 of Energy Act 2004)	- Legally complex to implement. - Difficulty in defining the appropriate level for the cap - Undermines locational price signal from TNUoS - Option currently only available to October 2034
c) TNUoS indexation (% of) in CfDs	High	Could only be implemented by significant changes to the current EMR strike price setting process..	- Could be applied universally - Maintains a degree of locational signal	- Would introduce considerably greater complexity into the CfD design process - Would have broader effects on competition and price discovery beyond the Scottish islands. - Likely practical and legal considerations given departure from current EMR strike price setting process already underway and other design features of EMR, and would have significant impact on EMR delivery.

Table 43 – Summary of policy options to address the funding gap for Scottish Islands wind

7.3. Financial support for marine technologies

7.3.1. Rationale

We have discussed in this report that Scotland and the UK more generally has the opportunity to be a world leader in wave and tidal renewable generation. Emerging technologies are more expensive and require additional support to bring to commercial scale. Historical evidence has demonstrated that the costs of renewable technologies can reduce dramatically when supported at the early stages to establish a critical mass. These technologies are also riskier requiring higher cost forms of financing (predominantly equity) during the construction phase.

Higher levels of support and additional sources of construction finance are necessary ingredients for the establishment of new generation technologies.

7.3.2. Options

a) Continued higher financial support levels

Wave and tidal projects currently receive 5 ROCs per MWh. Our analysis suggests that in the absence of other forms of funding, marine projects on the Islands and elsewhere in the UK will require at least this level of support for the first commercial scale projects. It is expected that costs will come down rapidly with greater deployment and the level of financial support could reduce accordingly.

The Government has indicated an aspiration to move to technology neutral auctioning for the allocation of CfDs in the 2020s. This may come too early for wave and tidal, but we may expect based on the cost trajectory of other forms of renewables 2030 that marine energy could be competitive with other forms of low carbon generation by 2030.

b) Capital grants for generation projects

Given the technology risk associated with wave and tidal projects, financing for the construction phase of projects will need to come from equity supplied from the balance sheets of the larger developers, or from private equity for independent developers. Availability of the latter is limited and expensive making it challenging for independents including the developers of the technologies themselves to progress projects on their own.

Most of the existing projects have already received capital grants from European, central or local government sources. As well as providing valuable finance, such grants help to de-risk the capital of other investors. Increasing the level of capital grants available to developers of marine projects may be considered.

c) Capital grants for supply chain

A significant opportunity has been identified to develop supply chains for marine renewables on the islands and within Scotland. These opportunities include component manufacturing, construction and operation and maintenance. Early support through capital grants for local suppliers may allow them to become cost effective providers resulting in a greater local content. We have already discussed the potential for significant job creation associated with marine renewables and many of these jobs could be on the islands. The potential could be further enhanced should Scotland become an exporter of marine technology.

d) Low cost equity/debt secured by Government

The availability of project finance is extremely limited for marine projects during the construction phase. Even post-commissioning it may be difficult to re-finance projects with debt until plants have established a track record of good availability and capacity factor. Government backed funding, such as that which may be available from the Green Investment Bank (as is already being made available to offshore wind), could help in this regard. By lowering the overall cost of capital, such funding could reduce the level of financial support required through ROCs or CfDs.

Another potential source of funding is the European Investment Bank (EIB). The recent €100m loan for the Malta-Sicily HVAC interconnector is an example of it lending to major energy infrastructure projects.

7.3.3. Summary

Table 44 below summarises the policy options for providing financial support to marine technologies, with an assessment of the likely impact of each in terms of deployment of renewables capacity on the islands, the implementation requirement and the advantages and disadvantages of each option. As mentioned above, any potential intervention would have to comply with EU law, including the 3rd Energy Package and State Aid regulation.

Policy option	Impact	Implementation	Advantages	Disadvantages
a) Continued higher financial support levels	High	Already exists under RO. For CfDs - would have to be considered as part of the EMR strike price setting process.	- Provides marine technologies with financial support to make early projects viable	- Significantly more expensive than other forms of renewables in the early stages
b) Capital grants for generation projects	High	Ongoing on a case by case basis.	- Bridge funding gap and valuable source of capital during construction phase	- Must be funded
c) Capital grants for the supply chain	Medium	Ongoing on a case by case basis.	- Seed capital may accelerate investment in local supply chains, bringing down costs and attracting greater project interest	- Must be funded
d) Low cost equity/debt secured by Government (e.g. GIB)	High	GIB has been operational since October 2012 and could invest equity into marine projects.	- Provides finance which may be difficult to source from capital markets	- Project/ operational risk transferred to Government

Table 44 – Summary of policy options to provide financial support for marine technologies

7.4. Greater support for marine R&D

7.4.1. Rationale

In order to promote further Scotland and the UK as a world leader in the development of marine technologies additional funding and test sites could be considered to accelerate learning and speed up commercial deployment of marine technologies.

