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Orcadian Microgrid electrification concept

Prepared for

The North Sea Transition Authority

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Contents

Abbreviations

bbl/d	Barrels per day
AC	Alternating current
API	American Petroleum Institute
BPT	Buoyant Production Technologies Ltd
CAPEX	Capital Expenditure
CATS	Central Area Transmission
CCGT	Combined Cycle Gas Turbine
CNS	Central North Sea
CNSE	Central North Sea Electrification
CoP	Cease of Production
CSA	Cross Sectional Area
CTS	Capacitive Transfer System
DER	Distributed Energy Resource
ETAP	Eastern Trough Area Project
EOI	Expression of Interest
ESS	Energy Storage System
GHG	Green House Gas
GI	Gas Import
GL	Gas Lift
INTOG	Innovation and Targeted Oil and Gas Decarbonisation
IPIECA	International Petroleum Industry Environmental Conservation Association
MV	Medium voltage
NSTA	North Sea Transition Authority
NZTC	Net Zero Technology Centre
NSTA	North Sea Transition Authority
OGTC	Oil and Gas Technology Centre
PMS	Power Management System
SAGE	Scottish Area Gas Evacuation System

SCGT	Simple Cycle Gas Turbine
SEAR	Shearwater Elgin Area Line
SEGAL	Shell-Esso Gas and Liquid System

Executive summary

The imperative to reduce emissions is driven by the North Sea Transition Deal agreed between industry and the government in March of 2021. As a result, the North Sea Transition Authority launched "The Decarbonisation competition for the electrification of offshore oil and gas installations", working with BEIS, to fund technical and commercial studies on offshore electrification in the UK North Sea. With the benefit of this support, the Orcadian consortium has developed an off-grid, or microgrid, approach to platform electrification.

The microgrid solution proposed by Orcadian delivers a practical and achievable solution, which will enable Operators to exceed the emission reduction commitments outlined in the North Sea Transition Deal. The key benefits of the Orcadian solution are:

- Emissions reductions – approaching an 80% reduction for offshore facilities.
- Lower costs – saving almost $2 billion and more than 25% cheaper than the power from the UK grid option, when capital and ten years of operating costs are included, for a subset of platforms.
- A practical way for operators to meet their North Sea Transition Deal commitments in terms of both the emission reduction targets and timeframe.
- Deliverable quickly, and in phases, which allows a staged deployment with a steadily improving reduction in emissions.
- Opportunities for re-use or redeployment – provides legacy infrastructure for the grid and/or other users.

This study set out to design and describe a viable, reliable, off-grid option for powering North Sea platforms. We believe the scenario we describe can be more effective and cost substantially less than a cable from shore: it will deliver an earlier, deeper cut to emissions and may enable mature fields to keep producing longer, maximising recovery, and enhancing energy security.

We have included a comparison of the costs of the microgrid solution we propose, with a power from shore option for a cluster of Central Graben fields. However, we appreciate that making a direct comparison is difficult given the limited information we have on those platforms operations.

Orcadian consortium

Development of the microgrid solutions has only been achieved by extensive collaboration between the consortium members;

- **Orcadian Energy** – custodians and operator of the microgrid concept, owner of the commercial model;
- **Crondall Energy** – Orcadian's client engineering team, managing delivery and development of the concept;
- **North Sea Midstream Partners (NSMP)** – Infrastructure investor who are also supporting the development of the commercial model;
- **Petrofac** – Energy service company providing expertise for EPC and O&M;
- **Wärtsilä** – Key equipment vendor for the microgrid concept providing energy storage and low emissions generation;
- **Enertechnos** - Innovative cable technology provider.

Additional support has been provided by Schneider Electric who assisted with the development of the distribution system and the associated automation system.

Why not just plug a wind turbine into the platform?

The option of installing a wind farm and hooking that power supply up to the platform switchboards to displace power generated by the onboard systems, while relying upon the existing generators for back-up power, is compelling, simple, and attractive. However, it has the flaw that it is not actually effective in significantly abating emissions. For the platform operators, the reliability of the power supply is paramount and wind power is variable and unpredictable, so a back-up system is essential. Batteries can be highly responsive but are bulky and heavy. See the 100MW, 100MWh Minety battery in Wiltshire to get a sense of the actual scale, and cost, of half an hour's worth of battery back-up for the core CNSE platforms in the Central Graben, that supply a quarter of the UK's gas. Firing up an open cycle gas turbine takes time, perhaps 10 minutes to get to full power, so inevitably the gas turbines could never be shut down, they would continue to run to provide a spinning reserve, but under low loads. Under low loads, gas turbines are highly inefficient, so emissions are not much reduced. Nevertheless, this approach has been adopted at Hywind Tampen, but only to provide c. 35% of the electrical energy required (1). To provide as much power as possible from renewable sources requires a different approach and an alternative back-up system.

Figure 1: Minety battery storage

How can this be done differently?

We table a proposed concept here, which will of course require further definition, but which we believe will provide operators with a means to marry intermittent renewable sources of energy with their stringent requirements for a reliable electricity supply, and is scalable to groups of platforms and entire North Sea regions.

This microgrid concept has three components:

- A wind farm using floating wind turbines. We show costs and emissions reductions based on a wind farm with capacity of about 120% of the platform demand, though this ratio can be further optimised in consultation with operators.
- Floating distribution hubs which will collect AC power from the wind turbines at 60 Hz and 66kV and distribute power to the platforms at 33kV. The hubs will include energy efficient gas fired reciprocating engines with sufficient capacity to deliver all the necessary power during the time when wind power is completely unavailable. There will also be modest battery capacity for frequency control and to minimise the physical spinning reserve requirement.

- A network of cables to distribute the power to the operators' platforms

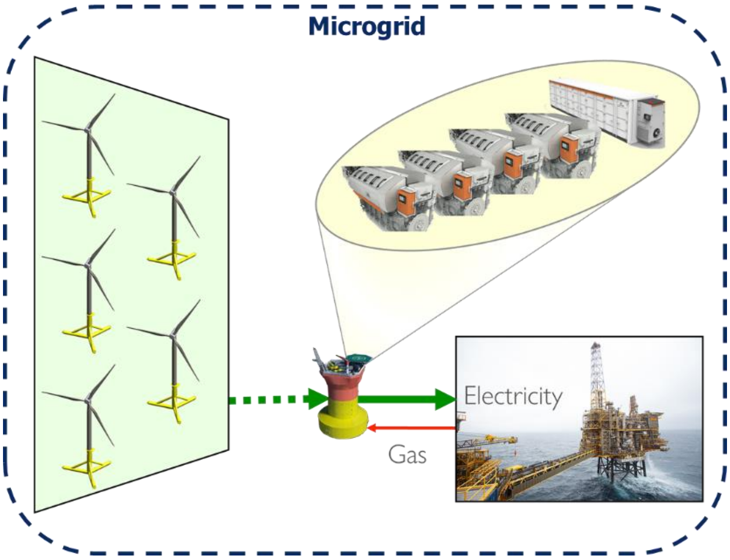


Figure 2: Conceptual microgrid layout

Platform modifications and the cable network

Of course, operators will need to make modifications to their platforms to be able to import power, to replace process heat, to change-out gas compressor drivers, and to decommission existing generators, and these costs are substantial. We have not attempted to optimise this part of the scope, though we have estimated the cost reductions accessible by changing the distribution voltage from 132kV to the 33kV we propose, and there is an opportunity to further reduce the distribution voltage, and hence modification costs, for platforms very close to the proposed distribution hub locations.

Installing more distribution hubs helps reduce the cost of the offshore cable network, and there is a trade-off between the cost of hubs and the cost of cables, which we have aimed to optimise.

Distribution Hubs

Our preferred concept for the distribution hub is to design a new floating facility, capable of supporting a 6,500 tonne topside, which does not need to weathervane and which is designed from the outset to be unmanned. In the interests of expediency, we describe a buoy based upon Crondall's BPT technology, but other approaches need not be ignored as we progress the engineering definition of the project. The BPT spar-buoy technology is being developed with support from BEIS in order to provide a suitable platform for floating substations for floating wind farms and for platform electrification. Our concept is to design one hub, but to deploy many; we expect six hubs could meet most of the demand in the Central North Sea, including the Outer Moray Firth, and the concept could be replicated in the Northern North Sea and West of Shetland.

Each proposed distribution hub will be designed to meet c. 80MW of demand and will have four or five 7.8MW 14V31DF engines, and the same number of 11.14MW 20V31DF engines, supplied by

Wärtsilä; with a 15MW, 1.5 minute battery to meet short term fluctuations in supply or demand. This energy storage system (ESS) minimises, but does not eliminate, the need for physical spinning reserves and contributes to frequency control and power stability. There is scope to reduce costs by trimming the back-up capacity if operators have the option to load shed inessential systems (say water injection) when the wind turbines are becalmed, but we have not assumed that in our initial system design.

Windfarms

In this report we lay out a range of costs for constructing and installing the windfarms; in particular, a 320MW wind farm in the vicinity of the Central Graben has been costed with support from BW & SBM. We intend to augment our consortium with an established player in the floating wind business and both of these companies are enthusiastic to join our team. We have focused on these established offshore contractors as our paramount goal has been to lay out a realistic plan to deliver the project and have it in operation by 2027. This goal remains in sight, but it will require potential customers to take up our offer to consolidate our consortium and progress the engineering definition of our solution very rapidly.

The companies we selected to make proposals to design, build and install the wind farm are all Tier One contractors with deep experience of delivering offshore projects and well-developed designs for the floating wind units. However, many alternative floating wind technologies could be deployed here and providing an opportunity for promising floating wind technologies to be included in the scope of this wind farm, as a means of accelerating technology development and enabling the proof of the myriad concepts being invented seems worthwhile. Interest in participating in this has been expressed by Wind Catching, Sea Wind, Floating Power Plant and Sea Twirl, which we have noted.

Emissions Reduction

Our analysis indicates that wind power can meet between 62% and 69% of power demand with the balance being delivered by the gas engines. Scope 1 emissions are just over 146 kgCO2e/MWh, well below today's grid and substantially below current offshore generator emissions, perhaps approaching an 80% reduction if the true inefficiencies of simple cycle gas turbines under partial load are taken into account.

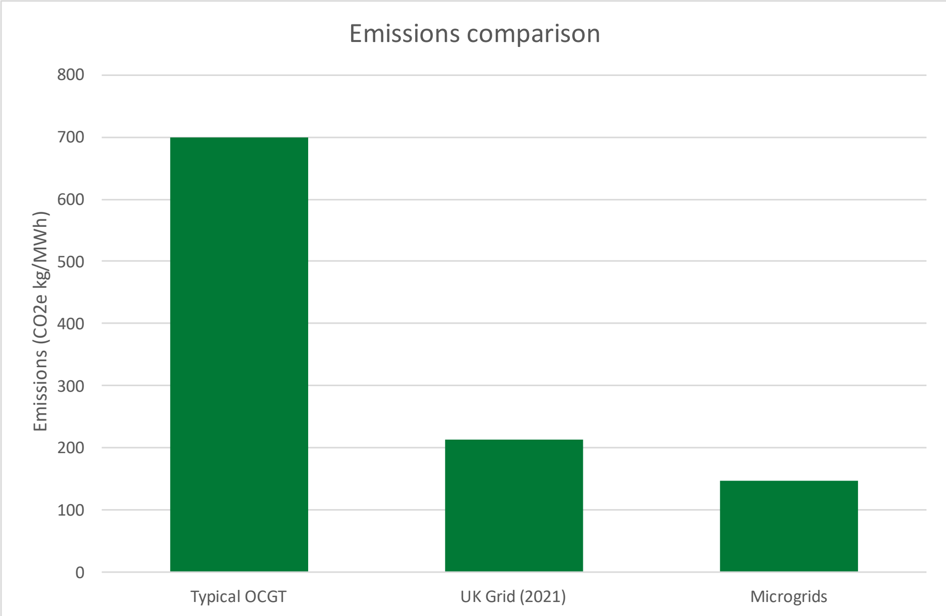


Figure 3: Electrification emissions comparison

Capital Costs

To provide context for our cost estimates, we present costs for three microgrids, serving nine platforms, that we would aim to install in the Central Graben. We compare this with the costs of a power from shore (PfS) option for the same platforms, assuming a connection to the UK grid. The costs of the distribution hubs are comparable to, but about 10% less, than the cost of onshore and offshore convertor stations and a cable to the Central Graben, but crucially this investment will enable the Operators to source low-cost, zero emission offshore wind power, rather than pay the price for wholesale electricity from the grid.

The cost of distribution cables, to and from three hubs located close to the facilities, is substantially reduced from the cost of cables to the same platforms from a single hub, the saving is about 40%.

We also estimate that the cost of brownfield modifications to the customer platforms will be modestly reduced by about 8%. This is due to power being delivered at close to the platform voltage, reducing the size and complexity of voltage step down, as well as the removal of any compensation due to the short cable distances and Enertechnos cable.

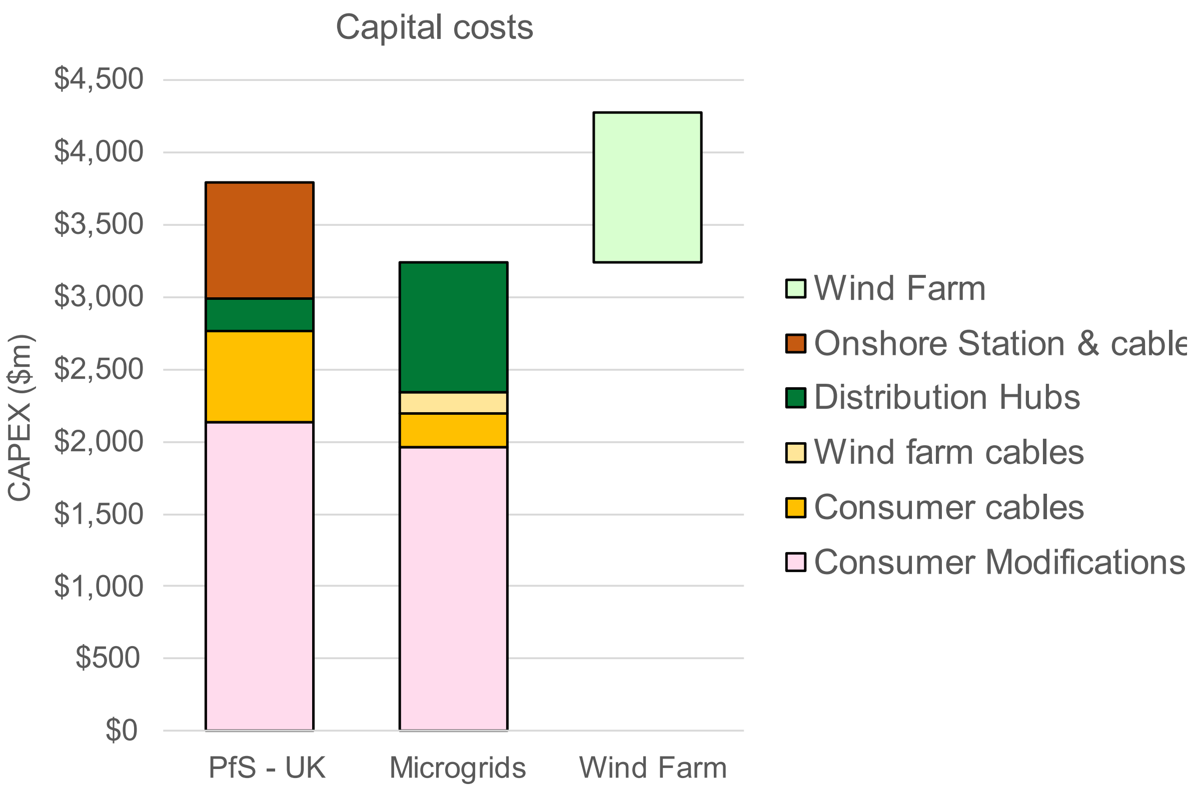


Figure 4 Capital cost comparison

Operating Costs

Importantly, annual operating costs of the system, including fuel for the gas engines, would be drastically reduced from over $300 million per annum, which is the cost of purchasing electricity in the power from shore UK option, to just over $80 million per annum, if the wind farm is included in capital costs.

This includes an allowance for carbon emissions taxes, assumed to be $100/tonne but not including the benefit of any free emissions allowances which Operators may have access to. Power purchase costs from the UK grid are assumed to be £110/MWh.

An estimate has also been made of the costs of operating the current system of onboard generation, Orcadian does not have access to the detailed information which would be required to estimate this accurately, but we have used parameters which we believe are not unreasonable

Wind farm costs can either be treated as a capital cost (Figure 4) or an operating cost, if power is purchased from a wind farm operator. Thus providing customers with flexible implementation strategies for the floating wind farm.

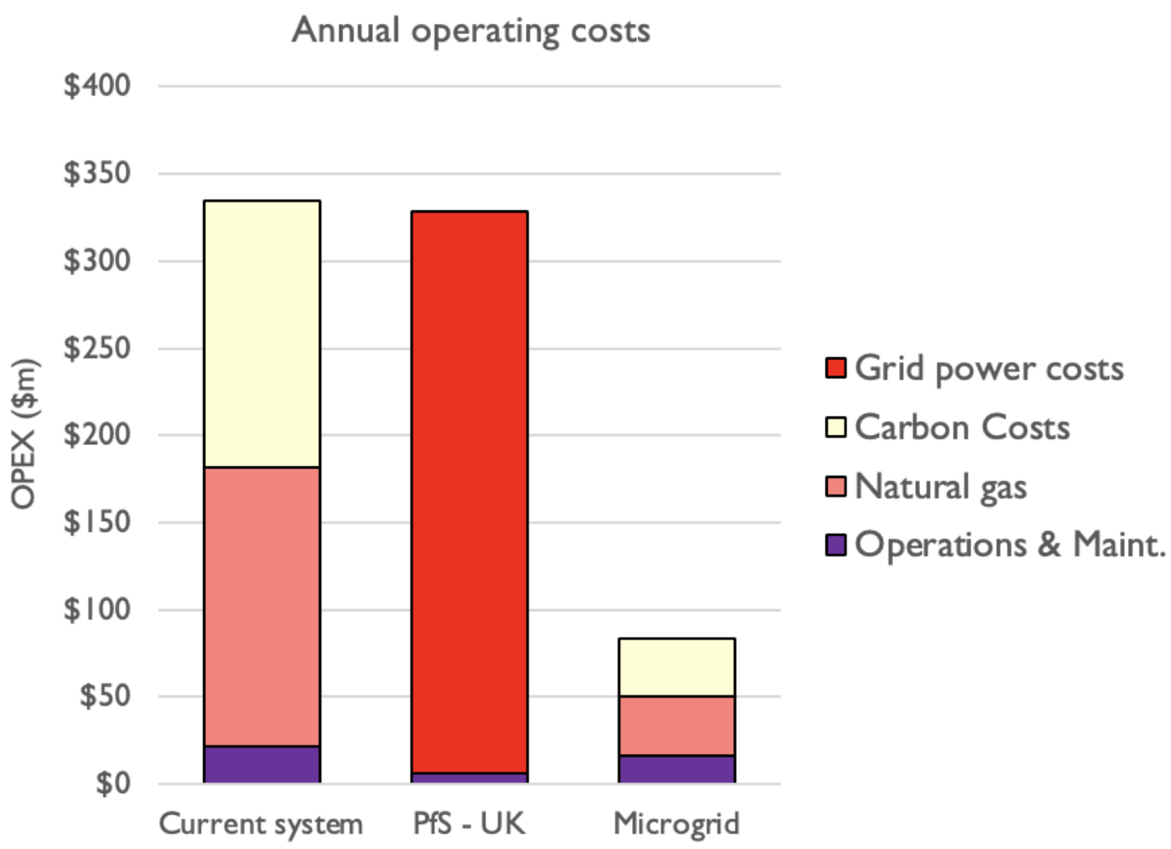


Figure 5 Operating cost comparison

Wind farm costs

The assumption of power costs for wind power are not based upon the wind farm costs from this report. If we assume that the entire capital cost of a wind farm, based upon the work undertaken by BW and SBM, is spread over ten years of demand the power cost would be c. $50/MWh, which is less than half the price of electricity sourced from the national grid. However, that does not include any return for the wind power developer. Typically, the cost of wind farms would be amortised over a much longer period, so how low-cost that power will be, will likely become dependent on the ability, to tie-back to the shore, those floating wind farms in a cost effective and timely manner so that no power or installed generation capacity is wasted, as platform demand declines. The novel cable technology we advocate will enable a later tie-in to the grid and a number of potential tie-in schemes are described in the report, but the ideal scheme will depend on which microgrids are ultimately constructed. In conclusion, an indicative levelized cost of electricity of $50/MWh may represent a reasonable estimate at this stage.

Total Costs

For simplicity, when comparing the total cost of the various schemes we include the entire capital cost of the microgrids, including the wind farm and the costs of operating and maintaining the microgrids, with the capital costs of the power from shore option and purchasing electricity for a ten-year period. In this scenario we are considering the electrification of nine platforms in the Central Graben with 250MW of power demand. We compare the total costs of our proposed system with the total costs of an onshore grid tie-in and convertor station, a cable to the offshore convertor platform, cables to the consumers, the expected costs of brownfield modifications, and of course the cost to purchase power from the grid. We assume a gas price of 50p/therm, an electricity price of £110/MWh, and an emissions levy of $100/tonne, as adopted in other UK industry studies, recognising that those are very far from current prices.

In terms of total capex and ten years of operation, the Orcadian solution is projected to save 26%, almost $2 billion, when compared to a power from shore UK option.

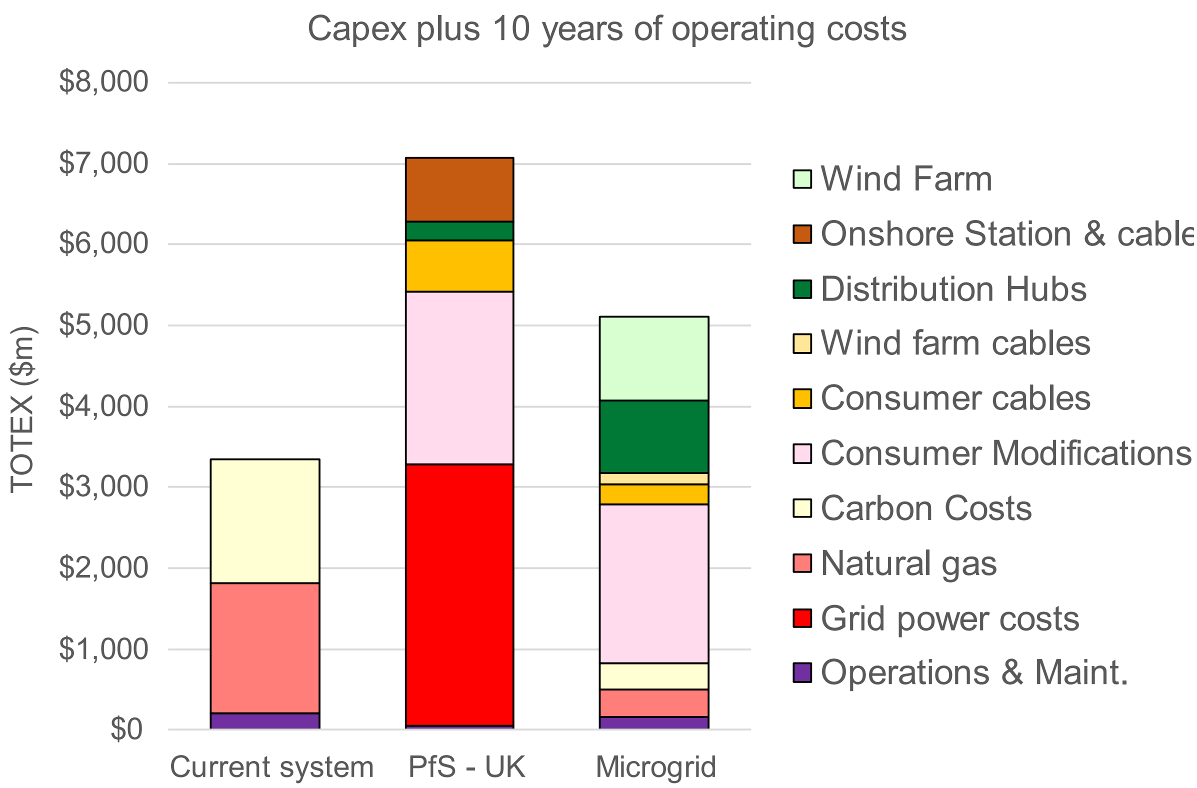


Figure 6: 10 Year TOTEX comparison

North Sea Transition Deal – 2030 target

The North Sea Transition Deal requires the offshore industry to reduce emissions by 50% by 2030. To meet this target the NSTA have identified that the entire UK offshore industry must achieve a CO_2 abatement of 3 million tonnes per annum. Implementing six Microgrids, for the CNS and OMF only, would deliver 98% of the 2030 abatement reduction target for the entire UK offshore industry. In comparison we estimate that the power from the UK option would deliver 88% of the same target.

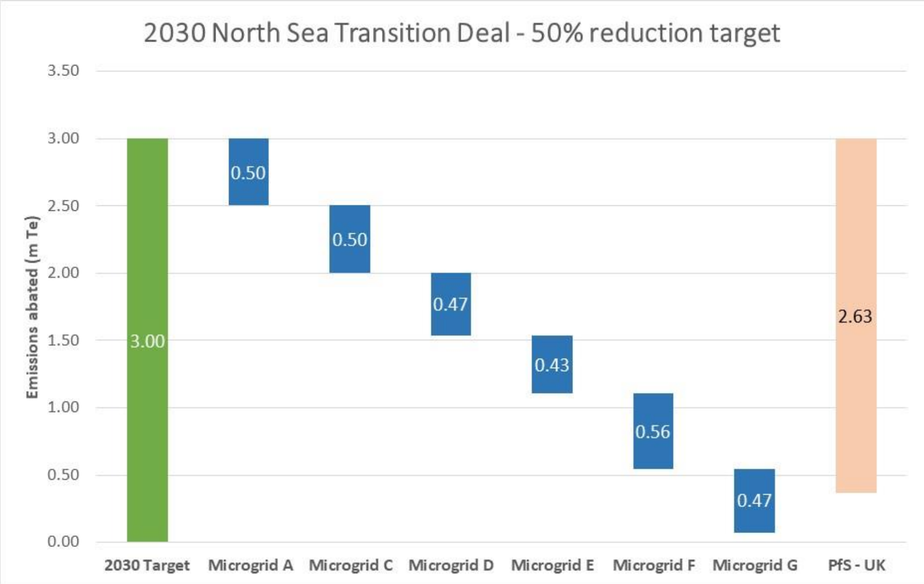


Figure 7: 2030 North Sea Transition Deal target

Rather than maximising emissions abatement there is an opportunity to save significant costs by reducing the wind farm size from 120% to ~35% of demand, this would still enable facilities to abate 50% of their emissions, while reducing the cost of each Microgrid. This provides an opportunity to adjust capital costs and to optimise the abatement costs across the industry, with the size of the wind farm to be agreed with the participants in each Microgrid.

Abatement Cost

If we consider electrification of the Central Graben region (250MW)[1], we expect to abate 1.47 million tonnes/annum. If that abatement were to continue for 10 years, 14.7 million tonnes would be abated. This is a longer period than currently expected, but is not an unreasonable assumption, given the propensity for Cessation of Production dates to be deferred as Operators develop incremental reserves and drive down operating costs, which can indeed be a feature of this solution.

The incremental costs, excluding emissions taxes, of implementing the microgrid scheme when compared to the current operational paradigm is about $3 billion. This equates to $200/tonne, whilst a power from shore scheme abatement cost is about $360/tonne when calculated on the same basis.

Energy Security

For the microgrid option, however the commercial arrangements are structured, there will be a very substantial reduction in the future cost of power (once we take into account maintenance and obsolescence of current generation equipment) and this cost saving will materially reduce late life costs for these platforms, potentially deferring cessation of production, maximising economic recovery, and contributing to UK energy security.

[1] Requiring microgrids A, C, & D defined in section 3.3 of this report

Adoption of Microgrids, eliminates a new burden on the grid; diversifying power supply to Central Graben fields, when compared with a single cable which is vulnerable to accidental damage; and by accelerating the deployment of floating wind technologies in line with recent UK Energy Security Strategy goals and Scottish Government's objectives.

Schedule

The Microgrid project can be delivered and be in operation by the beginning of 2027. However, to meet this schedule we would need to have the whole-hearted support of the operators firstly to define the project, and secondly to structure the financing of the project, as soon as possible.

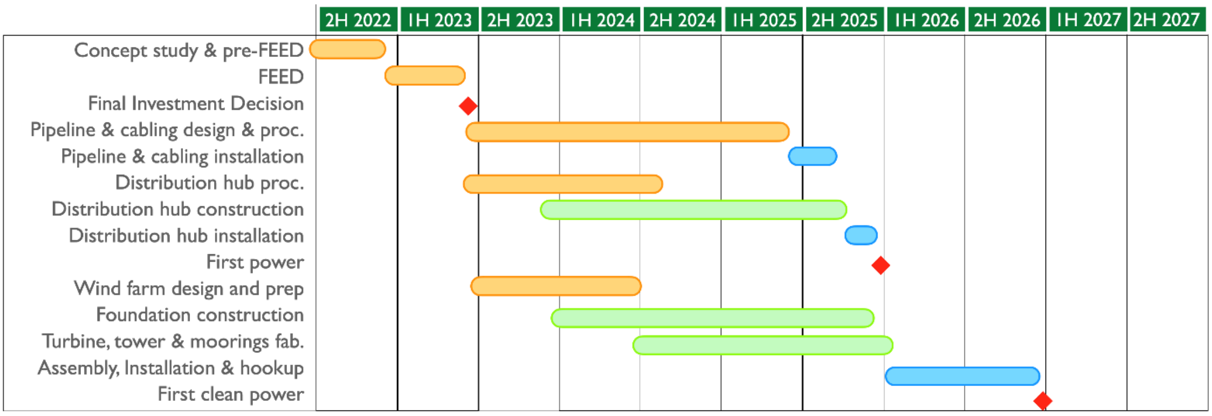


Figure 8: Microgrid delivery schedule

The schedule above is based on a mid 2022 commitment to progress the project (with Final Investment Decision in mid 2023), and it shows an overall duration of approximately four and a half years from the start of the conceptual study to the microgrid being fully installed and ready to provide decarbonised power to the oil and gas production facilities. This is based upon a single microgrid, however multiple microgrids could be developed in parallel enabling rapid electrification of the North Sea.

Importantly, the first distribution hub could be operational at the beginning of 2026. This will immediately impact emissions, with a potential reduction of c. 35% for the connected facilities, the same as the Hywind Tampen project, even before wind power is brought online; this can be achieved before the wind farm is commissioned because the distribution hub generators and architecture are much more efficient than open cycle gas turbines located on individual facilities. This will also provide operators an opportunity to reduce power generation OPEX and build confidence in the performance of the system before decommissioning their existing generators.

Project Delivery

The proposal developed by the Orcadian led consortium offers field operators and owners with the opportunity to bi-laterally purchase a reliable supply of decarbonised electricity delivered to their platform. With the microgrid solution, and its benefits, capable of scaling from a single facility to multiple, reducing the complexity of electrification compared to a basin wide power from shore concept. Power purchase agreements are to be agreed with individual customers, this could include free issue of gas in order to ensure the generation of back-up power, and retaining the liability for the policy costs of the remaining carbon emissions.

Key to our approach is the early participation of the supply chain in our consortium, we have benefited from the involvement of Petrofac, Wärtsilä, Enertechnos, and Schneider Electric in the overall design of the solution and their early engagement gives us confidence that we can structure a project delivery consortium which can underpin the delivery of the project. Further engagement with key suppliers of wind turbines is essential, and we intend to build upon the existing relationships or either BW Ideol or SBM who have invested significantly in these relationships and in building the internal capability to deliver on floating wind projects.

At this early stage in the project it is not possible to make a detailed or firm commercial proposal to potential customers, however, with their support, this can be developed as the project progresses through the completion of pre-FEED and FEED.

Separate from this report, we intend to prepare a phased work programme to progress the project through to a sanctionable state and we will seek funding for this work programme from the operators of the facilities we intend to serve. The scope of this work programme will depend upon which companies and fields elect to participate but we would aim to do the following:

- Preliminary environmental impact assessment;
- Concept definition and pre-FEED engineering work, all in conjunction with customers:
    - Electrical specification, preparation of a basis of design and functional specification for the wind farm, distribution Hub and cables, confirmation of gas import options;
    - Final selection of distribution hub floating structure;
- Identification of preferred wind turbine contractor and developer and engagement in a partnership with the Consortium;
- Supporting application(s) in the INTOG process
- Preparation of a detailed cost estimate and schedule, recognising that the buoy could precede the wind farm;

A second phase of work in the run up to project approval could entail:

- FEED level engineering definition of the Distribution Hub;
- Environmental, ornithological and marine surveys;
- Preparation of an Environmental Statement;
- Selection of EPC and installation contractors;

This work package could be for a single customer with a small distribution hub and wind farm, or for multiple customers with many distribution hubs and a number of wind farms. With the support of interested potential hub customers, the Orcadian consortium would propose to coordinate and lead this work scope in addition to developing a mutually acceptable commercial proposal.

1 Introduction

1.1 Background

In the UK Government's "Net Zero Strategy" published on the 19th October 2021, the government asked for a "step-change abatement of emissions to be delivered by the electrification of existing and new offshore assets, through connections to onshore networks or offshore renewables.". Previous industry work on electrification of the North Sea from shore has concluded that "the economics of electrification are very challenging and require improvements across several areas including government, regulatory and fiscal support".

Funded by the NSTA, the Orcadian consortium consists of Orcadian Energy, Crondall Energy, Petrofac, Wärtsilä, Enertechnos, and North Sea Midstream Partners and has developed an innovative solution which realises significant emissions reduction through electrification of existing Central North Sea (CNS) facilities, whilst also breaking down the electrification problem into manageable pieces.

The solution described in this document entails the construction and operation of local wind farms, which will supply intermittent electrical power to distribution hubs located close to the customers platforms and existing gas infrastructure, with highly efficient, gas fuelled, reciprocating engines, and battery back-up power located upon them, to create a number of microgrids. These will supply highly reliable and very low emissions electricity to CNS operators, starting in the Central Graben region.

The microgrids aim to minimise brownfield modifications on oil and gas facilities receiving the power by using Medium Voltage (MV) Alternating Current (AC) distribution, and an innovative cable technology to minimise losses from MV AC power distribution. Importantly the system is designed to be operated in both conventional and CTS mode.

1.2 Aim of the study

The aim of this study is to:

- Develop the conceptual design of a microgrid power hub concept to
  - Drive down offshore emissions
  - Provide a lower cost option compared to power from shore
- Demonstrate to potential customers that this approach can be implemented on an accelerated timescale.

The Orcadian consortium has considered it to be vital to remember during the conceptual design phase that the needs of the consumer are the priority, and our approach has been to demonstrate a secure, decarbonised, reliable power source that will be relatively easy for operators to incorporate into their facilities.

1.3 Purpose of this document

The overarching intent of this document is to communicate the conceptual design for electrifying North Sea oil and gas production facilities with microgrids that transform intermittent wind power into reliable, decarbonised power. It is important to remember that the solution described herein does not all have to implemented in one grand project to succeed and that the likely final architecture of the solution will gradually evolve from what is described, as the system will grow organically as customers subscribe to the solution, or not.

Nevertheless, we feel it is important to illustrate the full potential of this system in the CNS, so the document provides the following information related to the proposed microgrids;

- Approximate location and size of the facilities;
- The most appropriate architecture for the microgrids;
- An evaluation of offshore wind farm technology providers;
- The conceptual design of back-up power generation using battery storage and gas fired reciprocating engines;
- A Class V probabilistic CAPEX estimate for each Microgrid;
- A commercial strategy for how the project can be delivered;
- Estimation of the GHG emissions for the lifecycle of the project;
- A high-level road map to delivering net zero power from the microgrids.

1.4 Consortium

Development of the microgrid solutions has only been achieved by extensive collaboration between the consortium members, Orcadian Energy, Crondall Energy, North Sea Midstream Partners (NSMP), Wärtsilä, Enertechnos and Petrofac.

Orcadian Energy are the custodians of the microgrid concept, acting as the microgrid system operator, owner of the commercial model, and the technical concept.

Crondall Energy are Orcadian Energy's client engineering team, managing the delivery and development of the Microgrid concept.

North Sea Midstream Partners (NSMP) are an infrastructure investor who are also supporting the development of the commercial model for the microgrid concept.

Wärtsilä are a global leader in innovative technologies and lifecycle solutions for the marine and energy markets. Wärtsilä are a key equipment vendor for the microgrid concept, providing highly efficient, low emissions gas fired engines, as well as the energy storage system.

Enertechnos are a cable technology provider, with their patented cable providing the potential for a significant increase in the transmission distance for MV AC power.

Petrofac is a global energy services company providing expertise on how to implement the microgrid concept from an Engineering Procurement and Construction (EPC) and Operations & Maintenance (O&M) perspective.

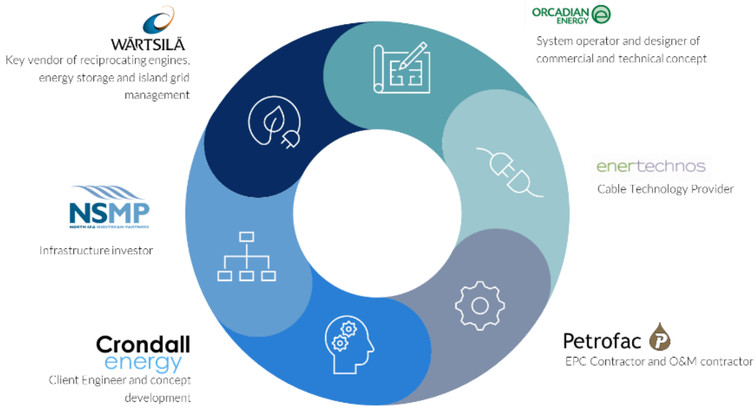


Figure 1-1: Microgrid consortium

Additional support has been provided by **Schneider Electric** who assisted with the development of the distribution system and the associated automation system.

Multiple floating wind vendors have been consulted with respect to the wind power generation technology.

1.5 Project workshops

To maximise the input of the consortium members during this project a series of virtual workshops were held with the purpose of:

- Gaining engineering input from across the disciplines and engineering experience and expertise;
- Holding 'brainstorming' sessions with respect to concept selections;
- Peer-reviewing concepts put forward by Crondall and Orcadian.

The workshops held as part of the study, and their purpose, is outlined in the table below.

Workshop	Purpose
Scenario identification	A blank canvas approach to identify all possible solutions for delivering reliable, low emission power to North Sea facilities, without a connection to the national grid.
Floating wind selection criteria	To peer review the selection criteria for floating wind providers.

Workshop	Purpose
Concept review	Review of the short listed microgrid concepts. Focus on reviewing the proposed microgrid architecture for the North Sea, load profiles, gas tie-in points, cable considerations, back-up power generation and topsides equipment requirements.
CAPEX review	Present and review the assumptions, methodology, and results of the Class V CAPEX estimate.
Lifecycle emissions review	Present and review the estimated greenhouse gas (GHG) emissions associated with the microgrid over the full lifecycle of the facility.

Table 1-1 Summary of study workshops

2 Concept selection process

There are multiple oil and gas production facilities located all around the Central North Sea area and a myriad of means to interconnect and supply these platforms with power. To design and frame the consortium concept select workshop, some initial screening regarding power generation alternatives, wind turbine location, back-up energy options, the size of the power hub required, location of wind farms, alternative fuels, carbon capture and power cable technology was completed.

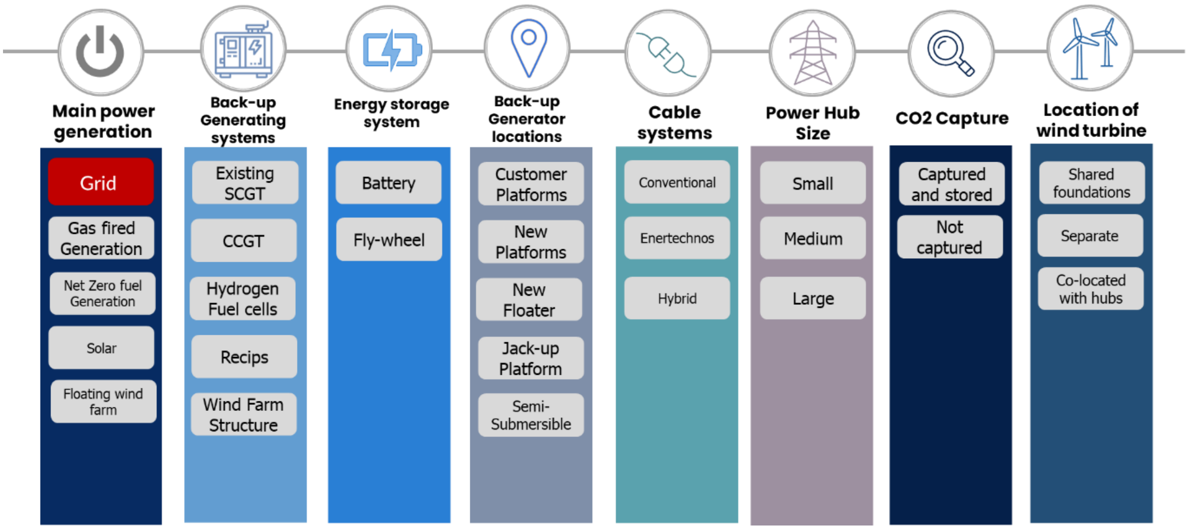


Figure 2-1: Concept mapping

2.1 Initial screening questions

2.1.1 Main power generation

The purpose of this study was to establish an off-grid option so alternatives that required a grid connection were not considered (hence on-gird alternatives being denoted in red above).

To drive down emissions the main power generation for the microgrid should come from a renewable source. The only viable renewable energy source, that could provide sufficient power to the microgrid, is wind power.

Solar panels would not be effective in the Central North Sea to power the microgrid due to the limited daylight hours and strength of the sun. The potential for emissions reduction is extremely limited.

Technology deriving power from the waves is still very much in its infancy with test devices able to produce a couple of MW of power. These devices are subject to significant wear and tear and the fatigue life for this technology is an area of concern. Wave power could augment wind power but is not a standalone option currently.

On the other hand, the Central North Sea is inherently suitable for generating power from the wind due to the consistent high wind speeds all year round, day and night. Wind turbine technology is well proven, with ever increasing capacity, but it is acknowledged that floating wind turbine technology is still at an early stage of development. This study has completed a market screening of companies offering offshore wind power generation technology (See Section 7).

2.1.2 Back-up power generation alternatives

Given that the bulk of the power will be provided by wind turbines, and the requirement to ensure that the power supply is uninterruptible and decarbonised, additional and efficient back-up power generation is required. Four main options were considered:

- New simple cycle gas turbines;
- New combined cycle gas turbines;
- New reciprocating engines;
- Utilisation of existing power generation facilities on the oil and gas production facilities.

Power generation type	Advantages	Disadvantages
Simple cycle gas turbines	• Proven technology in an offshore environment • Good power density (power per unit equipment weight) • Less maintenance than other power generation types	• Poor efficiency ~30% • Limited GHG emission reduction potential • Low efficiency at low loads, particularly less than 60%. Microgrid power generation will need to be flexible to match changing output from wind farms • Limited fuel flexibility, natural gas only
Combined cycle gas turbines	• Good efficiency ~45% offshore and 60% onshore	• No fuel flexibility, natural gas only • Limited application in an offshore environment • Low efficiency at low loads, particularly less than 60%.
Reciprocating engines	• Good efficiency, ~49% and emissions reduction potential • Proven technology – used in the shipping industry for many years • New engines are designed to be retrofittable for alternative fuels such as ammonia, leading to increased GHG emission reduction potential • Good turn down capacity without compromising efficiency • Significant GHG emission reduction potential • Quick response, a gas engine can start-up in less than a minute.	• More maintenance required than simple or combined cycle gas turbines • Lower power density than SCGT

Power generation type	Advantages	Disadvantages
Existing power generation facilities	• Reduced microgrid CAPEX	• Facilities have been in operation a number of years and maintenance requirements will be high • Reduced potential GHG emissions reduction as existing facilities utilise SCGTs which have a low efficiency • Existing generators will be low loaded, due to wind, reducing efficiency and increasing emissions • Power distribution/management more complex (balancing intermittent wind power), as interfacing with multiple legacy automation systems • Battery storage is still required. This will need to be located on a separate floating structure or on the existing oil and gas production facility resulting in increased brownfield modification work

Table 2-1: Power generation types considered

Reciprocating engines may require more maintenance than simple cycle gas turbines or a combined cycle gas turbine but the increase in maintenance is not considered too onerous, especially given the reduced running hours possible as the engines will be used for back-up power only. The facility can still be designed as a normally unmanned installation and will not result in excessive or significantly increased maintenance visits. This study has assessed the maintenance requirements and included them in the GHG emission and OPEX estimates. The lower power density associated with reciprocating engines is an issue but as the difference will not materially impact the structure type selected (floating), and the costs associated with additional structural steel required are not large, this feature will have limited negative impact on overall project economics.

