Aberdeen Harbour Shore Power Demonstrator

Outline Business Case

0050506

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Contents

Table of Tables

Table of Figures

Glossary

Term	Definition
AHB	Aberdeen Harbour Board
BAU	Business as Usual
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
CAS	Clean Air Strategy
CCGT	Combined Cycle Gas Turbine
CMDC	Clean Maritime Demonstration Competition
CMP	Clean Maritime Plan
CPC	Connected Places Catapult
D&B	Design & Build
DBM	Design, Build and Maintain
DfT	Department for Transport
DNO	District network Operator
DPD	Detailed Project Development
DSV	Diving Support Vessel
GHG	Greenhouse Gas Emissions
HOTs	Heads of Terms
IMO	International Maritime Organisation
IRR	Internal Rate of Return
MCA	Multi-Criteria Analysis
MGO	Marine Gas Oil
MPSV	Multi-Purpose Supply Vessel
NPV	Net Present Value
O&M	Operation & Maintenance
OBC	Outline Business Case
OPEX	Operating Expenditure
PM	Particulate Matter
QA	Quality Assurance
REPEX	Replacement Expenditure
SE	Scottish Enterprise
SPV	Special Purpose Vehicle
TEM	Techno-Economic Model
VFM	Value for Money

1. Executive Summary

1.1. Project Overview

Aberdeen Harbour Board (AHB) have commissioned this outline business case (OBC) to assist the investment appraisal, due diligence and eventual delivery of a low carbon "demonstrator" shore power system for vessels at berth at selected areas of Aberdeen Harbour. Critical to the delivery of the project is access to external grant funding support which could come from the forthcoming DfT Clean Maritime Plan (CMP), anticipated to commence 2023 following a call for evidence process during 2022.

The OBC has been completed in the context of a Detailed Project Development (DPD) commission which includes design development to concept stage and in some areas detailed design and stakeholder consultation. The outputs can ultimately inform Employers Requirements documentation which can be used for procurement of contractors.

In 2021, Buro Happold Ltd (Buro Happold) along with the Tyndall Centre for Climate Change Research were commissioned to undertake a feasibility study to identify the best routes for Aberdeen Harbour to decarbonise. Following an assessment of carbon emissions across harbour operations and buildings it became apparent that 78% of all emissions from the port are the result of 3rd party vessels operating under engine to meet their own power needs whilst at berth and 97% of all Aberdeen Harbour emissions were derived from vessels either at berth or in transit within the Harbour. The feasibility study recommended the installation shore power equipment, making use of low carbon grid supplied power, across multiple quayside areas. Further funding was sought and secured from the Clean Maritime Demonstration Competition (CMDC) to identify a suitable area within the harbour to develop a shore power demonstrator project and produce an Outline Business Case (OBC).

Following an operator engagement process and assessment of shore power demands, five berths at Albert and two at Mearns on the Point Law Peninsula were identified as preferred areas for a shore power demonstrator project. This was primarily due to:

- Heavy vessel utilisation of the berths, with fewer operators
- External operator intent to move operations to the area in future
- Net zero aspirations of existing Point Law Peninsula operators. which has resulted in good buy-in
- Good duration of typical vessel visits, meaning less handling of shore power equipment per vessel charge

A supplier engagement process was undertaken which ultimately led to a preferred technical solution being identified, with a key driver being the need to minimise impact on existing quayside operations (i.e. loading / unloading of vessels and tracking of the quayside cranes). This then led to spatial coordination and technical development of the preferred shore power infrastructure, identification of the optimal commercial delivery models for AHB, full financial modelling and development of the management case.

The preferred shore power solution in its basic form includes:

- **A centralised "E-house"** which includes transforming and frequency conversion equipment within a series of prefabricated steel containers and situated on new concrete plinths away from quayside operations with good access to existing grid supplies. This grid power is stepped down at the E-house to lower voltages and the frequency converted to align with the vessel requirements.
- **Trenched low voltage cabling** which connects the E-house to a series of above ground "shore power connection boxes" at the quayside.
- **A series of manoeuvrable cable reels** which provide the final connection from the shore power connection point onto the vessels. These cable reels are housed in new storage building when not in use.