7.4.2. Options

a) Extension of EMEC (European Marine Energy Centre)

The EMEC facility currently can support projects up to capacity of 11 MW. Depending on the available grid capacity it may be possible to extend this facility further if required at a later date.

b) Further direct funding

Significant funding for R&D into marine has been secured but further direct funding could be considered.

c) Commercial scale competition

To the extent that there is a perceived barrier to moving from the current test facilities to the first commercial scale project, the Governments could organise a competition to build the first commercial scale tidal or wave project, say 5 MW. A similar incentive is already in place through the £10m Saltire Prize. However, the competition could be made site specific with participants bidding for the support level required and would be guaranteed transmission capacity (secured through one of the options described in this section). The precedent here would be the CCS demonstration competition that the Government is currently running. Such an approach could accelerate the bridging between testing and commercial operation.

7.4.3. Summary

Table 45 below summarises the policy options for providing greater support to marine R&D, with an assessment of the likely impact of each in terms of deployment of renewables capacity on the islands, the implementation requirement and the advantages and disadvantages of each option.

Policy option	**Impact**	**Implementation**	Advantages	Disadvantages
a) Extension of EMEC	Medium	Would depend on demand for new test beds.	- Would allow further testing, potentially including new technologies	- Limited spare grid capacity unless this is addressed by some other means (see below)
b) Further direct funding	Low	Various potential sources; could be implemented quickly	- May accelerate research and development	- Has to be funded
c) Commercial scale competition (with grid capacity secured)	Medium	Would require organisation of competition along the lines of CCS demonstrations – approx. two year lead, and 2-3 year development time. Grid access would also need to be secured.	- Would ensure that at least one project is demonstrated at the next scale - Would remove grid access issues for that project	- Grid capacity still needs to be found and risk of perceptions of 'queue jumping' - Projects of unsuccessful parties may be put back further

Table 45 – Summary of policy options to provide greater support for marine R&D

7.5. De-risking Scottish Island transmission

7.5.1. Rationale

Many interviewees from smaller and independent developers and community owned schemes identified the high costs associated with user commitment as a major barrier to the development of the projects. For many, particularly those with untested technologies, the liabilities and associated security requirements cannot be covered. As a result these developers are dependent on 'anchor projects' such as large windfarms in the Western Isles and Shetland, and larger marine projects in Orkney, to underwrite new transmission investment, and hope that there is sufficient spare transmission capacity to accommodate their projects. Whilst these user commitment rules are doing what they are designed to do, which is to protect consumers from stranding of transmission assets associated with higher risk generation projects, they may place potentially undue barriers to developers of new marine technologies. If the policy intent is to promote marine generation, having a regulatory regime that can create barriers may appear counter-productive, especially when compared to other countries where connections for emerging technologies are prioritised. For these reasons there may be grounds for pursuing measures that lower the risks of securing transmission capacity for certain classes of developer.

7.5.2. Options

a) Less onerous securities and liabilities

One option to assist marine developers to secure transmission capacity would be to reduce their liabilities and securities in circumstances where the attributable local works exceed a certain threshold. This would require a change to the CUSC, potentially only on an interim basis. To allow all Scottish Islands generators to share these benefits it may be necessary to extend these arrangements for smaller wind projects. This would not seem unreasonable given that future wind projects are unable to share in the embedded benefits that existing small scale windfarms are currently enjoying, the key of which is avoiding transmission charges[84].

b) Redefinition of the Main Integrated Transmission System (MITS)

A change in the definition of the MITS to incorporate the links to the Scottish Islands could reduce the levels of liabilities and securities required for generators on the Scottish Islands, depending on the definition of attributable works. Overall, TNUoS charges would be similar (with a high wider charge associated with new Island zones) but the requirement for upfront capital and guarantees might be lower. Another potential benefit to generators on the Islands would be if they could be treated as financially firm and then benefit from the Connect and Manage arrangements that allow generators to bid for compensation if they are curtailed. For generators on Shetland, for example, this would reduce the technology risks associated with the proposed multi-switching station at Spittal.

The downside with this option is that a redefinition of MITS and/or classification on attributable works would have major implications across the GB system, including how TOs establish the needs case for investment. A further objection may be offering compensation to generators who have only paid for a single circuit connection through their TNUoS charges.

[84] The charging arrangements for generators in net exporting zones is under review, and in the future distribution connected generators may be exposed to a proportion of transmission charges. This will reduce the advantage that existing generators have over new entrants.

c) Securities and liabilities for marine technologies guaranteed by Government

An alternative to reduced securities and liabilities would be for Government to underwrite them for marine projects (and potentially smaller or community owned wind projects). Again this could be for a time limited basis until the marine technologies become established and developers will increasingly have the financial capacity to underwrite the securities and liabilities.

d) Umbrella service for smaller generators

To the extent that small project size is seen as a barrier to negotiating a connection offer with the TO, it would be possible to offer an umbrella service to smaller generators in order to aggregate their volumes. Again, a third party guarantor could underwrite the liabilities and securities. A similar scheme has been tried before (pre-CMP 192) by NGET/SHE-T but did not proceed due to the lack of suitable guarantor. This option could be re-visited in light of the more favourable treatment since CMP192, particularly if the Governments were willing to act as the guarantor.

e) Greater allowance for anticipatory investment

A solution that allowed for greater anticipatory investment could improve the availability of grid capacity for projects unable to underwrite expensive transmission links. This could be achieved by lowering the 'threshold' for the level of user commitment in needs cases. By the regulator allowing this investment, customers would in effect be underwriting the capacity and exposed to any stranding risk. This decision is within the vires of Ofgem, who may consider the wider benefits of approving investment ahead of need as part of a co-ordinated policy/regulatory initiative to promote the UK marine energy industry.