The disadvantages associated with reciprocating engines are far outweighed by the advantages. They are extremely efficient, highly responsive, offer good flexibility with turndown capacity without compromising efficiency and companies such as Wartsila have developed engines that will be able to run on alternative fuels with minimal modifications. These technical aspects will enable significant GHG emission reduction compared to gas turbines.

2.1.3 Energy storage system

To balance the power supply and demand as well as ensuring the frequency of the power supplied is within the correct range, in addition to spinning reserve, an energy storage system will be required in the form of batteries, alternative options will be reviewed in future phases of this project.

2.1.4 Location and type of back-up power

The wind farm, back-up power generation and the energy storage system could be located on the same facility or on different floating structures. If on different floating structures, the facilities could be located near to each other, or the back-up power generation could be located closer to the oil and gas production facilities consuming the power in order to optimise power cable lengths.

The final location of the facilities was given considerable deliberation and the conclusions are addressed in the summary of the consortium concept select workshop, see Section 2.2 .

2.1.5 Cable systems

A variety of power distribution solutions are available for the microgrid, these include; MV DC, HV DC, MV AC, and HV AC. To minimise cost, the concept focused on MV AC solution which would minimise modifications for electrification of facilities and simplify regulatory requirements. The microgrid design has leveraged, but does not rely upon, the Enertechnos innovative cable design, to reduce costs.

Transmission at MV AC reduces facility modifications and associated cost compared to alternatives as power can be supplied close to the platform's voltage. This removes the requirement for larger converter stations (HV DC), large switchgear (HV AC). While the short connection distance and Enertechnos cable reduces the cable dimensions and removes the need for compensation onboard the facility, both of which reduce cost.

2.1.6 Microgrid size

The microgrid can be designed to supply different power demands, and to supply single or multiple oil and gas production facilities. The more oil and gas facilities that are to be supplied with power from a single microgrid, the longer the cabling for power distribution, and the more operators and partnerships that will be involved in the decision to invest in the microgrid. The latter will increase the complexity as all the operators will need to be in agreement to the terms and conditions offered to them. If the microgrid is made too small, then economies of scale will be lost and the associated economic benefit. The microgrid size will need to consider all these factors when grouping the oil and gas production facilities. We have iterated towards distribution hubs of ~80MW serving either single facilities (Elgin/Franklin) or multiple co-located platforms.

2.1.7 CO2 capture & net zero fuels

Carbon capture units could be installed on the back-up power generation units whether they be reciprocating engines or gas turbine type. This could impact the floating structure type or the location of the back-up power generation. This would add cost and complexity to the project, especially regarding disposal of the CO2.

Net zero fuels have also been considered as a means to mitigate future CO_2 emissions. At present it is too soon to be certain which fuel will be readily available from a low-carbon source, but during the concept select process the consortium has considered the potential designs that could be future proofed and achieve net zero targets with the use of alternative fuels.

Selection of engines capable of running on low-carbon fuels appears the best option to enable future emissions reduction.

2.1.8 Wind turbine location

The question of whether the wind turbine would be located on its own separate structure or on the same structure as the back-up power generation and energy storage, was addressed in the workshop, see Section 2.2 .

We preferred independent structures as this choice maximised the optionality in selecting the floating wind technology and minimised any necessary redesign of the wind turbine foundations. Both the Floating Power Plant and Wind Catching designs could be modified to incorporate back-up systems, but the immaturity of the Wind Catching design and the comparative costs of the Floating Power Plant system confirmed the value in keeping the back-up systems separate from the wind turbines.

In addition, when the wind turbines are located on their own structures there is more flexibility in the location of the wind farm which can be positioned to optimise helicopter operations, interactions with existing facilities, environmental concerns, and cable lengths. In addition, the same wind farm can supply power to multiple power distribution hubs. For the Central Graben we have selected a provisional location for the wind farm which would then serve three distribution hubs.

It may be possible to connect to a nearby planned wind farm. For the purposes of the concept select screening this option is not explicitly included. However, we did consider this approach, specifically using power from the proposed GreenVolt wind farm, when looking at options to power microgrids in the Outer Moray Firth.

2.2 Consortium concept select workshop

As part of the concept select process a blank canvas approach was taken by the Orcadian Consortium, with a dedicated workshop to identify all possible concepts for the microgrids. The concepts considered worthy of further evaluation by the participants in this workshop are shown in Table 2-2 and expanded upon below.

Scenario 1A and 1B: Wind turbine & back-up power generation on individual facilities

The major drawback in this concept (See Figure 2-2) is that existing floating wind turbine designs have been designed such that each turbine has its own floating structure and typically those foundation are located relatively close to the water.

Figure 2-2: BW Ideol's Floatgen unit during a winter storm (22nd December 2019)

The floating structure would require significant modifications to be able to house the additional topsides and have room for power generators, battery storage and power distribution as well as the associated ancillaries. Topsides facilities are not normally located so low to the water as they are at risk of being exposed to green-water loading. If the topsides structure was raised there will be an impact on the wind turbine design which would require additional testing to demonstrate its fatigue life under the new operating conditions.

Floating wind units which are weathervaning would lead to technically complex and costly turrets and sliprings with an onerous ongoing maintenance requirement. Each wind turbine structure would need to have a dedicated gas supply with an associated riser, which could lead to asset integrity issues and a requirement for hazardous area classification of the electrical equipment on the wind turbines. A gas metering skid would be required on each wind turbine structure. All these aspects could lead to an impractical design with excessive costs, technical complexity and concerns over technical safety.

As a result, this concept has not been considered suitable for the microgrid.

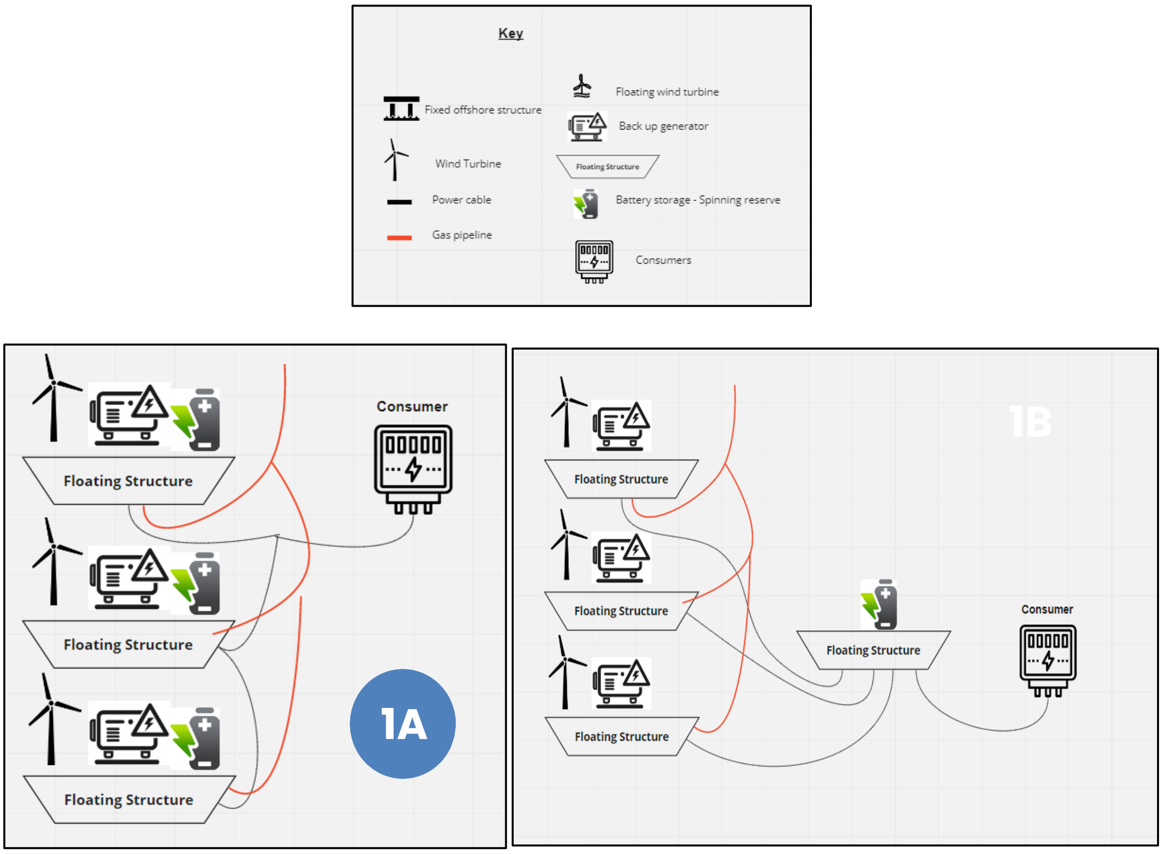


Figure 2-3: Scenario 1A and 1B

Scenario 3A and 3B: Wind turbines connected to a central power hub located on fixed facility

A new platform could be purposely designed for the microgrid, space could be provided for future carbon capture units or storage of alternative fuels. This type of facility is only suitable for shallow water depths and the deeper the water, the more the structure will cost. Based upon Orcadian's recent experience with CAPEX estimations for wellhead platforms on the Pilot field development, we expect that a floating structure would cost roughly the same as platform, at water depths of roughly 100m, though the potential savings in 80 metres of water are minor. Most of the Central North Sea has a water depth of between 80 and 150m, thus for much of the Central North Sea a floating structure would be more economical, and of course we can replicate the entire design of a floating facility much more easily than a fixed platform.

A jacket and topsides would not be redeployable and decommissioning costs would be higher. The period over which the platform may be required to supply power could be limited as the existing life of many of the oil and gas production facilities in the Central North Sea are between 5 and 10 years. Hence having the possibility of redeploying a unit is highly advantageous, which is limited for a fixed facility.

Using an existing platform for the back-up power generation and distribution could reduce the potential CAPEX associated with the back-up power generation hub. However, an existing fixed facility is unlikely to be in a location that would be optimal for power cables from the wind farm to the fixed facility housing the back-up power generation and from the fixed facility to the consumers. For an existing fixed facility, the original topsides will require removal, which will have to be done offshore at considerable cost. An ageing asset will have increased maintenance requirements and is not redeployable. After the existing facility has been repurposed it will still need to be decommissioned. The work required in refurbishment and life extension of an existing platform will not be known without detailed surveys and completing such work offshore will be expensive. Any savings in CAPEX in using an existing structure are likely to be eaten up quite quickly. A microgrid concept using this solution would not be repeatable or scaleable.

An existing Jack-up rig could be an option but the possibilities are limited as the units that might be available can only be deployed in shallower waters. Jack-ups that can drill in up to 120 metres of water are in high demand. It would be more advantageous to look at redeploying an existing semi-submersible drilling rig or floating production unit and this idea has been incorporated in Scenario 2, the preferred concept.

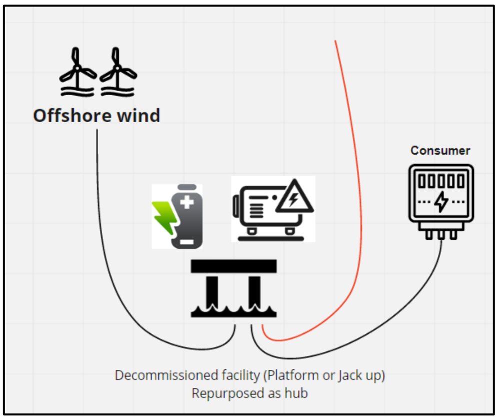


Figure 2-4: Scenario 3A

Scenario 4: Wind turbines, with back-up generation from existing production facilities

This scenario where power comes from wind turbines, with the back-up power generation from the existing production facilities and only energy storage being located on a separate facility, provides an opportunity to reuse existing infrastructure and removes the need for a dynamic cable at the distribution hub by re-using the power generation on the existing fixed oil and gas production facilities for back-up power.

However, the power generation on the existing oil and gas production facilities are simple cycle gas turbines which will severely limit potential emission reductions, ageing power generators will require increased maintenance and they will not be suitable for conversion for use with alternative fuels.

The existing power generators could be replaced with new reciprocating engines but extensive modifications to the topsides would be required, and these would have to be completed offshore. Reciprocating engines are typically heavier than gas turbines and the platform may not have the capacity to accommodate sufficient gas engines.

The production facility is likely to need to be shut down in order to install the new engines resulting in a loss of revenue for the facility. The concept could be used across multiple facilities but redeployment possibilities are poor. Considering these facts this concept has not been considered to be the preferred scenario.

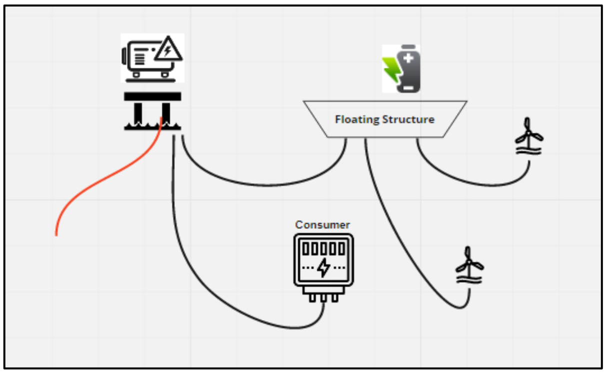


Figure 2-5 Scenario 4

<table>
<tr><th>Scenario</th><th>Concept</th><th>Opportunities</th><th>Risks</th></tr>
<tr><td>1A</td><td>Wind turbines, back-up power generation, and batteries co-located on the same foundations.</td><td rowspan="2">• Scalable approach
• Standardised approach</td><td rowspan="2">• Limits wind turbine structures that can be considered and/or may require redesign of structure to be suitable for wind turbine
• Multiple gas risers and associated asset integrity issues (overpressure protection requirements)
• Gas inventory on each structure will change hazardous area classifications and a number of technical safety requirements
• Limited potential storage for net zero fuels
• Multiple bunkering required (diesel and net zero fuels)
• Each floating structure will require its own ancillary systems (inc metering), increasing maintenance, CAPEX and OPEX</td></tr>
<tr><td>1B</td><td>Wind turbine and back-up power generation co-located on the same foundations, with the battery storage on a separate floating structure.</td></tr>
<tr><td>2A</td><td>Wind turbines connected to a central back-up power hub with both back-up power generation and battery energy storage on the same floating structure.</td><td rowspan="2">• Scalable system
• Potential to locate the power distribution hub close to the consumers and keep turbines away from platforms/helicopter operations
• Single gas riser required
• Easier to future proof with potential for installation of carbon capture or the use of alternative fuels
• Allows flexibility of the renewable energy source
• Potential for excess wind energy storage
• Potential for onboard generation of net zero fuels (hydrogen/ammonia)
• Larger structure reduces impact of motions
• Potential for accommodation/local control room if later deemed required</td><td rowspan="2">• Single point of failure (with a robust design in place, this risk should be mitigated)
• For weathervaning floating installations, a complex slip ring is required (select foundations which do not weathervane).</td></tr>
<tr><td>2B</td><td>Wind turbines connected to a central back-up power hub with back-up power generation and battery energy storage on separate dedicated floating structures.</td></tr>
</table>

Scenario	Concept	Opportunities	Risks
3A	Bottom fixed structure - Decommissioned facility, platform or jack-up, repurposed as a power distribution hub with separate offshore wind farm.	• Removes the need for a dynamic cable • Potentially reduced CAPEX • Single gas riser • Easier to future proof with potential for installation of carbon capture or the use of alternative fuels	• Unlikely to be repeatable in every microgrid • Fixed platform is water depth dependant and only suitable for shallower water depths • Repurposing an existing facility may mean a compromise on design capacities and ability to future proof the facility • Requires decommissioning of the fixed structure and removal of topsides, timing unlikely to be guaranteed • Can't be relocated/redeployed • Maintenance of ageing substructure
3B	Bottom fixed structure - New facility, platform or jack-up, repurposed as a power distribution hub with wind farm separate.	• Removes the need for a dynamic cable • Potentially reduced CAPEX • Single gas riser • Well understood structure for hub facility • Potential to future proof with design allowing for installation of carbon capture or the use of alternative fuels	• Water depth dependent fixed platforms only suitable for shallow water • Fixed platform may not be redeployed/relocated • Design considerations required for alternative fuel storage/carbon capture • Maintenance of substructure
4	Wind turbines with back-up power generation from existing production facility and energy storage on a separate facility	• Fewer moving parts – existing facilities provide main generation • Existing gas riser • Reduced CAPEX • Repeatable design	• Inefficient generation – decreasing potential emissions reduction • Contracting issues, as power generation owned and maintained by O&G operator • Control of power hub – generation scheduling • Considerable upgrade needed to ensure grid management system can control existing generators • Beholden to other facilities availability – impacted by their maintenance risk • Very disruptive to switch to net zero fuels – generator capability, storage space etc

Scenario	Concept	Opportunities	Risks
5	Wind farm with subsea energy storage and separate back-up power generation facility	• Reduces the space for topsides or creates spaces on the topsides for alternative equipment such as carbon capture unit or alternative fuels storage.	• Overcomplicates process, limited potential benefit • ROV required for maintenance • From an electrical perspective not ideal to have subsea connections • Requirement to marinise equipment • Reduces future flexibility • Still requires separate facility for power generation

Table 2-2 Concept selection workshop results

2.3 Preferred option, Scenario 2A

The consortium's preferred concept is to have the wind turbines on their own dedicated structures, a separate floating structure to house the back-up power generation, energy storage and power distribution. It has been considered that Scenario 2B with energy storage and back-up power generation on different floating structures would be more expensive and only increase the technical complexity of the microgrid. Scenario 2A enables both the wind farm and back-up power generation hub to be redeployed, increasing the likelihood of the facilities being reused in the future. This concept is scalable to provide the power output required by the consumers, the design can be repeated on different microgrids and only one import gas riser is required. The commercial arrangements for power offtake agreements with multiple parties would be simpler, than other concepts.

The floating structure containing the back-up power generation and distribution could be an existing facility such as a semi-submersible drilling rig or Sevan 300 series or a purpose built unit.

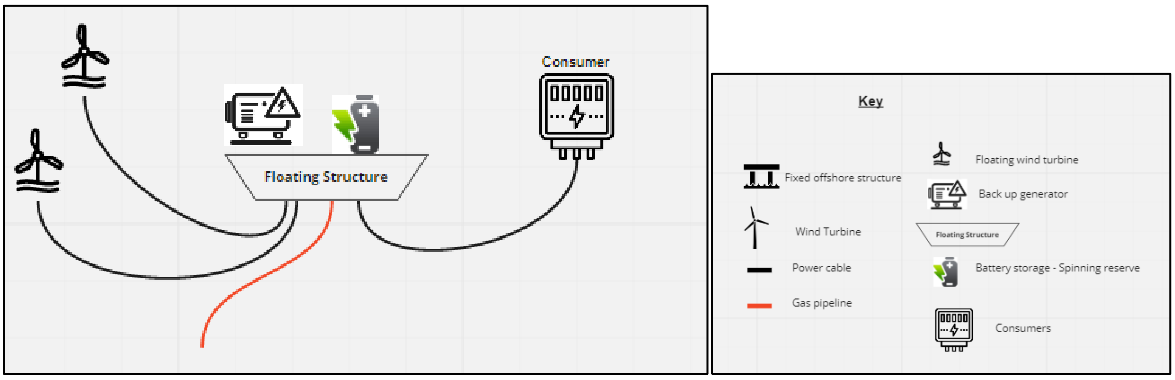


Figure 2-6 Preferred microgrid concept

3 Microgrid architecture

Electrification concepts to reduce GHG emissions from North Sea assets have, to date, focused upon a connection to shore, with power provided by either the UK or Norwegian Grid. This requires the use of extremely long and expensive cables and significant onshore and offshore infrastructure, as well as reinforcement of the national grid. There are also potential issues about ensuring an uninterruptible power supply, and it may not be wise to have a quarter of the UK's gas supply dependent upon a single cable to shore. Finally, for a power from shore project it will be difficult to tailor all the requirements of the different operators and to allocate the costs involved in an equitable manner.

The proposed microgrids shift the focus of electrification of North Sea assets from connection to the national grid to local generation. Microgrids provide all the necessary infrastructure to enable reliable generation of decarbonised power local to the consumer, without the need for connection to the grid.

The following section outlines the selected microgrid architecture, and its components.

3.1 Microgrid concept

The core concept of a microgrid is a self-sufficient energy system that serves local consumers with reliable, decarbonised power.

Workshops conducted by the Orcadian consortium identified and evaluated several conceptual layouts for the microgrid. The selected concept is shown in Figure 3-1 and has the following key components:

- **Floating wind farm**
  Cornerstone of the concept, enabling the microgrid to deliver low emissions power. The wind turbines have a floating structure to ensure the solution is independent of water depth and the design developed can be used across the North Sea.
- **Floating distribution hub**
  Floating facility ensuring applicability across the North Sea and to enable a "design once, build many" philosophy. The distribution hub houses all back-up power generation and distribution equipment as well as the associated ancillaries for providing power when the wind farm can't meet the required demand.
- **Cabling**
  Cabling between the wind farm, distribution hub and consumers.
- **Gas import**
  Gas will need to be imported, metered and conditioned for the back-up power generators. The route through which the gas is imported is dependent upon microgrid location and the nearby gas export infrastructure.
- **Consumer**

The consumers are the oil and gas platforms that require reliable and low emission power. Power is provided at 33kV to minimise brownfield modifications on the consumer platforms and standardise the microgrid design.

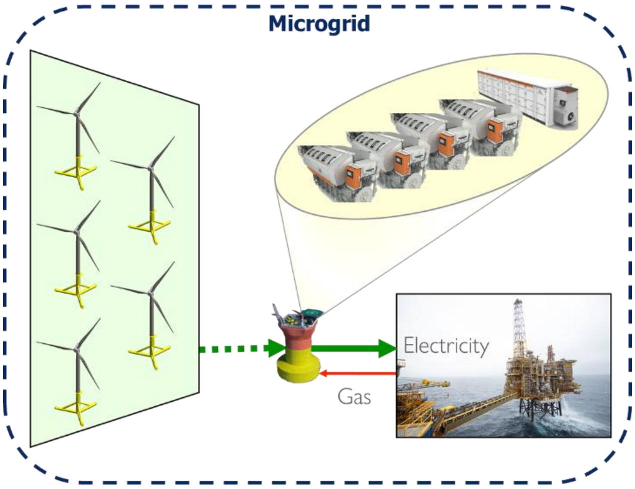


Figure 3-1: Conceptual microgrid layout

The concept is focused on driving down lifecycle costs of ownership, and therefore the distribution hub is designed to be a Normally Unattended Installation (NUI). The project has a target visit frequency of once every 6 months. For the purposes of GHG emission and cost estimations a more conservative and conventional visit frequency of once every two weeks has been considered to ensure that those estimates are conservative and achievable. The key driver for the requirement for maintenance visits is the running hours for the back-up power generators.

The proposed concept delivers a deep cut in emissions for North Sea assets, providing a 77-83.9% reduction in emissions compared to traditional onboard fossil fuel power generation currently in use on oil and gas production facilities. The microgrid concept can be delivered by 2027 meeting the UK Government's North Sea Transition Deal target to cut GHG emission 50% by 2030. By 2050 many of the existing oil and gas processing assets will be decommissioned, but new developments, for example carbon capture projects or green hydrogen, may be able to take advantage of locally available electrical power.

The microgrid concept allows existing assets in the Central North Sea to decarbonise in a short-term time frame in line with the UK Government's and offshore industry's stated goals. To deliver the longer term goal of a Net Zero basin, the power generators selected for the microgrids will be able to be converted to run on ammonia, or other net zero fuel.

When the oil and gas facilities that were receiving power from a microgrid are decommissioned, the microgrid infrastructure can be reused either by connecting to the shore, providing electricity to the UK grid, providing power to carbon capture projects, offshore green hydrogen, or redeployed to an alternative location.

3.2 North Sea Microgrid layout

The Orcadian microgrid concept focuses on simplifying the electrification of the North Sea, by creating several independent microgrids that can supply a small number of oil and gas production facilities rather than connecting the individual facilities to the onshore power grid via long subsea cables. This has several key advantages;

- Significantly reduces the CAPEX for the operators, when compared to a cable from shore;
- Reduces the necessary collaboration and agreement between facility operators, as the microgrid can be operated by a third party who will offer arms length pricing;
- The operators' project teams can focus on the brownfield modifications for facilities that are targeting early electrification;
- Enables staged reuse of microgrid infrastructure as facilities reach Cessation of Production (COP).

The proposed microgrids are shown in Figure 3-2. They have been designed to minimise the number of microgrids, optimise cable lengths between the wind farms, minimise back-up power generation and consider the CoP dates for all assets. Also shown on the map is an overlay of the Sectoral Marine INTOG (Innovation and Targeted Oil and Gas Decarbonisation) licensing areas, which identifies suitable areas for the floating wind farms. The microgrid grouping is flexible and the concept that has been developed can be scaled up or down as required by the platform operators.

We expect that the microgrid layout that emerges as operators commit to the concept will be different from the one proposed herein, but nevertheless this illustrates the possibility to electrify the entire Central North Sea.

The concept can just as easily be applied to assets in the Northern North Sea and West of Shetland, though for the wilder waters West of Shetland a somewhat beefier buoy might be required.

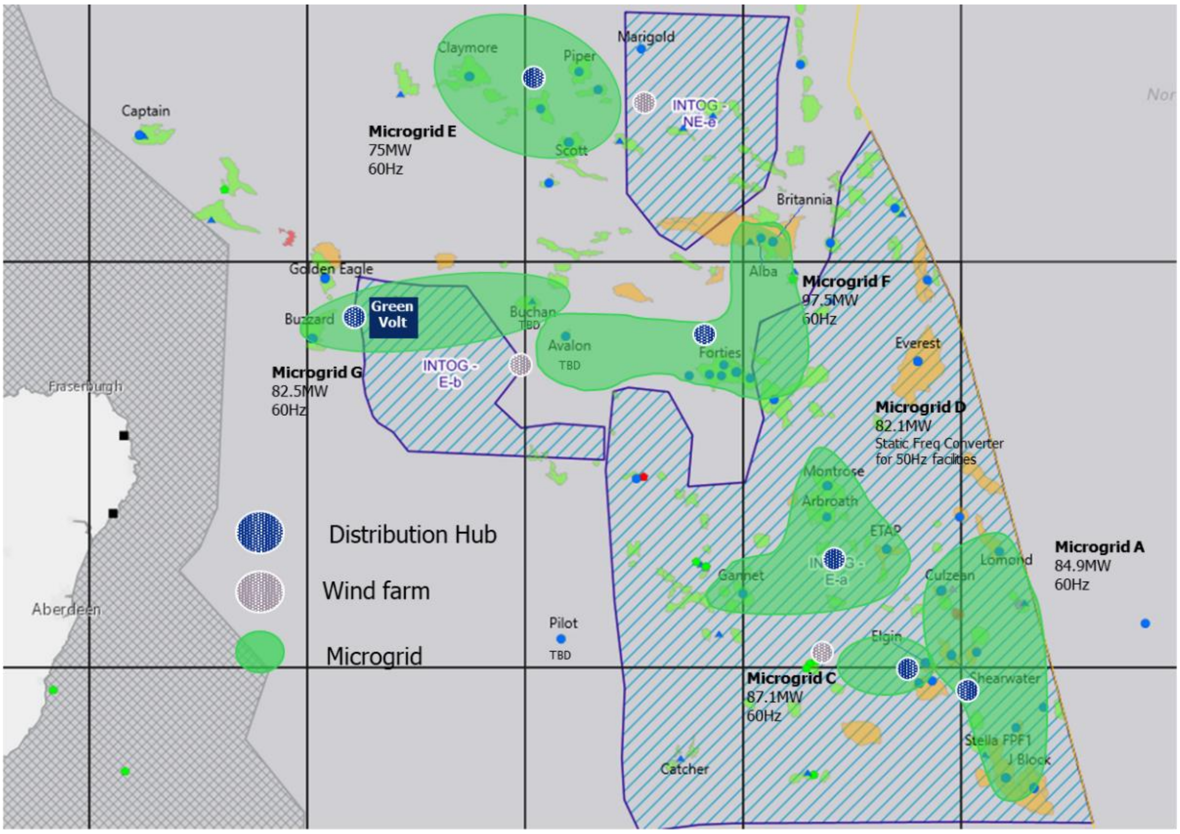


Figure 3-2: North Sea Microgrid layout

Although the concept for each microgrid is similar with respect to wind and back-up power generation. Each microgrid is unique with respect to power demand, cable routing, and the gas import line. The following subsections provide the architecture and key metrics for each microgrid.

3.3 Microgrid layouts

This section provides the cable layout and load profile for each microgrid, the data has been anonymised where appropriate.

3.3.1 Microgrid A

Microgrid A comprises of the following oil and gas production facilities:

- Shearwater
- Culzean
- J Area
- Lomond
- Stella FPF1

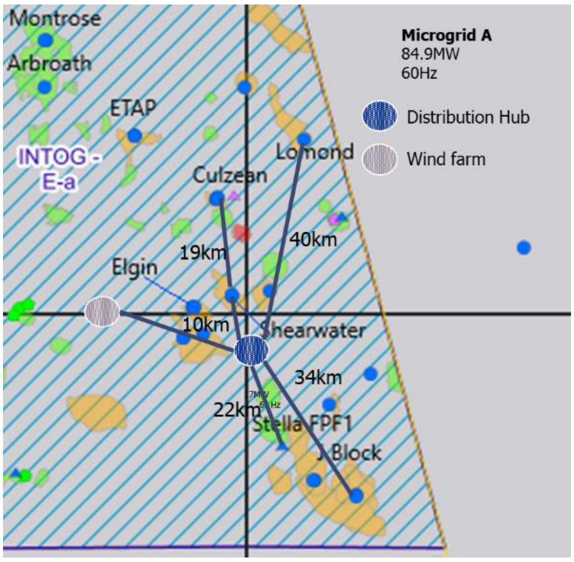


Figure 3-3: Microgrid A - Cable routing

Microgrid A has a peak power demand of just over 80MW. The back-up power generation has been located centrally to optimise cable lengths. The wind farm has been located to the west of the oil and gas production facilities, and its location has been optimised to be able to send power to Microgrids A, C and D. By co-locating the wind turbines which serve multiple microgrids, we can reduce the number of wind farm sites required.

3.3.2 Microgrid B

'Microgrid B' terminology was used in early stages of the study for initial microgrid layouts. Subsequently, the microgrid layouts have been further optimised, removing the initial requirement for Microgrid B. To enable consistency between the interim reports and this document, 'Microgrid B' has not been used and remaining Microgrid nomenclature has been kept the same.

3.3.3 Microgrid C

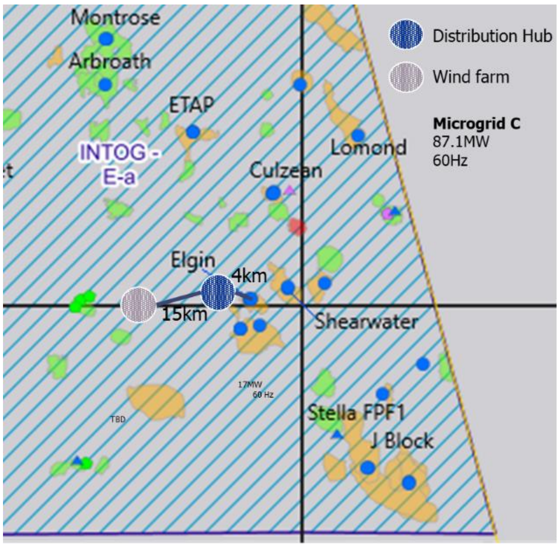


Figure 3-4: Microgrid C - Cable routing

Microgrid C has a peak power demand of 87MW and is intended to provide power to the Elgin/Franklin production facility. Both wind farm and distribution hub have been located to the west of the production facility to minimise cable lengths.

Microgrid C was kept separate from Microgrid A because the power demand for Elgin/Franklin is substantial, making the combined facility an extremely large hub. The back-up power distribution hub has been located close to the Elgin Franklin production facility, and to the west, to minimise cable lengths to the facility and the wind farm.

Given the short distance from Microgrid C to Elgin/Franklin there is scope to optimise overall project costs by reducing the voltage between the distribution hub and the platform.

3.3.4 Microgrid D

Microgrid D comprises of the following oil and gas production facilities:

- Gannet
- Montrose/Arbroath
- ETAP

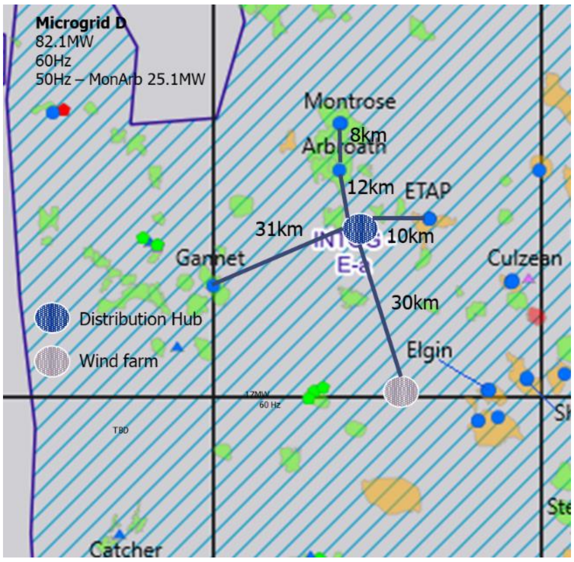


Figure 3-5: Microgrid D - Cable layout

Microgrid D has a peak power demand of 80MW and aims to provide power to the facilities to the north of Microgrid C. The back-up power distribution hub is located centrally between the facilities to minimise cable lengths and the wind farm has been located further south. The wind farm site will provide power to Microgrids A, C and D and has been located to optimise cable lengths.

3.3.5 Microgrid E

Microgrid E comprises of the following oil and gas production facilities:

- Piper
- Scott
- Claymore
- Marigold

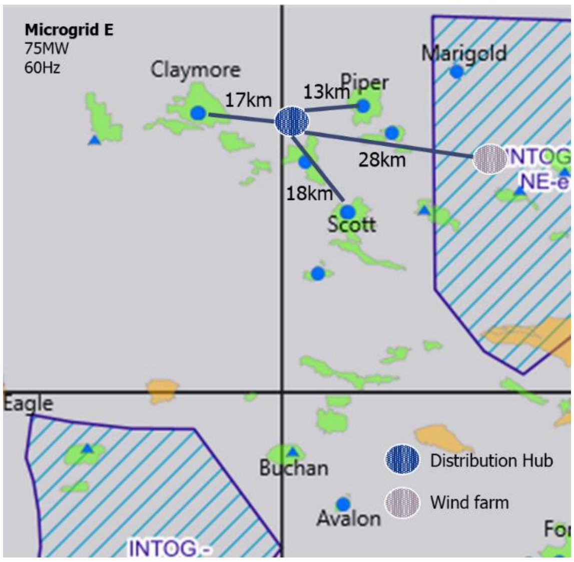


Figure 3-6: Microgrid E - Cable layout

Microgrid E aims to provide power to the cluster of oil and gas production facilities to the northern part of the Central North Sea. The peak power demand is just over 70MW. During the study it has been noted that Marigold is to be developed via a tie-back to the Piper platform. This study has included costs for power cables laid to the Piper platform only and that as part of the tie-back the operator would supply power to Marigold. The back-up power distribution hub is located centrally between the production facilities with the wind farm as near as practical to the east but within the INTOG licensing area.

3.3.6 Microgrid F

Microgrid F comprises of the following oil and gas production facilities:

- Greater Britannia
- Alba
- Forties
- Avalon

Microgrid F has a peak power demand of just under 100MW. The wind farm has been located in the INTOG licensing areas between the Microgrids F and G as the same wind farm will supply both grids.

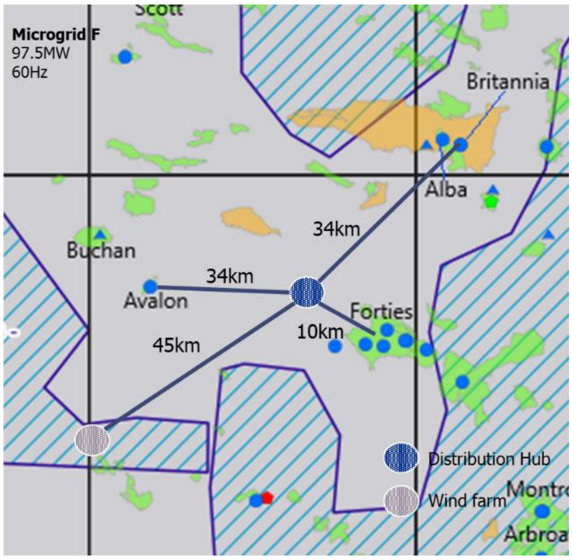


Figure 3-7: Microgrid F - Cable layout

3.3.7 Microgrid G

Microgrid G comprises of the following oil and gas production facilities:

- Buzzard
- Buchan

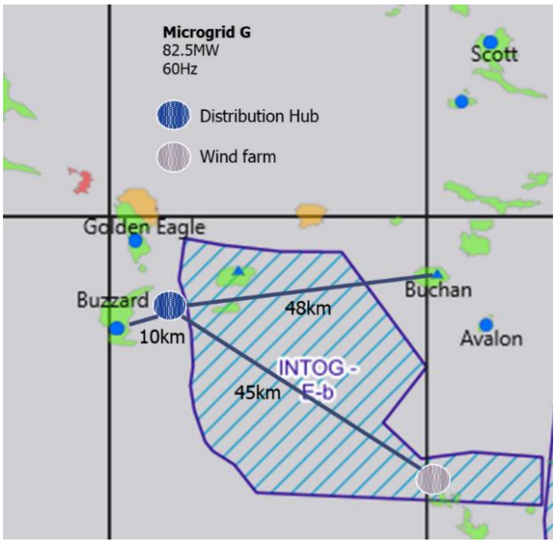


Figure 3-8: Microgrid G - Cable layout

Microgrid G has a peak power demand of 82MW. The wind farm is located between Microgrid F and G in the INTOG licensing area as this wind farm can supply power to both microgrids. We should note that the proposed GreenVolt wind farm could replace the wind farm proposed for Microgrids G and F. Should the GreenVolt wind farm supply 50Hz power, frequency conversion can be performed onboard the distribution hub as necessary.

3.4 Key metrics

Table 3-1 provides the key metrics for each microgrid; distribution hub CAPEX, wind farm CAPEX, and emissions reduction compared to a typical North Sea asset as well as the estimated emissions per MWh.

To reflect the inherent uncertainty in CAPEX estimation at the concept stage and so as not to ignore the potential for cost reduction once more detailed engineering has been undertaken, Crondall Energy has used a probabilistic cost estimation method which provides a range for the final cost estimate.

The wind farm is sized to 120% of the demand[2], to minimise both the GHG emissions and cost of abatement. The CAPEX estimate for the wind farms includes the cost of cables to the relevant distribution hub.

The methodology and battery limits of the lifecycle GHG emissions estimate for each microgrid is detailed in Section 8 . Table 3-1 provides the potential scope 1 GHG emissions reduction associated with the installation of the microgrid when compared to the emissions for a typical Simple Cycle Gas Turbine. To provide a reference a typical SCGT emits 700 kg CO_2 e /MWh, while the UK grid in 2021 emitted 212 kg CO_2 e/MWh.

Microgrid		**Distribution hub CAPEX estimate**			**Wind farm CAPEX estimate**			**Emissions**	
	Fields	P 5% (US$m)	Mean (US$m)	P 95% (US$m)	P 5% (US$m)	Mean (US$m)	P 95% (US$m)	Reduction %[3]	CO_2 e kg/MWh
A	Culzean Lomond Stella J-block	422.6	452.2	487.1	365.5	427.7	513.6	79	147.9
C	Elgin Franklin	330.8	349.3	370	324.4	403.3	485.9	79	147.9
D	Gannet MonArb ETAP	409.1	433.2	461.7	365.5	427.7	513.6	79	144.2
E	Piper Scott Claymore Marigold	358.9	377.9	399.5	362.7	424.5	511.5	78	150.6
F	Avalon Forties Alba Britannia	437.1	464.5	494.3	432.2	504.9	600.4	79	144.8
G	Buzzard Buchan	411.1	436.2	464.5	[4]			79	144.6

Table 3-1: Microgrid key metrics summary

[2] Rounded to the nearest whole 15MW wind turbine.

[3] Generation emissions reduction compared to a typical North Sea fixed facility utilising a SCGT. Data provided by Net Zero Technology Centre

[4] It is assumed that Microgrid G will utilise the GreenVolt wind farm for renewable generation. Commercial agreement will have to be reached for purchasing energy from this wind farm, however the wind farm CAPEX element will be minimised.

3.5 Production facilities not included

There are several production facilities that have not been included within a microgrid. This is primarily due to the distances of these facilities from the nearest microgrid, while connection is feasible the increase in costs associated with the cabling would increase overall costs. These facilities are;

- Captain
- Pilot
- Catcher

Marigold has been included as part of the load profile creation for microgrid E, but no cabling has been allocated, as recent press releases indicate this development is planned to be a tie back to the Piper platform (2).

Golden Eagle has not been included in microgrid G, due to its short distance to shore (~70km). This facility could be incorporated within the microgrid if the operator showed interest.

4 Microgrid – Distribution hub

The distribution hub will house all the necessary equipment to transform intermittent renewable energy into stable, highly reliable, and low emission electricity for the consumer. To achieve this the distribution hub will house the following equipment: back-up power generation, associated ancillaries, power management system, Energy Storage System (ESS), and distribution equipment. The external connections for the distribution hub are the gas import line, power import cables from the floating wind farm, and the power export cables to the consumer.

To minimise OPEX, the distribution hub shall be operated as a NUI facility, with a target visit frequency of 6 months. Accordingly, accommodation and welfare services would be provided on a Walk to Work (W2W) vessel that would be utilised as the primary means of access and egress from the facility.

A key design decision for the distribution hub is the selection a floating structure, this enables;

- Solution to be depth independent – allowing application across the North Sea
- Liquid fuel storage capability and increased topsides weight capacity – enabling storage of future net zero fuels and use of reciprocating engines
- Redeployment – the distribution hub
- Redeployment to form part of another microgrid or potentially used as a floating power plant either in the North Sea or elsewhere in the world. Could lead to greater residual value for the hub and improved environmental performance.
- Repeatable design – as a depth independent solution, the distribution hub can be designed once and built many times.

This section discusses the floating structures that have been considered, the topsides equipment required, and the Operations & Maintenance philosophy. The estimated topsides weight, can be provided upon request.

4.1 Floating structure

Three floating installation types have been considered suitable for the distribution hub:

- Sevan unit;
- Buoy;
- Semi-submersible.

At this stage of development, the preferred floating structure for the distribution hub has not been finalised. Instead, the following subsections present the short list of suitable candidates, with final selection in future development phases.

The distribution hub will require multiple three phase cables[5] and an import gas line. If the unit were to be designed to weathervane it would require an internal turret which would require the power cables to be separated into individual circuits before going into the swivel. This would lead to a large,

[5] Notionally the design has focused on 10 cables, which is a mixture of import and export. Each cable has been assumed to be a 3 phase cable, in a trefoil arrangement. This quantity can be increased or decreased as required, without significant changes to the concept, due to the spread moored facility design.

technically complex, and costly slipring assembly. The gas import line would require dynamic seals in the swivel. Both the power and gas import swivel would require significant maintenance.

With the semi-submersible, Sevan unit and buoy, there is no requirement for a slipring and the power cable can run through a J-tube before coming to a termination point and straight into the transformer/switchboard. No dynamic seals will be needed for the gas import line and the maintenance requirements will be much lower than for a swivel assembly. Thus, a ship shaped vessel, which would require an internal turret for operations in the North Sea, is not preferred.

The distribution hub is to be operated as a NUI facility from the outset, with accommodation and welfare services provided on a Walk to Work (W2W) vessel that would be utilised as the primary means of access and egress from the facility. Accordingly, the distribution hub will not require a permanent accommodation block[6] or the associated welfare facilities, reducing equipment and systems onboard the hub, reducing lifecycle costs.

4.1.1 Sevan

The Sevan unit was pioneered by Sevan SSP and has had 12 units constructed of which 5 have seen operation in the North Sea.

4.1.1.1 New build

A scenario with a new build Sevan unit and associated CAPEX estimate has not been included. The information in the public domain is for Sevan units that have been built to store over 300,000bbl of produced oil, and to support a topsides facility capable of processing the oil and gas. Whilst it is possible to estimate the cost of a Sevan hull, this would include the costs associated with:

- Structural steel for the crude oil storage and process topsides,
- A blast wall, and
- Living quarters

It is not possible to determine how much of the structural steel is associated with these requirements and how much is required for hull strength. The distribution hub will not require crude oil storage, nor will it need a blast wall or living quarters. Accordingly, a "standard" cost for an oil & gas Sevan 300 unit would not be an appropriate reference point.

With availability of two potential redeployment units, the concept has focused upon these due to the anticipated cost saving compared with a new build. The use of a new build Sevan hull is not ruled out and if the project were to proceed to the next stage it would be recommended to approach Sevan for a quotation and proposal.