The main benefit of the system design is that it allows minimal infrastructure on the quayside and capacity has been built into the design for future cabling (i.e. to allow for vessel battery charging).

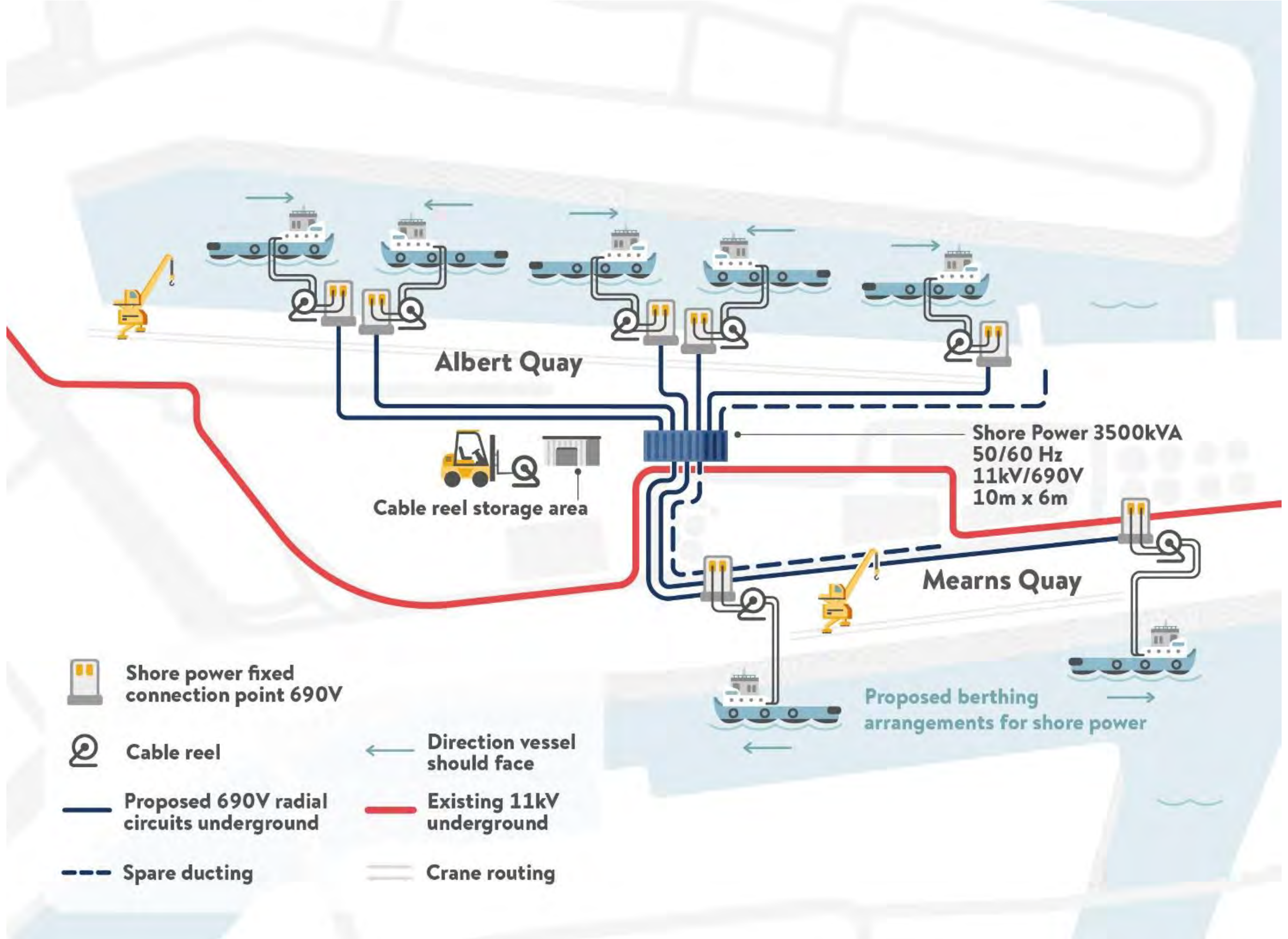


Figure 1—1 Illustration of shore power infrastructure at Albert and Mearns Quay

1.2. OBC Overview

The OBC has been developed based on the Five Case Model which includes a review of the Strategic, Economic, Commercial, Financial and Management cases for the progression of the delivery of shore power infrastructure.

The main project objectives prioritised during the progression of the project are as following:

1. Develop a business case for shore power which provides a low carbon solution to burning marine fuel whilst at berth for operators and Aberdeen Harbour that reduces the overall carbon emissions of Aberdeen Harbour by 10%.
2. Demonstrate a proof-of-concept shore power design and project blueprint for roll-out across the Harbour and other UK ports.
3. Provide evidence to inform future policy development on shore power within Scotland and the UK including the "Call for Evidence on Shore Power".
4. Contribute towards the Scottish/UK Government and Aberdeen Harbour's sustainability policies and carbon reduction targets.
5. Reduce carbon emissions and air pollutants into the local community, delivering a social benefit to Aberdeen.
6. Provide a shore power solution at Albert and Mearns Quay that minimises operational impact.
7. Provide shore power to users at a cost competitive to marine fuel.

1.2.1. Strategic Case

1.2.1.1. Overview

The proposals for a low carbon shore power solution at Point Law Peninsula present a significant opportunity for Aberdeen Harbour and Aberdeen city, to reduce its future carbon emissions and enhance its reputation, whilst acting as a demonstration for the UK on how a transition to a low carbon commercial harbour can be achieved.