7.5.3. Summary

Table 46 below summarises the policy options for de-risking Scottish Island transmission, with an assessment of the likely impact of each in terms of deployment of renewables capacity on the islands, the implementation requirement and the advantages and disadvantages of each option.

Policy option	Impact	Implementation	Advantages	Disadvantages
a) Less onerous securities and liabilities	Medium	Would require CUSC modification with 1-2 year lead time	- Would enable more smaller and marine developers to secure transmission capacity	- Would imply socialisation of project risk - Would be discriminatory
b) Redefinition of MITS	Medium	Would require significant CUSC modification possibly initiated through Significant Code Review – lead time of 2-3 years	- Could facilitate securing of transmission capacity for Island generators, particularly smaller projects and community owned schemes	- Would involve a major code change - Could be discriminatory - High potential for unintended consequences
c) Securities and liabilities for marine technologies underwritten by Government	Medium	Would require Government guarantees, but	- Would enable more marine developers to	- Would transfer non-performance risk to Government

		could be implemented relatively quickly	secure transmission capacity	- Would be discriminatory
d) Lower user commitment level required for needs case/facilitation of anticipatory investment	High	Part of the standard investment approvals process	- Would allow island connections to be built further ahead of need facilitating connections in the future	- Would transfer greater proportion of cable stranding risk to consumers - Potentially would be discriminatory to other generators
e) Aggregation service for smaller generators, guaranteed by third party e.g. Government	Medium	Co-ordinated via SHE-T/SHEP-D. Could take up to 12 months to achieve critical mass. Would require Government guarantees.	- Would provide smaller generators with access to firm transmission capacity	- Would transfer project risk to Government - Smaller generators would still need to wait for second cable in Orkney

Table 46 – Summary of policy options to de-risk Scottish Island transmission

7.6. Interim solutions for accommodating more capacity

7.6.1. Rationale

Lack of available grid capacity has been highlighted in this report as the single biggest barrier to wider deployment of renewables on the Scottish Islands. Where this starts to constrain the deployment of tidal and wave generation, this could damage any aspiration for Scotland and the UK more generally to become a world leader in marine generation. The ability to accommodate greater volumes of marine generation prior to transmission links being in place would mitigate this risk.

Considerable efforts have already been made, especially on Orkney, to connect greater volumes of renewables, involving sophisticated automated network management solutions and innovative commercial arrangements. Hence, options may be limited but still worth exploring. Clearly, if the timing of transmission links is not the constraining factor on the deployment of marine renewables, any interim solutions are less valuable.

7.6.2. Options

a) Displacement of existing generation

We have discussed earlier the existing fossil-fired generating capacity on Shetland (LPS – 67 MW, SVT – 100 MW) and Orkney (10.5 MW at Flotta). In theory there is the possibility that some of the generation from these plant could be displaced by greater volumes of renewable generation. However, since renewables are intermittent and asynchronous only limited volumes can be accommodated on island systems. Also additional reinforcement of distribution networks may be required. The resulting costs may not be justifiable as a transitional measure, but should further delays to transmission links occur then further analysis of these options may be considered. A further benefit would be the carbon savings associated with displacing highly emitting fossil fuel plant on the islands.

b) New sources of industrial load

Any increases in demand would facilitate connection of greater volumes of renewable generation. Offering lower energy prices may be a means of attracting larger industrial consumers and this has already been done in Shetland with an ice manufacturer. However, this may be politically difficult on a larger scale since GB consumers would effectively be subsidising the energy costs of commercial entities. The potential in the near term may be relatively limited.

c) Electrification of heat and transport

Another option for increasing demand would be greater electrification of the heating and transport sectors. The roll-out of heat pumps and electric vehicles (which also have the benefit of battery storage) could significantly increase the scope for connecting more renewable generation. Again, this is unlikely to have a large impact in the near term and may require reinforcement to distribution networks. However, greater electrification may have longer term benefits and hence unlike some of the other options for transitional solutions this is less likely to involve regret expenditure.

d) Greater deployment of smart technologies

Active network management systems allow more intermittent renewables to be connected. To a significant degree these opportunities have already been exploited via the RPZ in Orkney and planned NINES initiative in Shetland. Hence, there is potentially limited opportunity to extend smart technologies further. One possible exception is through the deployment of additional electrical storage. Again, if transmission links are further delayed a more detailed assessment of the costs and benefits of electricity storage could be considered.

e) Compensation for existing renewable generators to allow marine technologies to be connected

Further wind generation cannot be connected to the RPZ on Orkney since under the last in first off (LIFO) principles of access the levels of curtailment for new generators would be too high. (The unanticipated growth of micro-generation has accelerated this situation.)