[6] Small scale emergency accommodation will be required in the event personnel cannot access the W2W vessel

4.1.1.2 Redeployed unit

There are two Sevan FPSO units that could potentially be redeployed to be used as the floating distribution hub which would be of a suitable size. They are the Hummingbird Spirit and the Voyageur Spirit, both are Sevan 300 FPSO units.

The Voyageur spirit is owned by Altera and is currently in lay-up in Kishorn port in Scotland after seeing service in the Huntingdon field in the North Sea since 2013 (3). The Hummingbird Spirit, which is owned by Teekay, is to be decommissioned from the Chestnut field in the UK Central North Sea (4) in 2022 where it has been in operation since 2008.

	Units	Voyageur Spirit	Hummingbird Spirit
Year delivered		2008	2007
Hull Diameter	m	60	60
Riser slots	No. of	10	7
Process deck area	m^2	3825	3825
Main deck area	m^2	3450	3450
Persons on board capacity		54	47

Table 4-1 Voyageur and Hummingbird - Some key details (5)

Either redeployment candidate would require removal of the topsides, cleaning of cargo tanks, and Repair & Life Extension (R&LE) of the hull. The Microgrid topsides equipment and bulk structural steel has been estimated to be in the region of 6,500te which is within the capacity of a Sevan 300 unit.

4.1.2 Semi-submersible

The depressed oil market during the COVID-19 pandemic and the focus on energy transition has led to a reduced requirement for drilling rigs and at present there are a number of drilling rigs that are idle. During the 'Concept scenario identification' workshop it was considered that a suitable rig could be picked up for a 'good price' and refurbished. The full impact of the Russia-Ukraine war on the oil market is yet to be seen but is likely to lead to an uptick in drilling and may lead to a reduction in the number of rigs available or an increase in purchase price.

A semi-submersible unit is stable, suitable for the risers (will have a dry riser balcony), power cables, gas import line and doesn't require complex and expensive swivel arrangements.

An example of a semi-submersible rig that would be suitable for use on the microgrid hub is the 6th generation semi-submersible developed by Aquadrill. Some technical details are displayed in Table 4-2.

Parameter	Units	Value
Design		GVA 7500
Year built		2009
Length	m	116.5
Breadth	m	96.6
Max water depth	m	3000
Min water depth	m	100
Variable deck load	te	7000
Helideck		Sikorsky S61/S92
Accommodation	persons	180
Main engines		8 x Watsila 12V32

Table 4-2 Semi-submersible Aquarius - key details (6)

The Microgrid topsides equipment and bulk structural steel has been estimated to be in the region of 6,500te which is within the specified vertical deck load of the Aquadrill Aquarius unit. The variable deck load is likely to be in addition to the 8 Wärtsilä engines in the engines room which would give a further weight margin as the existing engines would not be needed and could be removed.

In 2021 Aquadrill sold the 'Leo' semi-submersible drilling rig to BW Energy to be used in a gas to power project offshore Namibia (7). The fact that other companies are using this type of structure for a floating power project does add evidence to suggest that the semi-submersible unit would be a good option for the microgrid back-up power generation.

Any existing semi-submersible purchased would need to have the existing topsides removed together with refurbishment and life extension of the hull as part of any redeployment.

4.1.3 Buoy

Buoyant Production Technologies (BPT) is a wholly owned subsidiary of Crondall Energy responsible for developing novel technologies related to floating production, subsea, and renewable projects. The BPT spar-buoy technology is being developed with support from BEIS, in order to provide a suitable platform for floating substations for floating wind farms and for platform electrification. The company has also developed, with the support of the NZTC, a series of production buoy concepts focussed on the use of technology to achieve low offshore manning, lower emissions, smaller scale and lower TOTEX requirements. The design has a number of patented features and is scalable for different size payloads. An equipment list with the estimated equipment weights and sizes has enabled BPT to complete a preliminary layout and sizing for a buoy.

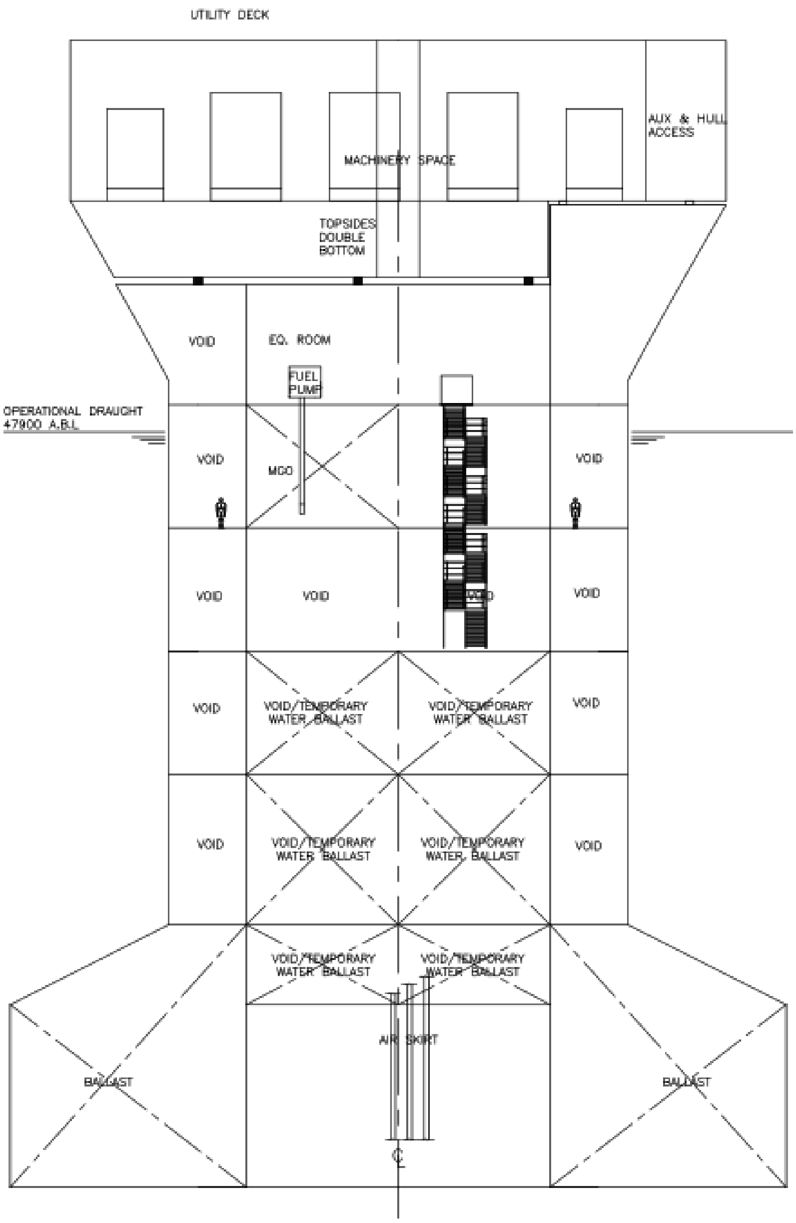


Figure 4-1 Expected arrangement of the BPT Buoy

4.2 Topsides – Electrical & Utilities

The purpose of this section is to describe:

- Electrical system;
- Back-up generation;
- Energy Storage System (ESS);
- Power management system;
- Utility requirements for the back-up power generators;
- Flare and vent requirements.

This section has given particular consideration to how the fuel gas will be imported and conditioned. High pressure gas will need to be let down to the low pressure gas required by the back-up power generators. We have also assessed over-pressure protection requirements.

4.2.1 Electrical system

The electrical system is the core of the distribution hub and facilitates the transformation of intermittent renewable wind energy into reliable, low carbon electricity for the consumer.

Figure 4-2 provides an example of the overarching Single Line Diagram (SLD) for the distribution hub for each microgrid.

Power will be imported from the floating wind farm via two separate cables at 66kV, to minimise cable core size and reduce losses. Power export to the consumers is standardised at 33kV, to minimise cable core size, and reduce losses. However, there is an opportunity to reduce this voltage further if requested by the consumer, with the necessary transformer located onboard the distribution hub.

Back-up power generation is provided by Wärtsilä 31DF engines, utilising imported gas for fuel. Redundancy is minimised to one of each size of engine, due to the low running hours at full load. The gas fired generation is supplemented by an Energy Storage System (ESS), sized to provide sufficient power to reduce spinning reserve.

The distribution hub provides an onboard power supply for the utility systems, utilising a standard FPSO distribution architecture, as shown in the SLD. This is primarily supplied from the main 33kV switchboard, with the back-up generators acting as essential generators when required. During an emergency scenario, a UPS supplies provide power for critical systems, such as the automation system, telecommunication system, emergency lighting, etc. This is supplement by a dedicated emergency generator, as shown in the SLD.

4.2.1.1 Electrical operations philosophy

During normal operations, energy from the floating wind farm is prioritised, with the gas fired generation providing any short fall in generation capacity, the overall philosophy is to minimise GHG emissions and ensure continuity of supply to the consumer.

Should a shutdown of the distribution hub occur, i.e. loss of gas supply, trip of all wind generation, trip of all gas fired generation, the onboard generators can be started via the starting air header, which will have sufficient capacity for multiple restart attempts. The generators can then operate in diesel mode, as there is sufficient onboard diesel storage to deliver power to all consumers for 12 hrs, providing time to either restart the gas supply, or shutdown consumers to extend the run time on liquid fuel while the issue is resolved.

For a black start scenario[7], The facility will need to be manned and the emergency generator started locally. This will then provide sufficient power for the necessary utility systems to restart main generation on liquid or gas fuel, at which point power can be reinstated to the consumers.

[7] A black start scenario is where there is no residual energy onboard from any source, therefore no starting air header, no UPS power, etc.

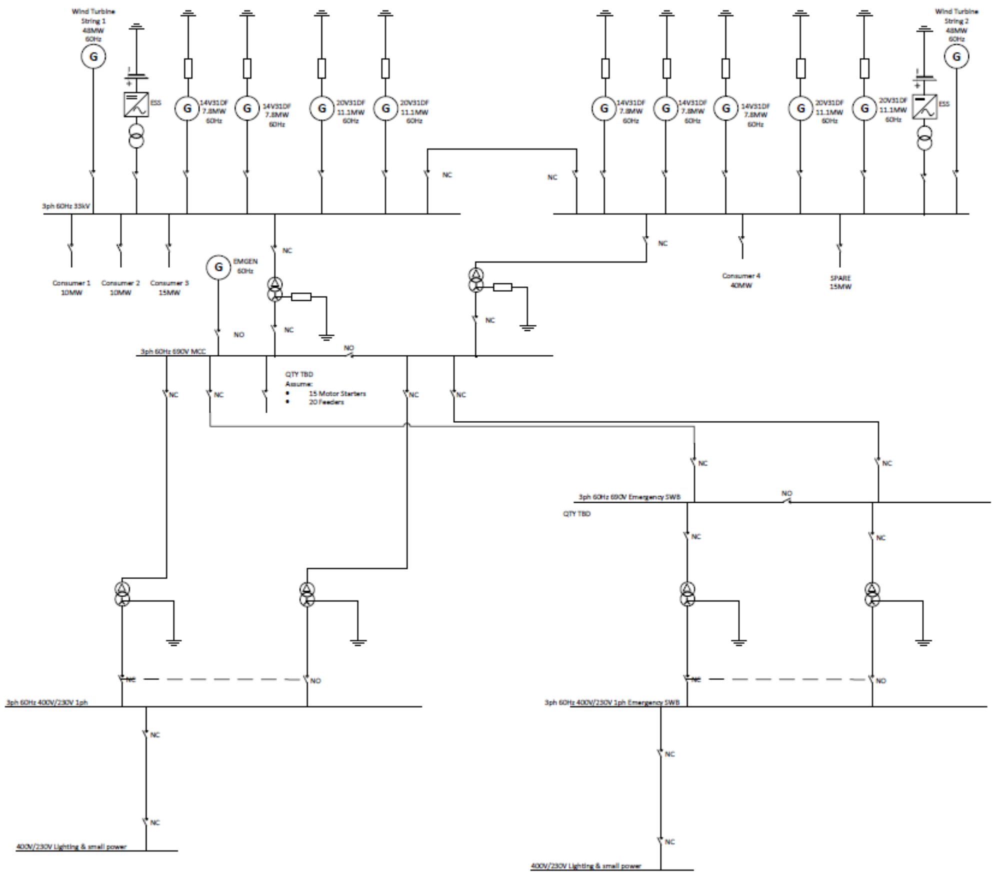


Figure 4-2: Example Single Line Diagram (SLD) Distribution hub

4.2.1.2 Back-up power generation

When there is insufficient wind energy to provide the power required by the consumers then the additional energy will be supplied via reciprocating engines using fuel gas.

The Wärtsilä 31DF range of engines has been selected as the preferred solution for this concept as it provides several major benefits to gas turbine alternatives:

- High efficiency 49% (without heat recovery) – significantly higher than a SCGT (~30%), and comparable to an offshore Combined Cycle Gas Turbine (CCGT) (~45%)
- High efficiency for low load factor[8] – critical for intermittent wind energy, where partial loading is required with high efficiency achieved down to 20% load factor. A SCGT or CCGT is unable to achieve comparable efficiencies at low load.
- Net zero fuel capable – Wärtsilä have confirmed all 31DF engines will be compatible with future net zero fuels, this is expanded upon in section 0.
- Low maintenance – 31DF is designed from the ground up to enable remote monitoring and predictive maintenance. With maintenance activities simplified through the extensive use of plug and play maintenance activities
- Large installation base – Over 3,000 31DF engines have been installed, which have amassed a run time in excess of 53 million hours.

4.2.1.2.1 31DF engine

The Wärtsilä 31 represents a new generation of medium-speed engines, setting a new benchmark in efficiency and overall emissions performance across the complete operating range.

The engine is available in a diesel version optimised for heavy or light distillate fuels and in dual-fuel and pure-gas versions. Configurations range from 8 to 20 cylinders with a power output of 4.6 to 12.2 MW at 720 and 750 rpm. It is designed to withstand longer maintenance intervals, minimising downtime and costs associated with maintenance.

The Wärtsilä 31 is suitable for a broad range of applications including as a main generator, auxiliary generator, or associated with ship propulsion. It can be optimised for running either as a constant speed generator or for variable speed applications.

[8] Load factor is the power demand divided by the generator capacity

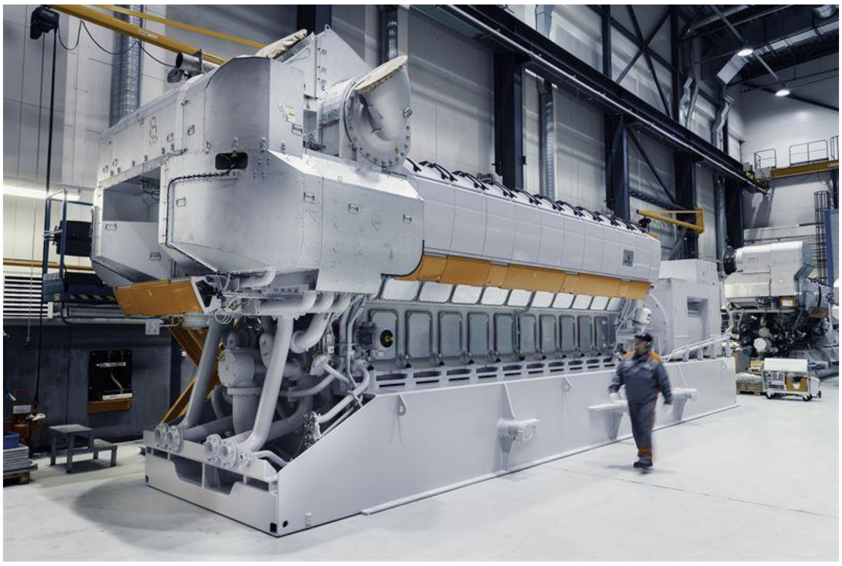


Figure 4-3: Example of 31DF engine

In the offshore oil and gas sector, the Wärtsilä 31 is ideal, where operational flexibility, high-power density, long intervals between overhauls and high levels of safety are of paramount importance.

The engine's modular structure brings unprecedented multi-fuel flexibility. The advanced fuel injection system enables the most efficient and economical use of low-sulphur fuel oils (<0.1%S), making it especially suited for operating in emission-controlled areas. The advanced UNIC engine control system, injection system and variable valve timing together enable optimal running performance across the full load range, while maintaining high efficiency and consequently low emissions. In addition, the Wärtsilä 31 is able to handle extended periods of low load (defined as loads between 20 and 0%) which is beneficial for intermittent renewable applications.

Furthermore, the Wärtsilä 31 is designed for long periods of maintenance-free operation, allowing for maximum schedule flexibility, while cutting operating costs. The shift from using single parts to using larger, pre-assembled exchange units that are delivered ready to install – such as injectors, high pressure fuel pumps and cylinder heads – enables easier and more efficient maintenance and simplifies logistics onboard.

4.2.1.2.2 Generator selection

The final selection of generator numbers is dependent upon each microgrid's demand, and wind farm size. Therefore, final selection will be performed in future phases once the microgrids are confirmed. In the interim, the following section outlines the generator sizes selected, the data behind this decision, and the proposed solution.

Figure 4-4, provides the generation run time against the back-up generation load factor. There are three key takeaways from this graph that impact the selection of generation onboard the facility:

- The first is that, due to the imported renewable power, the generators are at full load for only ~16% of the year (~1,400hrs), this means a lower level of sparing is acceptable than a traditional oil and gas facility.

- Secondly, for ~62% of the year (~5,500hrs) the back-up power is at low load factors (<20%), meaning that multiple smaller generators are required to achieve high efficiency. As running large generators at low load factors results in a reduction in efficiency, increased maintenance, and consequently increased emissions.
- Finally, the total run time per engine is 43-50% of the year (~3,800-4,400hrs), this reduces the maintenance burden enabling the facility to operate as a NUI.

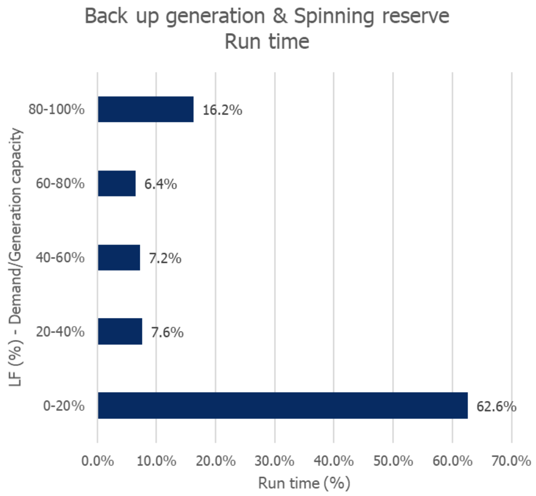


Figure 4-4: Load factor vs generator run time

Utilising the above information, the currently selected generators are the 14V31DF (7.8MW) and 20V31DF (11.14MW), as this ensures optimal loading of the generators for maximum efficiency. The split of these generators is currently half 14V31DF and half 20V31DF, as preliminary analysis indicates this optimises the loading of the generators. The sparing for the generators is currently assumed to be just one of each engine size, an alternative approach could be to eliminate spare engines and to shed inessential loads at the customer's facilities. An example of the proposed generation for various microgrid demands is shown in Table 4-3 below. This is preliminary in nature and will require further refinement in future phases of the project.

Engine	Microgrid demand		
	75MW	85MW	90MW
	QTY	QTY	QTY
14V31DF – 7.8MW	4	5	5
20V31DF – 11.14MW	4	5	5
Sparing	1 x 14V31DF, 1 x 20V31DF		
Over capacity	126%	134%	126%

Table 4-3: Example generation schedule

4.2.1.2.3 Energy Storage System (ESS) and operating reserve

Any electrical grid experiences fluctuations in both demand and generation, to counteract this a combination of operating reserve types is required to ensure continuous supply for the consumer, as shown in Figure 4-5. For the microgrid application with its large volume of wind generation this becomes critical due to the continuous fluctuations in wind generation. Typically, an oil and gas facility provides operating reserve through the maintenance of spinning reserve in its main generators, typically +/- 20%, this requires running the main generators at less than full capacity.

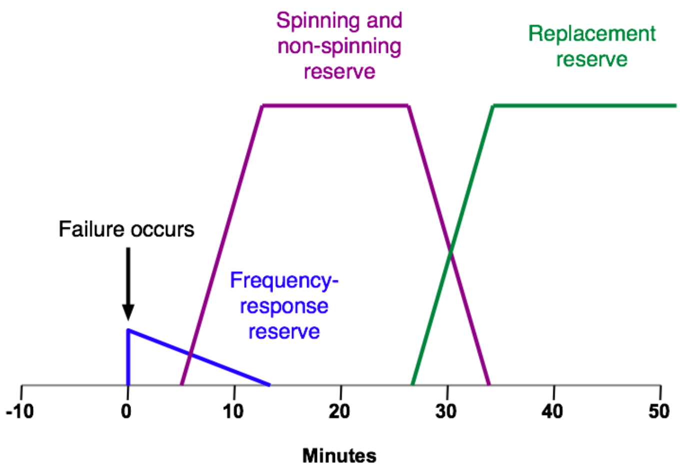


Figure 4-5: Purpose of operating reserve

To minimise emission the Microgrids will utilise a combination of an ESS and generators to provide the operating reserve necessary to ensure grid stability. To align with traditional oil & gas facilities, an operating reserve capacity of +/- 20% will be provided by each microgrid. Operating reserve for the microgrid can be split into two scenarios;

- Maximum wind generation – in this scenario all power could be provide by the floating wind turbines, thus requiring no back-up generation
- Partial or no wind generation – in this scenario back-up generation is required to ensure continuity of supply

For the partial or no wind scenario, back-up generation will be running. The power management system will load each generator to provide operating reserve (both frequency response and spinning reserve) without impacting emissions, for example 60% of generator capacity.

For maximum wind scenarios, no back-up generation is required. In this instance the operating reserve will be provided by the ESS system and a single generator operating at partial load. The ESS shall be sized to deliver 15MW for 1.5 minutes, providing sufficient time to start additional generation (45 second start time for 31DF engines). Enabling the ESS to provide frequency response and minimise spinning reserve. A single generator is required to provide spinning reserve, to increase grid stability by providing mechanical inertia and to reduce short cycling of the batteries which significantly reduces their lifespan. This will necessitate the curtailment of wind production, but the use of the ESS minimises the volume of curtailment, thus minimising emissions.

There may be opportunities to optimise, in conjunction with the platform operators, the overall spinning reserve arrangements once the facilities are operational, however, we believe the framework outlined above is feasible and should deliver a highly reliable power supply for all customers.

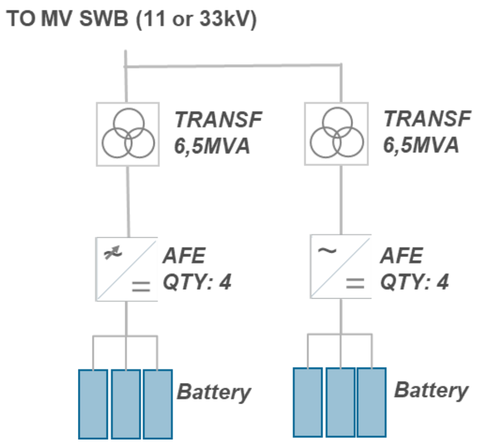


Figure 4-6 Battery technology overview – Wärtsilä

The ESS has been limited to 15MW and 1.5min run time, to reduce cost, weight and space impact to the distribution hub design. Wärtsilä's ESS can easily be scaled to deliver greater power and energy, however the benefit would be limited as additional generation is required to charge the ESS after use, minimising the emissions saving. Therefore, its most effective application is to minimise spinning reserve by providing the necessary energy to support the Microgrid while a generator is started.

4.2.2 Fuel gas

Fuel gas could be sourced either directly from one of the oil and gas production facilities that the power distribution hub will provide power to, or from an export gas pipeline. One of the likely export gas pipelines that could supply gas is the Central Area Transmission System (CATS) pipeline which has been used to obtain typical gas composition and physical properties.

The back-up power generation floating structure will require an import riser and fuel gas conditioning which is described in the subsequent sections.

The potential tie-in locations for gas import are discussed in Section 5

4.2.2.1 Fuel gas properties and quantities

For the purposes of estimating the cost of each Microgrid an assessment of the suitable subsea gas tie in options has been performed, section 5 . Several Microgrids could utilise main pipeline export routes, such as CATS. Therefore, the following section assumes the natural gas meets the CATS pipeline specification.

The typical gas pipeline specification for gas entering CATS includes:

- A hydrocarbon dewpoint which, at all pressures in excess of 10,340kPag, does not exceed -2°C,
- A water dewpoint of 7,500kPag of -26°C

The CATS pipeline typically has a required delivery pressure of 130barg, thus gas could be delivered to the power hub at a high operating pressure and would need to be let down.

Fuel gas consumption will vary depending upon the amount of electrical power that cannot be supplied by the wind farm. For each microgrid the wind farm electrical power generation has been estimated using statistical wind speed data for the wind farm location, by month. Microgrid D has an electrical power demand of 82MW and the estimated fuel gas consumption to provide power when there is insufficient wind power available is shown in Figure 4-7.

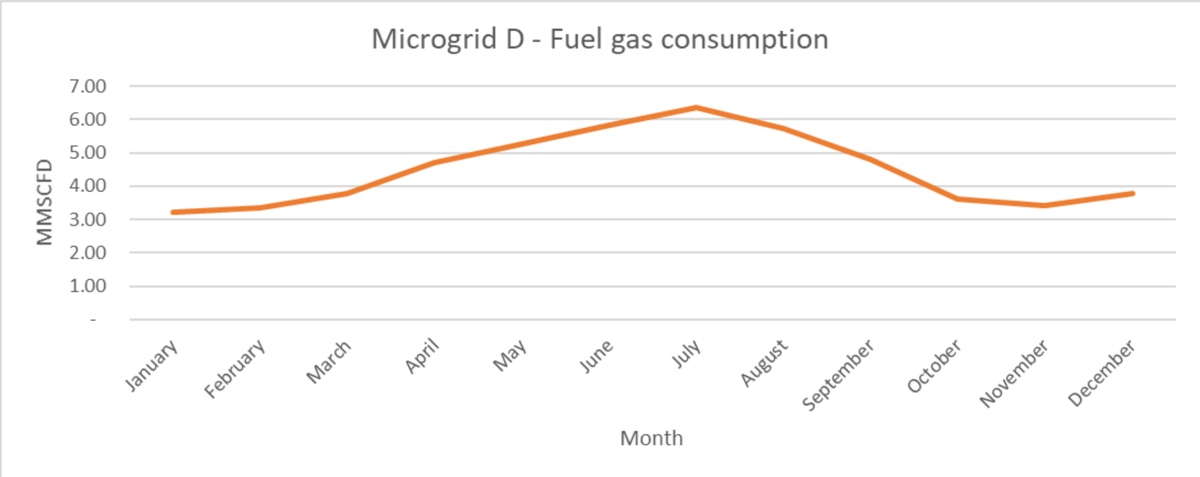


Figure 4-7 Microgrid D – Estimated fuel gas consumption

The subsea pipeline to transport the gas to the power hub will be 4" in size. So long as gas velocities are acceptable, frictional pressure losses in the line are not critical as the gas is not needed at a high pressure and will need to be let down.

4.2.2.2 Fuel gas metering

Fiscal metering of all fuel gas imported to the power generation facility will be required. It is proposed to install a Coriolis type metering skid with 2 x 100% runs and a 3rd run as the master meter.

4.2.2.3 Fuel gas conditioning system

The Wärtsilä 31DF product guide states that the power generator will require the fuel gas at a pressure of circa 10barg and at a temperature between 0 and 60°C. The fuel gas supplied from an export pipeline will be at high pressure, circa 130barg, and will be cold. The temperature of the gas is likely to be close to the seabed temperature which could be as low as 5°C.

If the fuel gas is let down from a pressure of 130barg to say 35barg at the topsides, there will be an associated drop in temperature across any pressure let down device due to the Joule-Thompson affect. As a rule of thumb for every 2bar of pressure drop, there would be resultant drop in temperature of the gas of 1ºC. Thus, a temperature drop in the region of 50ºC would be experienced. As the arrival temperature of the gas could be as low as 5ºC, the gas will need to be heated before any pressure let down to avoid the temperature dropping below the dew point of the gas.. The electric heater will also need to ensure that the fuel gas reaches the power generators at a temperature above 0ºC, as required in normal operation.

The electric heater would consist of a series of pipes with a heating element inside as shown in Figure 4-8 .

Figure 4-8 Fuel gas hazardous area process heater (7)

The fuel gas will need to be supplied to multiple power generators operating in parallel and each power generator will have a dedicated pressure control valve (PCV) controlling the rate of gas for combustion to each unit to meet the power demand output. This PCV will be part of the power generation package.

The power generators could be operating with all generators at full load or one at partial load, depending upon how much power is being supplied by the wind farm at any given time. The fuel gas system will need to have a considerable degree of flexibility and deliver fuel gas over a wide range of flow rates.

There are two main ways to reduce the pressure of the fuel gas from the import pipeline pressure for use in the power generators, an orifice plate or a control valve. Using orifice plates alone is not possible as the fuel gas flow rates vary considerably and the frictional pressure losses across such a device would vary corresponding to the flow rate. Using a PCV on its own could be problematic, as the pressure drop across it is large and the valve will need to control the downstream pressure at a wide range of flow rates. It is probable that an orifice plate would be used in series with a pressure control valve to drop the fuel gas pressure from the pipeline pressure to a pressure of 35barg (The requirement for 35barg is only an estimate and will be confirmed during detailed design.)

To prevent the main pressure let-down PCV and local power generator PCV controllers from negatively interacting with each other it is proposed to have a buffer volume of gas between them. This buffer volume could be contained within a 'fuel gas surge drum' which would physically be a 'length of pipe' that has a larger diameter than the main pipe run.

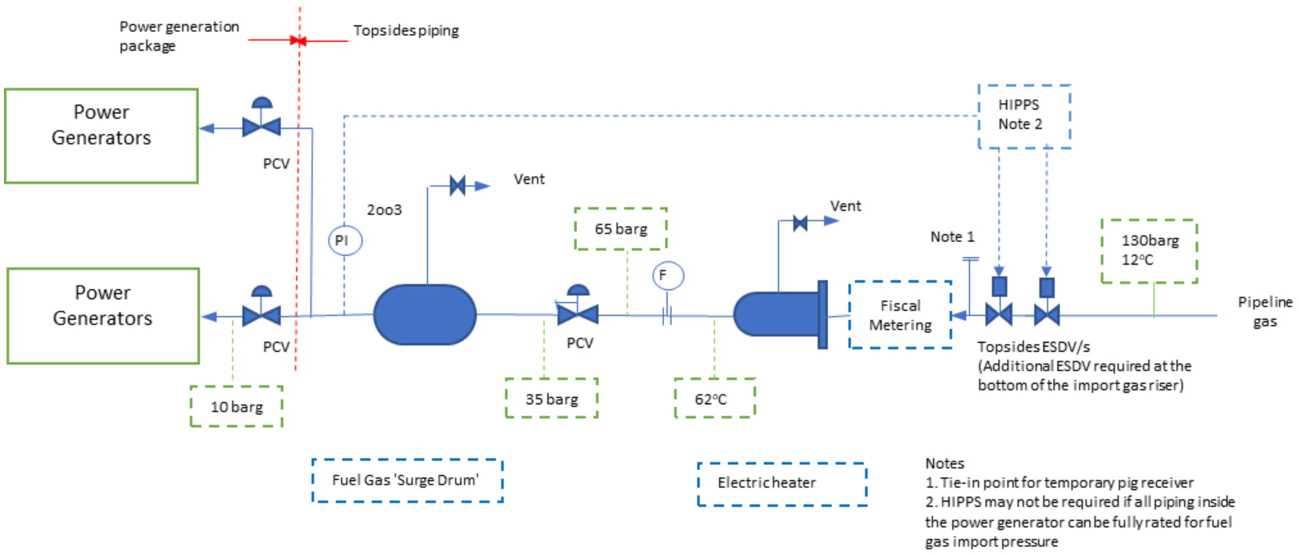


Figure 4-9 Fuel gas conditioning schematic

4.2.2.4 Over pressure protection

The pipeline fuel gas operating pressure will be 135barg and the required pressure at the inlet to the power generator package is 10barg. In order to remove a high-pressure low-pressure interface it is proposed to fully rate the topsides piping for the import gas pipeline pressure. It should be noted that the topsides design pressure only has to allow a margin on the subsea pipeline operating pressure and does not necessarily need to be rated for the full subsea pipeline design pressure as the operating pressure in the pipeline is constant and will only change slowly over a 'long' period of time due to the volume of gas in it. There will be plenty of time for any increase in pressure to be picked up and the topsides shut down if required.

In the event that the power generator package fuel gas piping can't be fully rated for the pipeline operating pressure, then a High Integrity Pressure Protection System (HIPPS) can be employed with a set pressure of circa 40barg. Preliminary calculations have indicated that, in the length of time a HIPPS could close a topsides fuel gas inlet Emergency Shut Down Valves (ESDVs), the amount of gas that would enter the topsides piping would not increase the pressure in the topsides piping beyond 40barg.

The 'fuel gas surge drum' would be an expansion in the pipe size for a 'short run' of piping and would be designed to a piping code and would not require a PSV.

The fuel gas heater is a series of pipes with an electric element and would need a PSV for thermal relief only, in the event the exchanger was shut in and heat was still being supplied by the electrical elements. The volume of the exchanger would be extremely small and any thermal relief would be correspondingly small. Due to the small relief load and infrequency of the event occurring, this PSV relief could be discharge to atmosphere at a safe location.

4.2.2.5 Emergency depressurisation

The topsides fuel gas piping system volumes are small and are likely to contain less than 500kg of hydrocarbon and there will be no hydrocarbon containing vessels. As such it is not envisaged that emergency depressurisation of the fuel gas piping is required.

4.2.3 Flare and venting requirements

The fuel gas import and conditioning system envisaged should not lead to any significant relief loads with the implementation of fully rated topsides piping to the fuel gas subsea pipeline operating pressure and the installation of a HIPPS (if required to protect the power generation fuel gas supply piping). The only potential relief load would be for a 'thermal' case PSV on the electric heater. The relief scenario would be extremely infrequent, and the volumes associated with such a relief would be extremely small. The PSV for this particular relief scenario could be vented to a safe location. As such it is not anticipated that a flare system is required for the power generation hub.

When the fuel gas import and conditioning system, or parts of it, need to be shut down for maintenance then the system should have the capability to be purged and vented to a safe location. This could be done via an automated system controlled from the onshore control room so that the system is prepared for when a maintenance crew arrives.

There should be no liquids on the topsides fuel gas lines in normal operation as the gas should always be kept above the dew point. When a system is depressured the gas would be well above dew/bubble points that the fluid would be in the vapour phase.

4.2.4 Diesel

Diesel will be required for:

- The emergency generator;
- 'Black starts';
- Running the Wartsila DF engines at full load for 12 hours in the event of loss of wind power or fuel gas supply;
- Spiking fuel gas in the Wartsila DF engines whilst they operate on fuel gas.

It has been estimated that 150te of diesel would permit 12 hours of the DF engines operating on diesel at a full load of 75MW. When running on fuel gas the Wartsila DF engines require diesel to be spiked into the engine to aid combustion. 150te of diesel would provide circa 6 weeks of spiking with the engines operating on fuel gas at maximum load. The amount of diesel required to operate the engines at full load for 12 hours will need to be kept in reserve at all times. Thus, it is proposed that around 300te of diesel should be stored on board the back-up power generation hub and diesel should be bunkered on board before the storage volume reaches 150te. It should be noted that the microgrid will not be running at full load on gas continuously for extended periods of time, so the 150te of diesel will take significantly longer than 6 weeks to be used up.

4.2.5 Cooling medium and seawater system

A closed loop cooling medium system with a mixture of TEG/Water in a 30:70 ratio will be required to provide cooling to the power generators. A seawater lift system with seawater lift pump and coarse filtration will be provided to cool the cooling medium via a plate and frame exchanger.

4.2.6 Instrument air

Start-up instrument air required for the power generator will be provided by Wärtsilä as part of the power generation package. The use of instrument air for all other instrumentation will be avoided. Control valves will be electronically activated. An example of such a control actuator is the 'Rotork CVL Linear' electric process control actuator which comes in a range of sizes (8). Any control valves installed on the power hub are not anticipated to be large in size and will be relatively easy to source.

Shut Down Valves (SDVs) will have electrohydraulic activation. An example is the 'Rotork Skilmatic range of actuators' (9). As with the control valves, the SDVs will be relatively small as all piping is small bore, relatively easy to source and valve closure times (pertinent for SDVs) will be short.

4.2.7 Nitrogen

Nitrogen will be required for the purging of topsides fuel gas piping and the Wärtsilä engine. There is no flare or vent system that requires continual purging.

The Wärtsilä Product guide for 31DF engines stipulates a requirement for nitrogen to be supplied at a pressure of 8barg ±1.75bar before the purging valve with the quality outlined in the table below.

Property	Value
Nitrogen	≥95%
Oxygen	≤1%
Dew point (atm pressure)	40 ºC

Table 4-4

The Wärtsilä Product Guide also stipulates a required purging rate for the fuel gas lines between the Gas Valve Unit (GVU) and engine as follows:

1. Required inert gas amount: 5 times the total volume of gas pipes that are to be purged Flow:
2. Standard purging time is 20 seconds; thus flow should be 5 times the gas pipe volume per 20 seconds.

The power hub will consist of multiple power generators which can be purged individually. The fuel gas piping to the power generator will be small bore piping and will not lead to a volume of more than $0.1m^3$ between the GVU and the engine. This would lead to a nitrogen air requirement of $90am^3/h$.

Nitrogen will be supplied by a Pressure Swing Adsorption unit and will require:

- An air compressor upstream
- Air Dryer

- Air Tank
- Adsorption Tanks
- Nitrogen gas tank (Receiver providing buffer volume to the system)

A similar quality of nitrogen suitable for purging the engine will be suitable for purging the topside fuel gas lines thus the one package sized for 90am^3/h will be sufficient for the topsides purging requirements.

The quantity of air a PSA unit will typically need to supply the nitrogen will vary depending upon the purity of the nitrogen to be produced. For 95% purity nitrogen an air flow rate of 1.8 times the required nitrogen flow rate is required and for 99.999% purity, 5.5 times the required nitrogen flow rate is required. Thus, an air supply of 200am^3/h is required if 95% purity nitrogen is considered acceptable. The air compressor power requirement would be 25kW.

4.2.8 Drains

An open drains system will be provided for power generator skids with the skids connected to an open drain collection tank. From there any oily water collected will be pumped into a TOTE tank which will be transferred for treatment onshore.Further assessment of drain system requirements will be completed in subsequent project design phases and is beyond the scope of this conceptual study.

4.2.9 Automation – Power Management System

The distribution hub power management system will provide an automation system to manage the following key functions;

- Distributed Energy Resource (DER) management
- Load sharing
- Frequency/Voltage regulation
- Load shedding
- Electrical distribution management
- Remote system monitoring
- Data capture and historization

Significant input to this section has been received from Schneider Electric and their cooperation and goodwill is acknowledged. The architecture is based on Schneider Electric's EcoStruxure Power Automation System (EPAS) which has been employed for microgrid power management across the globe.

The block diagram in Figure 4-10 is a depiction of the constituents of the power management system (PMS). The power management system comprises all the components, other than those in dashed boxes.

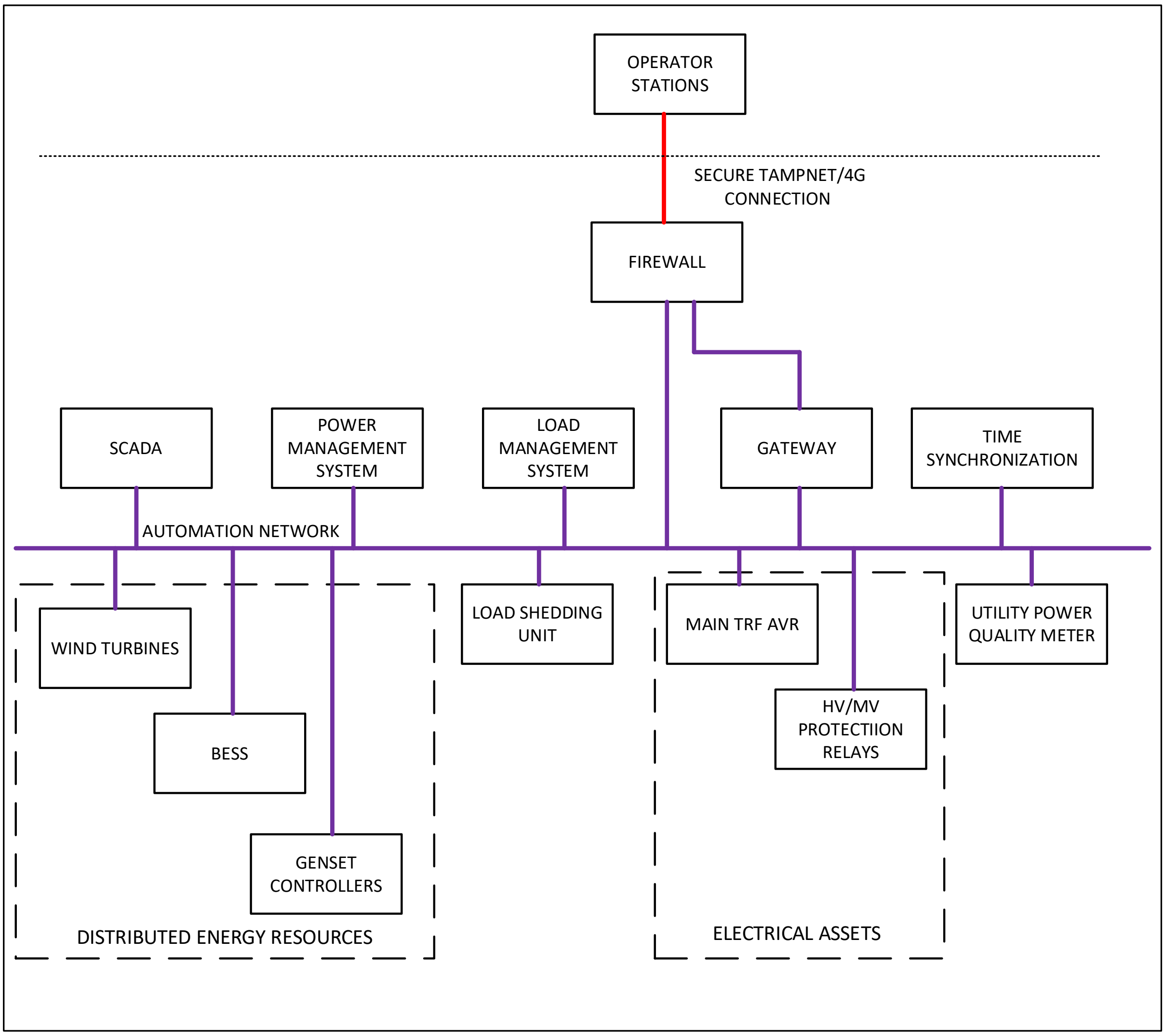


Figure 4-10 Power Management System (PMS) Block Diagram

Detail of the functionality of each of the components is examined in turn.

4.2.9.1 Distributed Energy Resources (DER)

The PMS will communicate with the interface controller for each of the DERs. Communication will be through industry standard protocols such as Modbus TCP/IP or DNP3. The PMS will monitor the DER's power output parameters, monitor their status and will provide appropriate setpoints for power production.

4.2.9.2 Electrical assets

Electrical assets consist of the substation transformers and the associated switchgear, circuit breakers and protection relays. They will function as intelligent electrical devices and so will be able to communicate with the PMS using protocols such as IEC 61850.

4.2.9.3 Load management

Should the situation arise that the distribution hub is unable to satisfy the power demand for the microgrid, then load shedding will be employed. Load shedding will be carried out according to pre-determined priorities. The load shedding unit for each load will be managed by a redundant pair of controllers. Ring communication topology may be employed to provide security of communication.

4.2.9.4 SCADA

The Supervisory control and data acquisition (SCADA) package will provide the window to the operation. Through it (and the associated stations connected to it) the full system status will be visible. It will provide an alarm management function as well as the ability to view events and trends. It will also provide a data archiving function.

4.2.9.5 Power management

Power management is at the heart of the PMS and the controllers will carry out the functions of;

- DER management
- Load sharing
- Frequency/Voltage regulation

4.2.9.6 Gateway

The gateway provides a means of collecting data from the field devices (e.g. circuit breakers) and transferring data to the upper layer.

4.2.9.7 Time synchronisation

A GPS connected time server will ensure that all connected devices on the power automation network are synchronised to a common time source.

4.2.9.8 Firewall and cyber security

The firewall is a means of ensuring separation between the hub automation network and the outside world. It is likely that the communication link between the hub PMS and the remote monitoring and control centre will be through a non-dedicated network e.g. Tampnet. A full cyber security assessment would be required to ensure that the system is suitably hardened and not vulnerable to cyber attack.