The combination of ambitious stakeholders, a clear long-term masterplan and ownership structure make this shore power project an ideal test bed for the type of innovation and collaboration required to respond to the climate emergency.

1.2.1.1. Context

Countries and organisations around the world have declared a climate emergency in light of increasingly overwhelming scientific evidence of the detrimental effects humans are having on our planet. The UK and Scottish Governments have made a legal commitment to reach Net Zero by 2050 and 2045 respectively. To support continued economic growth, the UK and Scottish Governments have declared significant investment is to be made to support these Net Zero commitments.

In 2020 the UK's net territorial greenhouse gas emissions were 405.5 million tonnes carbon dioxide equivalent. The transport sector accounted for the largest proportion of carbon emission in the UK (24% of greenhouse gas emissions in the UK in 2020). Domestic shipping in 2020 accounted for 5.3 $MtCO2_e$ and international shipping in 2020 accounted for 6.1 $MtCO2_e$.[1] Additionally, shipping makes significant contribution to nitrogen oxides (NOx), sulphur dioxide (SO_2) and primary $PM_{2.5}$ and PM_{10} (particulate matter, PM with diameter less than 2.5 micrometres and 10 micrometres respectively) emissions. These primary and secondary pollutants derived from shipping emissions contribute to adverse human health effects, as well as environmental damage.

It is widely acknowledged that shore power can make an important contribution to decarbonising the shipping sector and improving the air quality for local communities. Currently, vessels run their onboard diesel engines whilst at berth, to power amenities. Shore power would allow vessels to turn off their engines and plug into onshore power sources when berthed, reducing carbon emissions, noise and air pollution. Shore power technology is established in many ports across the globe, particularly in regions such as Scandinavia where lower cost of electricity, supporting policies and capital funding mechanisms for shore power allow for greater adoption of this technology.