However, the output from marine generation may not be closely correlated with wind, as illustrated by the Heriot Watt analysis for CMP213, suggesting that some could be connected to the RPZ with relatively low impact on wind generators, although further analysis would be required to validate this.

Even with low correlation existing wind generators would be affected. One option would be to compensate wind generators in the RPZ for additional curtailment resulting from connecting marine. Defining what is 'additional' curtailment would be difficult and an appropriate level of compensation would have to be determined. The alternative would be to curtail the marine generation itself, although this would run somewhat counter to the intent of a mechanism designed to promote marine output. A further complexity with this approach is that, there is currently no regulatory mechanism that would allow SHEP-D to take risk on curtailment payments without changing aspects of the price control. Hence, the complexity of this solution, even if the potential was proved through detailed system modelling, may make it difficult to justify as a transitional arrangement, unless there was further delay to transmission links.

f) Making spare capacity available on transmission links

Due to the anticipated phasing of marine projects it is unlikely that the new 180 MW HVAC cable to Orkney will be fully utilised initially. This will create some spare capacity that could be made available to other generators such as wind, albeit not until the transmission link is operational. This capacity may only be available on a temporary or non-firm basis, although through active network management techniques (and the fact that marine and wind generation is not fully correlated) the levels of curtailment may be acceptable for wind generators.

Mechanisms may also be considered whereby capacity contracted to existing parties not used by a certain date could be released back to the market.

7.6.3. Summary

Table 47 below summarises the interim solutions for accommodating more capacity, with an assessment of the likely impact of each in terms of deployment of renewables capacity on the islands, the implementation requirement and the advantages and disadvantages of each option.

Policy option	Impact	Implementation	Advantages	Disadvantages
a) Displacement of existing generation	Medium	Dependent on agreements with individual generators. Any additional works required to distribution networks may take several years.	- Would allow more renewable generation to be accommodated and would displace carbon emitting fossil fuel generation.	- Generators at oil terminals previously unwilling to consider - Opportunity may be limited for local system stability reasons - May require reinforcement to distribution networks
b) New sources of industrial load	Medium	Dependent on identifying suitable loads.	- Would allow more renewable generation to be accommodated	- Opportunities may be limited in the near term
c) Electrification of heat and transport	Low (near term) Medium (long term)	Dependent on other policy areas. Take up of heat pumps and electric vehicles may be slow.	- Would allow more renewable generation to be accommodated, particularly if accompanied by smart grid technologies	- Extent of electrification may be limited within the timeframes before transmission upgrades would be possible
d) Greater deployment of smart technologies	Low	May require additional funding e.g. through future LCNF/NIC. Deployment timeframes of 12 months+.	- Would allow greater proportion of renewables to be connected to distribution networks	- Opportunities largely exhausted on Orkney (through RPZ) and on Shetland (through NINES) with exception of greater electricity storage
e) Compensation for existing renewable generators to allow marine technologies to be connected	Low	New regulatory arrangement under RIIO required to allow DNO to recover compensation payments. Commercial terms would need to be	- Would allow more marine plant to be connected, potentially at relatively low curtailment costs (depending on the level of generation coincidence with wind)	- Would be complex to implement as no mechanism currently exists to be able to do this - Difficult to find a regulatory solution in the timeframes required for a transitional measure

		agreed with multiple generators which could take up to a year.		
f) Making spare capacity available on transmission links	Medium	Commercial arrangements to be agreed with TO.	- Would free up unutilised capacity and could accelerate certain projects	- Non firm access may present a barrier depending on levels of curtailment and level of financial support

Table 47 – Summary of interim solutions for accommodating more capacity

8. CONCLUSION

Our study concludes that the costs of deploying renewables on a large scale in the Scottish Islands is high, and that there are a number of technological and environmental challenges. However, onshore wind on the Scottish Islands is cost competitive with several other forms of low carbon generation and, particularly in the case of Orkney and Shetland, depending on the hurdle rates used, is significantly cheaper than Round 3 offshore wind. The development of renewables on the Scottish Islands would provide a number of socio-economic benefits, including the creation of local jobs, and there is an opportunity to establish Scotland as a world leader in marine technologies.

We have also concluded in our study that further renewable generation on the Scottish Islands will not be developed on any scale in the near term under current policy and support levels, including those projects identified in this report as already being under development. The costs of connecting to the transmission system are too high, making it difficult for developers and the regulator acting on behalf of customers to commit to costly new transmission infrastructure. In turn, the lack of grid access deters new developers, particularly those not in a position to meet the financial commitments required to secure future grid capacity. Ongoing uncertainty will inevitably lead to delays meaning that, despite the potential, renewable generation on the Scottish Islands would only make a minimal contribution to 2020 renewables targets, and an opportunity to develop the UK as a world leader in marine renewables could be lost.