4.2.9.9 Remote control centre

The PMS will supplement its local control stations with a remote control centre. The remote control centre will provide full and complete control of the microgrid and its components from an onshore location. The location of the onshore control has yet to be defined, but is anticipated to be within the Aberdeenshire region

4.2.10 Telecommunications

Communication to shore is critical for the microgrid, to enable control from a remote location. The primary method of communication to shore will be via a connection to the Tampnet network, which will be fully redundant where practicable. The connection to the Tampnet network will be via one of the following methods;

- Tampnet 4G
- Tampnet fibre optic network
- Microwave Line Of Sight (LOS) - 30 km from existing facility with fibre optic shore connection

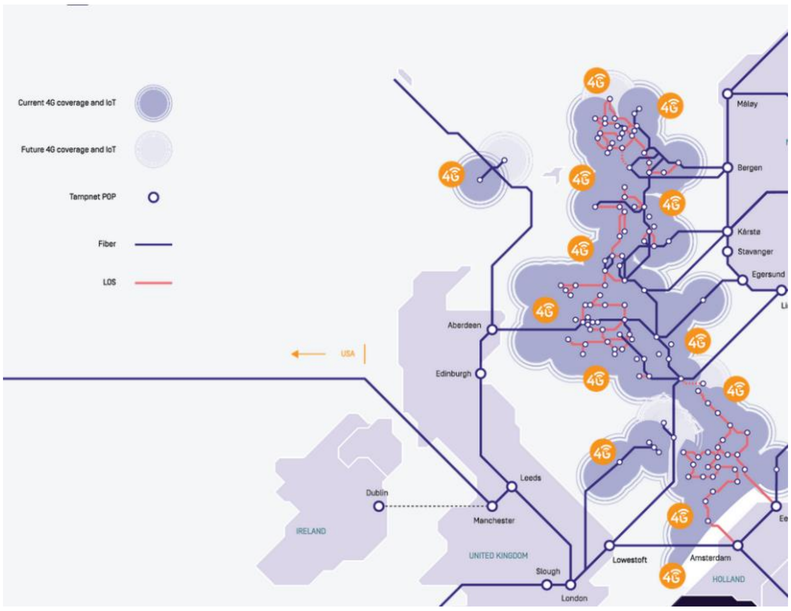


Figure 4-11: Tampnet network coverage

Due to the critical nature of shore communications an alternative method will be provided should the Tampnet connection fail, thus increasing the availability of the complete microgrid. To achieve this a single VSAT connection will be provided for remote access to critical systems; PMS, navigation, etc. Due to the low bandwidth and high latency of a VSAT link, non-critical data (such as condition monitoring) will be stored on the distribution hub and not transmitted until the higher bandwidth Tampnet connection is reinstated.

4.3 Operations

The following section outlines the operations philosophy for the distribution hub.

4.3.1 Operations philosophy

The unit is designed from the outset to be normally unattended. To achieve this operational requirement, the facilities shall be capable of being remotely monitored and controlled. The operations and maintenance philosophies for the Floating NUI will be developed to meet the following prioritised goals:

1. To minimise risk to personnel and the environment by operating in an environmentally responsible manner whilst unattended;
2. To maximise the operational performance of the facility
3. To minimise OPEX through the remote operation and monitoring of the facility;
4. To maximise the efficiency of planned maintenance periods and minimise unplanned maintenance through the use of a robust maintenance management system and condition-based monitoring;
5. Providing a safe working environment for offshore inspection and maintenance activities.

For the sake of robust costing, provision of a helideck has been included in the project Capex calculations. However, to reduce the risk inherent in helicopter transfer and to offer future reduction in both CAPEX and OPEX operations and maintenance activities it is intended that personnel will be transferred to the facility via a walk to work (W2W) vessel rather than by helicopter. A helideck will be provided on the W2W vessel to provide an emergency evacuation facility (i.e. medivac). Systems and facilities for personnel will not be provided on the distribution hub if they can be provided by the walk to work vessel.

A cost benefit analysis of the helicopter and the W2W options will be conducted in future design phases to validate this.

The distribution hub NUI is to be operated remotely, with remote control stations located onshore.

The distribution hub NUI will be fully pre-commissioned at an onshore/nearshore location prior to installation offshore. A local control station will be available on the distribution hub to aid manned intervention.

4.3.2 Bunkering

By preference, storage tanks will be provided on the facility, sized such that the necessary bunkering frequency required for normal operations does not exceed the planned maintenance frequency and that bunkering can take place whilst the facility is being attended. The designs have been sized to provide three months of diesel storage during normal operation, with final capacity to be selected in future phases.

Should bunkering be necessary on a more frequent basis, a remotely controlled bunkering station shall be employed, preventing the need for personnel access during this operation and therefore any associated interruption to normal operations. The bunkering shall be connected to a manifold located along the side of the hull allowing easy access from the bunker vessel.

4.4 Maintenance and inspection

Personnel will attend the distribution hub NUI for routine maintenance, unplanned maintenance and statutory inspection requirements.

As far as possible, where allowed by the regulatory bodies, spaces within the hull shall be inspected remotely, without recourse to physical inspection unless issues are identified by the remote means of inspection. Mooring line inspection will be completed using a remotely operated vehicle operated from a supply vessel.

Spare parts and replacement equipment items including spare engine components, will be stored at an onshore location and appropriately preserved to ensure their readiness for use. No storage facilities will be provided on the distribution hub NUI.

4.4.1 Manning

The maintenance and inspection crew size will be determined by the burden of work to be liquidated. An appropriately sized walk to work vessel will be selected, able to accommodate the crew required.

To minimise the duration of the maintenance and thus the downtime of the distribution hub NUI, maintenance and inspection activities will be completed on a day & night shift basis.

4.4.2 Personnel facilities

No accommodation facilities shall be provided for inspection and maintenance crew on the distribution hub NUI. All accommodation and associated personnel support services e.g. toilets, changing room, laundry, galley, recreational facilities etc. shall be provided on the attending walk to work vessel. For the duration of the maintenance period a temporary accommodation container will be installed. This container will accommodate a break room and sanitary facilities. The temporary unit shall not be plugged into the facilities systems apart from power supply.

All PPE required by personnel will be provided from the walk to work vessel. The distribution hub NUI will not provide any changing rooms or locker facilities.

4.4.3 Maintenance frequency – Generator sets

The proposed generator engines are Wärtsilä W14V31DF dual fuel and the Wärtsilä W20V31DF dual fuel type. The number of units will dependent upon the specific grid. A 75MW load is assumed with 1 sparing of each generator.

Component	**Time between inspection or overhaul (h)**	**Expected lifetime (h)**
	MDF/ GAS operation	**MDF/ GAS operation**
Piston	32000	Min 96000
Piston Rings	32000	32000
Cylinder liner	32000	128000
Cylinder Head	32000	64000 … 128000
Connecting Rod	32000	128000
Inlet Valve	32000	32000
Exhaust Valve	32000	32000

Component	Time between inspection or overhaul (h)	Expected lifetime (h)
	MDF/ GAS operation	MDF/ GAS operation
Maine bearing	32000	64000
Big end bearing	32000	32000
Intermediate gear bearing	64000	64000
Balance shaft bearing	32000	32000
Inspection valve (wear parts)	8000	N/A
High pressure fuel pump	24000	24000
Main gas admission valve	16000	16000
LP and the HP turbochargers	16000	80000

Table 4-5 Time between Inspection or Overhaul & Expected Lifetime

Maintenance and inspection activities will be completed on a periodic basis during planned maintenance periods with maintenance equipment and personnel delivered to the facility via a W2W vessel.

Wherever possible, the maintenance work scope will be scheduled following analysis of equipment performance during operations e.g. using a predicative maintenance approach rather than scheduled.

5 x W20V31DF + 5 x W14V31DF (4,400 Running hours P/A)										
Years 1 to 10	1		2		3		4		5	
Running hours accumulation (projection)	2200	4400	6600	8800	11000	13200	15400	17600	19800	22000
Maintenance activity (frequency) 500 hours	1	1	1	1	1	1	1	1	1	1
Maintenance activity (frequency) 1000 hours	1									
Maintenance activity (frequency) 2000 + 500 hours	1	1	1	1	1	1	1	1	1	1
Maintenance activity (frequency) 4000 hours		1		1		1		1		1
Maintenance activity (frequency) 8000 hours				1				1		
Maintenance activity (frequency) 12000 hours						1				
Maintenance activity (frequency) 24000 hours										
Maintenance activity (frequency) 32000 hours										
Maintenance activity duration (hours)	300	344	214	950	214	654	214	950	214	344
Number of 12 hour shifts required to execute maintenance	26	30	18	80	18	56	18	80	18	30
Shifts required onboard 2 x Field Service Engineers	13	15	9		9		9		9	15
Shifts required onboard 4 x Field Service Engineers				20		14		20		
Bedspace requirements (assume depart after final shift)	13	15	9	20	9	14	9	20	9	15

Table 4-6 Genset. Maintenance breakdown estimates: Frequency, durations manning, levels & bedspace

4.4.4 Maintenance frequency – Energy storage

Energy Storage maintenance					
Years 1 to 10	1	2	3	4	5
Maintenance activity (frequency)	Annual	Annual	Annual	Annual	Annual
Maintenance activity duration (hours)	24	24	24	24	24
Number of 12 hour shifts required to execute maintenance	2	2	2	2	2
Days required onboard 2 x Field Service Engineers	1	1	1	1	1
Bedspace requirements (assume depart after final shift)	2	2	2	2	2

Table 4-7 Energy Storage. Maintenance breakdown estimates: Frequency, durations manning, levels & bedspace

4.4.5 Hull inspection

Where possible, inspection will be completed remotely, either using autonomous vehicles (drones/ ROVs) or digital imagery.

- External hull above the waterline, and topsides visual inspections will be completed by autonomous vehicles or digital imagery;
- Hull spaces will be inspected through digital imagery, software analysis of images will be used to ascertain degradation. Where anomalies are identified a manned inspection will be factored into the next planned maintenance and inspection window;
- External hull below the waterline and mooring line inspection will be completed by ROV.

4.4.6 Offshore handling

All spare parts and necessary equipment for the maintenance of the facility will be delivered offshore via a walk to work vessel.

Spare parts and equipment shall be limited in size by the crane and handling capabilities of the walk to work vessel and the available handling facilities on the Floating NUI.

A laydown area will be provided on the main deck level with access routes for materials handling trolleys to all key equipment located on the Floating NUI on all decks. Access hatches and lifting beams shall be provided to lower equipment from the Process deck to the internal mezzanine and tank top of the top deck structure as appropriate. Hatches will be sized for the maximum dimensions of spare equipment and lifting beams/ slings to their maximum weight.

Slings for all lifting beams shall be brought offshore on the W2W vessel.

All lifting of equipment and spare parts shall be done by the crane on the W2W vessel. The facility shall be equipped with monorails where material transportation is foreseen as well as above all large equipment components that might require replacement at some point in time.

4.4.7 Emergency escape and evacuation

In case of emergency whilst personnel are located on the Floating NUI, the primary means of evacuation will be via the walk to work system to the attending vessel. In case of this being unavailable, personnel will muster awaiting the walk to work vessel. Should the walk to work vessel not be available and immediate evacuation will be required, life rafts and an escape to sea system is provided. The floating NUI is equipped with two muster areas including all required safety equipment, immersion suits, life rafts and escape to sea system. The attending (W2W) vessel will provide a helideck to provide an emergency evacuation facility (i.e. medivac).

4.5 OPEX estimate

Based on previous experience and maintenance proposals from the consortium members the OPEX estimate is shown in Table 4-8.

	Estimate	Contingency (%)	Contingency (#)	Total (incl. contingency)	Unit
Overall Opex (incl. maintenance)	**5,300,318**	**27**	**1,421,831**	**6,722,150**	**$/annum**
Onshore Opex	1,150,000	23	265,000	1,415,000	$/annum
Offshore Opex	4,150,318	28	1,156,831	5,307,150	$/annum
of which, maintenance	2,803,318	26	730,081	3,533,400	$/annum

Table 4-8 OPEX Estimate

5 Microgrid – Gas import

Crondall has completed a review of potential tie-ins for gas import (GI) to supply gas to back-up power generation at the identified microgrids. The following gas import tie-in options were taken into consideration for each Microgrid during the study:

- Hot tapping into an existing export route;
- Use of pre-installed tees on existing gas export routes;
- Connection to major gas export systems via new or existing tie-in structure;
- Subsea connection at existing gas exporting/gas lift infrastructure;
- Topside tie-in at gas assets via new/retrofitted riser or existing spare riser.

Crondall has completed a 'scoring' for all the potential tie-in options for each microgrid and completed a CAPEX estimation for each microgrid. However, no final selection can be made at this stage as the operators of the infrastructure, that the tie-in points propose to tie-in to, have not been consulted. If the project were to go ahead then contact with the individual operators would need to be established to ascertain their interest. Each microgrid has multiple tie-in point options so this is not anticipated to be a problem.

5.1 Tie-in option scoring

A long list of potential tie-in options was generated for each microgrid. Each option was scored using the scoring system outlined in Table 5-1 and ranked. All options with the two highest scores were shortlisted for costing. Having multiple tie-in options would give the developer flexibility to negotiate more favourable commercial terms.

Assigned Scoring	Score 3	Score 2	Score 1
Distance/pipeline length	Less than 15km.	Up to 30km.	Over 30km.
Tie-in complexity	Robust connection. Easy access for tie-in. No structures required.	Small subsea structure. Congested approach.	Congested approach. Larger subsea structure required. Limited contractor availability.
Interference with current operations	No disruption with production/export.	Min disruption, tie-in within planned shutdowns.	Major disruption to production.
Asset modification scope	No modifications to existing assets.	Min modifications (i.e control update, spool tie-in).	Major modifications (riser retrofit, major controls upgrade).
Tie-in Risk	Negligible	Minimum risk or disruption to asset operations. Work within 500m zone	Risk to existing assets leading to operation disruption. Work within 500m zone

Assigned Scoring	Score 3	Score 2	Score 1
System Availability	High availability (export route).	Adds host availability or 3rd party subsea tie-back availability in equation.	Major previous issues with asset availability.
Tie-in point CoP	2040 and beyond.	2035	Up to 2030
Comparative Tie-in Cost (*Note: not based on actual cost)*	Lower comparative.	Similar range with majority.	Higher comparative.

Table 5-1 Gas Import Tie-in Option Criteria and Score

5.2 Microgrid A

Microgrid A is planned to provide power to Judy (Harbour Energy), Shearwater (Shell), Culzean (TotalEnergies), Lomond (Harbour Energy) and Stella (Ithaca Energy) assets. The long list of potential tie-in options has included tying into nearby gas export pipelines, CATS T5 and T6, the Fulmar SEGAL tee as well as the Elgin platform.

Nearby export routes considered for tie-in are listed below and shown in Figure 5-1.

- Shearwater 24in gas export to SEGAL Tee
- Elgin 34in gas export to SEAL
- Stella 10in export to CATS Tee 5
- Judy 20in export to CATS Tee 6
- Culzean 22in gas export to CATS T5
- Lomond 20in gas export to CATS RP at North Everest

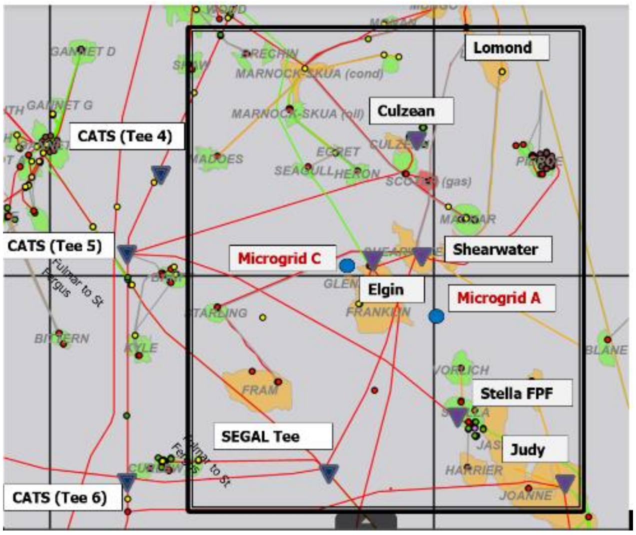


Figure 5-1 Microgrid A and C catchment area

CATS T5 and T6 and Fulmar SEGAL Tee were also added to the long list of potential tie-in options for Microgrid A.

From information provided by TotalEnergies (10), the Elgin operator, two additional tie-in points were identified at subsea infrastructure.

The short list tie-in options are listed below.

- Existing Elgin gas export SSIV/Tee manifold (score - 22)
- CATS T5 with re-use of Banff Tie-in (CoP in 2020) (score - 22)
- Elgin WHP B with new retrofitted riser (score - 21)
- Pre-installed tee on SEAL line (score - 21)
- Mechanical clamp Hot Tap at the nearest (to Microgrid A) gas export (score - 21)

5.3 Microgrid C

Microgrid C (Figure 5-1) is planned to provide power to a single asset, Elgin, operated by TotalEnergies and is in the same 'catchment area' for potential tie-in points as Microgrid A. Thus, the same gas export infrastructure has been considered for Microgrid C as Microgrid A when compiling the long list, with the addition of CATS Tee2, Tee3 and Tee4.

The short listed options include:

- Existing Elgin gas export SSIV/Tee manifold (Score - 22)
- CATS T5 with re-use of Banff Tie-in (CoP in 2020) (Score - 22)
- Elgin WHP B with new retrofitted riser (Score - 21)
- Pre-installed tee on SEAL line (Score - 21)
- Mechanical clamp Hot Tap at the nearest (to Microgrid C) gas export (Score - 21)

5.4 Microgrid D

Microgrid D (Figure 5-2) is planned to provide power to Montrose and Arbroath (Repsol Sinopec), ETAP (BP) and Gannet (Shell) production and processing facilities. In developing the long list of tie-in options the following local gas export routes have been considered:

- ETAP 16in gas export to CATS T2
- Montrose –Arbroath 6in gas import CATS T2
- Gannet 20in to SEGAL (Fulmar)

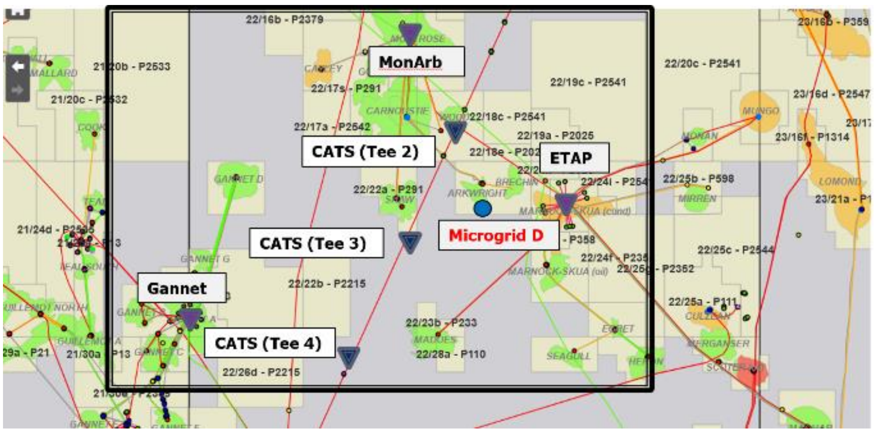


Figure 5-2 Microgrid D Catchment Area

The short-listed potential tie-in options include:

- Hot tap Mechanical on ETAP export (Score - 22)
- CATS T2 new tie-in (Score - 22)
- Hot Tap welded ETAP Export(Score - 21)
- Pre-installed Tee at Fulmar (Score - 21)

5.5 Microgrid E

Microgrid E (Figure 5-3) is planned to provide power to Claymore (Repsol Sinopec), Piper (Repsol Sinopec) and Scott (CNOOC) production and processing facilities. The longlist of potential tie-in options has been based on the gas export infrastructure of the production facilities taking power from the microgrid and SAGE export pipeline:

- Piper 18in to gas export SSIV to FUKA
- Scott 10in gas expo to SAGE
- Claymore 16in to 6in import from SSIV Piper B

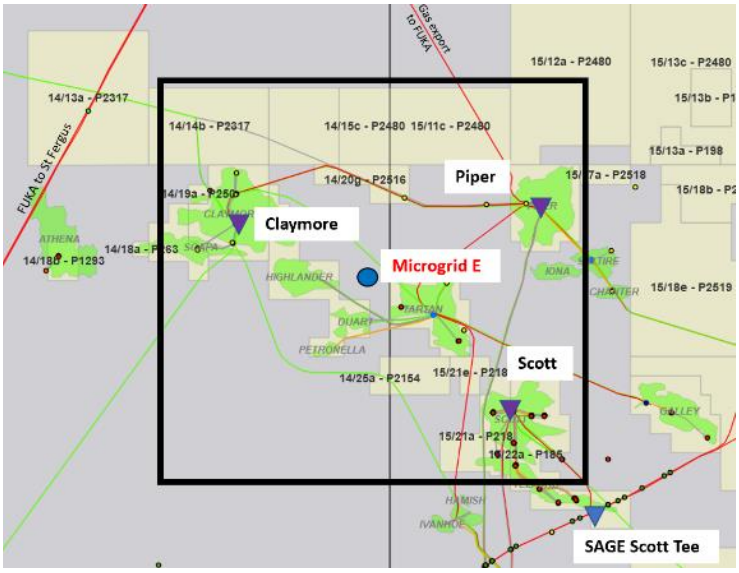


Figure 5-3 Microgrid E Catchment Area

The shortlisted options for Microgrid E include tie-ins via:

- Hot tap via Mechanical connector to the nearest gas export (Score - 22)
- Welded Hot Tap to the nearest gas export (Score - 21)
- New Tie-in at SAGE Scott Tee (Score - 21)

5.6 Microgrid F

Microgrid F (Figure 5-4) is planned to provide power to Britannia (Harbour Energy), Alba (Ithaca Energy), Forties (Apache Corporation) and Avalon (owned by PING Petroleum, currently development is in the feasibility stage) production and processing facilities. Local gas export infrastructure is scarce, with a 28 inch pipeline from Britannia to St Fergus. Alba exports gas to Britannia via a 4km long pipeline. The Forties field has no dedicated gas export and NGLs are transported within oil export.

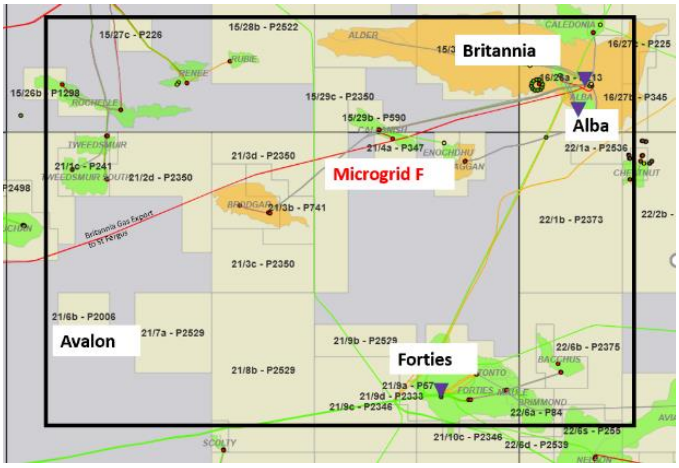


Figure 5-4 Microgrid F Catchment area

The longlist included all tie-in options within 50km radius this included Nelson field (Shell) 10in gas export to Fulmar line, Fulmar 20in (Kittiwake and Nelson Tie-in) and SAGE (Scott tee) tie-in locations. The shortlisted options are listed below:

- Hot Tap with mechanical clamp Nelson export (Score – 19)
- Hot Tap Welded at Britannia export (Score - 20)
- New tie-in at SAGE/Fulmar tee (Score - 20)
- Pre-installed Tee (not confirmed) on Britannia export (Score - 20)
- Hot tap mechanical connector on Britannia export (Score - 20)

5.7 Microgrid G

Microgrid G is envisaged to provide power to Buzzard (CNOOC) and Buchan re-development (Jersey Oil & Gas Plc). The Buzzard platform exports gas via a 10in pipeline to Captain Tee (FUKA pipeline). Other gas infrastructure nearby includes the Golden Eagle platform (CNOOC) which has a 6 inch gas export to PLEM at Ettrick tie-in to SAGE.

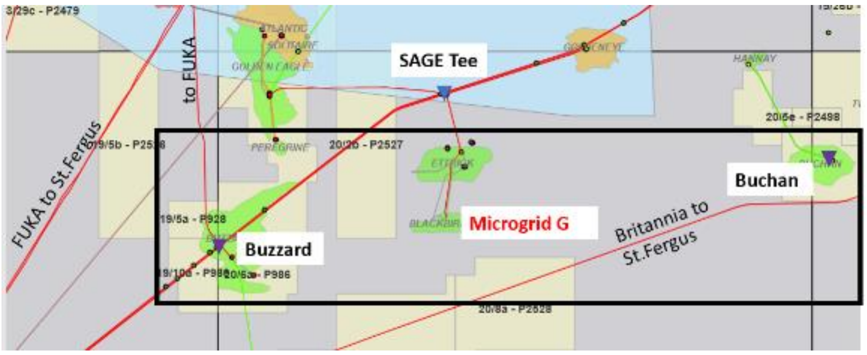


Figure 5-5 Microgrid G catchment area

The shortlisted options with the highest scores include:

- New Tie-in at Ettrick tee at SAGE (Score - 21)
- New Tie-in at Buzzard Tee at FUKA (Score - 20)
- Welded hot tap into SAGE (Score - 20)
- Welded hot tap into Britannia export (Score - 20)

6 Microgrid – Cabling

Enertechnos Ltd has been responsible for defining the power distribution system, firstly between the floating wind turbines to the distribution hub, and then from the distribution hubs to the production platforms.

Once defined, the configuration has been optimised by reducing the number of components to a workable level and by using either a repeatable size criterion or using standard sized vendor provided items to capture best value for money.

Enertechnos Ltd has built a database of capabilities of various cables and lengths to assess the likely sizes that would work, followed by a cost database for each size of cable.

An overview of the loads and locations indicated that loads for Microgrids of between 70 and 90MW was possible to achieve, allowing a nominal size of circa 75MW+/-20% to be built as a standard repeatable design.

The following sections describe the approach taken to propose a pragmatic set of cable sizes, layout, and develop costs for each Microgrid.

6.1 Cable selection and approach

6.1.1 Cable technology

Subsea power cables have been used extensively in the oil and gas business and in the renewables sector for offshore wind installations, as well as other applications.

Enertechnos has developed a new type of cable called CTS which acts to balance the reactive power components inherent in conventional cables to allow lower voltage drop, greater active power transfer and longer distances, all in AC. This enables the use of lower voltages and AC transmission over greater distance with lower losses, reducing the cost of electrification for North Sea assets.

For the Orcadian Microgrid electrification concept, Enertechnos has initially sought to minimise any downside risks associated CTS cable. This has focused on ensuring that any installed cable can operate in both Normal and CTS modes, providing the benefits of CTS cable whilst remaining functional to operate as a normal cable if required. Once operational data proves the expected CTS advantages it is anticipated the cable will be designed for CTS mode operation only.

Where benefits are marginal or where potentially higher risks exist (such as where higher levels of mechanical fatigue are expected) we have chosen to propose the use of conventional cable. One area is in the dynamic risers between the floating wind turbines and the distribution hub. Once the fatigue analysis is completed, a final selection can be made. However, as the floating wind turbines shall export at 66kV, the cables tend to have lower current flows, thus conventional cable is suitable due to the low voltage drop.

In most respects CTS cable looks and is the same as normal cable, manufactured with the same machines as normal cable. The main difference is that the conductor is arranged into two discrete elements. It is this difference that changes the behaviour of the cable to enable it to balance the inductive reactance with the capacitive reactance, reducing the net negative impacts considerably. However, CTS is always designed to be inductive overall to ensure stable operation.

The terminations are a little more complex as the two elements are diverted via a dielectric assurance and switching system prior to linking into the conventional cable switch gear and circuit breakers.

6.1.2 Conventional cable and CTS cable – comparative benefits

A conventional cable can be modelled for lengths of up to 240km using an electrical Π or PI simulation model reliably to capture the properties key parameters – resistance, inductance and shunt capacitance (11).

For a balanced three phase system with each phase comprising identical equidistantly spaced cables, the self and mutual inductances can be considered as a single value (12).

For cables buried in ground or in water, capacitance between cables can be ignored as the ground or water can be considered to be at the same potential, and the screen of each phase's cable is connected together and earthed (single or cross bonding) (13). Therefore, only the shunt capacitance needs to be considered.

This produces a PI model as represented in Figure 6-1.

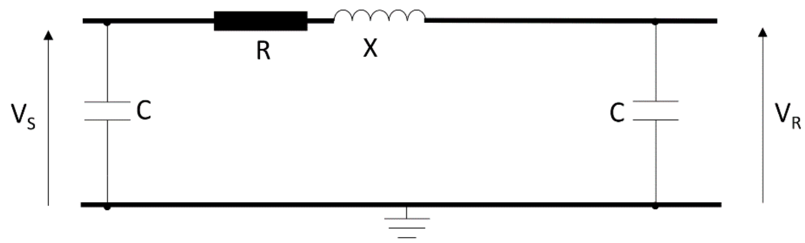


Figure 6-1: PI Model for a three phase cable.

6.1.2.1 Conventional cable

There are several challenges associated with conventional cable, which the following subsections detail.

6.1.2.1.1 Voltage drop

The loss of electrical potential across the series impedance of the cable when the connected load is primarily resistive or inductive. The voltage drop is proportional to the current drawn by the load and the series impedance along the cable.

As voltage drop increases (i.e. on a longer cable) this results in sub-optimal performance of connected electrical equipment including lower torques and speed outputs from induction motors. From a consumer's perspective, the voltage drop represents a cost as a result of the lost energy.

6.1.2.1.2 **Current carrying capacity**

There is a fixed limit of current that a connected cable can withstand in constant operation at the maximum operating temperature.

In a heavily loaded line with voltage drop, more current needs to be supplied to provide the same amount of active power. This increases the temperature of the conductor, which increases the AC resistance that then increases the voltage drop, and accordingly increases losses.

6.1.2.1.3 **Voltage rise**

When a conventional cable is lightly loaded the cable consists of many parallel paths to ground via the capacitance of the cable insulation. The primarily inductive series reactance and capacitive shunt reactance counteract each other to lower the impedance to ground of the cable at its far end. This causes the voltage to rise at the receiving end of the cable (Ferranti effect) (14)and increases the charging current and reactive power generated by the cable.

This effect is only significant on lightly loaded long cables, when the shunt admittance is significant relative to the load at the end of the cable. In general, the platform loads are relatively constant and thus light loads are not expected from the distribution hub to the platforms, However, the cables from the turbines to the hubs are likely to experience light loads under low wind conditions.

6.1.2.1.4 **Reactive power consumption**

For heavily loaded cables the inductance of the line absorbs reactive power and produces a lagging power factor. This increases transmission losses and potentially harmonic distortion creating instability.

For lightly loaded power cables, generation of reactive power in the cable shunt capacitance produces a leading power factor and voltage rise at the receiving end of the cable (Ferranti effect).

6.1.2.2 CTS cable

CTS cable comprises a conductor split into two elements, a red and green element, linked by a capacitance. A CTS cable can be operated in CTS enabled mode, also known as CTS mode, where the red element forms one end of the cable, and the green element the other.

Alternatively, a CTS cable can be operated in normal mode, functioning like a conventional cable with the red and green elements joined together at the sending and receiving ends of the cable. It should be noted that a CTS enabled cable has a lower skin effect than a conventional cable because of the enhanced configuration of the conductor.

In terms of a distributed parameter model, this is shown in Figure 6-2.

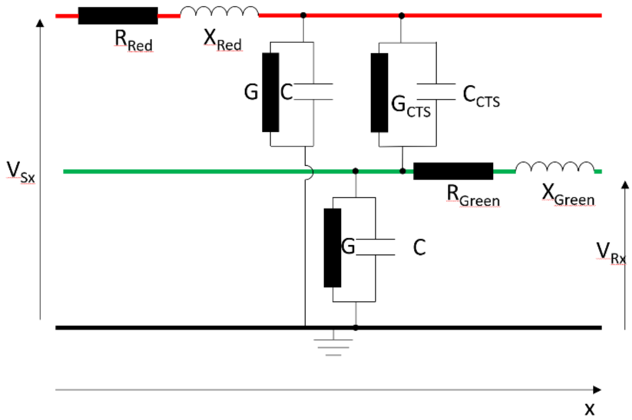


Figure 6-2: Distributed parameter model for CTS cable

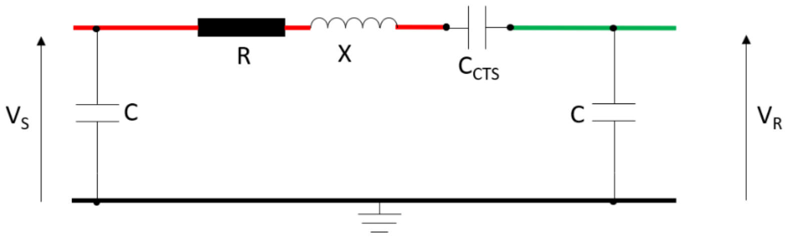


Figure 6-3: PI model for CTS cable.

This model can be simplified to that shown in Figure 6-3 as $R_{Red} = R_{Green}$ and $X_{Red} = X_{Green}$. Conductance is neglected due to its negligible value relative to capacitance.

The series impedance of the cable can be found from the equation below. This shows that the series capacitance and inductance produce a lower net series impedance.

$$Z = R + jX = R + j\omega L - \frac{j}{\omega C_{CTS}}.$$

CTS can bring improvements to each of the challenges for conventional cable detailed above.

6.1.2.2.1 **Voltage drop**

The lower net series impedance results in a smaller voltage drop for a given current across the length of the cable.

For instance, conventional 3 phase 630mm^2 cables at an operating voltage of 33kV can supply a maximum 16MW, 0.9p.f. load with a 5% voltage drop across a distance of 30km. In this scenario, the cable is lightly loaded at 33.7%.

CTS enabled 3 phase 630mm^2 cables at an operating voltage of 33kV can supply a maximum 34MW, 0.9p.f. load with a 5% voltage drop across the same distance.

In this example, the CTS can supply over double the power across the same distance with the same voltage drop.

The reduction in Cross Sectional Area (CSA) of cable for a given power delivery, reduces the CAPEX of the cable for the Microgrid.

6.1.2.2.2 **Current carrying capacity**

The same amount of power may be sent down a cable at a lower current due to the lower voltage drop, offering improved (lower) losses.

The combination of these two factors means that it may be advantageous to use cable with a lower distribution voltage, due to the smaller voltage drop. This can offer potential cost savings in terms of transformer, cable, switchgear, and operations & maintenance (O&M) procedures.

Use of a conventional 3 phase 630mm^2 cables at 20kV to supply the same 16MW, 0.9p.f. load across a distance of 30km would give a 12.2% voltage drop.

CTS enabled 3 phase 630mm^2 cables at 20kV can supply the same 16MW, 0.9p.f. load with a 5% voltage drop across the same distance, offering a 7% current and apparent power reduction due to the lower losses and higher receiving end voltage compared to the equivalent 20kV cable.

The lower transmission voltage is beneficial for consumers, as this can be matched to their facility voltage, reducing brownfield modifications and the associated cost.

6.1.2.2.3 **Voltage rise**

A cable consists of many parallel paths to ground via the capacitance of the cable insulation. When a cable is lightly loaded, the charging current drawn by the shunt capacitance becomes significant relative to that of the load. At the far end of the line, the series impedance and shunt capacitance counteract one another to increase the receiving end voltage and increase the charging current to be greater than that drawn by the capacitance alone.

The distributed series capacitance within CTS cable reduces the interaction of the series and shunt impedances. As a result, the voltage rise at the receiving end of the cable is lower and the charging current and reactive power generated by the cable are lower too.

In the event of the planned or unplanned partial or full disconnection of platform loads such that normally fully loaded lines are now lightly loaded, the use of CTS cable will allow the Microgrid to continue distribution to existing loads with lower voltage rise.

6.1.2.2.4 **Reactive power consumption**

For heavily loaded cables the reactive power absorbed by the transmission line is reduced due to the lower series impedance, improving a lagging power factor. For the comparison between CTS and conventional cable at 20kV detailed in section 6.1.2.2.2 a 32% reduction in reactive power consumption, from 8.9Mvar to 6MVar was calculated.

For a lightly loaded power cables the reactive power generated by the transmission line's shunt capacitance is reduced, improving a leading power factor.

For the Microgrid this reduces losses and the requirement for reactive compensation, reducing CAPEX for both the Microgrid and the consumer

6.1.3 Modelling of the cable

The cables were modelled using a PI model as shown in Figure 6-1.

The inductance and shunt capacitance values per km and current carrying capacity values are for TFKables copper, XLPE cables with a metallic screen (15), considered representative for cables used for medium and high voltage applications in the distribution of power from windfarms.

The resistance of the cable was calculated in accordance with IEC60287-1 *Electric cables – Calculation of the current rating – Part 1-1: Current rating equations (100 % load factor) and calculation of losses – General.*

Conductance was neglected due to its negligible value relative to the shunt capacitance of the cable.

This exercise was undertaken for cables ranging in cross sectional areas (CSAs) of between 400mm^2 to 1600mm^2 and for distribution voltages of 11kV, 20kV, 33kV, 66kV and 132kV.

For modelling the CTS cable, the series impedance (inductive reactance) of the cable was reduced to 10% of that of a conventional cable, in accordance with measured results. This approach is a representative method of detailing the reduction in the net series impedance offered by the CTS cable, as described in section 6.1.2 .

Initial load flow studies were undertaken to assess the permissible loading and voltage drop limits across the parameters laid out in Table 6-1, for the CTS cable operating in normal and CTS mode.

Parameter	Range
3-Ph Voltage Rating (kV_{rms})	11, 20, 33
Platform Power Demand (MW)	5, 10, 19.35, 19.6, 40, 55, 80
No. of Parallel Circuits	1, 2, 3
Cable Cross-Sectional Area (mm^2)	800, 1000, 1200, 1600
Length (km)	2, 5, 10, 20, 30

Table 6-1 Parameters used in initial loadflow studies

Load flow studies for additional distances, loads, voltages and sizes were undertaken as required once the parameters for all the hubs had been established.

Permissible voltage drop and cable carrying capacity limits are detailed in Table 6-2.

Cable mode	Maximum Voltage drop (%)	Maximum current carrying capacity (%)
Normal	15	105
CTS enabled	5	105

Table 6-2 Maximum permissible voltage drop (%) and current carrying capacity (%) limits.

The limits selected reflect the idea that the CTS cable will be the standard method of operation for this system providing a maximum voltage drop of 5%.

In the event of an error with the CTS equipment the cable will switch to normal mode (operating as an ordinary cable) supplying the same loads but with a maximum voltage drop of 15%.

Maximum carrying capacity is set at 105% of the cables current carrying capacity when buried in ground. This is to reflect that in practice, the cables for this project will be installed subsea rather than in the ground.

The results of the initial load flow studies as summarised in Figure 6-4.

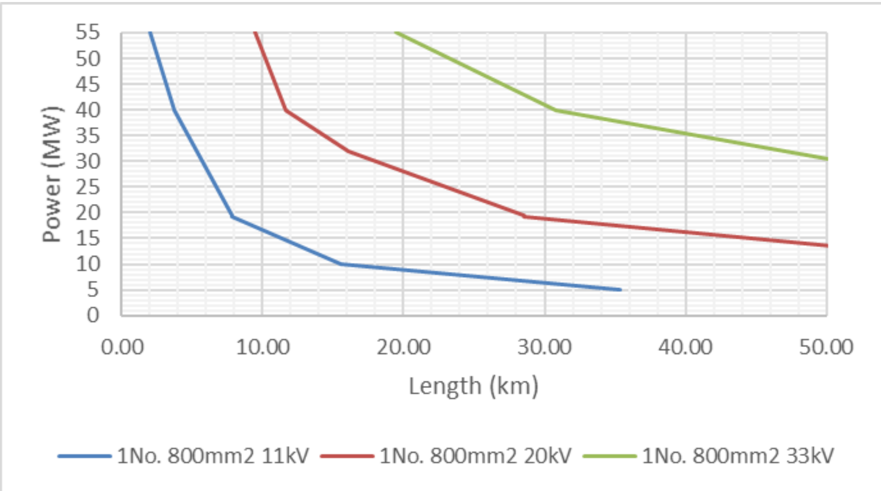


Figure 6-4: The maximum power and length that can be supplied with a maximum 15% voltage drop for the system in normal mode.

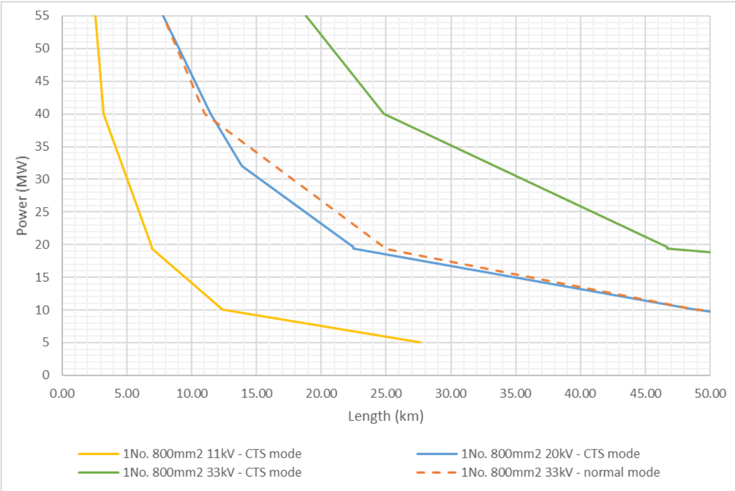


Figure 6-5: The maximum power and length that can be supplied with a maximum 5% voltage drop using CTS cable in CTS mode.

Figure 6-5 shows the maximum power and length that can be supplied with a maximum 5% voltage drop for the cable with CTS enabled, with the performance of the same cable in normal mode for reference. Figure 6-5 clearly shows the reduction in voltage drop for an equivalent length and power of a cable in CTS mode when compared to Figure 6-4, and how the performance of a 20kV CTS enabled cable (blue line) is equivalent to that of a 33kV cable (orange dashed line) operating as a conventional cable.

The cable sizing exercise was initially undertaken for Hubs A, C and D. The average load of the platforms to be supplied by these hubs is 30MW, and the average distance this power needs to be supplied across is 22km. From an initial glance at Figure 6-4 and Figure 6-5 it is immediately apparent that 11kV is unlikely to be a feasible solution for the majority of hub-to-platform links.

The upper limit on the current that can pass through a given cable is primarily determined by the voltage and the CSA (Cross sectional Area). The power each cable can deliver increases by approximately 7% for a 200mm2 increase in CSA.

The relevant load profiles and equipment distances for each Microgrid is presented in section .

A discussion on the distribution hub to consumer links and the voltages and cable configurations selected is presented in section 6.3 .

6.1.4 Installation

The subsea installation of the cable is identical for both conventional and CTS cable and all the normal design, accessories and install procedures will be used and followed.

6.2 Cable routing selection and Microgrid consolidation

Distribution of the power from the distribution hubs to the consumers was investigated at 3 different voltage levels 11, 20 and 33kV. Delivery of power to the hubs from the turbines was investigated at 33 and 66kV as these are the export levels that have been standardised for offshore wind farms in general.

Calculations have been completed to estimate the maximum transmission distance for a given voltage drop. For the purposes of this project, these have been set at a notional 5% voltage drop for CTS mode and 15% voltage drop for cable in conventional mode (or using conventional cables).

Inherently the power drop is a function of current, so the lower the voltage and the greater the power required, the shorter the distance capable to fulfil that requirement. In line with these results, the Hubs are placed closest to the highest power users, most commonly between 5 and 15km.

This study looked at the use of conventional subsea cable as well as use of CTS-enabled cable that can run in either CTS or conventional mode. In line with the predicted performance and risks of each application, a choice of where CTS is used has been selected.

Based on the likely design Enertechnos would use for this type of application, CTS is capable of being enabled if the cable length from the distribution hub to the consumer is greater than 20km. For distances less than this a conventional cable has been selected.