Within the Sixth Carbon Budget the UK Government projects that in order to achieve net zero by 2050, approximately 13% of emissions reduction in shipping would be delivered through efficiency and electrification, with the remaining emissions saving delivered through the development of zero-carbon fuels. The Sixth Carbon Budget projects that by 2050, 3 TWh/a of electricity would be used in electric propulsion and shore power, compared to 0.2 TWh/a in the baseline.

In May 2021 Buro Happold and Tyndall Centre for Climate Change Research completed a feasibility study on the decarbonisation strategy of Aberdeen Harbour. It was estimated ca. 44,000 tCO_2/a of carbon emissions are produced throughout the port every year. The study determined that 78% of emissions were derived from ships using marine fuels while at berth, 19% for vessels in transit within port limits (2km) and just 3% from use of electricity and gas on the port estate i.e. buildings. Therefore, it was evident that reducing vessel emissions whilst at berth, by building shore power capability at Aberdeen Harbour, should be the priority focus area to reduce port emissions.

The societal cost associated with the carbon emissions and air pollutants that are generated by ships whilst at berth was calculated to be in the region £7.5M per annum. However, with recent changes to the Government's methodology for calculating carbon value (June 2021), the societal cost is estimated to be in the region of £14M per annum in 2024.

[1] DEPRATMENT FOR BUSINESS, ENERGY & INDUSTRIAL STRATEGY, 2022, 2020 UK Greenhouse Gas Emissions, Final Figures.

1.2.1.2. Guiding principles for AHB

AHB are committed to decarbonising their operations and providing infrastructure for their customer to decarbonise their operations. This is evident from their strategy which sets out the harbour's purpose, mission and vision:

- Purpose – creating prosperity for generations
- Mission – to connect our customers to what they need, where and when they need it
- Vision – to become Scotland's premier port, offering world class facilities to national and international customers and stakeholders

Additionally Aberdeen Harbour's strategy states the following in relation to the climate and emissions:

- We have a significant responsibility to protect the natural resources of the harbour and adjacent coastal region, protecting these environmental assets, to deliver benefits to the community and ensure long-term sustainability in all its dimensions
- We aim to become an exemplar in environmental stewardship and sustainability leadership, pioneering green port innovation and facilitating energy transition solutions
- We aim to encourage port business to adopt sustainable approaches and to encourage innovation in design, operation towards net zero and reduce all the dimensions and metrics of the environmental footprint
- We will continually strive to improve and grow our services.

It is evident that developing shore power capability within Aberdeen Harbour is consistent with the Port's strategy:

- Many port users of the Harbour are requesting shore power infrastructure within the port. Therefore, implementing shore power would align with the mission to connect customers to what they need, where and when they need it. It would also align with the Port's vision to offer world class facilities.
- Shore power delivers a clear carbon benefit and air quality benefit to the community and environment and helps meet the objectives of the Scottish and UK Government's Climate Change strategies.
- Shore power is a mature technology but underutilised within the UK. Aberdeen Harbour could use this technology to create a blueprint for decarbonising ports across the UK and further reduce the carbon footprint.
- Shore power increases the low carbon service offering available at Aberdeen Harbour.

1.2.1.3. The do-nothing approach

The do-nothing approach for Aberdeen Harbour would means vessels continue using marine fuel oil whilst at berth, as no low carbon alternative would be available. Implementing shore power infrastructure at the Albert and Mearns Quay berths within Aberdeen Harbour makes strategic sense for the following reasons and the alternative do-nothing approach would be a significant opportunity missed for the Port:

1. Albert and Mearns Quays have a large energy demand and a small number of high frequency visitors, who are committed to climate change commitments and are willing to implement the appropriate infrastructure on their vessels.
2. Operators within both quay's have requested shore power infrastructure within Aberdeen, meaning there would be a high likelihood that shore power would be heavily utilised.
3. A shore power development project could form the basis of a blueprint for the decarbonisation of ports across the UK.
4. Implementing shore power within Albert and Mearns Quay could reduce the Harbour's emissions by ~3,500 tCO2/a and presents a societal value of £800,000 per annum.
5. Marine fuel oil has approximately doubled in price within the last year[2]. Marine fuel could further increase in price if carbon taxation is applied, narrowing the price gap with electricity.