Government will need to weigh up the costs and benefits of renewable generation on the Scottish Islands against other sources of electricity, as set out in this report and elsewhere, and in particular consider the impact on the local economies and communities, as well as the wider GB consumers. Should the political commitment be there for Scottish Islands renewables to be a key contributor to Scottish and UK 2020 renewable strategies and beyond, then a coordinated policy and regulatory response will be required urgently, incorporating some of the measures outlined in this report.

A. APPENDIX

A.1. INTERVIEWEES

- 2020 Renewables
- Alasdair Allan, MSP
- Alistair Carmichael, MP
- Angus MacNeil, MP
- Aquamarine
- BMP/IP/GDF Suez
- Brifor
- Comhairle nan Eilean Siar (Western Isles Council)
- Community Energy Scotland
- Distributed wind
- EDF/ AMEC
- Enertrag
- Highlands and Islands Enterprise
- National Grid
- North Yell
- Ofgem
- Orkney Islands Council
- Orkney wind
- Pelamis
- ScotRenewables
- Shetland Islands Council
- SHE-T
- SHE-D
- SPR
- SSER
- Statkraft
- The Crown Estate
- Vattenfall/ Pelamis
- Viking

A.2. DATA POINTS

# Developers	Onshore wind	Wave	Tidal
Western Isles	3	2	-
Shetland	3	1	-
Orkney	3	-	1

Table 48 – Number of developers who submitted cost estimates

A.3. MODELLING INPUTS

Cost driver	Unit	Shetland Islands	Orkney Islands	Western Isles
Yield	%	44%	42%	35%
Discount/ hurdle rate	%	10% discount rate / technology specific hurdle rate	10% discount rate / technology specific hurdle rate	10% discount rate / technology specific hurdle rate
Plant operating lifetime	years	20	20	20
Capital costs	(£/kW)	1,800	1,800	1,800
Operating costs	(£/MW/year)	99,000	89,000	58,000
Connection and UoS charges (central Capex/ 100% converter costs)	(£/MW/year)	96,630	79,930	129,392
Variable O&M	(£/MWh)	3	3	3
Learning rates	%	Learning rates were applied based on Ernst & Young study for Onshore Wind >5MW		

Table 49 - Central assumptions used for 'best estimate' LCoE for Scottish Island wind under the central capex and 100% converter station scenario

Cost driver	Unit	Wave	Tidal
Yield	%	30-35%	26%-35%
Discount/ hurdle rate	%	10% discount rate / technology specific hurdle rate	10% discount rate / technology specific hurdle rate
Plant operating lifetime	years	25 years	25 years
Capital costs	(£/kW)	4,200 – 8,200	4,300 – 8,400
Operating costs	(£/MW/year)	90,000 – 420,000	120,000 – 220,000
Connection and UoS charges (central capex/ 100% converter costs)	(£/MW/year)	79,930 (Orkney HVDC) 96,630 (Shetland) 129,392 (Western Isles)	79,930 (Orkney HVDC) 96,630 (Shetland) 129,392 (Western Isles)
Variable O&M	(£/MWh)	1.56 – 3.77	1.56 – 3.77
Learning rates	%	Based on RenewableUK Channelling the Energy	

Table 50 - Assumptions used for Scottish Island wave and tidal LCoE under the central capex and 100% converter station scenario

A.4. TNUOS

The below tables show the variation in TNUoS depending on two key variables: The scale of transmission capex (shown with low, medium and high) and the level of converter costs (30%, 50% and 100%) which is currently being decided upon by project TransmiT. The cost scenarios for transmission capex were provided by SHE-T and the resulting ranges of the local circuit charges were provided by NGET.

Central capex assumptions, 30% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	74.46	25.42	1.29	0.17	**101.34**
Shetland Islands (Nov-18)	60.52	25.42	0.00	0.17	**86.11**
Orkney Islands AC (Apr-18)	42.96	25.42	0.00	0.17	**68.55**
Orkney Islands HVDC (2025)	33.31	25.42	0.00	0.17	**58.90**

Central capex assumptions, 50% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	82.48	25.42	1.29	0.17	**109.36**
Shetland Islands (Nov-18)	63.53	25.42	0.00	0.17	**89.12**
Orkney Islands AC (Apr-18)	42.96	25.42	0.00	0.17	**68.55**
Orkney Islands HVDC (2025)	39.32	25.42	0.00	0.17	**64.91**

Central capex assumptions, 100% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	102.51	25.42	1.29	0.17	**129.39**
Shetland Islands (Nov-18)	71.04	25.42	0.00	0.17	**96.63**
Orkney Islands AC (Apr-18)	42.96	25.42	0.00	0.17	**68.55**
Orkney Islands HVDC (2025)	54.34	25.42	0.00	0.17	**79.93**

Low capex assumptions, 30% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	74.08	25.42	1.29	0.17	**100.96**
Shetland Islands (Nov-18)	59.82	25.42	0.00	0.17	**85.41**
Orkney Islands AC (Apr-18)	30.11	25.42	0.00	0.17	**55.70**
Orkney Islands HVDC (2025)	28.54	25.42	0.00	0.17	**54.13**