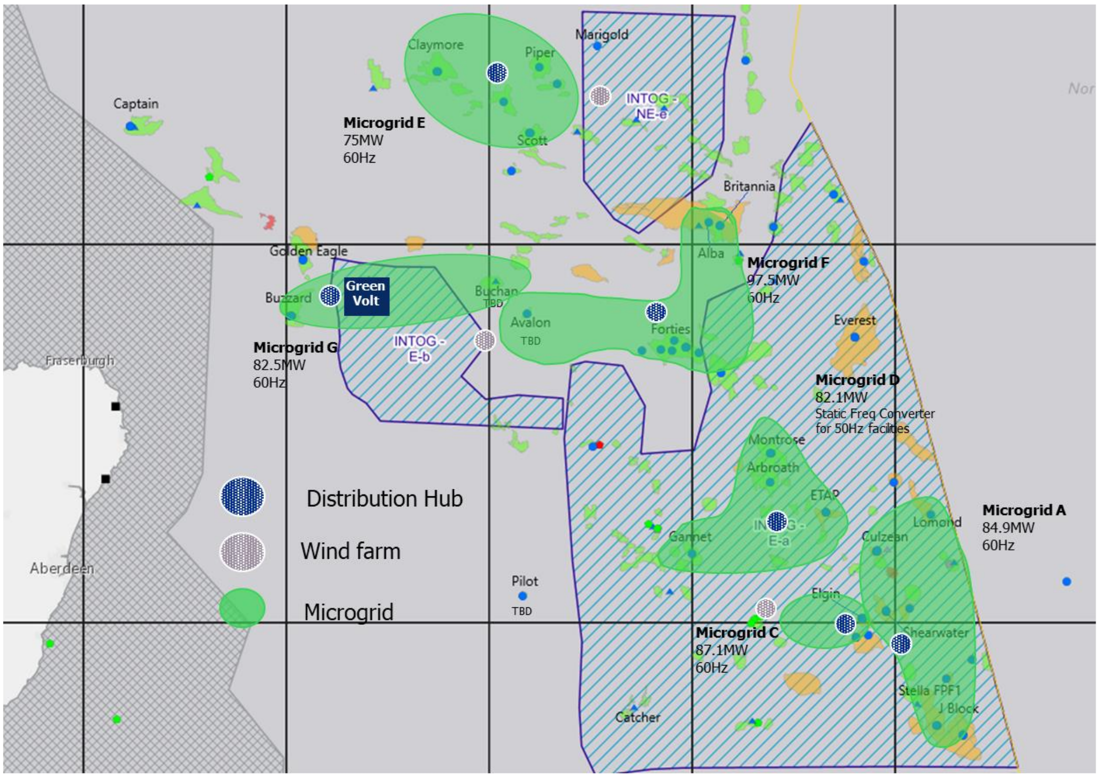


Figure 6-6: North Sea Microgrid layout

As detailed in section 3.2 , the Microgrids have been grouped as shown in Figure 3-2, to minimise cable lengths and maximise each Microgrid lifespan. In addition, Microgrids have been consolidated to minimise their unit costs and utilise a standard 75-90MW distribution hub as much as possible.

The wind farms have also been consolidated to reduce impact to fishing and shipping, as well to provide the opportunity for cost savings. Each wind farm shall be split into strings of floating wind turbines, with individual strings connected to the distribution hub of each Microgrid. The wind farm strings are independent, with each distribution hub utilising two strings, i.e. wind turbines are not shared between Microgrids.

6.3 Costed cable connections

6.3.1 Cost build up

Costs have been based on a number of public and proprietary databases, together with real cable manufacturing metrics to calculate baseline costs for 33kV cables from which other sizes and voltage ratings have been extrapolated. The mixture of sources has included; The UK's Energy Systems Catapult's work on offshore wind farm costs, and the experience of the Microgrid consortium.

The cable cost estimates have been based on the actual tonnes of copper used for each cable size multiplied by a projection of copper costs for the 2024 period based on published projections as in Figure 6-7.

Whilst Copper prices have increased dramatically recently, we have not included higher prices for two main reasons. Firstly, we want to create a cost estimate that is equivalent to that generated in the 2021 industry paper investigating power from shore and secondly once the current world events have subsided, we might expect the prices to reduce and revert to the long term averages.

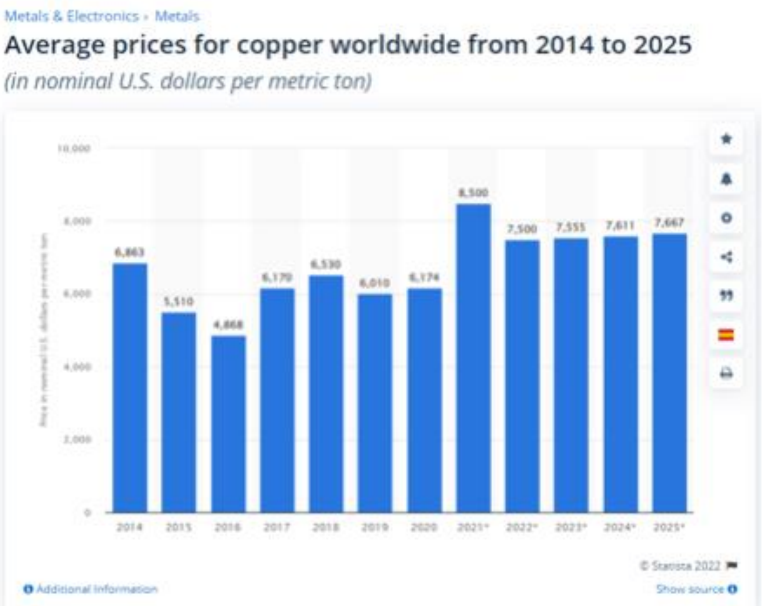


Figure 6-7: Historic and projected Copper Prices used for comparison purposes (16)

From this base cost we have added a cost uplift to account for the non-copper costs, derived from single phase cable manufacturing costs. This is multiplied by three and a factor added for the encasement and armouring of the trefoil aggregation of the phases.

Cross checks were performed against multiple sources to provide assurance that costs were within an acceptable total cost error range. The sources for the cross check include; oil and gas cable cost metrics, data shared by the specific operators, and costs from the Catapult's estimates.

This methodology will enable a cost variance analysis in future phases, to enable the assessment of the impact of copper price variances on the overall Microgrid costs.

Costs were developed on a kilometre basis for calculating the costs of each link. The build-up for the installation costs was based upon industry rates, and included the following items:

- Mobilisation and demobilisation days,
- 15% waiting on weather,
- Cable lay vessels,
- Cable burial spreads,
- Support vessels,
- Cable crossings.

For cost build up purposes, unit costs for installation, hook up and commissioning, plus a consistent set of percentage multipliers for unallocated provisions, contingency, engineering, project management, freight, certification, and insurances, were used and cross checked, to ensure the most direct comparison with industry e. Table 6-3 outlines the percentages applied for each of these categories.

Cost build up from material costs

Design	6%	of materials & install
Project Management/Install Eng	8%	of materials & install
Insurance	3%	of materials, Eng&PM & Install
Certification	2%	of materials, Eng&PM & Install
Owners costs	10%	of materials, Eng&PM & Install
Contingency / UAP	25%	of all costs

Table 6-3: Cost build up percentages used in this project

The cost build up for two sample cable sets have been included in Table 6-3 to Table 6-7. The data within Table 6-4 is representative of the cable options between the wind farms and the distribution hubs. The data Table 6-7 is representative of the cable options between the distribution hub and consumers for a 33kV and 800mm^2 3-phase cable. It should be noted that the engineering, project management, insurance and certification of the installation costs are included within the install costs listed within the tables.

	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable
Cable Length km	5	10	15	20	25	30	35	40
X-sectional Area of Conductors mm2	400mm	400mm	400mm	400mm	400mm	400mm	400mm	400mm
Voltage level	66kV	66kV	66kV	66kV	66kV	66kV	66kV	66kV
crossings	4	5	6	7	8	8	9	10
Material costs	$ 1,569,500	$ 3,139,001	$ 4,708,501	$ 6,278,002	$ 7,847,502	$ 9,417,002	$ 10,986,503	$ 12,556,003
Connectors	$ 716,345	$ 716,345	$ 716,345	$ 716,345	$ 716,345	$ 716,345	$ 716,345	$ 716,345
TOTAL Materials	$ 2,285,845	$ 3,855,345	$ 5,424,846	$ 6,994,346	$ 8,563,846	$ 10,133,347	$ 11,702,847	$ 13,272,348
PM&ENG	$ 868,621	$ 1,465,031	$ 2,061,441	$ 2,657,851	$ 3,254,262	$ 3,850,672	$ 4,447,082	$ 5,043,492
Install	$ 2,543,444	$ 3,189,114	$ 3,834,784	$ 4,480,454	$ 5,126,124	$ 5,771,795	$ 6,417,465	$ 7,063,135
Crossings	$ 340,000	$ 425,000	$ 510,000	$ 595,000	$ 680,000	$ 680,000	$ 765,000	$ 850,000
Owners Cost	$ 603,791	$ 893,449	$ 1,183,107	$ 1,472,765	$ 1,762,423	$ 2,043,581	$ 2,333,239	$ 2,622,897
sub total	$ 6,641,701	$ 9,827,939	$ 13,014,178	$ 16,200,417	$ 19,386,656	$ 22,479,395	$ 25,665,633	$ 28,851,872
UAP	$ 1,660,425	$ 2,456,985	$ 3,253,545	$ 4,050,104	$ 4,846,664	$ 5,619,849	$ 6,416,408	$ 7,212,968
TOTAL	$ 8,302,126	$ 12,284,924	$ 16,267,723	$ 20,250,521	$ 24,233,320	$ 28,099,243	$ 32,082,042	$ 36,064,840

Table 6-4: Cost build up of Normal cable 400mm2, 66kV, 5-40km

	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable
Cable Length km	5	10	15	20	25	30	35	40
X-sectional Area of Conductors mm2	400mm	400mm	400mm	400mm	400mm	400mm	400mm	400mm
Voltage level	66kV	66kV	66kV	66kV	66kV	66kV	66kV	66kV
crossings	4	5	6	7	8	8	9	10
material	$ 1,720,783	$ 3,441,567	$ 5,162,350	$ 6,883,134	$ 8,603,917	$ 10,324,700	$ 12,045,484	$ 13,766,267
Connectors	$ 1,074,517	$ 1,074,517	$ 1,074,517	$ 1,074,517	$ 1,074,517	$ 1,074,517	$ 1,074,517	$ 1,074,517
TOTAL Materials	$ 2,795,300	$ 4,516,084	$ 6,236,867	$ 7,957,650	$ 9,678,434	$ 11,399,217	$ 13,120,001	$ 14,840,784
PM&ENG	$ 1,062,214	$ 1,716,112	$ 2,370,009	$ 3,023,907	$ 3,677,805	$ 4,331,703	$ 4,985,600	$ 5,639,498
Install	$ 2,543,444	$ 3,189,114	$ 3,834,784	$ 4,480,454	$ 5,126,124	$ 5,771,795	$ 6,417,465	$ 7,063,135
Crossings	$ 340,000	$ 425,000	$ 510,000	$ 595,000	$ 680,000	$ 680,000	$ 765,000	$ 850,000
Owners Cost	$ 603,791	$ 893,449	$ 1,183,107	$ 1,472,765	$ 1,762,423	$ 2,043,581	$ 2,333,239	$ 2,622,897
sub total	$ 7,344,749	$ 10,739,758	$ 14,134,768	$ 17,529,777	$ 20,924,786	$ 24,226,296	$ 27,621,305	$ 31,016,315
UAP	$ 1,660,425	$ 2,456,985	$ 3,253,545	$ 4,050,104	$ 4,846,664	$ 5,619,849	$ 6,416,408	$ 7,212,968
TOTAL	$ 9,005,174	$ 13,196,743	$ 17,388,312	$ 21,579,881	$ 25,771,450	$ 29,846,144	$ 34,037,713	$ 38,229,283

Table 6-5: Cost Build up of CTS cable 400mm2, 66kV, 5-40km

	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable	Normal Cable
Cable Length km	5	10	15	20	25	30	35	40
X-sectional Area of Conductors mm2	800	800	800	800	800	800	800	800
Voltage level	33kV	33kV	33kV	33kV	33kV	33kV	33kV	33kV
crossings	4	5	6	7	8	8	9	10
material	$ 2,633,020	$ 5,266,040	$ 7,899,060	$ 10,532,080	$ 13,165,099	$ 15,798,119	$ 18,431,139	$ 21,064,159
Connectors	$ 690,047	$ 690,047	$ 690,047	$ 690,047	$ 690,047	$ 690,047	$ 690,047	$ 690,047
TOTAL Materials	$ 3,323,067	$ 5,956,087	$ 8,589,107	$ 11,222,127	$ 13,855,147	$ 16,488,167	$ 19,121,186	$ 21,754,206
PM&ENG	$ 1,262,766	$ 2,263,313	$ 3,263,861	$ 4,264,408	$ 5,264,956	$ 6,265,503	$ 7,266,051	$ 8,266,598
Install	$ 2,543,444	$ 3,189,114	$ 3,834,784	$ 4,480,454	$ 5,126,124	$ 5,771,795	$ 6,417,465	$ 7,063,135
Crossings	$ 340,000	$ 425,000	$ 510,000	$ 595,000	$ 680,000	$ 680,000	$ 765,000	$ 850,000
Owners Cost	$ 746,928	$ 1,183,351	$ 1,619,775	$ 2,056,199	$ 2,492,623	$ 2,920,546	$ 3,356,970	$ 3,793,394
sub total	$ 8,216,204	$ 13,016,865	$ 17,817,527	$ 22,618,188	$ 27,418,850	$ 32,126,011	$ 36,926,672	$ 41,727,334
UAP	$ 2,054,051	$ 3,254,216	$ 4,454,382	$ 5,654,547	$ 6,854,712	$ 8,031,503	$ 9,231,668	$ 10,431,833
TOTAL	$ 10,270,255	$ 16,271,082	$ 22,271,909	$ 28,272,735	$ 34,273,562	$ 40,157,514	$ 46,158,341	$ 52,159,167

Table 6-6: Cost build up normal cable 800mm2, 33kV, 5-40km

	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable	CTS Cable
Cable Length km	5	10	15	20	25	30	35	40
X-sectional Area of Conductors	800	800	800	800	800	800	800	800
Voltage level	33kV	33kV	33kV	33kV	33kV	33kV	33kV	33kV
crossings	4	5	6	7	8	8	9	10
material	$ 2,895,639	$ 5,791,279	$ 8,686,918	$ 11,582,558	$ 14,478,197	$ 17,373,837	$ 20,269,476	$ 23,165,116
Connectors	$ 1,035,071	$ 1,035,071	$ 1,035,071	$ 1,035,071	$ 1,035,071	$ 1,035,071	$ 1,035,071	$ 1,035,071
TOTAL Materials	$ 3,930,710	$ 6,826,350	$ 9,721,989	$ 12,617,629	$ 15,513,268	$ 18,408,908	$ 21,304,547	$ 24,200,186
PM&ENG	$ 1,493,670	$ 2,594,013	$ 3,694,356	$ 4,794,699	$ 5,895,042	$ 6,995,385	$ 8,095,728	$ 9,196,071
Install	$ 2,543,444	$ 3,189,114	$ 3,834,784	$ 4,480,454	$ 5,126,124	$ 5,771,795	$ 6,417,465	$ 7,063,135
Crossings	$ 340,000	$ 425,000	$ 510,000	$ 595,000	$ 680,000	$ 680,000	$ 765,000	$ 850,000
Owners Cost	$ 746,928	$ 1,183,351	$ 1,619,775	$ 2,056,199	$ 2,492,623	$ 2,920,546	$ 3,356,970	$ 3,793,394
sub total	$ 9,054,752	$ 14,217,828	$ 19,380,904	$ 24,543,981	$ 29,707,057	$ 34,776,634	$ 39,939,710	$ 45,102,786
UAP	$ 2,054,051	$ 3,254,216	$ 4,454,382	$ 5,654,547	$ 6,854,712	$ 8,031,503	$ 9,231,668	$ 10,431,833
TOTAL	$ 11,108,803	$ 17,472,044	$ 23,835,286	$ 30,198,528	$ 36,561,770	$ 42,808,136	$ 49,171,378	$ 55,534,620

Table 6-7: Cost Build up CTS cable 800mm2, 33kV, 5-40km

6.3.2 Windfarm to distribution hub

33kV and 66kV, the standardised output voltages from wind turbine generators, are both capable of delivering the anticipated windfarm demand of ~90MW. Therefore, 33-66kV transmission voltages were considered for the connection between the windfarm and the distribution hub.

Two cables each at 33kV or 66kV cables can supply 90MW across 30km within permissible current carrying capacity and voltage drop limits, however a larger CSA is required to supply at 33kV.

The cost of utilising 33kV cables is approximately 40% greater than using 66kV cables, due to the greater CSA. The 66kV cable also offers a smaller voltage drop relative to the 33kV cable. Accordingly, 66kV has been selected as the transmission voltage from the windfarm to the distribution hub. Even with the necessary transformer at the distribution hub, to reduce the voltage to 33kV, the selection of 66kV for transmission from the windfarm to the distribution hub will reduce the overall Microgrid CAPEX.

The distances between the windfarm and the distribution hub are above 20km and are suitable for CTS implementation. However, the additional complexity in terminating CTS cables to the windfarm and between individual floating wind turbines, via lazy S risers, makes CTS less suitable due to the cable's early stage of development. Therefore, only the use of normal cables between the windfarm and the distribution hub is considered for all the options presented in Section 6.3.4 .

6.3.3 Distribution hub to consumer

The links between the distribution hubs and platforms were considered at 20kV and 33kV. As detailed in section 6.1.3 , 11kV is not feasible for the majority of hub demands and distances.

After analysis 33kV was selected as the distribution voltage from the distribution hub to the consumers. The standardisation provides obvious benefit of ensuring continuity between Microgrids, simplifying development. 33kV also minimises the CSA of the link between the distribution hub and consumers, with an increase in CSA corresponding to an increase in price per km greater than 7%. Increasing the cable CSA is typically not a cost-effective method of improving system performance relative to increasing the distribution voltage. For comparison, for a 30km connection delivering 20MW of power, a 20kV transmission voltage requires a 1000mm^2 CSA, whereas a 33kV transmission voltage requires only 400mm^2.

The 33kV distribution voltage is not fixed and for those facilities that prefer a lower voltage, to simplify brownfield modifications, this can be achieved but requires a larger CSA increasing cost. Thus, will have to be agreed with the consumer on a case-by-case basis

6.3.4 Option selection

The cable connection options discussed in sections 6.3.2and 6.3.3 are subsequently formulated into a series of options for each distribution hub. These are presented in Table 6-8 to Table 6-13.

6.3.4.1 Microgrid A

<table>
<tr><th rowspan="2">Option</th><th colspan="2">Cost of Cable (MMUS$)</th><th rowspan="2">Windfarm to hub (kV)</th><th rowspan="2">Hub to Shearwater (kV)</th><th rowspan="2">Shearwater to Culzean (kV)</th><th rowspan="2">Hub to Lomond/ Armada (kV)</th><th rowspan="2">Hub to J Area (kV)</th><th rowspan="2">Hub to Stella (kV)</th></tr>
<tr><th>Normal Cable</th><th>CTS Cable</th></tr>
<tr><td>3</td><td>187.51</td><td>195.70</td><td rowspan="7">66</td><td>20</td><td>20</td><td>20</td><td>20</td><td>20</td></tr>
<tr><td>4</td><td>178.96</td><td>185.11</td><td>33</td><td>33</td><td>33</td><td>33</td><td>33</td></tr>
<tr><td>5</td><td>177.51</td><td>183.54</td><td>33</td><td>33</td><td>20</td><td>33</td><td>20</td></tr>
<tr><td>6</td><td>169.72</td><td>176.70</td><td rowspan="2">66</td><td rowspan="2">66</td><td>20</td><td>20</td><td>20</td></tr>
<tr><td>7</td><td>171.95</td><td>179.14</td><td>33</td><td>33</td><td>33</td></tr>
<tr><td>8</td><td>182.51</td><td>188.61</td><td>33</td><td>33</td><td>33</td><td>33</td><td>20</td></tr>
<tr><td>9</td><td>183.04</td><td>189.20</td><td>33</td><td>33</td><td>33</td><td>33</td><td>33</td></tr>
</table>

Table 6-8: Microgrid A cable options, repeated options utilise alternative CSA. Dark green: Option selected

Table 6-8 details the different cable options for Microgrid A. Due to the number of possible connection variations (CSA and voltage) a rationalised number of options is presented. This is comprised of a connection from Windfarm to Hub at 66kV, with the links from hub to platform all at 66kV, 33kV or 20kV. The lowest cost combination of these voltages is also included as an option.

Options 3 to 9 supply the distribution hub from the windfarm using cables with a voltage of 66kV. Distribution between the distribution hub and the consumers is considered at a uniform voltage of either 33kV or 20kV in options 3 and 4. Distribution at 33kV is the cheaper of these two options.

Option 5 presents the lowest cost when distributing between the distribution hub and the consumers at either 20kV or 33kV. This combination offers a small cable cost saving relative to options 3 and 4, however a wider range of equipment and additional transformers would be required on the distribution hub to distribute at multiple voltages which does not outweigh the desire to standardise the voltage between the Microgrids.

Options 6 and 7 distribute between the distribution hub and consumers Shearwater and Culzean at a voltage of 66kV, and the other consumers at either 20kV or 33kV. This is due to the high power demand of Shearwater, and resulting large CSA cable required to supply Shearwater at either 20kV or 33kV. Option 6, distribution at a combination of 66kV and 20kV can be seen to be the lowest cost of these options. However, a wider range of equipment and additional transformers would be required on the distribution hub to distribute at multiple voltages. There would also be significant brownfield modifications required for Shearwater and Culzean to accommodate larger 66kV equipment, and additional safety hazards in the operation and maintenance of this equipment, all of which we are trying to avoid.

Option 8 presents the lowest cost combination of 20kV and 33kV distribution voltages, similar to option 5, but without any minor infractions of the voltage drop or current carrying capacity permissible limits.

Option 9 presents the cheapest combination of cables at 33kV distribution voltage, similar to option 4, but without any minor infractions of the voltage drop or current carrying capacity permissible limits.

Option 4 is the proposed option, as it is the lowest cost that offers a standardised distribution voltage to consumers. It should be noted that the 33kV cable between the distribution hub and Shearwater is slightly overloaded (~106%) for this option. However, the actual cable loading limit is expected to be higher due to the installation subsea rather than in dry ground, and the actual loading of Shearwater and Culzean is potentially to be lower than the 65MW modelled.

6.3.4.2 Microgrid C

Option	Cost of Cable (MMUS$)		Windfarm to hub (kV)	Hub to Elgin Franklin (kV)
	Normal Cable	CTS Cable		
3	51.95		66	20
4	49.19			33

Table 6-9: Microgrid C cable options, repeated options utilise alternative CSA. Dark green: Option selected

Options 3 and 4 supply the distribution hub from the windfarm using cables with a voltage of 66kV. Supplying this distribution hub's only consumer, the platform Elgin Franklin, is considered at either 20kV or 33kV. Of these, distribution at 33kV is the cheapest and is marked in green to signify it is the cheapest option.

However, the availability of weight and space on Elgin Franklin for a 33kV transformer and switchgear system rather than a lower voltage needs to be confirmed by the operator to confirm option 4.

Only the price for normal cable is considered here due to the short distance (4km) between the distribution hub and Elgin Franklin, which prohibits the benefits of CTS from being realised.

6.3.4.3 Microgrid D

Option	Cost of Cable (MMUS$)		Windfarm to hub (kV)	Hub to Gannet (kV)	Hub to MonArb (kV)	Hub to ETAP (kV)
	Normal Cable	CTS Cable				
5	119.85	124.02	66	33	33	33
6	131.07	136.07			20	33
7	137.28	142.75		20	33	33
8	148.49	154.80			20	33
8	148.49	154.80			20	33

Table 6-10: Microgrid D cable options, repeated options utilise alternative CSA. Dark green: Option selected

Options 3 to 8 supply the distribution hub from the windfarm using cables with a voltage of 66kV. Supplying the distribution hub's consumers is considered at all feasible combinations of 20kV or 33kV distribution voltages. Option 5, has been selected due to distribution at the standardised 33kV and representing the lowest cost.

6.3.4.4 Microgrid E, F and G

The benefits that a standardised distribution voltage offer in terms of greater ease in design, construction, spares, operations and maintenance, had been agreed for the assessment of hubs E, F and G. Therefore, only options for which all consumers can be supplied at the same distribution voltage, at a reasonable cost, are considered.

The costs for each hub are shown in Table 6-11.

Hub	Option	Cost of Cable (MMUS$)		Windfarm to Hub E (kV)	Hub to Claymore (kV)	Hub to Scott (kV)	Hub to Piper (kV)
		Normal Cable	CTS Cable				
E	1	98.45	101.46	66	33	33	33
	2	112.88	116.84	66	20	20	20
	3	110.65	113.65	33	33	33	33
F	Option	Cost of Cable (MMUS$)		Windfarm to Hub F (kV)	Hub to Avalon	Hub to Alba, Britannia	Hub to Forties
		Normal Cable	CTS Cable				
	1	180.01	186.61	66	33	33	33
G	Option	Cost of Cable (MMUS$)		Windfarm to Hub G (kV)	Hub to Buzzard	Hub to Buchan	
		Normal Cable	CTS Cable				
	1	156.26	161.19	66	33	33	

Table 6-11: Microgrid E, F and G cable option selection. Dark green: Option selected

For Microgrid E, three options are considered and shown in Table 6-11. As previously seen for distribution hubs A, C and D, a cable link at 66kV between the windfarm and distribution hub offers cost savings relative to using a lower voltage. Distribution between the distribution hub and the consumers was possible at both 20kV and 33kV. 33kV remained the lower cost option due to the smaller CSA required to achieve the same performance.

For hubs F and G, the distances between distribution hub and consumers, and power requirements of those consumers meant that distribution at a voltage lower than 33kV is prohibitive from a cost and performance basis. The only option considered is the use of cables at a voltage of 66kV between the windfarm and the distribution hub, and the use of cables at a voltage of 33kV between the distribution hub and consumers.

CTS has been selected in the cost estimates, as the cost difference between CTS and Normal cable is small compared to the operating benefits CTS can provide.

6.3.5 Cost savings of using CTS

Efficient power flow and better system stability have a complex interplay with many parameters controlling them, this includes the properties of the generator drivers and the loads. Offshore platforms have a very high proportion of rotating drivers, which inherently have low power factors which put a strain on the power system. In addition, wind turbines that use power electronics to export power (the majority of newer turbines) are dislocated from the inertia of the blades turning, so are poor at generating reactive power at distance. Pseudo-inertia can be created using a phase shift, but this is limited in solving some voltage regulation issues. As a result, compensation systems are frequently needed on the platform when using conventional cables.

When simulating power systems, it is generally better to have lower reactive power requirements and lower apparent power. This has a dual benefit of reducing the current which in turn lowers resistance and lower voltage drop which gives better voltage regulation and more efficient running of prime movers on platforms.

Table 6-12 shows the simulation result of a typical distribution hub to consumer cable, which indicate the advantages of CTS, the simulation also shows that if a conventional cable is used, a compensator of 28 MVARS would be required at the consumer end to keep voltage drop below 5% and allow efficient operation of the platform equipment.

Parameter	Conventional Cable	CTS	Reduction	
Reactive Power requirement (MVARs) from system	*36.3*	*28.4*	*22%*	↓
Apparent Power (MVA) required to be generated	*56.0*	*50.8*	*9%*	↓
Resultant Current (A)	*1077*	*978*	*9%*	↓
Resultant Voltage drop (pu)	*0.13*	*0.04*	*9%*	↓

Table 6-12: Performance of normal cable and CTS[9]

The property improvements translate into a range of savings compared to using conventional cable. Figure 6-8 shows the TOTEX reduction achieved by the CTS cable per Microgrid. The CTS cable reduces TOTEX, primarily by reducing the transmission losses, thus decreasing OPEX. TOTEX is further reduced by the removal of compensation at the consumer end, this reduces electrification CAPEX for the consumer and the associated risks of brownfield modifications to their facility.

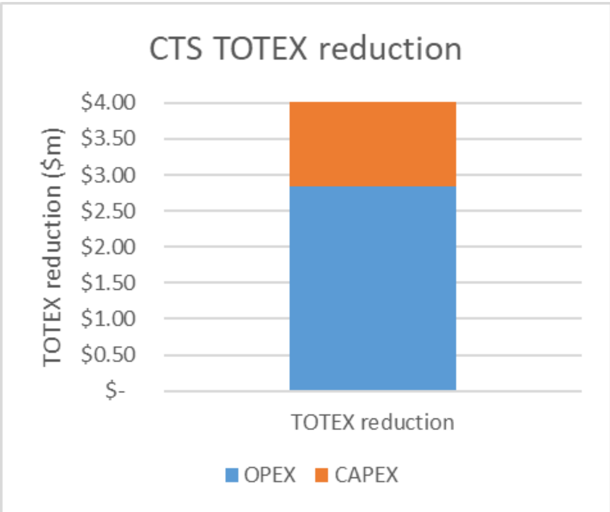


Figure 6-8: CTS TOTEX reduction per Microgrid

[9] Assuming a typical hub to platform load of 40MW, at 33kV;
- Load power factor = 0.8
- Distance = 20km
- CSA = 800mm^2

These same components result in CTS cable reducing emissions per Microgrid, as shown by Figure 6-9, with reduced losses dominating the CO2 saving and equating to ~3.5kg/MWh.

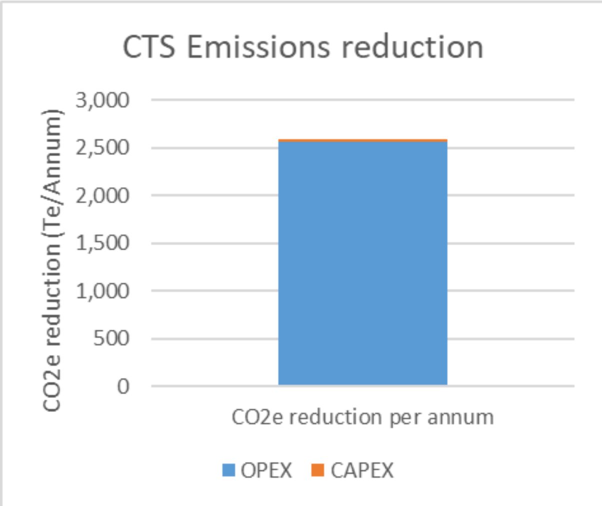


Figure 6-9: CTS emissions reduction per Microgrid

6.4 Microgrid operational performance.

A series of high-level studies undertaken on two indicative Microgrids, one containing all CTS cable, the other containing all normal cable.

Some differences are present in the configuration of the modelled system relative to the actual hub configuration intended.

These are primarily:

- Each wind turbine is individually connected to the distribution hub, rather than in two strings of six.
- All cables are in either CTS or normal cable. The actual hub configuration uses conventional cable between the windfarm and distribution hub, then CTS cable between the distribution hub and each platform.
- The operation of the CTS dielectric protection system is not considered within the study.

The reciprocating generators are modelled as open-loop systems without a controller. The wind turbine generators are modelled with fully rated converters with synthetic inertia and full active and reactive power control.

The results of comparison are therefore relevant in comparing the relative benefits of using CTS rather than normal cable, but the specific results cannot be directly applied to the actual hub configuration.

Six scenarios were considered, and the findings are summarised below.

6.4.1 Short circuit fault current

As per the comparison, the short circuit fault current of the modelled system was 30% greater for CTS cable than normal cable. Thus, CTS cable facilitates a more rapid response of protection devices, reducing equipment damage and lowering the risk to transient stability.

The response of the CTS dielectric protection system relative to the protection system would need to be considered for specific cases, meaning that not all operating scenarios may realise these benefits.

6.4.2 Transient load response

The biggest factor impacting the response of the system to the addition or shedding of a load is the source of generation; gas engines, wind turbine generators, or a combination. This is due to the type of control system used in the models for each source of generation. The use of CTS cable relative to the normal cable does not significantly change the system response.

6.4.3 Power-Voltage (PV) curve

The use of CTS cable ensures that for a given power (MW) supplied by the system a higher bus voltage (smaller voltage drop) is present on every bus relative to a system using normal cable.

In this type of study, the whole system's load increases in steps until the network becomes unstable, known as the system's stability boundary point and limit.

The maximum amount of power the system can support is the same for normal and CTS cable. However, CTS cable enables a 10% improvement in voltage drop of the system relative to the system using normal cable, at the busbar with the greatest voltage drop.

6.4.4 Reactive Power (Q) – Voltage (V): QV curve

The use of CTS cable requires significantly less reactive power to sustain the same voltage on each bus compared to a normal cable. Resulting in reduced generation to supply the apparent power (total of the active and reactive power) needed to operate the system.

When CTS cable is used in the modelled system, an 80% reduction is experienced, representing a significant improvement.

6.4.5 Line loading

The line loading of CTS cable is lower than that of normal cable, due to the lower series impedance of the cable. Increasing the power carrying capacity for CTS cable compared with conventional cable

6.4.6 Tripping of power generation sources

In the event of a trip of a power generation source, the voltage and frequency response of the system employing CTS cable only is better compared to that of a normal cable. When CTS cable is employed, the system has a longer time period to take corrective actions to maintain stability in the event of a generator tripping. This makes the system less likely to fail in the event of a generator trip, avoiding loss of platform production.

Tripping of a power generation source is considered for both wind turbine generators and gas turbine generators.

Comparison of Figure A3.18 and Figure A3.19 details that post-trip of wind turbine generators, the bus voltages for the system employing CTS cable are between 0.994 and 0.959p.u. These voltage levels are higher than those in the normal cable system which are between 0.991 and 0.909, thus CTS cable provides great grid stability on loss of generation.

More significant benefits of using CTS relative to normal cable are seen when the system is solely supplied by gas engines. The simpler control system modelled for each generator means that the system is unable to retain stability in the event of a trip for either cable used. In terms of frequency, in the event of a trip the system, using CTS cable ensures stability (within ±0.25Hz of the system frequency) for 3s. In the event of the same trip, the system using normal cable diverges from ±0.25Hz of the system frequency within 1s of the trip. This additional time improves grid stability significantly on loss of generation.

It should be noted that a single notional 6-hour shutdown of production from a typical platform producing 25,000 BOEPD at $90/bbl costs $562,500 in delayed revenue. By comparison the shutdown of the whole CNS would cost circa $11m, demonstrating that stability and reliability of availability of power is a key issue and having multiple power centres are critical to reduce power outage impacts. This deferment is in theory not recoverable until near the end of the platforms production life.

6.5 Connection to UK grid

The Microgrids are designed to operate independently but once the they are installed and established, there is an option to link neighbouring hubs together, with the link increasing the resilience and reliability of each linked Microgrid. The options can be broken down as follows;

- Option 1: Integrated Microgrid links
  Cables are sized to enable export of the entire power generated through the chain and then on to the national grid from Hub G (see Figure 6-10)
- Option 2: Independent CG and OMF links
  Treat the Central Graben (Microgrids A to D) and the Outer Moray Firth (Microgrids E to G) as separate systems each having their own link to shore (see Figure 6-11).
- Option 3: Hybrid Microgrid links
  A more efficient option is a hybrid of the first two options using a partial integrated set of interlinks and sending all power to shore from Hub G (see Figure 6-12). The partial option has the advantage that both OMF facilities and CG facilities can back each other up and as shown in section 6.4 at an overall lower cost, thus making it the preferred option of the three.

The final shore links will be timed in line with the shutdown of major platforms in any Microgrid, providing a surplus of energy. A key point in the actual design needs to take account of the frequency generated at 60Hz for customers and the Grid at shore at 50 Hz. Conversion may need to be onshore if surplus energy is desired, as it becomes available. Alternately certain hubs may look to dedicate one export cable to 50Hz and one to 60Hz with the turbine strings being switched to 50Hz in the turbine given they should be designed to switch from day one. This will need to be clarified during the next phase of the design.

6.5.1 Option 1: Integrated Microgrid links

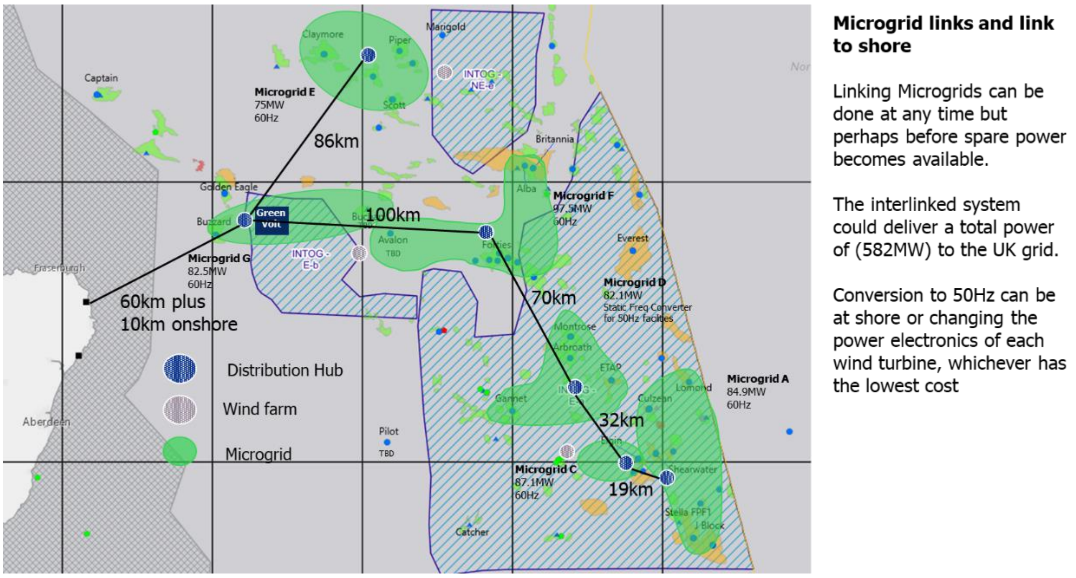


Figure 6-10: Hub interlinking and final shore link proposed for integrated option

For this option, connections between each Microgrid to shore via a daisy chain, results in a significantly greater distance and larger transfer of power than those seen on any individual Microgrids. In total the overall cable length of interlinks is 376km or 290km from Microgrid A to shore excluding the Microgrid E spur.

To achieve transfer of power within permissible limits, transfer of power at voltages of 66kV and 132kV are considered.

Microgrid to Microgrid connection at a voltage of 66kV within permissible limits requires multiple cables when the power is above 100MW. Use of a 132kV cable can supply this power with one single equivalently sized cable, with improved performance. The options considered are summarised in Table 6-13.

The use of 132kV cables offers a significant cost saving relative to the use of solely 66kV cables. For the example cable 'C to D', this translates to a 44% reduction in cost, from 86.2MMUS$ to 48MMUS in Table 6-13.

CTS cable offers a 4.5% CAPEX reduction compared to normal cable due to the lower impedance of CTS cable reducing voltage drop and resistive losses, allowing smaller cable sizes to be used relative to conventional cable for some hub-to-hub links.

In addition, CTS cable reduces the resistive loss by 4.76%, compared to a conventional cable Table 6-14. This equates to a lower fuel gas consumption of $ 0.26m per year to cover the 1.87MW of losses, if CTS is used versus normal cable, this equates to a CO2e saving of 2,392 tonnes per year, in addition to the CAPEX savings outline above.

Cable type	Total Cost for Option (MMUS$)	Breakdown of Option								
		Cable	*3-Ph Voltage Rating (kV_{rms})*	*No. of Parallel Circuits*	*Cable Cross-Sectional Area (mm²)*	Power Demand (MW)	Length (km)	*Capacity Usage (%)*	*V_{drop} (%)*	*Cost of Cable (MMUS$)*
CTS	986.59	A to C	66	1	800	96	20	101.20	1.70	32.34
		C to D	132	1	1000	192	30	99.20	1.09	50.94
		D to F	132	2	630	288	70	88.80	2.50	178.05
		F to G	132	3	500	384	100	88.70	3.70	305.73
		E to G	66	1	630	70	86	85.30	6.20	103.95
		G to shore	132	3	1000	550	70	96.70	3.16	315.58
Normal Cable	1033.05	A to C	66	2	400	96	20	71.00	2.80	40.43
		C to D	132	1	1000	192	30	101.00	2.80	47.96
		D to F	132	2	630	288	70	90.80	4.60	167.35
		F to G	132	3	630	384	100	80.20	4.00	346.06
		E to G	66	1	1000	70	86	76.00	10.90	134.72
		G to shore	132	3	1000	550	70	99.50	5.86	296.52

Table 6-13: Hub to hub and to shore cable performance & cost at 66kV and 132kV.

	Cable	*3-Ph Voltage Rating (kV_{rms})*	*No. of Parallel Circuits*	Length (km)	Maximum current per cable(kA)	Total power loss per cable (MW)	Total I^2R hub interlink to shore loss (MW)	Percentage Difference between CTS and Normal Cable (%)
CTS	A to C	66	1	20	0.949	1.385	39.28	4.76%
	C to D	132	1	30	0.943	1.741		
	D to F	132	2	70	0.718	6.622		
	F to G	132	3	100	0.646	13.997		
	E to G	66	1	86	0.725	4.136		
	G to shore	132	3	70	0.912	11.397		
Normal Cable	A to C	66	2	20	0.480	1.317	41.15	
	C to D	132	1	30	0.960	2.061		
	D to F	132	2	70	0.734	7.513		

	Cable	*3-Ph Voltage Rating (kV_{rms})*	*No. of Parallel Circuits*	Length (km)	Maximum current per cable(kA)	Total power loss per cable (MW)	Total I^2R hub interlink to shore loss (MW)	Percentage Difference between CTS and Normal Cable (%)
	F to G	132	3	100	0.648	12.565		
	E to G	66	1	86	0.764	3.863		
	G to shore	132	3	70	0.940	13.831		

Table 6-14: Resistive (I^2R) losses using CTS or normal cable.

6.5.2 Option 2: Independent CG and OMF Microgrid links

For the independent CG and OMF option, interlinks between Microgrids is restricted to three hubs in each area, as per Figure 6-11. Each area then has its own cable to shore that is built when export of excess power becomes viable and, in any event, at the cessation of production of the relevant platforms.

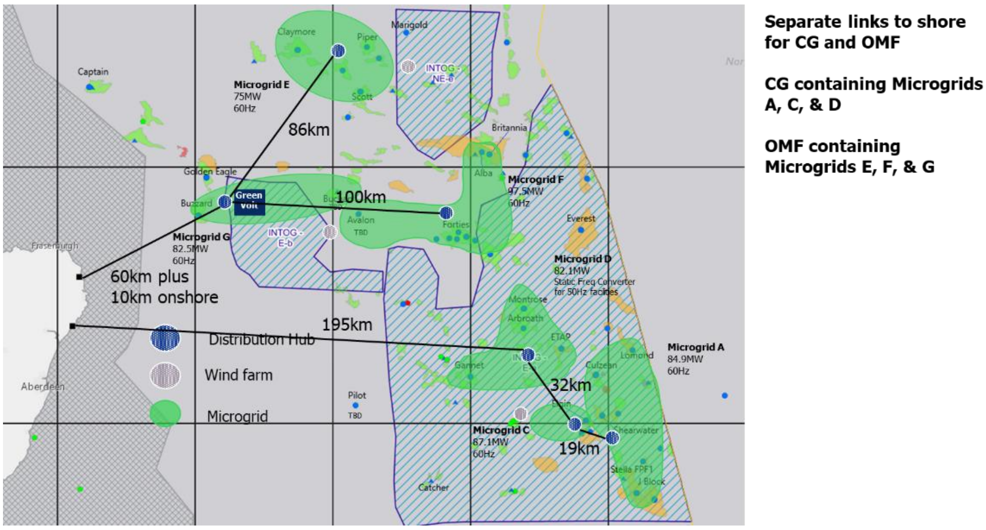


Figure 6-11: Independent CG and OMF Hub interlinks and shore links

The option of moving the wind farms and/or relocating the hubs closer to shore, especially for the closest CG Microgrid are not considered herein, but they should be investigated when considering shore delivery as it might provide a more economic option once Oil & Gas facilities reach COP. This would alleviate some of the charging current issues that this option faces when using AC export to shore.

In total the overall cable length of interlinks is 501km. To achieve transfer of power within permissible limits, transfer of power at voltages of 66kV and 132kV are considered, as shown in Table 6-15. Transmission of power at 220kV voltage between Microgrid D and shore was considered but not pursued due to the increase in charging current of the cable insulation being more significant than the reduction in load current at this voltage.

A CTS and conventional cable option were considered, CTS cable was the cheapest configuration due to the lower impedance of CTS cables reducing the voltage drop and resistive losses, allowing smaller cable sizes to be used relative to conventional cable for specific links. CTS cable provides a 46.93MMUS$, or 5% reduction in CAPEX compared to conventional cable.

Regardless of the cable selected, compensation will be required at both ends of the connection to shore, for CTS cable the compensation requirements are reduced significantly. For CTS cable this would be in the region of 90MVAR onshore and 30MVAR offshore. This corresponds to additional equipment CAPEX and OPEX costs and additional land required for the onshore compensation, all of which are not included within the cost for this option.

In addition, CTS cable reduces the resistive loss by 6.66%, compared to a conventional cable, Table 6-16. This equates to a lower fuel gas consumption of $ 0.40m per year to cover the 2.8MW of losses, if CTS is used versus normal cable, this equates to a CO_2e saving of 3,600 tonnes per year, in addition to the CAPEX savings outline above.