[2] https://shipandbunker.com/prices#MGO [Accessed 4th March 2022]

1.2.1.4. Key constraints and dependencies

There are a number of key constraints and dependencies which have been and will continue to be considered in the further progression of the project, these are summarised as follows:

Key constraints:

1. **Electricity grid constraints** – There are currently no significant costs impacting the project related to upgrades within the electricity grid. However, this could be an issue for the Harbour in the future if they look to expand their shore power offering to all areas within the port.
2. **Cable routing constraints** – various hazards were identified when completing a spatial coordination assessment of existing utilities and proposed cable routing for shore power infrastructure. These include crossing the mains sewer on North Esplanade East, crossing fuel lines on Albert Quay and North Esplanade East and crossing drainage channels on Albert Quay. Additionally, an overground solution is suggested for Mearns Quay, due to the deck being of suspended construction. Further detail of these constraints, risks and mitigations are provided within Appendix E.

Key dependencies:

The success of the shore power project is dependent upon the following:

1. Formal commitment for usage of shore power by vessel operators on Albert and Mearns Quay.
2. Securing suitable grant funding to allow for a competitive shore power sales price to be achieved vs marine fuel.
3. Identifying a delivery partner(s) whose internal rate of return (IRR) expectations for the project allows for cost competitive shore power sales prices to be offered to users.
4. Procuring shore power infrastructure from suppliers at a competitive capital cost that allows for competitive shore power sales prices to be offered to users.
5. Procuring an electricity purchase price from the UK grid that allows for competitive shore power sales prices to be offered to users.
6. Future marine fuel oil prices and carbon taxation.

1.2.2. Economic Case

1.2.2.1. Overview

During the design development and completion of the techno-economic model for the project a number of critical success factors were identified and became the cornerstone to the progression of the project:

1. Develop a business case for shore power which provides a low carbon solution to burning marine fuel whilst at berth for operators and Aberdeen Harbour that reduces the overall carbon emissions of Aberdeen Harbour by 10%.
2. Provide a shore power solution at Albert and Mearns Quay that minimises operational impact.
3. Provide shore power to users at a cost competitive to marine fuel.
4. Develop a blueprint for shore power implementation within Aberdeen Harbour that can be applied to the rest of the UK.
5. Provide fair and transparent allocation of shore power costs.
6. Transfer the delivery risk of the project where possible and mitigate risk as much as practicable.
7. Reduction of capital investment where possible, whilst ensuring project quality.
8. Transfer of operating risk where possible through O&M procurement.
9. Develop a resilient low carbon shore power supply to the site.
10. Futureproof for potential increased power requirements i.e. battery charging capability

1.2.2.2. Business as usual

To ensure the benefits of the shore power systems could be assessed it was necessary to confirm the counterfactual technologies for vessels at berth and outline the benefits of the shore power.

Traditionally, when ships are in port, they use their auxiliary engines to provide power for the ship's operations. This is sometimes known as cold ironing.

Business as usual (BAU) for Point Law Peninsula would involve the ships leaving their engines running whilst in berth to ensure power is available for the ship systems. This engine operation would mean greater emissions from the vessels whilst in port, contributing to global warming, as well as noise and air pollution within Aberdeen, which negatively impacts vessel crews, landside operators and the wider community.

1.2.2.3. Design development

The design development of the system included supplier engagement for key components and plant, as well as spatial coordination of key infrastructure around the quay. The resultant scheme is represented by a series of engineering drawings which will form the basis of the Employers Requirements which will be issued for tender subject to required approvals from AHB. The system design is shown in simplified form in Figure 1—1 which splits the system in to four distinct parts:

1. Centralised shore power E-house with grid connection
2. Trenched LV cabling from the E-house to the shore power connection points
3. Fixed above ground connection point
4. Shore side flexible cable reel

Figure 1—2 shows the equipment required by the standard BSEN80005-3 to connect a ship to a shore power supply system when the frequencies of ship and shore are the not the same.