Low capex assumptions, 50% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	80.85	25.42	1.29	0.17	**107.73**
Shetland Islands (Nov-18)	62.36	25.42	0.00	0.17	**87.95**
Orkney Islands AC (Apr-18)	30.11	25.42	0.00	0.17	**55.70**
Orkney Islands HVDC (2025)	33.62	25.42	0.00	0.17	**59.21**

Low capex assumptions, 100% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	97.76	25.42	1.29	0.17	**124.64**
Shetland Islands (Nov-18)	68.7	25.42	0.00	0.17	**94.29**
Orkney Islands AC (Apr-18)	30.11	25.42	0.00	0.17	**55.70**
Orkney Islands HVDC (2025)	46.3	25.42	0.00	0.17	**71.89**

High capex assumptions, 30% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	75.16	25.42	1.29	0.17	**102.04**
Shetland Islands (Nov-18)	76.58	25.42	0.00	0.17	**102.17**
Orkney Islands AC (Apr-18)	55.81	25.42	0.00	0.17	**81.40**
Orkney Islands HVDC (2025)	38.31	25.42	0.00	0.17	**63.90**

High capex assumptions, 50% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	84.63	25.42	1.29	0.17	**111.51**
Shetland Islands (Nov-18)	80.13	25.42	0.00	0.17	**105.72**
Orkney Islands AC (Apr-18)	55.81	25.42	0.00	0.17	**81.40**
Orkney Islands HVDC (2025)	45.41	25.42	0.00	0.17	**71.00**

High capex assumptions, 100% converter costs (£/kW/year)

£/kW/yr	Local circuit tariff (cable)	Wider zonal tariff (Z1)	Local circuit tariff (on island)	Local substation tariff	Total
Western Isles (Oct-16)	108.31	25.42	1.29	0.17	**135.19**
Shetland Islands (Nov-18)	89.01	25.42	0.00	0.17	**114.60**
Orkney Islands AC (Apr-18)	55.81	25.42	0.00	0.17	**81.40**
Orkney Islands HVDC (2025)	63.17	25.42	0.00	0.17	**88.76**

Input assumptions for the local circuit tariff (on island):

Assumptions of within-island circuit length (km)	132kV OHL Expansion Factor	Expansion constant (£/MWkm)	Local circuit tariff (on island)
10	10.331	12.51	1.29
0	10.331	12.51	0.00
0	10.331	12.51	0.00
0	10.331	12.51	0.00

A.5. DIVERSITY ANALYSIS

The calculated correlation co-efficients for Shetland Islands, Orkney Islands and Western Isles are shown in Table 51, Table 52 and Table 53 below. As the majority of wind plant in GB are anticipated to be connected to North Scotland (Onshore), South Scotland (Onshore) or offshore (for the purposes of this study we only considered three offshore wind areas namely Irish Sea, East England and Scotland), the correlation co-efficient of a specific wind site with these areas is particularly important when considering diversity benefits.

Wind speed in the Shetland Islands is found to be highly correlated (90%) with wind speed in the Orkney Islands and to a lesser degree (<70%) with wind speed in North Scotland (Onshore), Western Isles and Scotland (Offshore). Correlation with wind speed in South Scotland Onshore and the two other offshore wind areas considered here is considerably lower (around 50% and 30% respectively).

Wind speed in Orkney Islands is found to be highly correlated (75-90%) with wind speed in the Shetlands, North Scotland (Onshore), Scotland (Offshore), Western Islesand South Scotland (Onshore). However, correlation with the other two offshore wind areas considered here is low (around 40%).

Finally, wind speed in the Western Isles is found to be highly correlated (80%) with wind speed in North Scotland (Onshore), Orkney Islands and South Scotland (Onshore), but to a lesser degree (70%) with Shetland Islands and Scotland Offshore. Correlation with Irish Sea Offshore (50%) and East England Offshore (30%) is lower.

Interestingly, the calculated correlation co-efficients were found to vary only slightly on a year-to-year basis which further confirms the existence of the relationships described above. Illustratively, correlation co-efficients for 2012 are also included in Table 51, Table 52 and Table 53 as shown below.

Correlation Co-efficient relative to Wind Speed in Western Isles	Correlation co-efficient (1970 – 2012)	Correlation co-efficient (2012)
North Scotland – Onshore	81.3%	80.2%
Orkney	80.5%	79.8%
South Scotland – Onshore	78.3%	75.4%
Shetland	68.2%	65.9%
Scotland – Offshore	67.6%	66.0%
Irish Sea – Offshore	50.4%	45.3%
Midlands and North East - Onshore	47.3%	41.3%
North West England and Wales - Onshore	40.0%	36.1%
East England – Offshore	30.4%	34.3%
South West England and Wales - Onshore	24.4%	22.6%

Table 51 - Correlation Co-efficient relative to Wind Speed in Western Isles

Correlation Co-efficient relative to Wind Speed in Shetland Islands	Correlation co-efficient (1970 – 2012)	Correlation co-efficient (2012)
Orkney	90.2%	89.6%
North Scotland – Onshore	69.7%	66.6%
Western Isles	68.2%	65.9%
Scotland – Offshore	63.7%	61.2%
South Scotland – Onshore	55.1%	51.1%
Midlands and North East - Onshore	36.9%	33.3%
Irish Sea – Offshore	33.5%	31.4%
East England – Offshore	29.8%	32.8%
North West England and Wales - Onshore	29.3%	28.2%
South West England and Wales - Onshore	18.9%	17.5%