Cable type	Total Cost for Option (MMUS$)	Breakdown of Option								
		Cable	*3-Ph Voltage Rating (kV_{rms})*	*No. of Parallel Circuits*	*Cable Cross-Sectional Area (mm^2)*	Power Demand (MW)	Length (km)	*Capacity Usage (%)*	*V_{drop} (%)*	*Cost of Cable (MMUS$)*
CTS	895.39	A to C	66	1	800	96	20	101.20	1.70	32.34
		C to D	132	1	1000	192	30	99.20	1.09	50.94
		D to shore*	132	2	800	288	195	99.90	4.10	515.68
		F to G	132	1	300	96	100	84.0	4.2	62.57
		E to G	66	1	630	70	86	85.30	6.20	103.95
		G to shore	132	2	400	262	70	101	3.34	129.91
Normal Cable	942.32	A to C	66	2	400	96	20	71.00	2.80	40.43
		C to D	132	1	1000	192	30	101.00	2.80	47.96
		D to shore	132	2	800	288	195	99.90	4.10	515.68
		F to G	132	1	300	96	100	84.6	4.9	58.60
		E to G	66	1	1000	70	86	76.00	10.90	134.72
		G to shore	132	2	500	262	70	91.8	4.7	144.92

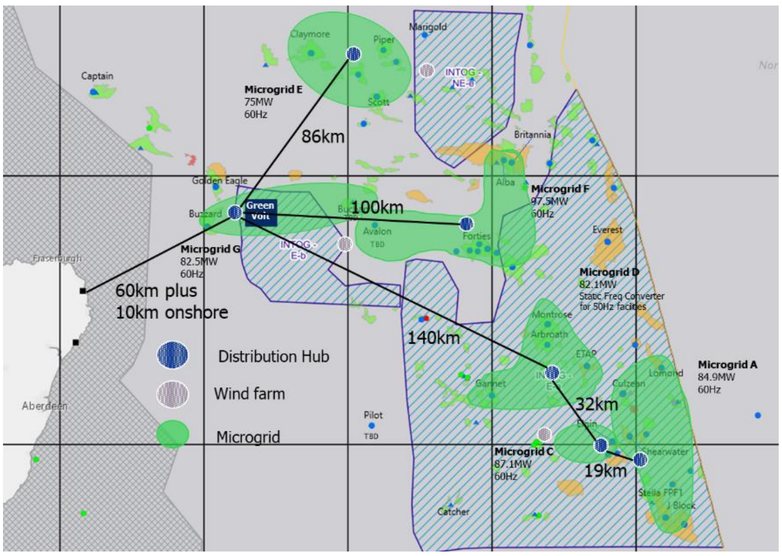
Table 6-15: Hub to hub and to shore cable performance & cost at 66kV and 132kV.

	Cable	*3-Ph Voltage Rating (kV_{rms})*	*No. of Parallel Circuits*	Length (km)	Maximum current per cable(kA)	Total power loss per cable (MW)	Total I^2R hub interlink to shore loss	Difference between CTS and Normal Cable (MW)	Percentage Difference between CTS and Normal Cable (%)
CTS	A to C	66	1	20	0.949	1.385	41.99	2.80	6.66%
	C to D	132	1	30	0.943	1.741			
	D to shore*	132	2	195	0.885	28.066			
	F to G	132	1	100	0.490	2.684			
	E to G	66	1	86	0.725	4.136			
	G to shore	132	2	70	0.660	3.979			
Normal Cable	A to C	66	2	20	0.480	1.317	44.79		
	C to D	132	1	30	0.960	2.061			
	D to shore	132	2	195	0.885	30.467			
	F to G	132	1	100	0.490	2.395			
	E to G	66	1	86	0.764	3.863			
	G to shore	132	2	70	0.670	4.684			

Table 6-16: Resistive (I^2R) losses using CTS or normal cable.

6.5.3 Option 3: Hybrid Microgrid links

An alternative option for interlinking the hubs is presented here. This offers the benefits of hub interlinking with lower cable capital costs than the other two options.



Part integration of links to shore for CG via Microgrid G of OMF

Give mutual back up between OMF and CG

Figure 6-12: Hybrid Microgrid interlinks with power to shore via Hub G

To achieve transfer of power within permissible limits, transfer of power at voltages of 66kV and 132kV are considered, and detailed in Table 6-17. CTS cable was the cheapest configuration due to the lower impedance of CTS cables reducing the voltage drop and resistive losses, allowing smaller cable sizes to be used relative to conventional cable for specific links. CTS cable provides a 12.86MMUS$, or 1.4% reduction in CAPEX compared to conventional cable

In addition, CTS cable reduces the resistive loss by 9.39%, compared to a conventional cable, Table 6-18. This equates to a lower fuel gas consumption of $ 1.1m per year to cover the 3.34MW of losses, if CTS is used versus normal cable, this equates to a CO2e saving of 13,500 tonnes per year, in addition to the CAPEX savings outline above.

Cable type	Total Cost for Option (MMUS$)	Breakdown of Option								
		Cable	*3-Ph Voltage Rating (kV_{rms})*	*No. of Parallel Circuits*	*Cable Cross-Sectional Area (mm^2)*	Power Demand (MW)	Length (km)	*Capacity Usage (%)*	*V_{drop} (%)*	*Cost of Cable (MMUS$)*
CTS	880.56	A to C	66	1	800	96	20	101.20	1.70	32.34
		C to D	132	1	1000	192	30	99.20	1.09	50.94
		D to G*	132	2	630	288	140	92.0	5.4	315.18
		F to G	132	1	300	96	100	84.0	4.2	62.57
		E to G	66	1	630	70	86	85.30	6.20	103.95
		G to shore	132	3	1000	550	70	96.70	3.16	315.58
Norma l Cable	893.42	A to C	66	2	400	96	20	71.00	2.80	40.43
		C to D	132	1	1000	192	30	101.00	2.80	47.96
		D to G	132	2	630	288	140	92.0	5.4	315.18
		F to G	132	1	300	96	100	84.6	4.9	58.60
		E to G	66	1	1000	70	86	76.00	10.90	134.72
		G to shore	132	3	1000	550	70	99.50	5.86	296.52

Table 6-17: Hub to hub and to shore cable performance & cost at 66kV and 132kV.

<table>
<tr><th></th><th>Cable</th><th>3-Ph Voltage Rating (kV_{rms})</th><th>No. of Parallel Circuits</th><th>Length (km)</th><th>Maximum current per cable(kA)</th><th>Total power loss per cable (MW)</th><th>Total I^2R hub interlink to shore loss</th><th>Percentage Difference between CTS and Normal Cable (%)</th></tr>
<tr><td rowspan="6">CTS</td><td>A to C</td><td>66</td><td>1</td><td>20</td><td>0.949</td><td>1.385</td><td rowspan="6">35.62</td><td rowspan="12">9.39%</td></tr>
<tr><td>C to D</td><td>132</td><td>1</td><td>30</td><td>0.943</td><td>1.741</td></tr>
<tr><td>D to G*</td><td>132</td><td>2</td><td>140</td><td>0.745</td><td>14.279</td></tr>
<tr><td>F to G</td><td>132</td><td>1</td><td>100</td><td>0.490</td><td>2.684</td></tr>
<tr><td>E to G</td><td>66</td><td>1</td><td>86</td><td>0.725</td><td>4.136</td></tr>
<tr><td>G to shore</td><td>132</td><td>3</td><td>70</td><td>0.912</td><td>11.397</td></tr>
<tr><td rowspan="6">Normal Cable</td><td>A to C</td><td>66</td><td>2</td><td>20</td><td>0.480</td><td>1.317</td><td rowspan="6">38.97</td></tr>
<tr><td>C to D</td><td>132</td><td>1</td><td>30</td><td>0.960</td><td>2.061</td></tr>
<tr><td>D to G</td><td>132</td><td>2</td><td>140</td><td>0.745</td><td>15.501</td></tr>
<tr><td>F to G</td><td>132</td><td>1</td><td>100</td><td>0.490</td><td>2.395</td></tr>
<tr><td>E to G</td><td>66</td><td>1</td><td>86</td><td>0.764</td><td>3.863</td></tr>
<tr><td>G to shore</td><td>132</td><td>3</td><td>70</td><td>0.940</td><td>13.831</td></tr>
</table>

Table 6-18: Resistive (I2R) losses using CTS or normal cable.

6.6 Conclusions

Distributing power from local floating wind turbines to distribution hubs and onwards to platform consumers is feasible. The final options selected for each Microgrid use a standardised windfarm to distribution hub voltage of 66kV and a standardised distribution hub to consumer voltage of 33kV. CTS is implemented between distribution hubs and consumers where cable lengths exceed 20km. The option selected and costs for each hub are presented in Table 6-19.

Whilst there are significant opportunities to lower or optimise the costs, those nuances are left for the next phase of design. This is because a significant amount of information and a large amount of work on each receiving platform is needed to perform this optimisation.

Experience tells us that standardisation of repeated elements (i.e. the distribution hubs or cables voltages and sizes) is, more often than not, a more productive way to reduce costs at the outset and especially more capable of managing and containing costs during implementation. This is because discounts can be sought on volume and mistakes are avoided or minimised as there is a lower number of components present in the system.

The final options selected for each Microgrid use a standardised windfarm to distribution hub voltage of 66kV and a standardised distribution hub to consumer voltage of 33kV. CTS is implemented between distribution hubs and consumers where cable lengths exceed 20km.

Microgrid	Cost (MMUS$)
A	185.11
C	49.19
D	124.02
E	101.46
F	186.61
G	161.19

Table 6-19: Option selected for each hub and associated cost

The interlinking of Microgrids and final link to shore is best done by daisy chaining each Microgrid to Microgrid G and linking that Microgrid to shore once production demand has dropped significantly or ceased. Microgrid interlinks have the capacity to provide back-up support to each other, however the timing of adding these links needs their own availability studies and cost benefit analyses (CBA). It should be noted that Microgrid A to shore via the other Microgrid is 270km plus an 85km spur from Microgrid E to Microgrid G. Enertechnos investigated three options, fully integrated; independent basins; and hybrid integrated. Of the three, detailed in section 6.5 , the assessment demonstrated that Hybrid Microgrid option was the lowest cost of all options, with the same or better functionality as the other options and thus this option is preferred.

In total these links and export to shore are estimated to cost between $800m to $1bn so the benefit of each link needs rigorous CBA assessments for their return on investment going forward, however links can be built over a significant time period and in phases to meet the needs of its users and the National grid.

When contemplating end of production reusage, an alternate may benefit from the re-location of some, or all, of the floating wind turbines and distribution hubs to reduce the cable lengths required.

This analysis also shows the use of CTS for the interlinks instead of conventional cable, for the preferred option CTS will save $4.83million per Microgrid in TOTEX over the field life and in addition lowers the CO_2 emitted by 2,600 tonnes per year per Microgrid compared to using conventional cables excluding the benefits and considerations derived from other criteria included in this report.

7 Floating wind farm

The floating wind farm is the key component of the Microgrid that enables a significant reduction in GHG emissions. The following section outlines the sizing basis for the wind farm, the type of floating structure required, the floating wind vendors review, and the licensing process for the INTOG region.

7.1 Sizing basis

If the installed capacity of the wind farm (MW) is equal to the microgrid power demand, there will be times when the wind speeds are insufficient to meet the demand power output and the gas fired back-up power generation will needed. The installed capacity (MW) of the wind farm can be increased so that the power demand from the microgrid can be met at a greater range of wind speeds thereby increasing the potential for GHG emission reductions.

Crondall has assessed the GHG emissions associated with the microgrid with its in-house GHG emissions estimation tool, details of which are given in Section 8.1 . This tool has been used to estimate the GHG emissions associated with microgrid A for different capacity wind farms as a percentage of the power demand from the wind farm facility. The results are shown in Figure 7-1 and it can be seen that when the wind farm installed capacity exceeds 120% of the microgrid power demand the incremental impact on reduction in GHG emissions declines rapidly. Included in this graph is the 50% emissions reduction line (For this a benchmark figure of 0.7 kg CO_2e / kWh is used as a typical value from generation using a simple cycle gas turbine generator). Reduction in GHG emissions at 100% or 120% capacity significantly exceed the 50% emission reduction by 2030 stipulated in the North Sea Energy Transition deal (see Section 8 for emissions by microgrid). Figure 7-3 clearly demonstrates that to meet the 2030 North Sea transition deal target, a wind farm sized at only 35% of the platform power demand is required for each Microgrid. This provides an opportunity to reduce the initial capital costs of the wind farm providing power to each Microgrid, with the option to scale up the wind farm size when further emissions reduction is required.

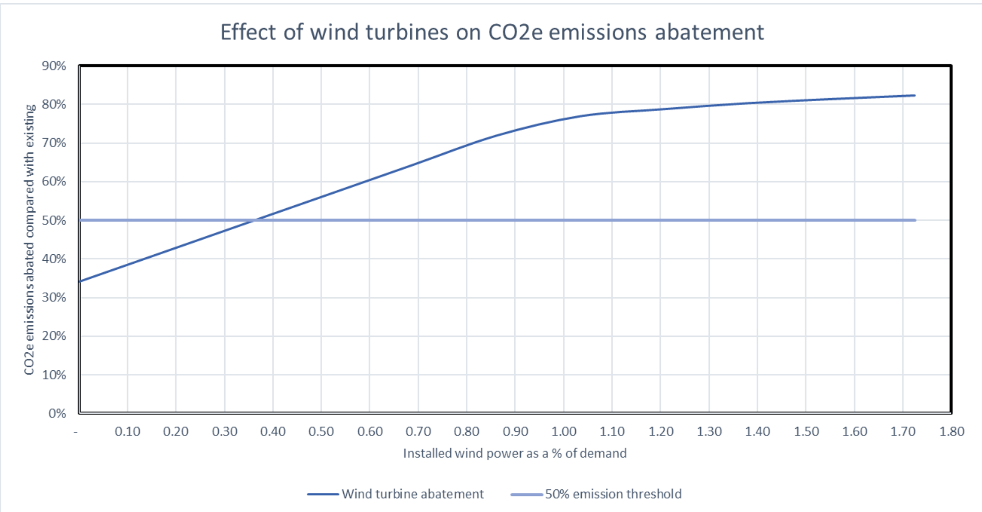


Figure 7-1 Impact of installed wind farm capacity

Figure 7-2 shows the reduction in CO_2 emissions in kilograms of CO_2e per kWh as the installed wind farm capacity as a percentage of power demand increases. Added to this graph is the CO_2e emission figures for the UK national grid, 0.212kgCO_2e/kWh as of 2021 (17). It can be seen that with the wind farm at 100% installed capacity of the microgrid power demand, these emission levels can be improved upon.

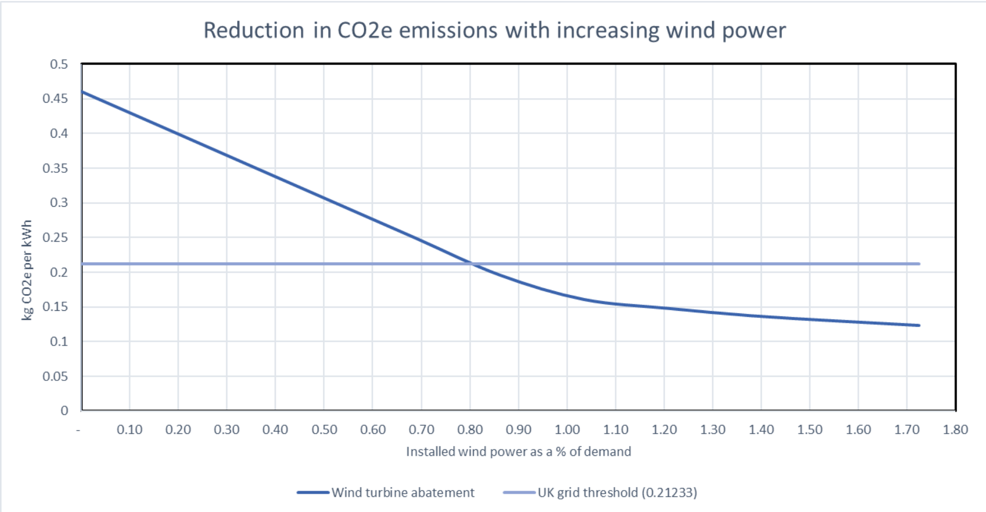


Figure 7-2 Wind turbine provision to better UK grid

Crondall has also estimated the cost of CO_2e abatement as the installed wind farm capacity is increased as a percentage of microgrid power demand for Microgrid A, see Figure 7-3 (Detail on CAPEX estimations and GHG emission calculations are given in Section 9 and Section 8 respectively.

As the installed capacity of the wind farm increases the emissions decrease linearly until you approach the microgrid power demand. Once the installed capacity of the wind farm exceeds the microgrid power demand the emissions reduction diminishes. The relationship between the cost of a wind farm and installed capacity increases linearly. Thus, once the wind farm capacity exceeds the microgrid power demand the cost of emissions abatement increases substantially, see Figure 7-3.

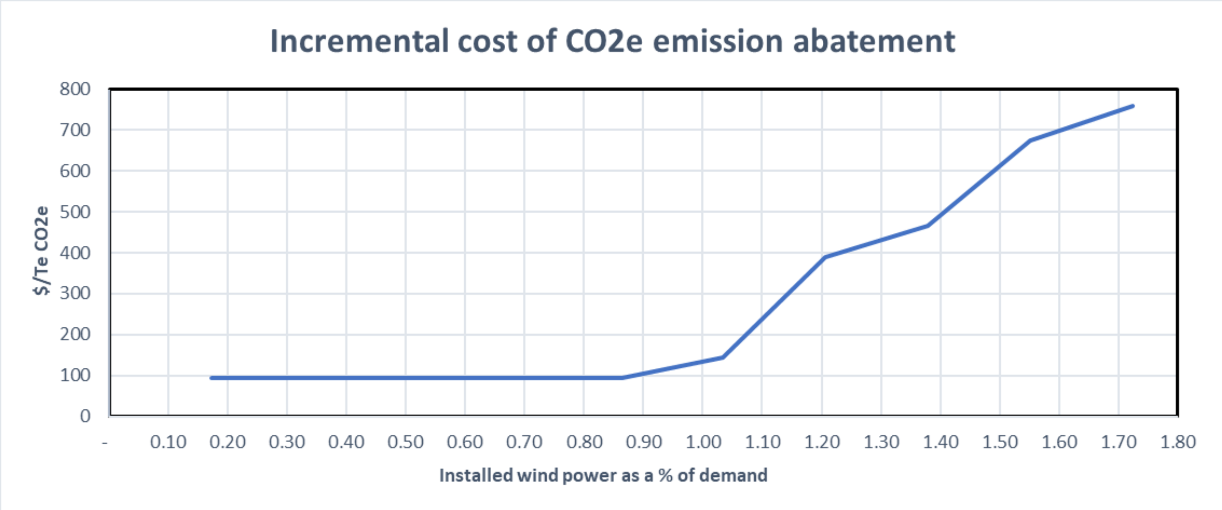


Figure 7-3 Incremental cost of CO_2e abatement

Sizing the wind farm for an installed capacity slightly greater than the microgrid power demand will give additional flexibility, for example, turbines can be taken down for maintenance and the wind farm can still generate the microgrid power requirement, and batteries can be charged when excess power is available etc.

Emissions abatement becomes more expensive as the installed capacity exceeds the microgrid power demand, because emissions abatement tends to plateau as the wind farm installed capacity increases beyond 110% of microgrid power requirement. Nevertheless a slightly higher wind power capacity provides some operational flexibility so Crondall has developed two sizing cases for the wind farm for which CAPEX estimates have been made:

- Case 1 - 100% of microgrid power requirement;
- Case 2 - 120% of microgrid power requirement.

The 120% case will also provide some future proofing for the facility to have lower emissions than the power associated with a future national grid.

7.2 Floating structure requirements

The proposed location of the wind farms shown in Figure 7-4 will require the wind turbines to operate in expected water depths in the range of 80 to 160m. This will mean that fixed foundations, that are currently used for wind power generation in shallower waters, will not be suitable. Figure 7-4 shows the main types of offshore foundations for wind turbines and the operating depth range. The wind farm for this electrification project will need to be a floating substructure type.

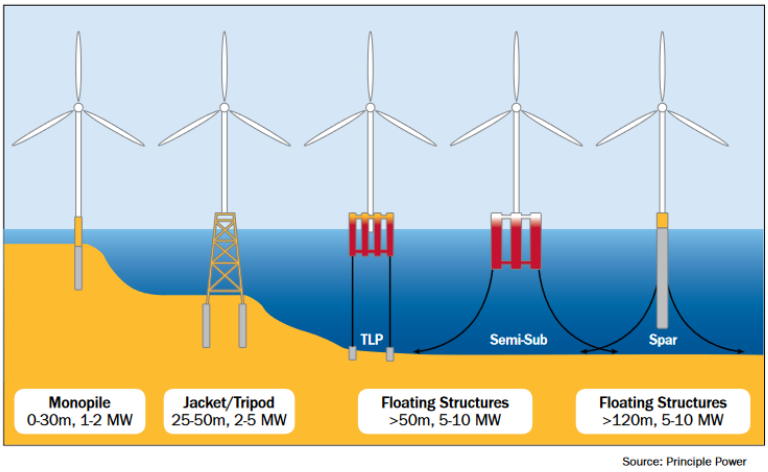


Figure 7-4 Suitable water depths for wind turbine structures (18)

Offshore wind power is still in its infancy in comparison with onshore structures. The global offshore wind market has grown from 2.2 GW in 2016 to 6.1 GW 2020. This represents only 7% of all wind power installations in 2020 (19).

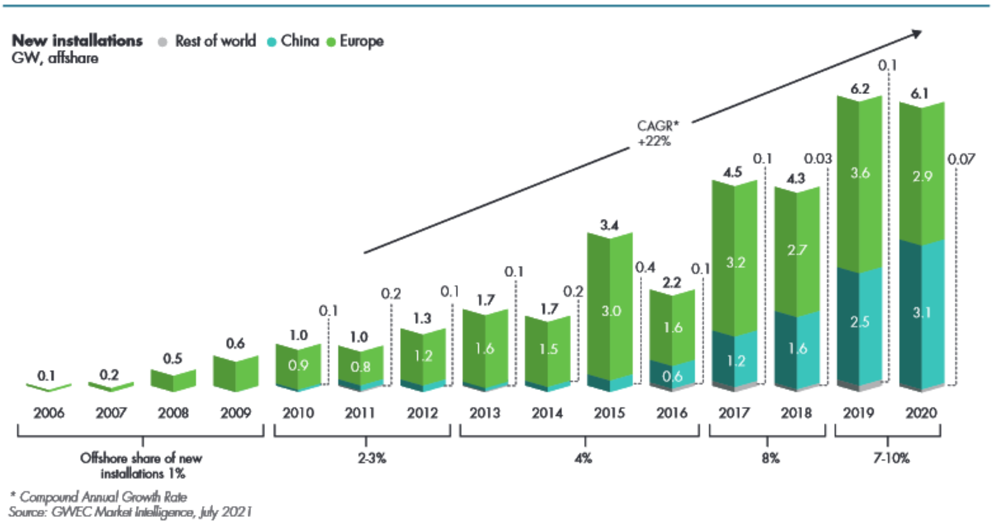


Figure 7-5 Offshore Wind Installations 2006 -2020

The limited experience of offshore wind farm installation, in water depths where fixed structures can't be deployed, means that feedback from existing projects is essential for successful design and development of the proposed new offshore wind farm installations. There are numerous companies developing technologies for 'deep' water offshore wind farms or projects managing a consortium of suppliers to put together wind farm installations; both are positioning themselves to take advantage of the anticipated growth in the market. The subsequent sections of this report lay out Crondall's analysis of the potential candidates to deliver the microgrid wind farm.

7.3 Engagement and review methodology

There are currently a number of alternative floating offshore wind turbine concepts available or under development from a variety of providers. The purpose of screening these technology providers is to:

1. Understand the technical capabilities of the companies offering solutions;
2. Find a company that can deliver a full floating wind power solution for the project;
3. Understand which technologies can achieve a full scale deployment by 227.

Crondall has identified possible 'solution providers' in an initial screening. From this, a short list was developed and an 'Expression of Interest' (EOI) was sent to in order to garner further information about their technologies, capabilities and desire to participate in the project. From the responses to the EOI's sent out, Crondall has completed a paired scoring for each solution provider. These companies have also been subject to a 'project requirement' screening to determine which solution provider is in an appropriate position to develop the wind power solution for the microgrid.

7.4 Initial identification of solution providers

Based on the consortiums own experience base, and in discussion with the Net Zero Technology Centre, the opportunity was taken to identify key technology providers and developers. The intention was twofold. Firstly, to reduce this broad spread of candidates to a short list of those capable of offering valid technical and cost input for a credible, realisable floating power generation solution for deployment in 2027. Secondly to identify alternative concepts / delivery methodologies valid for consideration beyond the initial 2027 deployment.

The initial market review identified 41 possible solution providers and these are shown in the table below.

Axis Energy Projects	Aerodyn Engineering	Bluewater	**BW Ideol**
EOLFI (Now Offshore Wind Shell)	Eolink	**Equinor**	Flotation Energy
Floating Energy Systems	**Floating Power Plant**	Flowocean AB	Floventis (SBM / Cicero)
Frontier Technical	Fukushima Forward	Gicon	GustoMSC (Part of NOV)
Hexicon	Japan Marine United Corp	Marine Power Systems	Modec
MonobaseWind	Nautilus	Ocergy	ODE
Odfjell Oceanwind	Olav Olsen (OOStar)	PelaStar	**Principle Power**

Saitec	**Saipem / Naval Energies**	**SBM Offshore**	**SeaTwirl**
Seawind	Sevan Wind (SWACH)	**Stiesdal (TetraSpar)**	Sway
Toda	Venterra	Vestas	**Wind Catching Systems**
X1 Wind (Pivot Buoy)			

Table 7-1 Wind farm solution providers identified[10]

During the consortium's 'Floating wind selection criteria' workshop the following filters were agreed to refine the identified providers:

- Technology maturity
    - Provision of appropriate readiness for 2027 project delivery
- Ability to Deliver
    - Extent of provision of scope
    - Alignment on commercial and project delivery objective
    - Maturity of supply chain relationships
    - Possibility of delivering local content and value added.
    -

7.5 Expression of interest

From the initial review a short list of 15 possible companies for further consideration was arrived at.

Following an evaluation of responses to the Expression of Interest, BW Ideol, Saipem and SBM were considered suitable partners for the microgrid project.

7.5.1 Project requirement screening

The following screening criteria have been applied to all ten companies.

1. Novel technology – solutions were not carried forward where the provider is proposing a commercially unproven innovative technology (e.g., novel turbine configuration) such that it is unlikely to have a sufficient technology readiness level in time for the project final investment decision needed to meet the start-up schedule of 2027;

2. Fully tested unit by 2027 – Regardless of proposed solution, in order to be considered suitable for the further consideration the wind generation unit will need to be 'fully tested' by 2027;

3. Delivery capability - The company will need to have the skills and resources to deliver the full scope of the floating wind power solution.

[10] Companies highlighted in bold were selected for further consideration

SeaTwirl, Seawind, Windcatching and Floating Power Plant have been considered to have technology that is novel and unlikely to be ready by 2027, while Monobasewind and Floating Power Plant have significant risk with not having the availability of a fully tested unit by 2027. Principle Power and Hexicon are acting as owners engineer with a licensed design and as such are not able to deliver the full scope of the floating wind power solution.

BW Ideol, SBM, and Saipem can offer the full scope for the floating wind power solution, with units fully tested and at a sufficient technology readiness level. Details of their technology are provided in the following section.

7.6 Selected wind farm solution providers

7.6.1 BW Ideol

BW Ideol brings together BW Offshore, an experienced oil and gas EPCI contractor and operator, with Ideol S.A.'s patented floating offshore wind technology. BW Ideol has two demonstrator projects in operation along with a commercial project under construction.

Figure 7-6 BW Ideol's Floatgen and Hibiki floating foundation demonstrators ***(images courtesy of BW Ideol)***

7.6.2 Saipem

Saipem, an experienced oil and gas EPCI contractor and operator, acquired and has incorporated Naval Energies in 2021. Naval Energies have extensive experience in the development of floating wind power solutions.

Figure 7-7 Naval Energies STAR1 floating structure design ***(image courtesy of Saipem)***

7.6.3 SBM Offshore

SBM Offshore are an experienced oil and gas EPCI contractor and FPSO operator. They are currently undertaking an EPCI contract for a wind farm in the Mediterranean, and a FEED for a North Sea pilot project.

Figure 7-8 SBM TLP floating structure design ***(image courtesy of SBM)***

It should be noted that the pace of development of technologies for offshore wind farm applications is increasing. The technology providers selected have plans in place now and as discussed, have developed sufficiently to be considered mature enough to deliver a wind farm to enable the microgrid to start up in 2027. The companies selected in the screening process will be able to develop further cost estimates and schedule once the project has secured a potential customer.

7.7 Wind farm study

The three wind power solution providers identified as suitable for the microgrid have been consulted to provide further information to develop the wind power solution further. Unfortunately, Saipem declined further engagement at this time due to previous commitments and workload, advising that their response could not be provided in the timeframe required by this report.

7.8 Maintenance

As is common for offshore wind turbines and in line with the distribution hub (4), the individual floating wind power units are designed from the outset to be normally unattended. To achieve this operational requirement, the facilities shall be capable of being remotely monitored and controlled, from an onshore location. The operations and maintenance philosophies for the Floating Wind Turbines will be developed to meet the following prioritised goals:

1. To minimise risk to personnel and the environment by operating in an environmentally responsible manner whilst unattended;
2. To maximise the operational performance of the facility
3. To minimise OPEX through the remote operation and monitoring of the facility;
4. To maximise the efficiency of planned maintenance periods and to minimise unplanned maintenance through the use of a robust maintenance management system and condition-based monitoring;
5. Providing a safe working environment for offshore inspection and maintenance activities.

7.8.1 Frequency

It is anticipated that maintenance will be split between the floating structure and the WTG, with maintenance activities coordinated to minimise repeat visits. Two levels of periodic maintenance are envisaged:

- Annual preventive maintenance consisting of:
    - External inspections of the hull structure;
    - Internal inspections of the hull structure;
    - Mooring lines inspections with an ROV;
    - Crane, fixed hoist points and fixed hooking points qualifications;
    - WTG Electrical maintenance/inspection;
    - WTG bearing maintenance/inspection;
    - WTG tower and nacelle inspection;
    - Extinguishers (if any) replacement;
    - Safety functions tests.
- 5 yearly Maintenance:
    - External hull inspections;
    - Internal hull inspections;
    - WTG rotor system inspection and maintenance;
    - WTG tower and nacelle detailed inspection.

7.8.2 Manning

The maintenance and inspection crew size will be determined by the burden of work to be liquidated. An appropriately sized walk to work vessel will be selected, able to accommodate the crew required.

7.8.3 Personnel facilities

No accommodation facilities shall be provided for inspection and maintenance crew on the floating wind turbine units. All accommodation and associated personnel support services e.g. toilets, changing room, laundry, galley, recreational facilities etc. shall be provided on the attending walk to work vessel.

All PPE required by personnel will be provided from the walk to work vessel. The floating wind turbine unit will not provide any changing rooms or locker facilities.

7.8.4 Offshore handling

All spare parts and necessary equipment for the maintenance of the floating wind turbine units will be delivered offshore via a walk to work vessel.

Slings for all lifting beams shall be brought offshore on the W2W vessel.

All lifting of equipment and spare parts shall be done by the crane on the W2W vessel.

7.8.5 Emergency escape and evacuation

In case of emergency whilst personnel are located on the floating wind turbine unit, the primary means of evacuation will be via the walk to work system to the attending vessel. The attending (W2W) vessel will provide a helideck to provide an emergency evacuation facility (i.e. medivac).

7.9 INTOG - Wind farm license application process

The Scottish Government is seeking to develop a Sectoral Marine Plan (SMP) for offshore wind energy for Innovation and Targeted Oil and Gas (INTOG) projects. The following section does not delve into detail on the INTOG process, instead providing an overview of the INTOG project types, current offshore wind licensing requirements, and the associated impact for the microgrid concept.

7.9.1 Project types

Due to the differences in scope and scale, the licenses are proposed to be split in to 2 categories, 'Innovation' being the first and 'Targeted Oil and Gas' being the second. The Innovation element will be run separately from the Targeted Oil and Gas element.

The objectives of the Innovation element of INTOG leasing are:

- To enable projects which support cost reduction in support of commercial deployment of offshore wind; including alternative outputs such as hydrogen;
- To further develop Scotland as a destination for innovation and technical development which will lead to risk reductions and supply chain opportunity.

The objectives of the Targeted Oil and Gas element of INTOG leasing are:

- To maximise the role for offshore wind to reduce emissions from oil and gas production;
- To achieve target installed capacity in a way that delivers best value for Scotland and supply chain opportunity in alignment with just transition principles.

7.9.2 Offshore wind farm license requirements

In order to obtain the license to operate the wind farm, a number of environmental surveys will be required and will need to be considered in the overall project schedule.

The key surveys that may take considerable time are:

- Ornithological surveys, >2 years;
- Sea mammal, length of time not defined but likely to be less than ornithological surveys;
- Geographical and hydrographical surveys, up to 5 years.

The geographical and hydrographical surveys are required for oil and gas developments. The figure given in the BVG Associates report seems quite conservative but does indicate that they will need to be considered as early as possible as they will be needed for the wind power provider to finalise costs associated with mooring of the turbines. The other surveys are easier to fit in within the project schedule.

The surveys are not considered a high risk to the project. There are areas nearby that are similar in nature with respect to survey requirements have had wind farm developments approved. Oil and gas installations nearby would have also had to submit studies stating their environmental impacts which have been accepted. However, in the next stage of engineering it would be required to engage some of the contractors that carry out the surveys to confirm what is required to be in place to conduct the surveys.

7.9.3 INTOG summary

To obtain a license for the microgrid wind farm it will be necessary to engage in the INTOG licensing process. The next application process is scheduled to start in June 2022. Orcadian will need to decide on the number of wind farm licenses it wishes to apply for and the capacity of each one, as well as whether to apply for Innovation or Targeted Oil and Gas licenses. It is unclear whether any operators would be in a position to give an indication to Orcadian of their intent to participate in the microgrid concept, within the first INTOG application period. Therefore, an ongoing dialogue with Sectoral Marine/Crown Estate will be required to obtain the necessary licenses.

8 GHG emissions estimate

Reducing the emissions associated with offshore Oil & Gas facilities is the primary objective of the Microgrid concept. The following section outlines the emissions for each Microgrid, detailing the following: a breakdown of emissions sources, comparison to UK grid, comparison to existing facilities, and impact upon overarching North Sea emissions goals. In addition, the estimation methodology and data sources are outlined.

8.1 Crondall's GHG emission estimation tool

Crondall Energy have developed a proprietary in-house GHG emission estimation tool for offshore energy. The tool has been developed in line with International Petroleum Industry Environmental Conservation Association (IPIECA) guidelines for reporting greenhouse gas emissions. These guidelines have been developed in conjunction with the American Petroleum Institute and the International Association of Oil and Gas Producers. The tool has been internally verified, benchmarking against the International Association of Oil & Gas Producers (IOGP) data, compared with external independent environmental consultant calculations as well as data from other oil and gas operators and NSTA emissions data.

The tool has calculated Scope 1, 2 and 3 emissions for each microgrid system i.e. the hub, wind farm, cabling, and operations in line with the following scope definitions:

- Scope 1: emissions produced directly during operation.
- Scope 2: emissions due to the production of imported energy during operation.
- Scope 3: emissions from third parties related to the Microgrid project, this includes activities such as construction, the charter of supply vessels, and end-use of the product.

Appendix B details which emissions scope has been considered for each system. The Microgrid has been assumed to have no Scope 2 emissions as it does not import energy.

The microgrid carbon emissions estimation have been made conservatively to ensure that the carbon emissions stated are achievable.

From a consumer's perspective, Oil & Gas facilities receiving power, the emissions will be classed as Scope 2. These emissions will relate to the Microgrid scope 1 emissions only.

8.2 Methods and data sources

The table overleaf summarises the calculation methods used in determining emission factors and the source of the emission factors. The following assumptions have been used:

- Microgrid life span – 20 years (10 year life span for original design intent and 10 years for a repurposed application);
- Battery back-up – No credit has been taken for emissions reduction;
- HC emissions are assumed to be equivalent to methane when not provided;
- Helicopter transport is used only for personnel transport (1 visit every 2 weeks);
- NO_X is equivalent to N_2O for GHG CO_2 equivalence calculation;

- If N_2O and NO_x estimates are provided, the NO_x includes N_2O.

Emissions estimates for Microgrid A, C and D have been completed and are displayed in the following sections.

System	Emission Source	Calculation method	Emission Factor Source	Microgrid data source
Hub	Construction	Emission factor per tonne of material	Industry papers	Project weight estimates.
	Mooring system construction	Emission factor per tonne of fuel	Government published figures	Project CAPEX estimate
	Transit to field	Emission factor per tonne of fuel	Government published figures	Transit route from shipyard
	Installation (moorings & cable) & hub	Emission factor per tonne of fuel	Government published figures	Transit route from shipyard
Wind Farm	Combined: Construction, transportation, installation, O&M	Emission factor per MW installed	Multiple industry papers	P50 emissions utilised from industry papers
Cabling	Combined: Construction, transportation, installation, O&M	Emission factor per MW per km (for specific voltage levels)	Multiple industry papers	Cable routing estimates
Operations	Power generation	API industry estimation methodology	Manufacturer data	Project electrical load profile & spinning reserve assumption
	Flaring & venting	Emission factor per volume/weight flared	Industry body emission factors	Facility gas capacity estimate; • Assume 3 ESD per year • Assume engine venting negligible
	Supply vessels	Emission factor per tonne of fuel	Government published figures	Distances based on hub location Assume 1 visit every 2 weeks
	Personnel transport	Emission factor per tonne of fuel	Government published figures	Distances based on hub location Assume 1 visit every 2 weeks

Figure 8-1 Data sources for GHG emission estimations

8.3 Microgrid A

8.3.1 Overall GHG emissions

Microgrid A has a total GHG emissions of 192.31kgCO_2e/MWh. This is made up of 44.45 kgCO_2e/MWh Scope 3 emissions and 147.9 kgCO_2e/MWh of Scope 1 emissions. The total microgrid GHG emissions are less than the UK grid in 2021 which had on average 212.3kgCO_2e/MWh. The figure for the UK grid does not include embedded carbon (scope 3), the emissions associated with construction and installation of the grid. On a comparable basis, the Scope 1 emissions associated with the microgrid are 30.3% lower than those associated with the UK grid. The emissions associated with power from the UK grid should lower over time as the contribution from renewable and low carbon sources is set to increase. However, significant additional infrastructure would be needed to supply power through an offshore cable to power offshore oil and gas facilities. With the UK grid transitioning from hydrocarbon power generation to renewables, the national grid and its consumers will have to become more flexible to cope with the intermittent nature of renewables. Accordingly, new, large and continuous demands from oil and gas consumers may be problematic to incorporate and a guaranteed power supply may only be obtained with premium pricing.

The Net Zero Technology Centre (NZTC), has published emissions figures associated with power generation for simple cycle gas turbines, they provide a low, medium and high case depending on the efficiency, age, condition of the turbine etc. The medium and high cases are typical for installations in the Central North Sea. The total carbon emissions (Scope 1 and 3) associated with the microgrid power supply is between 72.5-80.7% less than typical emissions associated with SCGTs being used on oil and gas facilities in the North Sea. If scope 1 emissions only are taken into account, the reduction in emissions is between 78.9-85.2%.

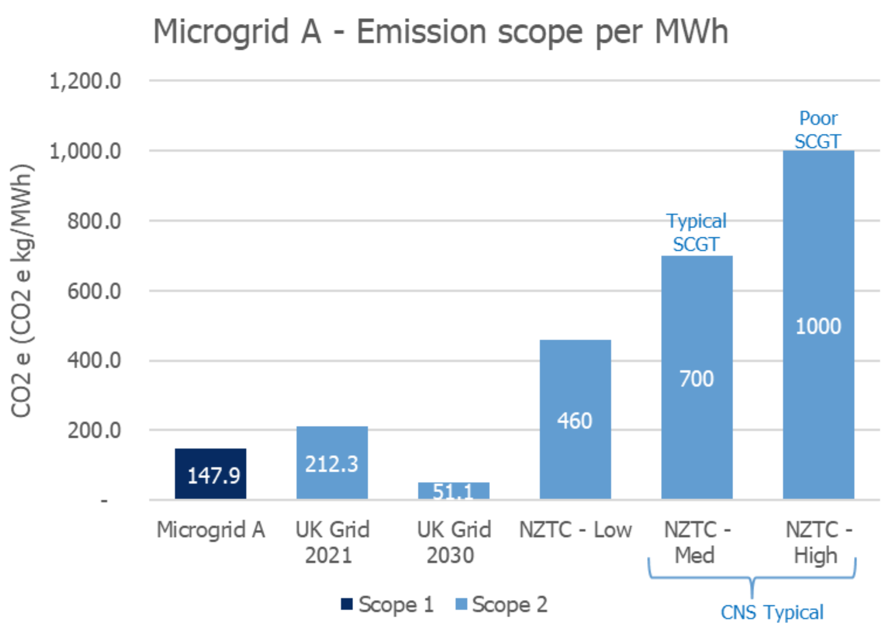


Figure 8-2 Microgrid A - Emission scope per MWh

8.3.2 Construction emissions

The GHG emissions associated with construction of the back-up power generation hub and the cables from the wind farm to the hub and from the hub to the consumer total just under 60,000te. The breakdown associated with these emissions are shown in Figure 8-3. The total GHG emissions associated with the wind farm installation has been estimated to be 282,379te using offshore GHG emission data published by the University of California (20). The study found that the mean GHG emissions associated with a floating wind turbine, 15MW in size, capacity factor of 0.5, operating life of 25 years was 15.35 kg CO_2e/Mwh giving a total of 50,425te of CO_2e. This data was pro-rated for the microgrid assumptions – 7 x 15MW turbines and a capacity factor of 0.6 – to determine the total emissions for the microgrid wind farm.

All construction emissions have been spread out over the field life of 20 years for estimating the GHG emissions per annum this is discussed in the subsequent section.

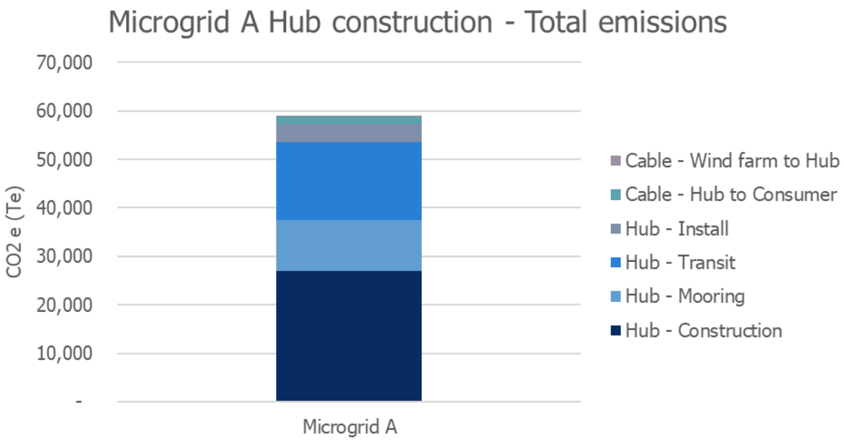


Figure 8-3 GHG construction emissions

8.3.3 Emissions per annum

The majority of GHG emissions associated with the microgrid, unsurprisingly, are from the back-up power generation and the combustion of natural gas (including the spinning reserve). The emissions that are associated with the construction and installation of the wind farm account for circa 12%, and the supply vessels, circa 11%, of total annual emissions.

It is quite likely that there will be scope to reduce the emissions associated with the installation of the wind farm and almost certainly opportunities to reduce emissions from the supply vessels in the future. Supply vessel operators are themselves in the process of decarbonising by using LNG powered vessels etc and the power used in wind turbine manufacturing is also likely to be decarbonised. As a result, the estimate of emissions calculated for these activities is considered to be conservative. It may also be possible to lower emissions by reducing the amount of power generator spinning reserve and increasing the wind farm size. A cost benefit analysis study could be considered in a subsequent engineering phase.

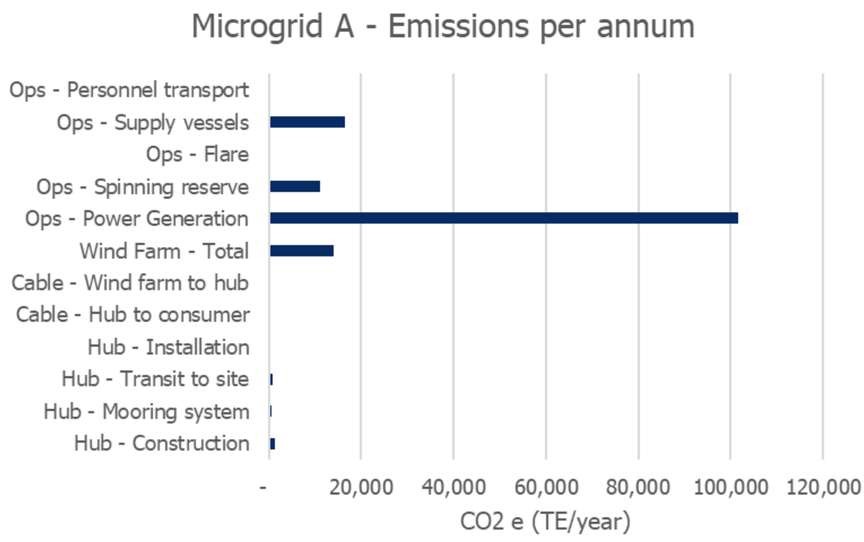


Figure 8-4 Microgrid A - Emissions breakdown

8.4 Emissions summary

The approach, assumptions and calculations made for Microgrid A have been repeated for each of the other Microgrids. Emissions have been calculated for each microgrid based on the wind farm size as shown in Table 8-1 Installed wind power. The installed power is the nearest point to 120% of power required while using 15MW turbines.