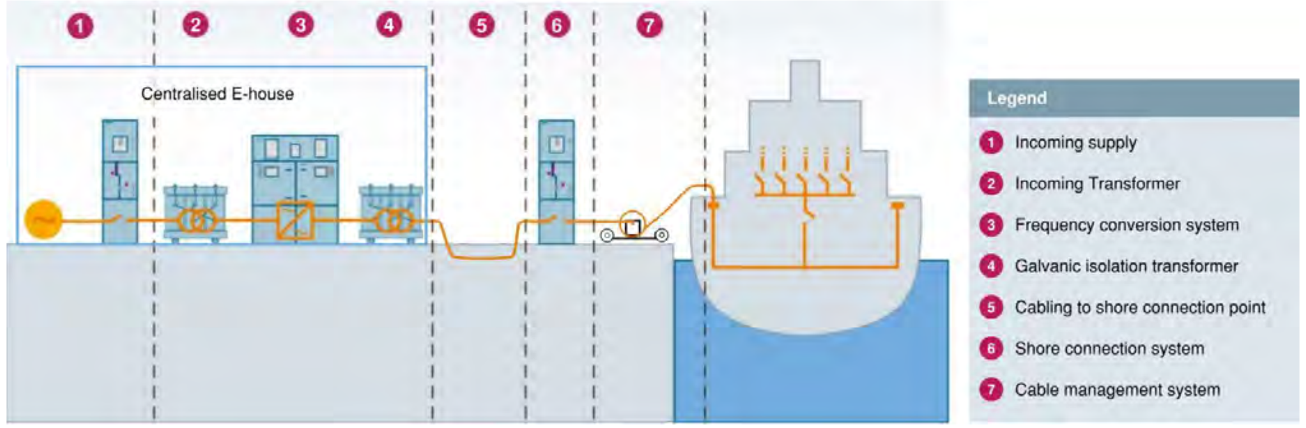


Figure 1—2 Block diagram of typical Low Voltage shore power connection system

The centralised shore power E-house option is feasible at a distribution voltage of 690 V, as this voltage reduces the cable losses encountered during distribution to the shore connection points. At this voltage shore connection points have power output up to 836 kVA, which provides a level of future proofing for battery charging or larger vessel power demand.

A fixed shore connection point was chosen to the ease of maintenance and operability. Also, if the location of this infrastructure is specifically designed to minimise operational impact it is deemed to be a more preferred solution for Aberdeen Harbour. The mobile cable reel connection system was preferred due to the flexibility this offered and to reduce space take on the quayside that could limit or constrain crane operations whilst not in use.

The centralised shore power E-house that would likely be a containerised solution with a space take of 10m × 6m. Power would be distributed underground to seven fixed connection points, that would be connected to vessel via a mobile cable reel. These cable reels would be stored in a central storage area while not in use. For the preferred solution the following points should be noted:

1. To reduce excavations through the reinforced concrete deck slab fixed connection points at Albert Quay are positioned in three locations (Figure 1—1). This allows for the cabling of two connection points to be completed within the same excavation channel. Therefore, there is a proposed berthing arrangement for the ships if they were connecting to shore power.
2. The fixed shore connection points on Albert Quay are as close to the quay edge as practicably possible, enabling the quayside crane to move up and down the quay. However, due to the suspended deck construction on Mearns Quay these connection points have to be set back on the quay, as excavations within the suspended deck could impact the structural integrity of the quay. Therefore, shore power connections points have been positioned at either end of the quay to allow for movements of the crane whilst in operation.
3. Spare ducting capacity within the trenched cabling has been designed to allow for future shore power / battery charging expansion.