Table 52 - Correlation Co-efficient relative to Wind Speed in Shetland Islands

Correlation Co-efficient relative to Wind Speed in Orkney Islands	Correlation co-efficient (1970 – 2012)	Correlation co-efficient (2012)
Shetlands	90.2%	89.6%
North Scotland – Onshore	89.4%	86.9%
Scotland – Offshore	83.3%	80.2%
Western Isles	80.5%	79.8%
South Scotland – Onshore	74.8%	70.6%
Midlands and North East - Onshore	52.3%	46.2%
Irish Sea – Offshore	47.9%	43.8%
North West England and Wales - Onshore	41.9%	38.7%
East England – Offshore	40.4%	41.5%
South West England and Wales - Onshore	26.4%	24.5%

Table 53 - Correlation Co-efficient relative to Wind Speed in Orkney Islands

A.6. SOCIO ECONOMIC BENEFITS

Detailed bottom-up analysis of Western Isles socio economic benefits

In addition to our Central generation scenarios, we performed a detailed bottom-up analysis of the socio economic benefits for the Western Isles based on the Environmental Statement (ES) containing the Environmental Impact Assessment (EIA) or other similar planning documentation. If published data was not available, developers have been contacted directly for information.

Table 54 gives the results of the socio-economic analysis for the total of 388 MW of currently planned projects for the Western Isles. The total number of direct and indirect FTE jobs for the Western Isles is calculated to be 384. An additional 701 FTEs are calculated for the rest of Scotland and 51 FTEs for the rest of the UK (although only construction jobs have been included for the rest of the UK). Therefore, construction of the link could generate one third of the minimum new jobs estimated to be required to maintain employment levels.

Table 54 – Socio-Economic Analysis (number of FTEs) of Western Isles Projects – Mid Scenario

				Western Isles				Rest of Scotland				Rest of UK		
				Construction		O & M		Construction		O & M		Construction		Data Source Comments
Project	Developer	Sector	Scale (MW)	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	
Bernera Wave Farm	Pelamis	Wave	10	15	3	12	4	22	33	1	37	4	7	Data provided by Pelamis, key additional assumptions stated
Lewis Wave Array	Aquamarine	Wave	40	58	12	14	5	72	118	2	44	0	0	Data provided by Aquamarine
Stornoway WF	Lewis Wind Power	Wind	130	42	9	60	21	39	73	0	50	8	6	Assessment from relevant EIA
Muaitheabhal	Eishken Estate	Wind	118	36	8	23	7	33	62	0	22	7	5	Assessment based on Muaitheabhal Extension
Muaitheabhal Extension	Eishken Estate	Wind	22	7	1	7	2	6	11	0	4	1	1	Assessment from relevant EIA
Druim Leathann	Druim Leathann Windfarm Ltd	Wind	42	14	3	7	2	13	24	0	9	3	2	Information from Scoping Report and some assumptions
Locheport	North Uist Community Turbine	Wind	7	2	0	1	0	2	4	0	2	0	0	Information from EIA screening and some assumptions
Lochcarnan Community WF	Private	Wind	7	3	1	0	0	2	4	0	0	0	0	Data awaited from Storas Uibhist
Loch Sminig	Community Owned	Wind	3	1	0	0	0	1	2	0	1	2	3	Data from CnES Committee report and some assumptions
Pentland Road WF	Pentland Road Windfarm Ltd	Wind	9.0	3	1	0	0	3	5	0	0	1	1	Info from decision notice and some assumptions
Sub Total			388	**181**	**38**	**124**	**41**	**193**	**336**	**3**	**169**	**26**	**25**	
Total				**384**				**701**				**51**		**1136**

Socio Economic Benefits – Top Down Analysis

Further to the explanations in section 5.1.1, the below paragraphs describe the 'top-down' methodology applied using the RenewableUK figures which we compared with our Central Scenario and our detailed bottom-up analysis (see above). The Western Isles serve as the example in this context and illustrate the approach adopted for the top-down analysis for the Western Isles, Orkney and Shetland.

Western Isles:

In order to sense-check the results, output from RenewableUK[66] has been used for a top-down analysis. This report provides direct and indirect FTE figures for onshore wind and marine renewables in the UK, as described in the methodology. A figure for FTEs/MW has been calculated and compared with FTEs/MW calculated from analysing individual projects (see detailed bottom-up analysis above).