Microgrid	Power required (MW)	Quantity of 15 MW turbines	Installed wind power (MW)	% of Power required
A	85	7	105	124%
C	87.1	7	105	121%
D	82.1	7	105	128%
E	75	6	90	120%
F	97.5	8	120	123%
G	82.5	7	105	127%

Table 8-1 Installed wind power

For the purposes of comparison, the wind farm for Microgrid G has been sized and calculations carried out as for the other Microgrids although it is more likely that it will be supplied by the Greenvolt wind farm.

Figure 8-5 shows the scope 1 emissions for each Microgrid. Reference points are included on the chart to include comparable emission levels.

Figure 8-5 Overall emissions by microgrid

It can be seen that all the Microgrids have very similar levels of emissions, all of which are below the comparable UK grid figure and well below that caused by gas turbine generation.

8.5 GHG Emissions comparison

In addition to looking at emission performance in relative terms, absolute values of emissions in terms of tonnes CO_2e per annum are necessary to establish performance against abatement targets.

UK offshore oil and gas facilities produce in the order of 14 million tonnes per annum, of which 10 million tonnes can be attributed to power generation, as depicted in Figure 8-6, provided by the NSTA.

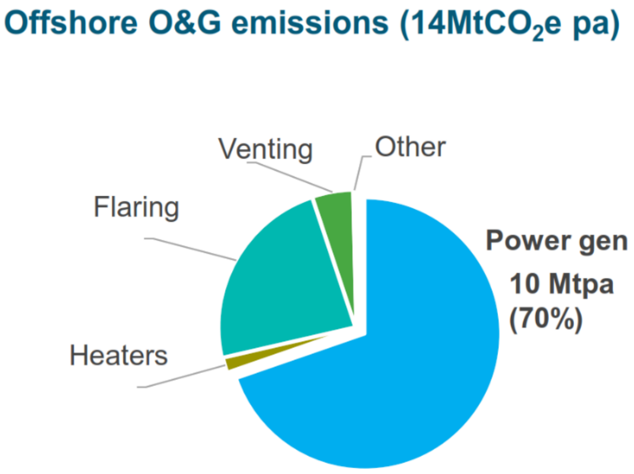


Figure 8-6 Annual offshore O&G emissions

Electrification is seeking to abate emissions as a result of power generation, therefore to achieve a reduction of 50% implies that annually a 5 million tonnes reduction in CO_2e is required. Even this however is a coarse measure and predictions of an achievable annual reduction are in the region of 3 million tonnes per annum, when considering facilities that will be decommissioned by 2030.

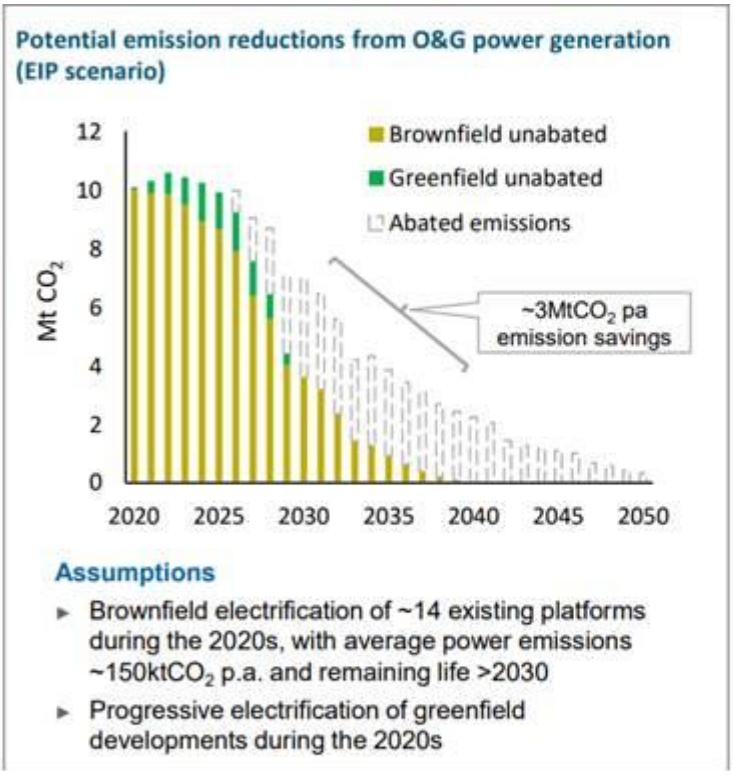


Figure 8-7 Potential emission reductions

Figure 8-7, provided by the NSTA, identifies the abatement potential. In order to evaluate the contribution towards these targets delivered by electrification, we need to make assessments of the current emissions. The NSTA has identified that offshore emission intensities are in the range of 450-800 kg CO_2e / MWh of power generation. Using these ranges, alongside the emissions calculated for each Microgrid gives the annual abatement figures as depicted in Figure 8-8.

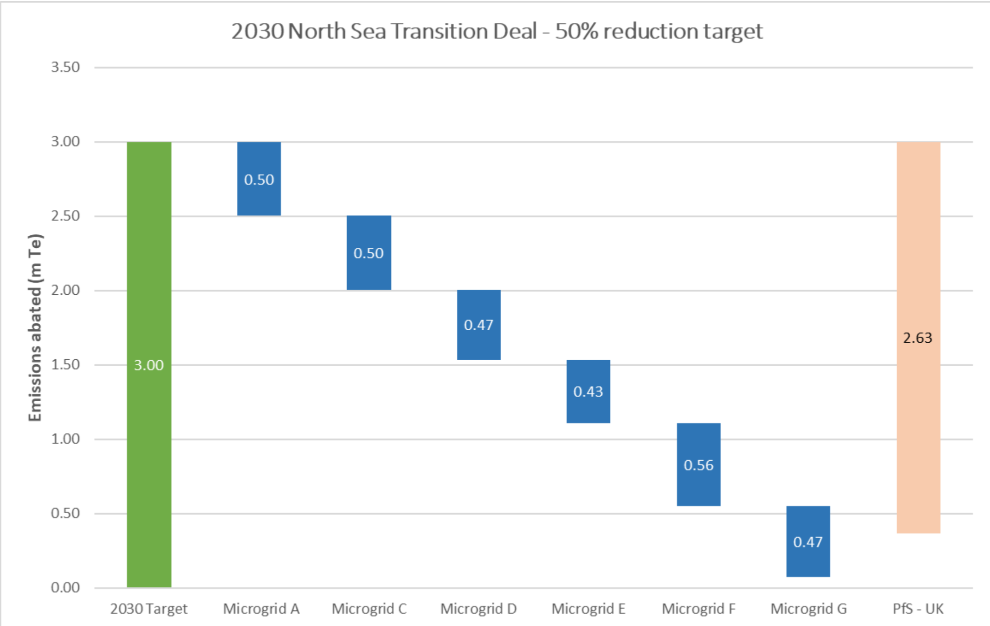


Figure 8-8: Contribution to 2030 emissions abatement target

Comparing these abatement figures with the targets previously mentioned indicates that predicting abatements using the upper range of emission intensity, electrification would deliver 98% of the 2030 abatement reduction for the entire UK offshore industry, not merely the CNS. For comparison Power for Shore (PfS) would deliver 88% of the 2030 target, for the entire UK offshore industry.

8.6 GHG emissions reduction conclusions

The microgrid concept outlined in this report will enable operators to meet the North Sea Transition Deal (NSTD) 2030 target to reduce GHG emissions by 50%. The microgrid concept can reduce existing facilities GHG emissions by 77-83.9% which is close to the 2040 target of 90%. To meet the 2030 target of 50% emissions reduction, Microgrids require a wind farm sized to ~35% of demand, allowing for a staged development of the wind farm, thus adjusting capital costs and optimising the abatement costs across the industry.

Further reduction in emissions is achievable through the following optimisations;

- Acceptance of load shedding by consumers
  Reduces the peak demand during low wind scenarios, reducing the time power is provided by gas fired engines, reducing emissions.
- Reduction in operating reserve

Reducing the operating reserve requirement from +/- 20% would reduce the gas fired reserve, reducing emissions.

- Increase in wind farm size

  Increasing the energy generated by the wind farm, reducing need for gas fired back-up.

To reach the net zero target by 2050, the microgrid will require the implementation of alternative fuels or carbon capture, which the Microgrid concept is capable of supporting. It should be noted however, that the fields to be supplied with power are expected to cease well before 2050 with most facilities shutting down well before 2040.

In summary, the microgrid concept allows for significant GHG emission reductions to go beyond the 2030 commitment to reduce emissions by 50%, utilising existing and proven technology.

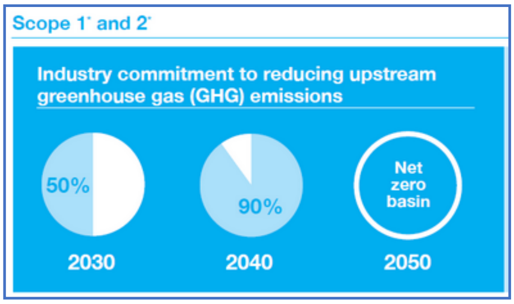


Figure 8-9 North Sea Transition Deal net zero goals (21)

9 CAPEX estimate

CAPEX estimates have been developed for each of the Microgrids and the associated wind farms. For each microgrid the costs of the floating structure, the redeployed Sevan 300 series unit, redeployed semi-submersible and the BPT buoy have been assumed to remain the same. The costs of the wind farm, power cabling, and gas import line have been estimated for each microgrid depending on the power demand of each grid, no. of cables and their lengths etc.

Details of how the cost estimate was compiled and assumptions used are laid out in the following sections.

9.1 Battery limits

The aim of the Microgrid is to be a utility provider and ensure continuity of supply to consumer. The CAPEX estimate for the Microgrid has the following battery limits.

9.1.1 Power cable to consumers

The CAPEX estimate is terminated at the point at which the cable reaches the topsides riser connection. The power cables to the power consumers are different for each microgrid so cable costs vary by microgrid.

9.1.2 Fuel gas import

Fuel gas for back-up power generation will be sourced either from a nearby gas export pipeline or one of the oil and gas production facilities taking power from the Microgrid. Gas tie-in options are discussed in Section 5 .

9.1.3 Brownfield modifications

The costs associated with the brownfield modifications on individual oil and gas production facilities, required to accept power from an external source, have not been included within the CAPEX estimate. These costs are specific to each facility and section 10 provides a discussion on the potential savings compared to other electrification concepts, primarily focused on lower import voltage.

9.2 Methodology and assumptions

9.2.1 Redeployed Sevan units

The cost for the purchase of a Sevan 300 series unit, Hummingbird or Voyageur Spirit has been based on three reference points, the book value, a value based on a potential day rate the vessel could achieve being redeployed in the North Sea and analogous sales.

9.2.2 Redeployed semi-submersible

Cost estimate has been based on analogous sales.

9.2.3 Mooring systems

The mooring system costs have been pro-rated on recent quotations from equipment suppliers for comparable vessel sizes to be moored in the North Sea. The costs have been modified to account for the microgrid location.

9.2.4 Topsides

The costs for topsides tagged equipment including batteries, power generators and associated ancillaries have been provided by Wärtsilä.

The costs associated with distribution equipment (i.e. switchgear, transformers, etc.) and Power Management System have been provided by Schneider Electric.

The costs associated with the telecommunications equipment is based upon analogous projects.

The cost associated with utility systems has been based upon estimated weight per tonne as were the bulk estimations for primary and secondary steel using a proprietary, confidential, in-house tool based on recent construction yard estimates.

9.2.5 Class and insurance

The costs associated with classification of the floating structure have assumed to be 1% and insurance for the structure to be 3% of the vessel value, moorings and hull upgrades.

9.2.6 Transport and transit

An allowance for crew costs and rotational mobilisation/demobilisation

The buoy has been assumed to be transported by a Heavy Lift Vessel (HLV) from Dubai to the North Sea. The semi-submersible has been assumed to be towed from lay-up in Norway to Lisnave, a shipyard in Portugal, and back out to the North Sea. The redeployed Sevan unit has been assumed to be towed from lay-up in Scotland to Lisnave and back out to the North sea. Typical day rates for HLV's and tug boats have been assumed.

9.2.7 Owner's site supervision

The construction and yard set up phase has been assumed to require a team of 18 for 20 months duration.

9.2.8 Owners PM and engineering

The following engineering phases are deemed to be required:

- FEED: Team of 27 for 6 months;
- EPCm: Team of 18 for 29 months;
- Mobilisation, Installation and Hook Up and Commissioning: Team of 9 for 12 months.

Man hour rates have been estimated based on average industry rates for engineering completed in Northern Europe.

9.2.9 Wind farm – Commercially sensitive

The CAPEX estimate for floating wind farm has used $3.46MUSD/MW based on the average of cost estimate data received from multiple floating wind vendors (22; 23; 24; 25). This cost includes;

- Floating structure
- Wind Turbine Generator
- Mooring system
- Engineering, construction, transportation, and installation

Two CAPEX estimates have been developed for the wind farm associated with each microgrid. One with the wind farm sized for 100% of microgrid power demand and another 120% of microgrid power demand. The sizing basis for the wind farm has been discussed in Section 7.1 .

9.2.10 Power cabling

The cabling costs have been provided by the cable manufacturer, Enertechnos, based on cable lengths required and the estimate has included allowances for power losses. Typical power cable laying vessel day rates have been used to estimate the cost of installation. Enertechnos expertise in using their in-house proprietary software, commercial electrical software, and knowledge for costs associated with connector crossing and the crossing of power cables and pipelines has been used.

9.2.11 Gas tie-in

Costs have been based on an internal confidential cost database, industry norms and service supplier quotations. Current market day rates have been used for dive support, survey, reel pipe installation, guard vessels and tugs.

9.3 Probabilistic cost estimate

A probabilistic estimate has been developed. The CAPEX estimate that has been developed for each line item is considered the 'most likely' cost for that line item. For each line item a 'best case' cost and a 'worst case' cost has been developed depending upon the certainty of the data used in developing the cost estimate. The levels of certainty in the data used are as follows:

1. **Well defined** scope with low level of uncertainty,
2. **Moderate uncertainty**,
3. **Uncertain scope** with a high level of uncertainty.

For each level of uncertainty a percentage of the 'most likely' case has been calculated using the following percentages:

Probabilistic scenario	Best Case	Most Likely	Worst Case
Well defined	85%	100%	125%
Moderate uncertainty	90%	100%	150%

Uncertain scope	95%	100%	200%

Table 9-1 CAPEX certainty levels

Once the best, most likely and worst case costs have been established for each line item, the data has been run through a Monte Carlo simulation. It has been assumed that the probability of a certain CAPEX value between the best and worst case follows a normal distribution probability.

9.4 Summary

The costing for each Microgrid has been split into two parts, CAPEX associated with the Wind Farm and CAPEX associated with the distribution hub, as shown by Figure 9-1.

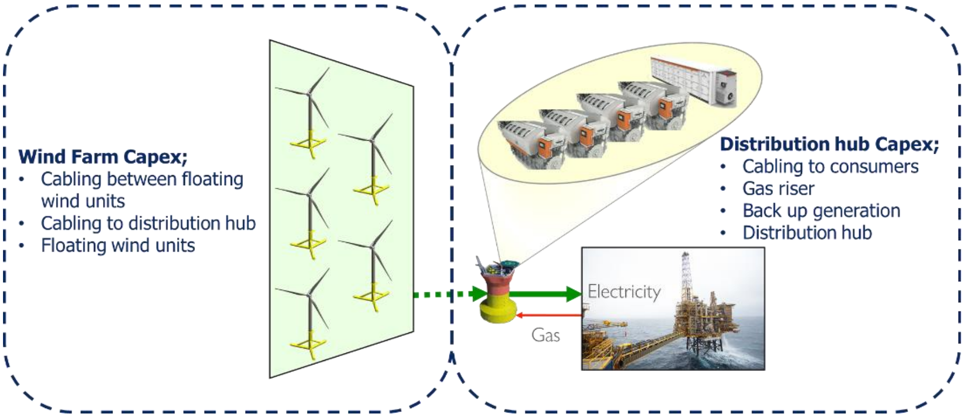


Figure 9-1: CAPEX breakdown

The table below summarises the CAPEX estimate for each Microgrid, providing costs for two sizes of wind farms. The two wind farm sizes are as identified in Section 7.1 The distribution hub CAPEX estimates are based on using the BPT buoy as its structure. CAPEX estimates based on using a Semi-submersible or Sevan structure are found in Appendix D.

Microgrid	Distribution Hub CAPEX estimate			Wind farm CAPEX estimate (minimum sizing)			Wind farm CAPEX estimate (c. 120% demand sizing)		
	P5 %	Mean	P95%	P5 %	Mean	P95%	P5 %	Mean	P95%
	US $m	US $m	US $m	US $M	US $m	US $m	US $m	US $m	US $m
A	422.6	452.2	487.1	276.2	321.9	383.7	365.5	427.7	513.6
C	330.8	349.3	370	279.9	350.5	422.7	324.4	403.3	485.9
D	409.1	433.2	461.7	276.2	321.9	383.7	365.5	427.7	513.6
E	358.9	377.9	399.5	275.0	318.7	378.7	362.7	424.5	511.5
F	437.1	464.5	494.3	345.5	399.0	473.2	432.2	504.9	600.4
G	411.1	436.2	464.5	[11]					

Table 9-2 CAPEX estimate summary

[11] It is assumed that Microgrid G will utilise the GreenVolt wind farm for renewable generation. Commercial agreement will have to be reached for purchasing energy from this wind farm, however the wind farm CAPEX element will be minimised

10 Brownfield modification cost reduction

Modifications of the existing Oil and Gas facilities, to enable import of electricity, is crucial to any electrification concept. Brownfield modifications are inherently complex and costly, due to being performed offshore on existing equipment and on facilities that may have been offshore for multiple decades.

Electrification of existing facilities can be split into two categories partial and full electrification. For both of these categories the existing generation is removed and replaced with power import and the associated equipment. In addition, process heat is modified so that it can be supplied from an electrical source. Therefore, all electrical power, except for emergency generation, is provided by imported electricity.

If the platform is only partially electrified, facilities with gas fired main drivers, such as compressors, will be retained. This simplifies electrification significantly for facilities that utilise gas fired main drivers, as the gas turbine is not in this case replaced with a motor and associated VSD.

Full electrification is when facilities either already utilise motor driven main drives, or are willing to replace gas fired main drives with an electrical equivalent.

The following sub sections provide the brownfield modification cost savings achieved through the application of the Microgrid concept, compared to a Power from Shore (PfS) concept. These focus on the cost savings associated with the connection of the power import cable to the facility, as the remaining costs are largely unaltered by the different power import concepts, i.e. new process heat packages, removal of gas turbines, etc.

10.1 Partial electrification

Detailed cost estimates for partial electrification have been provided by multiple operators and have been anonymised for this report, utilising the cost estimate from industry groups investigating Power from Shore (PfS).

For partial electrification, connection of the power import cable to the facility typically represents 25% of the total facility electrification costs. With the remaining costs associated with modifications that are required to electrify the facility, i.e. new process heat packages, removal of gas turbines, etc. The main components associated with the power import cable, that can be reduced as a result of the selected electrification concept, are as follows;

- **132kV/13.8kV or 11kV power import transformer**
  The power from shore options typically utilise a high AC voltage (132kV), this must be dropped to the platform voltage (typically 13.8kV or similar) to enable its use
- **Compensation**
  Conventional cable transmitting HV AC frequently requires compensation systems at the facility end. This is to compensate for reactive cable losses, that increase with distance, which result in transmission losses and stability concerns.

The Microgrid concept minimises these cost items;

- **Reducing the transformer size to 33kV/12.8kV**
  Not only reducing the size of the transformer but also the associated bulks and modifications.
- **Removes compensation**
  Compensation is removed due to the shorter cable lengths and use of CTS cable for longer lengths. Compensation takes up a significant volume of space and weight, especially for brownfield facilities. For a 40MW facility, this could be 4m x 3.5m, with an equipment only weight of 40Te.

This provides an opportunity to reduce the power import costs by 36%, representing an 9% reduction of the total facility partial electrification costs. For a typical North Sea facility, partial electrification has been estimated to cost ~$71m, utilising the cost estimate from industry groups investigating Power from Shore (PfS). Therefore, the Microgrid concept provides a ~$6.4m saving, bringing the total brownfield modification cost to ~$64.6m.

10.2 Full electrification

Detailed cost estimates for full electrification have been provided by multiple operators and have been anonymised for this report, utilising the cost estimate from industry groups investigating Power from Shore (PfS).

For full electrification, connection of the power import cable to the facility typically represents 22% of the total electrification costs. With the remaining costs associated with modifications that are required to electrify the facility, i.e. new process heat packages, removal of gas turbines, replacement of main drivers etc. The main components associated with the power import cable, that can be reduced as a result of the selected electrification concept, are as follows;

- **Installation of new switchboard and equipment room**
  Equipment room to house new switchboard and electrical equipment for electrification of main drivers.
- **132kV/13.8kV or 11kV power import transformer**
  The power from shore options typically utilise a high AC voltage (132kV), this must be dropped to the platform voltage (typically 13.8kV or similar) to enable it use
- **Compensation**
  Conventional cable transmitting HV AC frequently requires compensation systems at the facility end. This is to compensate for reactive cable losses, that increase with distance, that result in transmission losses and stability concerns.

The Microgrid concept minimises these cost items;

- **Reduces size of new equipment room**
  Removing the requirement for compensation and reducing the transformer size, provides an opportunity to reduce the equipment room size.
- **Reducing the transformer size to 33kV/12.8kV**
  Not only reducing the size of the transformer but also the associated bulks and modifications.
- **Removes compensation**
  Compensation is removed due to the shorter cable lengths and use of CTS cable for longer lengths. Compensation takes up a significant volume of space and weight, especially for brownfield facilities. For a 40MW facility, this could be 4m x 3.5m, with an equipment only weight of 40Te.

This provides an opportunity to reduce the power import costs by 36%, representing an 8% reduction of the total partial electrification costs. For a typical North Sea facility, full electrification has been estimated to cost ~$209m, from industry groups investigating Power from Shore (PfS).. Therefore, the Microgrid concept provides a ~$16.7m saving, bringing the total brownfield modification cost to ~$192.3m.

11 Microgrid – Delivery schedule

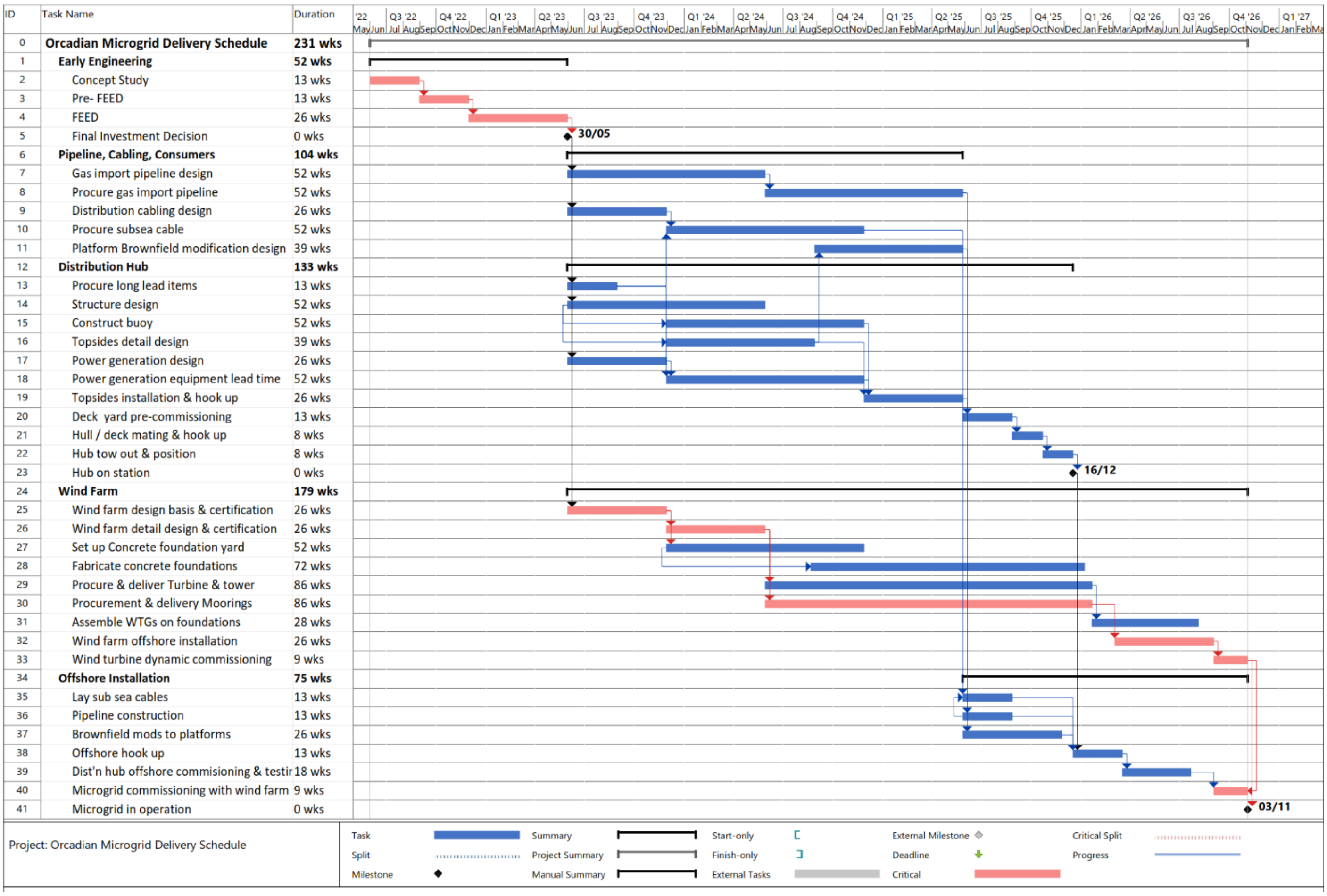


Figure 11-1 Indicative delivery schedule

Crondall has prepared an indicative delivery schedule as shown in Figure 11-1. Dates shown on the schedule are based on a nominal start date of 1 June 2022 and it shows an overall duration of approximately four and a half years from the start of the conceptual study to the microgrid being installed and ready to provide power to the oil and gas production facilities. The concept, pre-FEED and FEED engineering work would take a year to complete at which stage a final investment decision is required.

The schedule is for a typical Microgrid, although some of the elements e.g. the early engineering and the buoy's structural design would be common across all Microgrids. One section, however, that can be thought of as applying across multiple Microgrids is the Wind farm, as its schedule is based on the delivery of a single 320 MW farm, to supply multiple Microgrids. Schedules for specific Microgrids would require further analysis of the circumstances of each one and a review of capacity in construction facilities.

Importantly, with a mid 2022 commitment to progress the project (with Final Investment Decision in mid 2023) the first distribution hub could be operational at the beginning of 2026. This will immediately impact emissions, with an expected reduction of c. 35% (the same as the Hywind Tampen project) possible before any renewable energy is commissioned. This will also provide operators an opportunity to build confidence in the performance of the system before decommissioning their existing generators.

12 Roadmap to net zero

The microgrid proposed by Orcadian in this report goes a significant way to eliminating carbon emissions associated with oil and gas production facilities powered by the microgrid. It is critical for the Microgrids to achieve net zero to ensure their future use for either oil and gas facilities or other redeployment opportunities, to maximise their value. To achieve net zero, the implementation of long term energy storage, carbon capture from fossil fuel generated power, or the use of alternative fuels would be required. The following sections provides a high-level assessment of the requirements to implement such technology and has focused on carbon capture and alternative fuels. At present or in the foreseeable near future, battery technology has been considered insufficiently advanced to store sufficient power requirements to supply large power demands in the region of 80MW.

12.1 Carbon capture

12.1.1 Traditional liquid amine systems

Traditional liquid amine systems used to remove carbon dioxide from exhaust gases involves well proven and mature technology and has been used in natural gas processing for many years. However, the technology has remained largely uneconomical for power generation exhaust gases due to the high CAPEX costs and the problem with disposal of the captured carbon. The low partial pressures of CO_2 in power generation exhaust gases make the CO_2 more difficult to extract and thus higher amine flow rates are required to do so. The low pressure of the exhaust gas streams leads to high gas volumes and large piping and contactors/strippers all conspire to increase the CAPEX costs of a facility. Captured CO_2 then needs to be compressed from near atmospheric pressure to a pipeline pressure for disposal, which is likely to be greater than 75barg. If the CO_2 can be used in enhanced oil recovery, then this can provide a revenue stream for the project otherwise disposal further increases costs. The facility also requires additional power for compressing the flue gas to the contactor pressure, compressing CO_2 for disposal, pumps etc which in turn increases the exhaust gas emissions.

Two notable large scale power generation carbon capture projects have been built, Boundary Dam in 2014, utilising Shell's Cansolv technology and Petra Nova using Kansai Mitsubishi CO_2 Recovery system. Both projects were for coal power generation plants in the USA and Canada.

The introduction of 'carbon clusters', for example, the East Coast Cluster (Hull/Middlesbrough), Hynet (Liverpool) and the Acorn project (Scottish cluster) whereby the disposal of captured carbon is to be provided as a service will reduce some of the CAPEX for facilities wishing to capture and dispose of their carbon emissions. This project is not in the vicinity of these clusters and would still have to provide the CAPEX and facilities to compress captured carbon and send it either via pipeline or ship to one of these clusters.

There are companies such as Carbon Clean, Aker 'Just Catch', and CO_2 Solutions owned by Saipem and Svante that are looking to reduce the costs and energy requirements associated with carbon capture. Carbon Clean are developing 'Cyclone CC' technology that contacts the CO_2 rich gas with amine via a rotating 'flat' cylindrical unit and uses centrifugal forces to distribute the amine. This is bringing down the size and cost of the contactor considerably, as well as the quantity of amine required and thus the energy used in amine regeneration. However, this technology will take 2-3 years minimum to reach technical maturity.

For analysing the potential use of a liquid amine carbon capture system on this project, the following information, previously given to Crondall, has been used:

- A high-level technical quotation from Carbon Clean;
- An over the phone discussion on Aker's Just Catch system.

Both carbon capture systems are based upon gas fired turbine power generators which are less efficient than the reciprocating engines proposed for use on the microgrid.

The following table contains a high-level overview of the Carbon Clean proposal and some information gained on Aker's Just Catch technology. For the microgrid powered by the Wärtsilä reciprocating engines, the exhaust gas flow and carbon emissions have been estimated using the '31DF Product Guide' (26) and the potential size of a carbon capture unit for a 75MW microgrid has been estimated.

		Carbon Clean	**Aker 'Just Catch'**	**75MW Microgrid (Estimated)**
Power generation type		Gas Turbine	2 x LM2500 + G4 turbines	Wärtsilä 31DF series
Power generation	MW	18.3	60	75
Exhaust gas flow	te/h	247	-	507
Carbon emissions	tpd	348	-	740
Carbon captured	tpd	313	658	665
Heat supply (amine regeneration)	MW	10.4	30	33-42
Electrical supply[12]	kW	747	-	1530
Layout area	m	21W x 32.1L x 22H	22.6W x 22L x 31H	-
	m^2	675	497	500-600
Module weight	te	-	1000	1000
Estimated cost	MUSD	60-70	84-96	120-140

Table 12-1: Carbon capture comparison

[12] Excluding any CO_2 compression required for disposal

The topsides equipment weight for the back-up power generation and distribution power hub has been estimated to be in the region of 1900te and the total topside weight with structural steel has been estimated to be around 6,500te. A modular carbon capture unit weighing in the region of 1,000, not including primary and secondary structural steel requirements, would have a significant impact on the floating structure selection and structural steel requirements in the hull.

The potential cost of a carbon capture module unit not integrated into the facility is likely to be in the region of 120-240MUSD. The cost of the distribution hub for Microgrid A has been estimated to be roughly 300MUSD and the cost of the carbon capture unit alone would increase this cost by 40-80% at least. This does not include the cost of CO_2 disposal or module integration.

The impact of a carbon capture unit installed on the floating structures selected is shown in the table below:

Microgrid structure	**Impact of carbon capture unit**	
	Deck Area	**Weight**
Redeployed Sevan unit	Up to 20% of deck area would be taken up for the unit. The Sevan 300 has a deck area of 3450m^2 (5).	A redeployed Sevan would have sufficient existing topsides that could be removed that would weight more than a carbon capture unit
Buoy	The Buoy, which is bespoke new build unit, would need to be designed for the larger layout area required.	The unit would need to have sufficient hull strength and structural steel put into the buoy at the initial construction.
Redeployed semi-submersible	A 100 x 100m semi-sub would have sufficient deck area.	The semi-submersibles reviewed have a limit on topsides weight of 6-7,000te. Adding the carbon capture unit would require a larger, more expensive unit to be purchased.

Table 12-2 Impact of CC unit on microgrid floating structure

Heat integration between the carbon capture unit and the Power generators would be required. The reciprocating engines are 49% efficient. If a Wärtsilä 31 Smart Heat Recovery system can recover a further 10% (as advised in a presentation by Wärtsilä) of the heat energy this would not provide sufficient heat energy for amine regeneration. If insufficient heat energy is available to regenerate the amine, then the energy would have to come from burning more gas to heat steam and or more gas to burn in the power generator. Either way this would drastically reduce emission savings from the carbon capture unit.

As detailed in section 4.2.1.2.2 , the generation loading will vary significantly in proportion to the volume of wind energy generated. A carbon capture liquid amine system would have difficulties operating with this variation in load and the turn down requirement.

12.1.2 CO_2 disposal routes

Liquid amine carbon capture systems will produce an exhaust gas stream with a CO_2 content of approximately 95%, at a pressure of 1barg and 40°C which will need to have a disposal route. There are two disposal routes for the CO_2 rich stream:

1. Compressed and sent via a dedicated pipeline to an enhanced oil recovery programme/nearby reservoir identified for re-injection;
2. Compressed and liquified for transportation via a liquid CO_2 carrier.

In general CO2 pipelines do not require exotic steels. API 5L X60 or 65 is likely to be suitable as long as free water is strictly controlled to prevent corrosion. Pipelines carrying CO_2 can be more susceptible to 'running fracture' and may require additional toughness. Lower grade X60 or X65 have inherently high fracture toughness. The transport of CO2 is well understood and not anticipated to pose a problem. However, it is more difficult to find a place to inject the CO_2. Any nearby disposal reservoir identified will need to be proven to be acceptable for CO_2 storage which involves costly seismic surveys, the quantity of which is determined by the existing reservoir data.

To be transported by ship, CO_2 must be kept in its liquid state at temperatures and pressures above its triple point, approximately -56.6°C and 5.2 barg. Dedicated liquid CO_2 carriers of sufficient size are currently being developed and built by companies such as Hyundai Heavy Industries and Korea Shipbuilding & Offshore Engineering Co who have an 'Approval in Principle' by the classification society, DNV (27). These liquid CO_2 carriers will have the capacity for 40,000 cubic meters as opposed to liquid carriers currently in operation that have a capacity of 2,000 cubic meters. The liquid carrier systems currently being designed are for ship to shore or shore to ship bunkering. The technology for ship-to-ship bunkering required by the microgrid will need to be developed. This is considered possible as it is an 'extension' to existing technology, but the requirement is quite unique to the microgrid and unlikely to be developed by others at present.

To determine the feasibility of installing a carbon capture unit further work would be required to identify an economical disposal route. At present the cost of a carbon capture unit, technology limitations in bunkering and the costs involved with disposal are considered to be uneconomical.

12.1.3 Value Maritime

A company, known as 'Value Maritime', has developed a system (called 'Filtree') to capture the CO_2 from ship engine exhausts. It involves the use of a proprietary liquid carrier that picks up CO_2 from the engine exhaust gas in the same way as a traditional liquid amine contactor. However, the liquid carrier is continuously circulated to pick up more CO_2 until the carrier is saturated. The carrier is then stored in tanks that can be lifted off and transported to a place where the liquid carried can be regenerated and the CO_2 stored separately. The CO_2 is then used in industrial processes such as the growing of vegetables in green houses. The company offers the carbon capture as a service (CAPEX for the equipment is separate) whereby they will take the CO_2 rich liquid carrier, regenerate it and ensure that the CO_2 is used in an industrial process for a fee. The company is setting up facilities to do this in several ports over the world and there appears to be considerable interest in the shipping industry for their product. Crondall Energy were advised by Value Maritime that 12 ships are currently having the system installed.

The system has a much lower energy demand than a traditional liquid amine unit as the carrier is not being regenerated. This does make it easier to integrate with the microgrid facility. However, seawater is required to scrub the engine exhaust gases. Value Maritime advised that the system is easy to operate and would require minimal regular manual interventions which should fit well with the microgrids requirement to be a normally unattended facility.

It should be noted that the CO_2 captured is being re-used and that depending upon the final use of the CO_2, will determine whether the CO_2 is abated. In addition, the separation of CO_2 from the liquid carrier, transportation of the liquid carrier and separated CO_2 will need to be done in a manner which has minimal or no associated GHG emissions otherwise the emissions reduction potential of the microgrid will be limited.

Figure 12-1 shows Value Maritime's 'Filtree System' fitted on the back of a container ship's engine exhaust and Figure 12-2 shows the unit being lifted in place. One can see the compact nature of the unit and how an existing engine exhaust can be retrofitted. In Figure 12-3 the storage containers for the CO_2 rich liquid carrier can be seen.

Figure 12-1 A container ship fitted with Value Maritime's 'Filtree System' (28)

Figure 12-2 Filtree system being lifted in place

Figure 12-3 CO_2 rich liquid carrier storage containers

In discussions with Value Maritime they have advised that for a 10MW engine the following was applicable:

- The CAPEX for the equipment and installation would be 1.7million Euros;
- The fee for liquid carrier removal would be around 55Euros/te CO_2;
- The weight of the unit would be in the region of 20te;
- 2 x 20ft containers containing the liquid CO_2 carrier would need to be replaced every 5 days of operation.

Value maritime have developed a couple of sizes of the 'Filtree system' to fit on the exhaust stack of one or two engine sizes. Thus, one system would be required for each engine on the back-up power generation hub. This would be difficult to operate as the power requirement from the back-up power generation can fluctuate considerably. The carbon capture units are designed to work in continuous operation. It may be possible to design a larger Filtree carbon capture system to capture the exhaust from multiple engines, but this would need additional engineering and testing to prove the concept still works. Without the additional testing, installing a larger unit would be deemed risky. However, as one of the back-up power generators will be operating continuously as a spinning reserve, it could be possible to install one of the Filtree systems on that power generator. This concept could result in significant emissions reduction but requires further evaluation in the next stage of design.

12.2 Alternative fuels

This study has considered that a potential microgrid could be commissioned in 2027 and would have an operational lifetime for its original deployment of up to 10 years for oil and gas facilities, with subsequent redeployments for use in other applications, such as providing power to the UK national grid, offshore carbon sequestration projects etc.. The UK Government's North Sea Energy Transition Deal aims to achieve a 50% reduction in GHG emissions by 2030 and net zero by 2050. The vast majority, if not all the existing oil and gas production facilities being considered for electrification with the microgrid concept will be decommissioned well before 2050. This report has demonstrated that the microgrid concept is able to achieve GHG emissions reduction of 80%, exceeding the 2030 target of a 50% reduction. However, if any of the microgrids were to connect to the national grid or continue operation there will be a requirement to achieve the 2050 net zero goal, then the use of alternative fuels could be considered.

12.2.1 Main alternative fuels

The principle alternative fuels to the use of methane for combustion and power generation include:

- Hydrogen
- Methanol
- Ammonia

A summary of alternative fuel properties can be seen in Table 12-3 and Figure 12-4. The characteristics of these fuels are described below:

Hydrogen – has the highest calorific value per unit mass but the lowest energy density thus requiring significantly more storage volumes for the same amount of energy as the other fuels. The flammability range of hydrogen in air is extremely wide, the molecule size is small leading to increased safety concerns. The low temperature it needs to be stored at is also problematic as it requires specialist tanks and increased energy (to compress boil-off gas).

Methanol - Perhaps the easiest of the alternative fuels to store, it has a reasonable energy density and has a larger flammability range than methane but significantly less than hydrogen. Methanol will still produce CO_2 when combusted so must be produced via a 'green source' and will limit potential decarbonisation of power produced from the microgrid. It is also toxic to humans.

Ammonia – Slightly more complex to store than methanol but can be stored at a temperature much higher than methane, thus needing less energy to store (energy is required to compress boil off gas). It has a reasonable energy density but still requires 2.9 times the amount of storage as liquefied natural gas. The flammability range is slightly higher than methane but less than methanol and significantly less than hydrogen. Ammonia is highly toxic to humans.

Parameter	Units	Methane	Ammonia	Methanol	Hydrogen
Boiling temperature	°C	-162	-33	64.7	-253
Density at boiling point temperature	Kg/m^3	450	680	748	71
Flammability limits in air	Vol %	5-15	15-28	6.7-36	4-75
Lower heating value	MJ/kg	49.6	18.6	19.9	119
Energy in 1m^3	MJ	22320	12648	14885	8500

Table 12-3 Alternative fuel properties

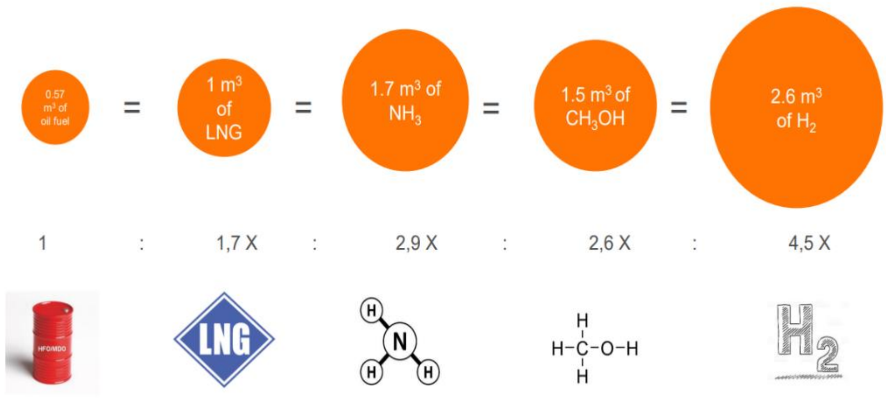


Figure 12-4 Alternative fuel energy density comparison (24)

All the potential alternative fuels have their advantages and disadvantages, and different users will be able to tailor their processes to suit one of these fuels more easily than they can for the others. As a result, it is quite likely that all of these fuels will be in use in the future in different sectors.

Currently none of the alternative fuels discussed are produced in large quantities with no CO_2 emissions associated with the production. The technologies to do so are in development and are expected to be more widely available in the next 10 years, or so, as the technologies mature, and economies of scale bring down the costs.

12.2.2 The use of alternative fuels in the microgrid concept

It is difficult to see which alternative fuel will be the 'fuel of choice' in the future and the likelihood is that all the fuel types will play their role. Different fuels will be taken up by different applications depending upon the industry in which they are used, what local resources are available, the source of decarbonised power available, the price of that power and what infrastructure has been installed locally. Hydrogen is perhaps the easiest to produce but for use on the on the microgrid, the cryogenic temperatures, low energy density and the significant difference in flame length between hydrogen and natural gas would make the fuel very difficult to incorporate on the microgrid.

Ammonia and methanol are more difficult to obtain from a decarbonised source but have much higher energy densities and lower flammability in air ranges than hydrogen. Methanol produces CO_2 when burnt, thus making it a 'life cycle' neutral fuel (when produced from a decarbonised source) without capture and re-use of the CO_2 but it is much easier to store and bunker as there are no cryogenic temperatures involved. The combustion of ammonia doesn't produce CO_2 but does have some SO_x and NO_x that will need to be captured by scrubbers (Wärtsilä are developing engines with very low NO_x and SO_x emissions).

Due to the uncertainty over which of the alternative fuels could be available in sufficient quantities from decarbonised sources, the microgrid concept has selected Wärtsilä 31DF engines. Not only are these engines highly efficient and have lower GHG emissions when combusting methane relative to previous engine models or gas turbines, but they have low maintenance, are digitally enabled and most importantly Wärtsilä are future proofing the engine with the capability to run using ammonia, methanol or hydrogen with minimal modifications. The modifications anticipated will depend on the fuel and are likely to include: burner changeout, update to software and fuel supply injection modifications. The company is aiming to avoid major changes to larger components. They have publicly stated that they anticipate that the 31DF engine series will be able to run on ammonia by 2025.

All the alternative fuels can be stored offshore and the safety issues with the fuels are known and manageable. With the correct mitigation measures in place these risks can be reduced to an acceptable level. The back-up power generation hubs are designed to be normally unmanned, thus reducing the potential consequences associated with the risks.

When the 31DF engines can be run on an alternative fuel there are two other key enablers for the microgrid to be able to use alternative fuels and achieve further decarbonisation in the power supply. The first is the availability of the alternative fuel the engine can run on. Just as important, it needs to be supplied from a decarbonised source or the emissions reduction potential is severely limited. The second is the ability to bunker the fuel on-board. The fuel will be needed in too large a quantity to be lifted on board in tote tanks. At present the technology and regulations are not in place for the bunkering of ammonia, methanol, or hydrogen. The technology to bunker from ship to land and vice versa is well established but the technology for ship to ship transfer will need to be developed. This is not anticipated to be onerous as less volatile fuels are bunkered presently on a regular basis. Unfortunately, it is quite a niche application and may not be the focal point of energy transition efforts for the company's owning the technology.