Figure 1—3, Figure 1—4, Figure 1—5 and Figure 1—6 are 3D render images of the proposed shore power infrastructure at Albert and Mearns Quay.

Figure 1—3 Shore power infrastructure on Albert Quay. Ground scarring showing LV cabling route to shore power connection point

Figure 1—4 Shore power infrastructure on Mearns Quay. Ground scarring showing LV cabling route to shore power connection point

Figure 1—5 Centralised shore power E-house

Figure 1—6 New cable reel storage area

1.2.2.4. Techno-economic modelling outputs

The economic modelling completed was used to initially consider the optimised technical solution but also enable sensitivity analysis prior to the more detailed financial modelling being completed. These results were preliminary and the financial model and case represent the final position.

Through this process it was clear that the electricity grid power import costs (fuel cost) and shore power sales price were key sensitivities in the success of the system vs. the agreed 9% IRR to be achieved following 20 years of operation.

The results show that to achieve an IRR exception of 9% the mark-up price needed would be 14.02 p/kWh, equating to a shore power sales price of 29.05 p/kWh.

Table 1—1 Summary of techno-economic results

	Scenario – Albert 5 / Mearns 2
Total CAPEX	£7.99M
Average OPEX per year	−£0.81M
Average REPEX per year	−£26k
Average revenue per year	£1.40M (£360k Y1; £730k Y2; 1.07M Y3; 100% utilisation Y4-Y20)
Shore power sales price	29.05 p/kWh (26.95 p/kWh for a 40-year term)
Mark-up price	14.02 p/kWh (11.92 p/kWh for a 40-year term)
Grant funding[3]	50%
NPV at 10 years	−£0.55M
NPV at 20 years	£3.23M
IRR at 20 years	9.0%
Discounted payback	12 years

Figure 1—7 shows the associated cash flow curve of the chosen scenario.