Onshore Wind Projection	Direct FTEs	Indirect FTEs	Total FTEs	Direct FTEs/MW	Indirect FTEs/MW	**Total FTEs/MW**
High – 16 GW projection	11,900	7,100	19,000	0.74	0.44	**1.18**
Medium – 15 GW projection	10,300	6,100	16,400	0.69	0.41	**1.09**
Low – 10 GW projection	6,500	3,500	10,000	0.65	0.35	**1.00**

Table 55 – Projected FTEs for Onshore Wind for the UK – RenewableUK figures [66]

From Table 55 it can be seen that the number of direct plus indirect FTEs per MW is 1.0 – 1.2. A comparison has been made with the detailed bottom-up approach, in which the wind projects have been aggregated and FTE/MW values calculated, shown in Table 56 below. In this case the direct FTEs are slightly higher than those given in RenewableUK data. The total FTEs are also higher, although RenewableUK data does not include induced FTEs. In addition, the remote location of the islands may lead to higher job creation, for example increased O&M jobs.

Onshore Wind Projects	Direct FTEs	Indirect + Induced FTEs	Direct FTEs/MW	Indirect + Induced FTEs/MW	Total FTEs/MW
Aggregated – 387 MW	305	330	0.9	1.0	**1.9**

Table 56 - Calculated FTEs for Aggregated Wind Projects

Marine Projection	Direct FTEs	Indirect FTEs	Total FTEs	Direct FTEs/MW	Indirect FTEs/MW	Total FTEs/MW
High – 2 GW projection	9,400	5,600	15,000	4.70	2.80	**7.50**
Medium – 1.5 GW projection	7,800	4,600	12,400	5.20	3.07	**8.27**
Low – 1.3 GW projection	5,000	2,700	7,700	3.85	2.08	**5.92**

Table 57 – Projected FTEs for Marine Renewables in the UK – RenewableUK figures[66]

Table 57 shows that the number of FTEs/MW varies between 5.9 and 8.3 for the three scenarios provided by RenwableUK. As this is a reasonably large variation, this has been compared against the FTEs predicted by Aquamarine and Pelamis for their marine projects. Both Aquamarine and Pelamis provided figures for direct FTEs. The multiplier factors described in the methodology have been applied to the marine projects to predict potential indirect and induced jobs.

Marine Projects	Scenario	Direct FTEs	Indirect + Induced FTEs	Direct FTEs/MW	Indirect + Induced FTEs/MW	Total FTEs/MW
Pelamis (10 MW)	High	56	90	5.6	9.0	**14.6**
Pelamis (10 MW)	Medium	49	77	4.9	7.7	**12.6**
Pelamis (10 MW)	Low	43	64	4.3	6.4	**10.7**
Aquamarine (40 MW)	High	164	201	4.1	5.0	**9.1**
Aquamarine (40 MW)	Medium	146	179	3.6	4.5	**8.1**
Aquamarine (40 MW)	Low	126	156	3.2	3.9	**7.1**

Table 58 – Calculated FTEs for Marine Islands Marine Projects

By comparing Table 57 and Table 57 it can be seen that the direct FTEs/MW compare well, ranging from 3.9-5.2 for the UK Marine Renewables and from 3.2-5.6 for the Pelamis and Aquamarine projects (depending on the scenario). However, the total FTEs per MW are higher for the Pelamis and Aquamarine projects which may be because induced jobs are not included in the UK Marine Renewables figures.

In order to calculate a 'top down' figure to compare with the figures obtained from the detailed bottom-up analysis, the generation scenarios described previously have been used. A value of 1.0 FTE/MW has been applied for onshore wind and 7.2 FTE/MW (average of marine values) has been applied for wave and tidal. The total predicted FTEs for the Western Isles are 760 in 2020 rising to 9,910 in 2030.

Western Isles:

Year	Western Isles Scenario	Onshore Wind FTEs	Wave FTEs	Tidal FTEs	Total FTEs
2020	400 MW wind; 50 MW wave	400	360	0	**760**
2025	550 MW wind; 500 MW wave; 200 MW tidal	550	3600	1440	**5590**
2030	550 MW wind; 1000 MW wave; 300 MW tidal	500	7200	2160	**9910**

Table 59 – Predicted FTEs from "top down" approach for the central for Western Isles for three years

For the purpose of the top-down analysis for Shetland and Orkney, the same methodology has been applied (using a ratio 1.0 FTE/MW for onshore wind and 7.2 FTE/MW for marine). The results are shown in Table 60 and Table 61 below.

Shetland:

Year	Shetland Scenario	Onshore Wind FTEs	Wave FTEs	Tidal FTEs	Total FTEs
2020	600 MW wind	600	0	**0**	**600**
2025	1200 MW wind; 100 MW wave; 100 MW tidal	1200	720	720	**2640**
2030	1600 MW wind; 400 MW wave; 200 MW tidal	1600	2880	1440	**5920**

Table 60 – Predicted FTEs from "top down" approach for Shetland for three years

Orkney:

Year	Orkney Scenario	Onshore Wind FTEs	Wave FTEs	Tidal FTEs	Total FTEs
2020	40 MW wind; 47 MW wave; 93 MW tidal	40	338	670	**1048**
2025	256 MW wind; 349 MW wave; 310 MW tidal	256	2513	2232	**5001**
2030	256 MW wind; 600 MW wave; 1000 MW tidal	256	4320	7200	**11776**

Table 61 – Predicted FTEs from "top down" approach for Orkney for three years