This study has looked at the possibility of housing the back-up power generation on a redeployed Sevan 300 series unit, a redeployed semi-submersible drilling rig or a newbuild buoy. All of the facilities considered have capacity for storage of net zero fuels, however further development is required to understand the necessary modifications to ensure the storage space is suitable for net zero fuels.

12.3 Summary – Road map to net zero

The inherent design of the microgrid allows for existing facilities to more than exceed the GHG emission reduction required as part of the North Sea Transition Deal. The target is a 50% cut in GHG emissions by 2030 in an economical way for the operators (actual reductions in emissions vary per microgrid but will be in the region of 80% as outlined in Section 8.6 .). The oil and gas production facilities associated with the microgrids looked at in the study will likely have ceased production much before 2050 and will not need to undergo further modifications to reach net zero. Instead, this section is focused upon achieving net zero to enable future connection of the Microgrids to the national grid or new hydrocarbon developments.

Further GHG emission reduction can be achieved by utilising technologies that are being developed. Traditional liquid amine carbon capture systems will have difficulties with reaching 'net zero' targets but could increase microgrid emissions reduction by capturing up to 95% of the CO_2 produced from the back-up power generators running on natural gas. They may be difficult to operate with multiple engines operating with fluctuating loads but some of the new and compact carbon capture technologies may make the application of this type of technology more feasible and easier to integrate as well being more economical. The number of carbon sequestration projects in the North Sea is increasing rapidly, providing an increased number of opportunities to dispose of captured CO_2. A Value Maritime 'Filtree' system could provide a partial solution and go some way to reducing GHG emission further by decarbonising the spinning reserve.

Alternative fuels, in particular, ammonia and renewable methanol, is the much more promising option to enable the microgrid facilities to reach net zero targets, once the Wartsila engine technology is ready and a source of the decarbonised fuel is readily available.

In summary net zero fuels represent the most likely solution to facilitate net zero electricity generation from the Microgrids. This is due to the distribution hub design utilising a structure with capacity for net zero fuel storage, and Wärtsilä 31DF engines that will be compatible with the currently foreseen net zero fuels. By comparison, Carbon Capture is not seen to be the optimal solution due to significantly increased CAPEX, and practical challenges associated with its implementation.

13 Microgrid future use

It is anticipated that the microgrids will provide power to the nearby oil and gas production facilities for around 10 years until those facilities cease production. If the life of one or more of these facilities are extended by the operators, the microgrid can obviously remain on station. However, once the microgrid is no longer required to provide power to the original production facilities there are several options for reuse. Both the wind power generation structures and back-up power generation structures are moored floating structures and can be deployed to alternative locations. With the microgrid redeployed:

- As the whole microgrid unit;
- Or separated with the wind and back-up power generation units being repurposed.

The worst-case scenario would be that the microgrid is scrapped for residual value. With the demand for decarbonised power anticipated to increase exponentially over the next 10 years this is seen as an unlikely scenario and the likelihood that the microgrid could be repurposed is high.

13.1 Connecting the microgrid to the shore

The simplest and possibly the most obvious use of the microgrid would be to provide power to the National Grid. There are several routes a cable to shore could take see Section 6.5 . Connection would likely require the installation of transformers on the distribution hubs so that power could be exported at 132kV, but adoption of the Enertechnos cable means that there is no requirement for HV DC connection to shore. Transition from 60Hz to 50Hz will be required, this can either be on an individual Microgrid basis or by the use of a frequency converter station at landfall.

For sure, the wind farms will provide power acceptable to the UK grid, but it may be necessary to convert the back-up generators to operate on net zero fuels, depending on Government policy at the time. Given the capability of the system to provide baseload power, it is likely that a premium pricing can be achieved for power supplied to the National Grid.

13.2 Redeploying the whole microgrid unit as one

The whole microgrid with the wind and back-up power generation could be deployed at an alternative location to provide reliable decarbonised power. The unit could be deployed to provide power to existing oil and gas fields elsewhere in the North Sea, to reduce cable costs, or else where round the world. The floating structures will have been designed for the harsh metocean conditions of the UK North Sea so should have considerable design life left for a redeployment to a location with more benign conditions and with some refurbishments, could be made suitable for further operations in the North Sea.

The microgrid could be employed to provide decarbonised power anywhere around the world. It does not necessarily have to be used to power existing oil and gas facilities. There are onshore industrial facilities that could utilise a source of decarbonised power, for example chemical plants or LNG facilities. The microgrid could be used to supply decarbonised power to towns close to the shore in areas that have a plentiful gas supply.

13.3 Redeploying the microgrid as separate entities

The wind farm does not necessarily need to be redeployed with the distribution hub.

The wind farm could continue operating at the existing location and provide power to the national grid. The downside with this is that a new connection to shore would be required, the onshore infrastructure may need upgrading and Crown Estate Scotland may have concerns about leaving legacy infrastructure in place as over time there may be too many cables and structures around the North Sea.

The wind farm could provide power to an existing windfarm nearby from its current location or be redeployed to be adjacent to another wind farm. The wind farm does not necessarily have to be in the North Sea.

The distribution hub could be employed as a floating power plant (gas to wire). This concept might provide an efficient means of developing stranded shallow gas discoveries in the North Sea or as a means of depleting gas reservoirs which would otherwise require installation of compression facilities.

The reciprocating engines are highly efficient, more so than gas turbines or burning other fossil fuels such as coal for power generation and could provide partially decarbonised power to places such as West Africa. The distribution hub could be operated to back-up a solar farm which is unable to provide power at night.

14 Commercial

The Orcadian consortium proposal is for an infrastructure focussed investor to facilitate the construction and commissioning of the facilities necessary to enable decarbonisation of power generation for oil and gas platforms in the North Sea.

Whilst Operators have the impetus, capability and capital to adopt and implement the scheme, it would involve the alliance and collaboration of multiple operators and field owners who would need timely alignment on complex governance structures and commercial arrangements, which could take a long time to design and negotiate.

The Orcadian consortium proposal cuts through that complexity by providing field operators and owners with the opportunity to bi-laterally purchase a reliable supply of decarbonised electricity delivered to their platform whilst recognising that customers would be required to free issue gas in order to ensure the generation of back-up power, and retain the liability for the policy costs of their remaining carbon emissions.

At this early stage in the project it is not possible to make a detailed or firm commercial proposal to potential customers, however, with their support, this can be developed as the project progresses through the completion of pre-FEED and FEED

We intend to structure a work programme inclusive of the following elements:

- Submit an application in the INTOG process;
- Preliminary environmental impact assessment;
- Concept definition and pre-FEED engineering work, see Section 15.2 , all in conjunction with customers:
    - electrical specification, preparation of a basis of design and functional specification for the wind farm, distribution Hub and cables, confirmation of gas import options;
- Further field specific model testing of the buoy;
- Identification of preferred wind turbine contractor and developer and engagement in a partnership with the Consortium;
- Preparation of a detailed cost estimate and schedule, recognising that the buoy could precede the wind farm;

A second phase of work in the run up to project approval could entail:

- FEED level engineering definition of the Distribution Hub;
- Environmental, ornithological and marine surveys;
- Preparation of an Environmental Statement;
- Selection of EPC and installation contractors;

This work package could be for a single customer with a small distribution hub and wind farm or for multiple customers with many distribution hubs and a number of large wind farms. With the support of interested potential hub customers, the Orcadian consortium will lead and undertake this work scope in addition to developing a mutually acceptable commercial proposal. The scale and cost of the project will depend on the level of participation, from upstream infrastructure owners and operators.

15 Next phase

The next phase of work will primarily be driven by the objective to obtain a client or clients and any resultant work scope would be defined by the individual project specific needs of those clients. The project needs to be taken from the generalised concept to the specific needs of a client.

15.1 INTOG licensing

The current schedule proposed by INTOG for the license application process states that it will start in June 2022 and be open for 2 weeks. Crown Estate Scotland have been undertaking consultation on the proposed INTOG process with industry, and may revise the process accordingly. Engagement with INTOG is required to keep informed of any changes to the INTOG process and how this could impact the scheduling of the microgrid projects and clarify what will need to be provided as part of the application process.

15.2 Engineering definition and optimisation

The engineering definition that would be undertaken depends upon the client's or clients' individual requirements. Further work required to develop the design includes:

- HAZID/ENVID;
- Environmental Impact Assessment;
- Developing process flow schematics/diagrams;
- Provide further definition of utility requirements;
- Optimising back-up power generator configuration.
- At present inspection and maintenance requirements have been based on information provided by Wartsila for the gas engines. Further work may be required to fully demonstrate that unattended operations are possible. Crondall Energy have a proprietary in-house tool to estimate the inspection, maintenance and repair requirements of the microgrid;
- Clarifying the method of access to back-up power generation hub;
- Review alternative energy storage options to the battery storage identified in this study;
- Define the remote-control operation and integrating control system with the power management;
- Integrated single line diagrams;
- Narrow down gas import options dependent upon client's facility.

Once a client is identified, the required power demand of the microgrid may need to be a different size to that outlined in this study. This study will need to be modified to match the required power demand.

15.3 Floating structure – Power distribution hub

To develop the buoy as an alternative option, further field and payload specific model testing is required. BPT are currently engaged in a programme of work funded by BEIS, to develop BPT's proprietary spar-buoy technology for use for floating substations. This BEIS funded work will build on earlier testing carried out by BPT at the University of Southampton to validate the spar-buoy concept. However, the power hub payload is somewhat greater, so further model testing will be needed to validate the up scaling of the substation hull. Further research could be conducted for a potential semi-submersible drilling rig depending on the client's floating structure preference. Information could be requested to develop the design and assess the potential for redeployment of the Voyageur or Hummingbird Spirit.

Further investigation as to how much space would need to be set aside for storing net zero fuels and what the impact would be on the distribution hub floating structure could be completed to demonstrate the future potential of meeting net zero goals.

The GHG emissions estimate has made some 'generalised assumptions' in calculating GHG emissions and can be considered conservative. These estimates could be refined relative to a particular client's project amongst other aspects such as optimising the number of supply vessels.

Further investigation could be conducted into the emissions reduction potential of installing one of Value Maritime's 'Filtree units' on the back-up power generators. As one of the back-up power generators will be operating constantly as a spinning reserve, it may make sense to have one of the Value Maritime's units abating these emissions.

15.4 Wind farm design

The wind farm design needs to be developed in conjunction with the wind farm developer. Some of this will be completed in a subsequent revision of this report [See HOLD in Section 7.7]. Once this is completed further definition on what may be required in the next stage will be available.

As part of any future studies or engineering phases it would be recommended to approach vendors capable of completing ornithological and marine surveys which will need to be completed in order to obtain the wind farm licenses. A better of understanding of how the data that will be used in these studies can be obtained and collected.

15.5 CAPEX estimations

With increased engineering definition the CAPEX estimate can be refined, giving greater certainty over the project economics.

If the microgrid is to be resized for a particular client project, then the CAPEX estimate for the new microgrid will be needed.

15.6 Brownfield modifications

The oil and gas production facilities that the microgrid supplies power to will no longer have the use of waste heat. Not only are there potential modifications to the existing electrical systems but the existing process facilities need to be reviewed to ensure that they are efficient in their use of energy and what equipment needs to be replaced or what new equipment is required needs to be identified. It is recommended that once a client is identified a high-level overview of their facilities is conducted outline the potential changes required.

16 Comparison to power from shore

The Microgrid concept is an off-grid option which can be compared to Power from Shore (PfS) concepts studied by other industry groups. One of the key purposes of this document is to provide operators with the data to evaluate this approach to electrifying platforms. For simplicity, this comparison will focus upon a 250MW development, proposed by another industry group investigating PfS, covering Microgrids A, C, and D, the platforms included in the comparison are Elgin/Franklin, ETAP, Shearwater, Gannet, J- Area, MonArb, Stella, Lomond and Culzean. To develop this comparison, PfS data from other industry group has been utilised in conjunction with the Microgrid concept data within this report.

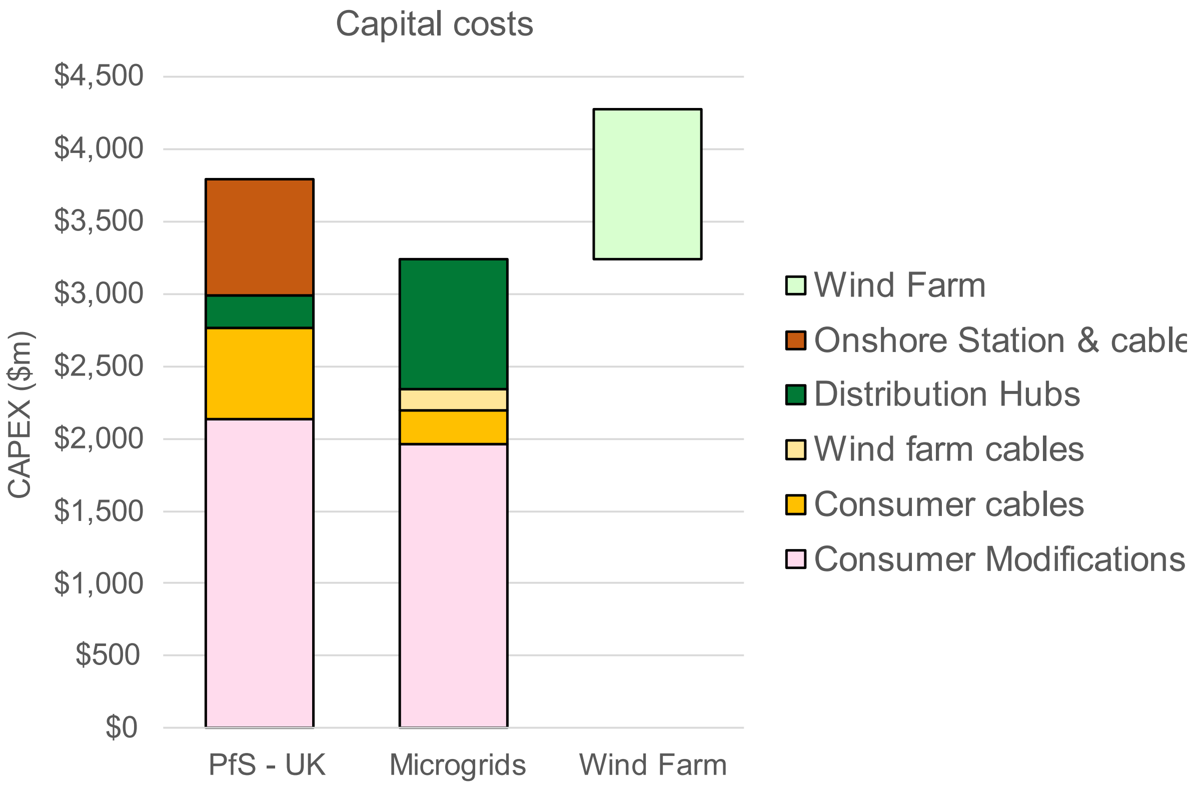


Figure 16-1: CAPEX comparison of electrification concepts

Figure 16-1 provides the CAPEX breakdown for the Microgrid concept and an industry PfS – UK option. A Norwegian option is considered highly unlikely to garner political support in Norway. The CAPEX component for PfS option can be broken down into three categories;

- **Distribution hub and cable to shore,**
  This includes all the cost necessary to install a HVDC link between an onshore converter station and an offshore converter station including a new fixed platform. This does not include the purchase cost of onshore land, nor the cost of any national grid reinforcement to supply 250MW. The offshore platform, or distribution hub is shown separately.
- **Cables to consumer,**
  This is the cost of the cabling from the offshore distribution hub to the consumer. This assumes the same nine facilities will be served as Microgrids A, C and D.

- **Consumer modifications.**
  The costs for partial or full electrification of individual platforms within the North Sea. This assumes the same facilities as Microgrids A, C and D.

The Microgrid CAPEX data is taken from the relevant sections within this report, the cost data utilises the mean costs from any probabilistic cost estimates. The only modification is to the distribution hub cost, where a 5% reduction has been applied to distribution hubs C and D, as it is expected that lessons learned from the first distribution hub will result in cost savings for subsequent units. The full capital cost of the wind farm is shown separately on the chart as the wind farm could either be funded by a third party and power purchased from that wind farm Operator, or be treated as a capital cost item.

As shown by Figure 16-1, on a like-for-like CAPEX basis, the Microgrid concept is significantly cheaper than a PfS option, given that the PfS option only enables consumers to purchase power from the grid, not generate it. Inclusion of the full cost of the wind farm incrementally increases the CAPEX of electrifying North Sea facilities; in this case there is a 10% increase compared to PfS – UK. This incremental increase is offset manyfold by the reduction in operating costs and the ability to reuse or redeploy both the wind farm and distribution hub once production from O&G consumers ceases. By comparison, PfS concepts cannot be redeployed in the same manner, limiting the ability to recoup the CAPEX expenditure.

An estimate has also been made of the costs of operating the current system, Orcadian does not have access to the detailed operator data, which would be required to estimate this accurately, but we have used parameters which we believe are not unreasonable. The methodology followed was to include the potential operating and maintenance cost savings noted for the nine platforms noted by other industry groups investigating PfS. Not all platforms indicated a potential saving, indicating that this approach potentially underestimates the full scope of savings possible.

For both emissions and gas costs we based our estimate upon the NZTC's estimate for the efficiency of a real world, and well used OCGT system, with emissions per MWh around 700 kgCO2/MWh. This allowed us to calculate both emissions and gas costs.

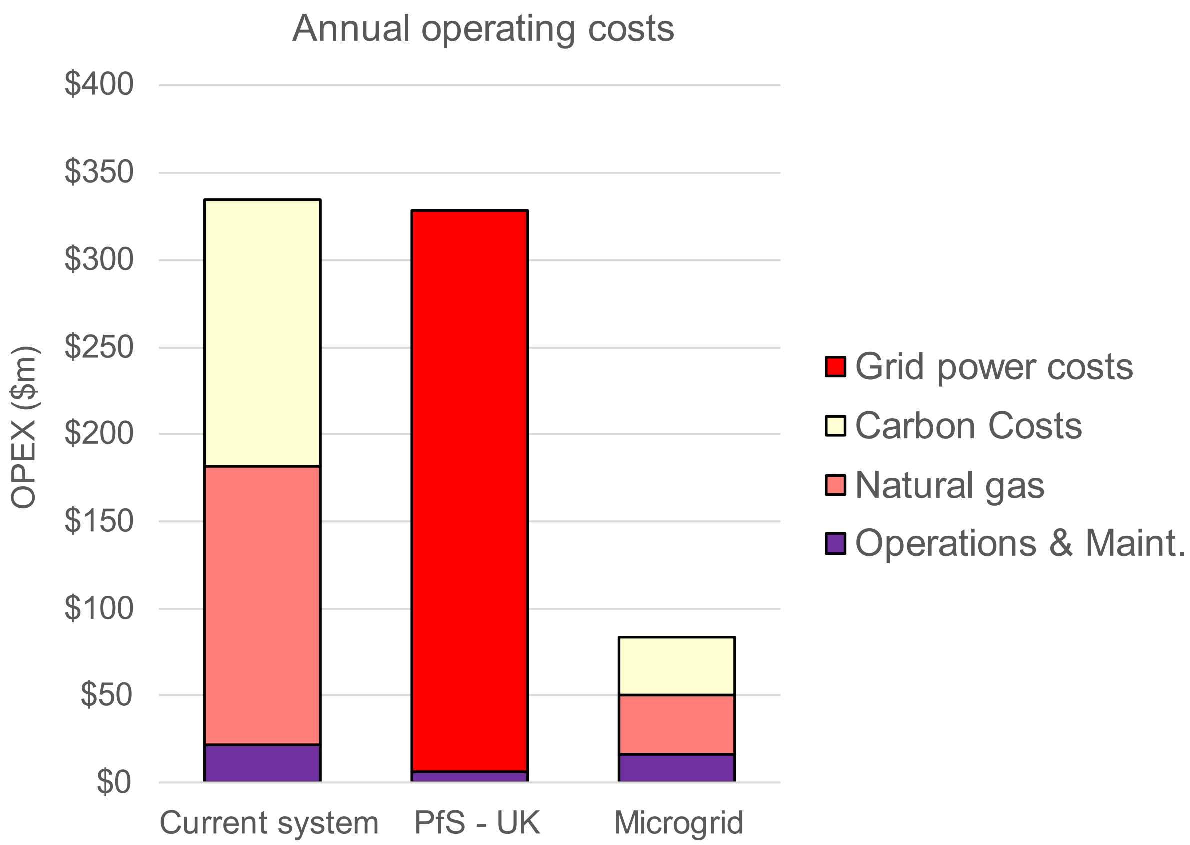


Figure 16-2: OPEX comparison of electrification concepts

Figure 16-2, provides the OPEX estimates for the different concepts. The estimate of operating costs for the PfS concept includes the cost of purchasing power, and we have made a modest allowance for operations and maintenance of the onshore and offshore converter stations.

As Figure 16-2 demonstrates, assuming the wind farm is a capital item, the OPEX for the Microgrid concept is significantly less than either the power from shore option or the current system. This is due to the use of the wind farm to provide the majority of power, with gas only utilised for back-up generation.

The prices of natural gas (50p/therm), emissions levies ($100/tonne), and wholesale electricity costs (£110/MWh, UK) are aligned with other industry group reports on offshore electrification, although clearly these costs have risen significantly in recent times.

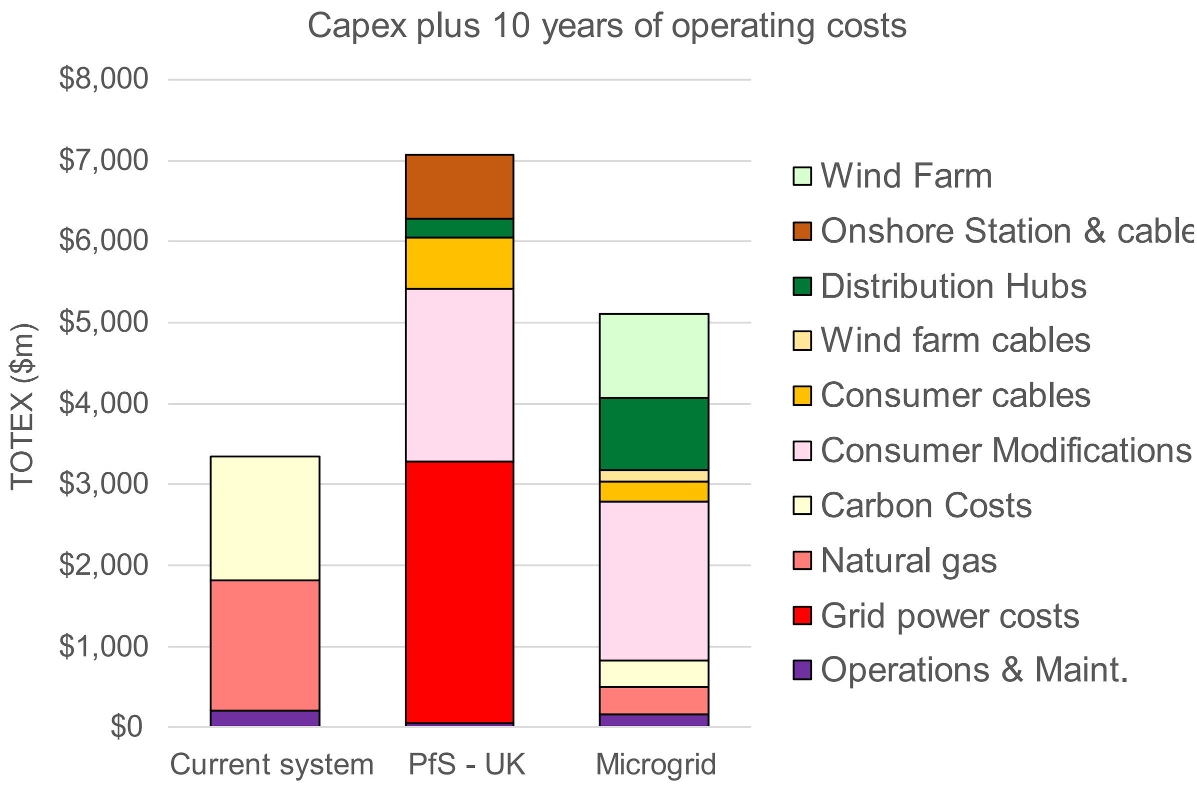


Figure 16-3: TOTEX comparison of electrification concepts

TOTEX over a 10-year field life is provided for each concept in Figure 16-3, this demonstrates a 26% reduction compared to PfS-UK. In addition, at COP of the oil and gas consumers' the Microgrids can be reused or redeployed as detailed in section 13 , whereas only the cable in the PfS option has any scope for reuse.

17 Conclusion

The microgrid solution proposed by Orcadian delivers a practical and achievable solution, which will enable Operators to meet their commitments under the North Sea Transition Deal: the key benefits of the Orcadian solution are:

- Emissions reductions – approaching an 80% reduction
- Lower costs – saving over $2 billion and more than 30% cheaper than the power from the UK grid option when capital, and ten years of operating costs, are included
- A practical way for operators to meet their North Sea Transition Deal commitments
- Deliverable quickly and in phases – allows a staged deployment with a steadily improving reduction in emissions
- Opportunities for re-use or redeployment – provides legacy infrastructure for the grid and/or other users.

To deliver this solution in a timely fashion an early commitment to support the development of the project will be sought from potential customers. The Orcadian consortium will develop a scope of work for the concept development, INTOG application and pre-FEED work and the opportunity to fund and to participate in this work will be offered to potential customers, who will then have the option to participate in the FEED phase, which will be designed to deliver a sanctionable project. This proposal will be prepared separately from this report.

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Appendix A CAPEX Data

A.1 Microgrid estimates – BPT buoy

A.1.1 Microgrid A

System	Component	CAPEX ($)	Uncertainty
Vessel as-is	Hull construction	43,787,675	Moderate
	Hull Engineering & Management	22,273,375	Moderate
Mooring system	Submerged Equipment and mooring lines	11,279,568	Moderate
	PM&E	2,255,914	Moderate
Topsides	Materials	79,944,306	*
	Fabrication	23,510,272	High
	Freight (Assumed 7%)	5,596,101	Moderate
	Topsides Engineering	16,121,330	Moderate
	Integration & commissioning	10,013,761	High
	Insurance & certification	6,759,289	Moderate
Cabling	Cabling cost between hub and consumers	143,599,800	Low
	Cabling cost between Wind farm and hub	56,280,000	Low
	Cable floats	388,920	High
Gas tie in	Gas Import 6"	10,940,000	Low
Wind farm (120%)	Floating wind farm	363,300,000	Low
Other project costs	Classification & insurance	1,883,497	Moderate
	Transport & transit	4,709,000	Moderate
	Owners site supervision	18,396,000	High
	Owners project management	15,686,580	Moderate
	Riser and umbilical (Exc)	21,500,000	Moderate
	Installation	6,284,000	High

A.1.2 Microgrid C

System	Component	CAPEX ($)	Uncertainty
Vessel as-is	Hull construction	43,787,675	Moderate
	Hull Engineering & Management	22,273,375	Moderate
Mooring system	Submerged Equipment and mooring lines	11,279,568	Moderate
	PM&E	2,255,914	Moderate
Topsides	Materials	86,986,962	*
	Fabrication	25,206,022	High
	Freight (Assumed 7%)	6,089,087	Moderate
	Topsides Engineering	15,555,717	Moderate
	Integration & commissioning	10,845,296	High
	Insurance & certification	7,320,575	Moderate
Cabling	Cabling cost between hub and consumers	16,680,000	Low
	Cabling cost between Wind farm and hub	32,510,00	Low
	Cable floats	250,020	High
Gas tie in	Gas Import 6"	10,526,400	Low
Wind farm (120%)	Floating wind farm	363,300,000	Low
Other project costs	Classification & insurance	1,883,497	Moderate
	Transport & transit	4,709,000	Moderate
	Owners site supervision	18,396,000	High
	Owners project management	15,686,580	Moderate
	Riser and umbilical (Exc)	21,500,000	Moderate
	Installation	6,284,000	High

A.1.3 Microgrid D

System	Component	CAPEX ($)	Uncertainty
Vessel as-is	Hull construction	43,787,675	Moderate
	Hull Engineering & Management	22,273,375	Moderate
Mooring system	Submerged Equipment and mooring lines	11,279,568	Moderate
	PM&E	2,255,914	Moderate
Topsides	Materials	86,986,962	*
	Fabrication	25,206,022	High
	Freight (Assumed 7%)	6,089,087	Moderate
	Topsides Engineering	15,555,717	Moderate
	Integration & commissioning	10,845,296	High
	Insurance & certification	7,320,575	Moderate
Cabling	Cabling cost between hub and consumers	91,770,000	Low
	Cabling cost between Wind farm and hub	56,280,000	Low
	Cable floats	388,920	High
Gas tie in	Gas Import 6"	17,688,000	Low
Wind farm (120%)	Floating wind farm	363,300,000	Low
Other project costs	Classification & insurance	1,883,497	Moderate
	Transport & transit	4,709,000	Moderate
	Owners site supervision	18,396,000	High
	Owners project management	15,686,580	Moderate
	Riser and umbilical (Exc)	21,500,000	Moderate
	Installation	6,284,000	High

A.1.4 Microgrid E

System	Component	CAPEX ($)	Uncertainty
Vessel as-is	Hull construction	43,787,675	Moderate
	Hull Engineering & Management	22,273,375	Moderate
Mooring system	Submerged Equipment and mooring lines	11,279,568	Moderate
	PM&E	2,255,914	Moderate
Topsides	Materials	77,742,114	Low
	Fabrication	22,980,022	High
	Freight (Assumed 7%)	5,441,948	Moderate
	Topsides Engineering	14,181,957	Moderate
	Integration & commissioning	9,753,745	High
	Insurance & certification	6,583,778	Moderate
Cabling	Cabling cost between hub and consumers	48,340,000	Low
	Cabling cost between Wind farm and hub	53,110,000	Low
	Cable floats	472,260	High
Gas tie in	Gas Import 6"	22,780,000	Low
Wind farm (120%)	Floating wind farm	295,500,000	Low
Other project costs	Classification & insurance	1,883,497	Moderate
	Transport & transit	4,709,000	Moderate
	Owners site supervision	18,396,000	High
	Owners project management	15,686,580	Moderate
	Riser and umbilical (Exc)	21,500,000	Moderate
	Installation	6,284,000	High

A.1.5 Microgrid F

System	Component	CAPEX ($)	Uncertainty
Vessel as-is	Hull construction	43,787,675	Moderate
	Hull Engineering & Management	22,273,375	Moderate
Mooring system	Submerged Equipment and mooring lines	11,279,568	Moderate
	PM&E	2,255,914	Moderate
Topsides	Materials	96,289,954	*
	Fabrication	27,446,022	High
	Freight (Assumed 7%)	6,740,297	Moderate
	Topsides Engineering	16,938,117	Moderate
	Integration & commissioning	11,943,712	High
	Insurance & certification	8,062,006	Moderate
Cabling	Cabling cost between hub and consumers	106,560,000	Low
	Cabling cost between Wind farm and hub	80,050,000	Low
	Cable floats	527,820	High
Gas tie in	Gas Import 6"	17,688,000	Low
Wind farm (120%)	Floating wind farm	415,2000,000	Low
Other project costs	Classification & insurance	1,883,497	Moderate
	Transport & transit	4,709,000	Moderate
	Owners site supervision	18,396,000	High
	Owners project management	15,686,580	Moderate
	Riser and umbilical (Exc)	21,500,000	Moderate
	Installation	6,284,000	High

A.1.6 Microgrid G

System	Component	CAPEX ($)	Uncertainty
Vessel as-is	Hull construction	43,787,675	Moderate
	Hull Engineering & Management	22,273,375	Moderate
Mooring system	Submerged Equipment and mooring lines	11,279,568	Moderate
	PM&E	2,255,914	Moderate
Topsides	Materials	86,986,962	*
	Fabrication	25,206,022	High
	Freight (Assumed 7%)	6,089,087	Moderate
	Topsides Engineering	15,555,717	Moderate
	Integration & commissioning	10,845,296	High
	Insurance & certification	7,320,575	Moderate
Cabling	Cabling cost between hub and consumers	81,130,000	Low
	Cabling cost between Wind farm and hub	80,050,00	Low
	Cable floats	444,480	High
Gas tie in	Gas Import 6"	31,356,000	Low
Wind farm (120%)	Floating wind farm		**
Other project costs	Classification & insurance	1,883,497	Moderate
	Transport & transit	4,709,000	Moderate
	Owners site supervision	18,396,000	High
	Owners project management	15,686,580	Moderate
	Riser and umbilical (Exc)	21,500,000	Moderate
	Installation	6,284,000	High

* Uncertainty applied for each material line item

** Assume connection GreenVolt wind farm

Appendix B Emissions classification

System	Emission source	Scope 1	Scope 2	Scope 3	Notes
Hub	Construction			✓	Construction of the unit insourced by Company for own use.
	Mooring system			✓	Mooring system for the unit insourced by Company for own use.
	Transportation			✓	Transportation of the unit insourced by Company for own use.
	Installation – Hub, mooring & cable pull in			✓	Outsourced to subcontractors by the company.
Wind farm	Construction			✓	Construction of the unit insourced by Company for own use.
	Mooring system			✓	Mooring system for the unit insourced by Company for own use.
	Transportation			✓	Transportation of the unit insourced by Company for own use.
	Installation			✓	Outsourced to subcontractors by the company.
	Operation & Maintenance			✓	Outsourced to subcontractors by the company.
Cabling	Hub to consumer Construction & installation			✓	Insourced by Company for own use.
	Wind farm to hub Construction & installation			✓	Insourced by Company for own use.
Operations	Back-up Power generation	✓			Direct emission from unit operation.
	Flaring – Emergency	✓			Direct emission from unit operation.
	Venting – Back-up generation	✓			Direct emissions from unit operation.
	Supply vessels			✓	Outsourced to subcontractors by the company.
	Personnel transport			✓	Employee travel on third party vessels, chartered aircraft etc.

Appendix C Wind power solution providers in development

The following section contains a description of the technologies that have been considered too immature in development for the project timeline at present. The technologies are promising and depending on how quickly they develop they could be considered for the project at a later stage.

C.1 Seawind

The Seawind Ocean Technology company, in its current form, was set-up in the Netherlands in 2014. The core of the Seawind system is the proprietary two blade upwind rotor with a teetering hinger. Teetering hinges are common in two bladed helicopter rotors designs, where the hinge connects the rotor blade to the hub and allows the blade to rise and fall (i.e., flap during rotation). This permits the equalisation of lift (or rotor thrust) between the advancing-blade half and the retreating-blade half of the rotor disc.

Teetering hinge rotor design in wind turbines dates back to the 1974 – 1981 NASA wind energy program. Part of the NASA team was Glidden Doman, who previously worked for Sikorsky Aircraft where he developed a tilting rotor hub. He later developed a number of successful land-based wind turbines, culminating in the 1.5MW Gamma 60 Project for a consortium of Aeritalia, Fiat Aviazione and ENEA in 1986. The Gamma system featured a teetering hub and came into service in Sardinia, Italy in 1992.

The rights for the Gamma technology were acquired by Doman and Silvestro Carusi in 2004. The design was further developed, and the rights eventually transferred to Seawind Ocean Technology.

The Seawind system teetering hinge allows the plane of the rotor to freely tilt relative to the nacelle. The design of the shore-based rotor unit has gone through extensive analysis and is proven on land based developments. The marine variant is far less mature.

DNV have completed a technology qualification report (excluding blades and support structure) in 2019. Extension of technology qualification to blades and support structure were due for submission to DNV in February 2022. Teeter hinge mock-up tests and system mock-up tests in a test basin are scheduled for Q4 2022.

Figure 18-1 Seawind teetering hinge rotor design (29)

The support structure is a novel concrete / steel concept. The construction methodology has been developed, but is untried and requires access to floating docks, a concrete production plant and attendant construction support facilities (e.g., storage, craneage etc.,). The Seawind platform structure is based on the adoption of special mix concrete mix which does not require reinforcements but only microfibers. This option is still being studied by Cemex.

Although there is available data for the shore units already in operation, and there have been concept design analysis completed, an aggressive testing and development plan is required to progress the floating solution proposed by SeaWind. Scale model testing will not be completed until the end of 2022, and offshore type testing on the smaller, 6.2 MW design unlikely to be completed before mid-2025. It is highly unlikely that adequate testing and experience of the 12.2 MW design will have been gained by the 2027 deployment envisaged for the initial Orcadian deployment.

Two laser sensors (Lidar) are used to detect extreme wind gusting. The Lidar / yaw system interface will require comprehensive testing in operation.

C.2 Wind Catching Systems

Wind Catching Systems, in collaboration with Aibel and the Institute for Energy Technology, IFE, is developing a floating multi-turbine technology consisting of several 1 MW turbines. The technology will cut acreage use by more than 80% and increase efficiency significantly in comparison to conventional floating offshore wind farms. The company's main owners, apart from the founders, are Ferd and North Energy. Wind Catching Systems was founded in 2017.

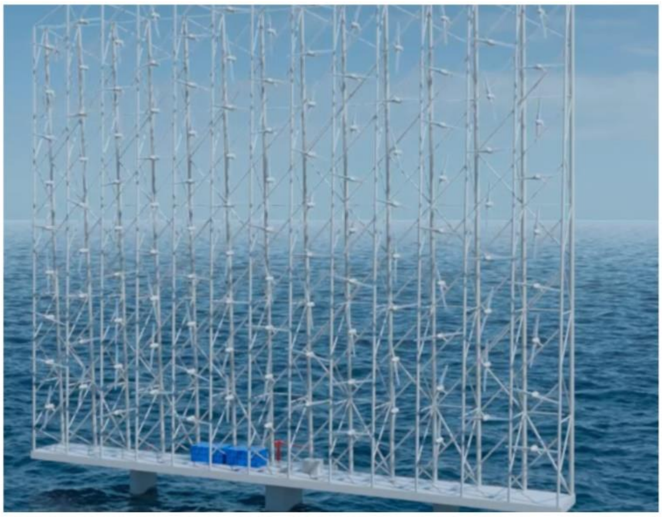

Figure 18-2 Wind Catching floating multi-turbine technology (30)

This would be Wind Catching Systems first commercially operational unit and identification of the actual suppliers within the supply chain is proposed to be done as part of the project.

The various elements of the system configuration are based on technology that has been well proven elsewhere, however not in the combined format of the their proposal. Therefore, although technically feasible the proposal still offers interface and supply / availability risks that have not been defined or mitigated.

The main turbine arrays completed wind tunnel testing in July 2021. Arrays of 2 to 14 rotors were tested, assessing blade tip spacing, rotor/frame interaction, multi-turbine effect gain and wake effects.

An ambitious development plan is proposed to meet a commencement of commercial operations target of mid-2026. To meet this target date a number of systems must be developed in parallel. Further development includes:

- Nacelle prototype development programme:
    - Q1 2022 Concept development
    - Q2 2022 Basic Design
    - Q3 2022-Q1 2023 Prototype fabrication, assembly and FAT
- CFD model development
    - During Q1 and Q2 2022, WCS will perform an extensive CFD development including rotor/frame interaction, multi-turbine effects, wake, vibrations, frame drag, etc.
    - Ocean basin/pool test

During Q3 2022 model test is planned in a large ocean basin with the facility to generate multi-directional waves, current and wind. The purpose of the test is to validate the various numerical models, to gain further understanding in transient yaw effects, and to demonstrate the feasibility of the technology to key stakeholders/government entities.

C.3 SeaTwirl

SeaTwirl's wind turbines use a vertical-axis wind turbine with a tower connected to the sub-sea structure, consisting of a floating element and a keel.

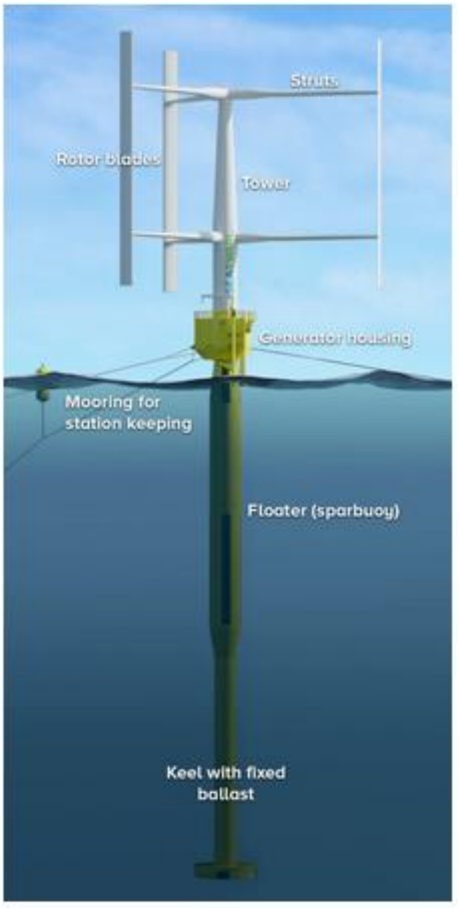

Figure 18-3 SeaTwirl vertical-axis turbine (31)

SeaTwirl has deployed a 30kW floating wind turbine close to shore off the coast of Lysekil, Norway, in July 2015 which has been successfully connected to the shore power grid.

In November 2021 SeaTwirl completed model tests of a 1:40 model of the SeaTwirl S2x. The S2 is a 1MW turbine also designed for a specific near shore location on the Norwegian west coast. SeaTwirl claim that the S2 is scalable to meet the Orcadian development requirements having been designed (though not certified) to DNV Class rules.

At the time of writing the report Crondall are awaiting details of a potential testing programme for a deep sea version of the technology.

C.4 Floating Power Plant

FPP has designed a floating semi-submersible platform that will host a single wind turbine from 4-15 MW and further supports 1-4 MW wave power. The principal components of FPP's hybrid floating wind and wave energy platform include the

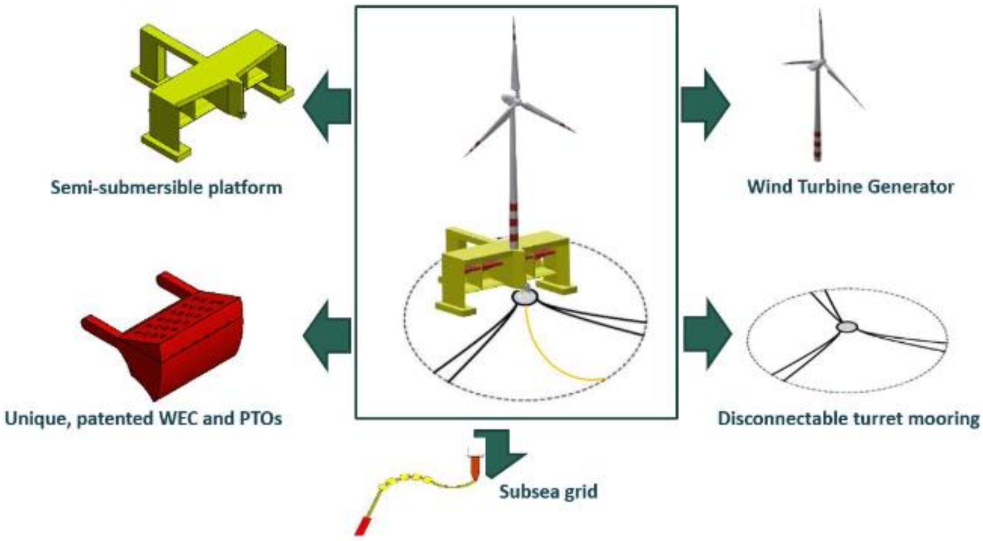

Figure 18-4 FPP Technology - Constituent Parts

In 2019 Floating Power Plant (FPP) signed a Memorandum of Understanding with The Oceanic Platform of the Canary Islands (PLOCAN) to investigate and develop a potential deployment of FPP's technology in the PLOCAN test facilities in Gran Canaria.

FPP and PLOCAN will work together to assess the test facilities and identify a suitable deployment location, before conducting the necessary site studies and licensing and consenting activities. PLOCAN will also assist FPP in establishing a new R&D subsidiary in Gran Canaria and establishing an operational plan. It is anticipated that this technology could be constructed and deployed at PLOCAN as early as Q1 2024.

Appendix D CAPEX summaries – Alternative structures

The CAPEX summaries for the alternative distribution hub structures, i.e. Semi-Submersible and Sevan are identified in the following table.

Microgrid	Distribution Hub CAPEX estimate (Semi sub)			Distribution Hub CAPEX estimate (Sevan)		
	P5%	Mean	P95 %	P5 %	Mean	P95 %
	(US $m)	(US $m)	(US $m)	(US $m)	(US $m)	(US $m)
A	426.8	453.9	487.8	479.7	509.2	544.2
C	334.9	352.7	372	386.7	407.2	430.1
D	413.4	436.8	463.8	463.3	491.5	523.3
E	361.4	381.8	403.7	414.8	436.4	459.8
F	439.7	468.2	500.7	492.3	522.8	555.3
G	417.4	440.6	465.4	469.6	495.1	526