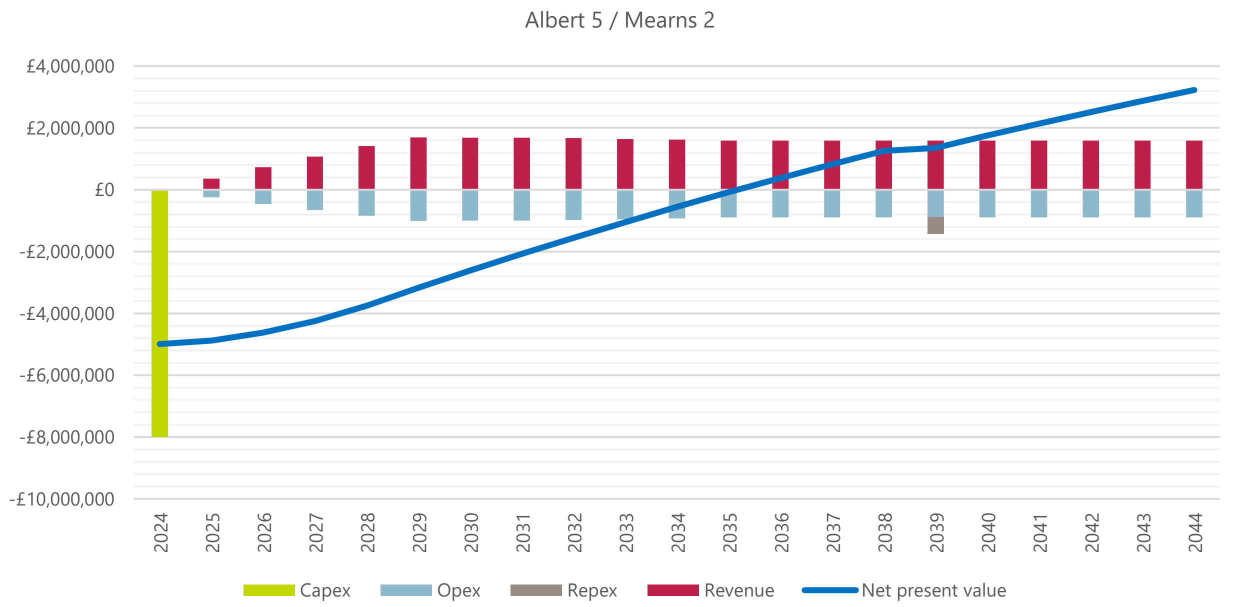


Figure 1—7 Cash flow curve of chosen scenario (5 shore power connection points at Albert and 2 at Mearns).

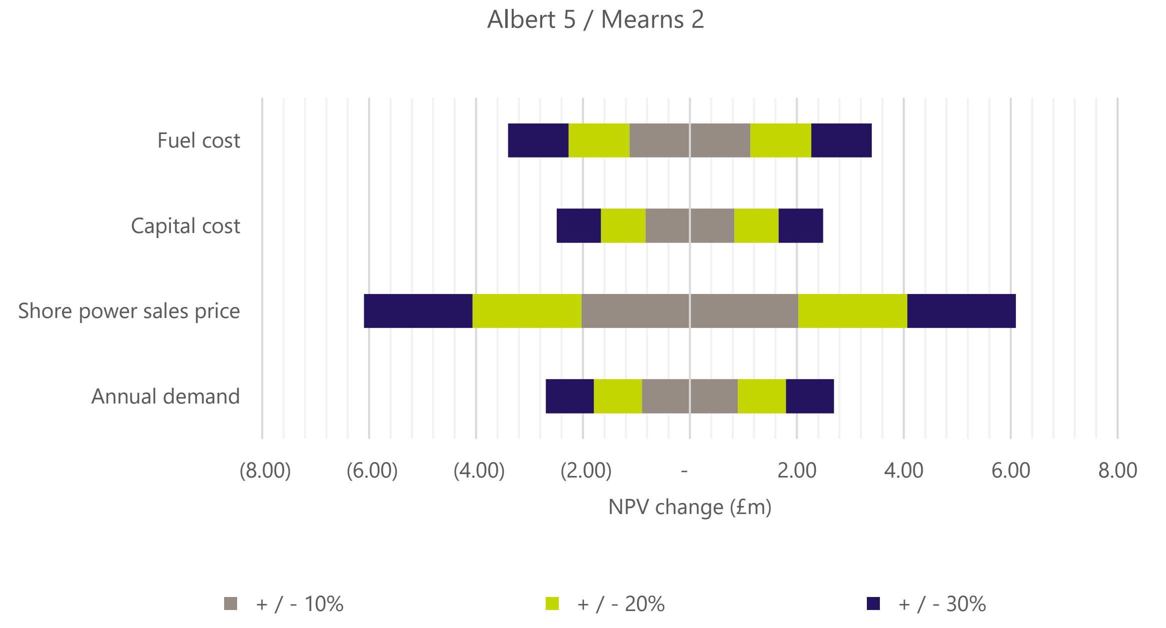


Figure 1—8 Sensitivity curves for chosen scenario (5 shore power connection points at Albert and 2 at Mearns).

1.2.2.5. Carbon Savings

Implementing shore power in Albert and Mearns Quay saves 62,000 tonnes of CO2e over the scheme lifetime (20 years). This equates to an 82% reduction in carbon emissions compared to the counterfactual of burning marine fuel whilst at berth.

Due to the phased projected rollout and uptake of shore power there is expected to be a phased emissions reduction over the first 5 years of the scheme lifetime. Following the full rollout of shore power and subsequent decarbonation of the UK grid, emission reductions per year are estimated to be in the region of 3,500 tCO2/a. As a percentage of overall harbour emissions for berthed vessels this equates to approximately a 11% saving in emissions.

[3] 50% grant funding assumed within base case. Impact of grant funding assessed between 25%-100% within financial model.

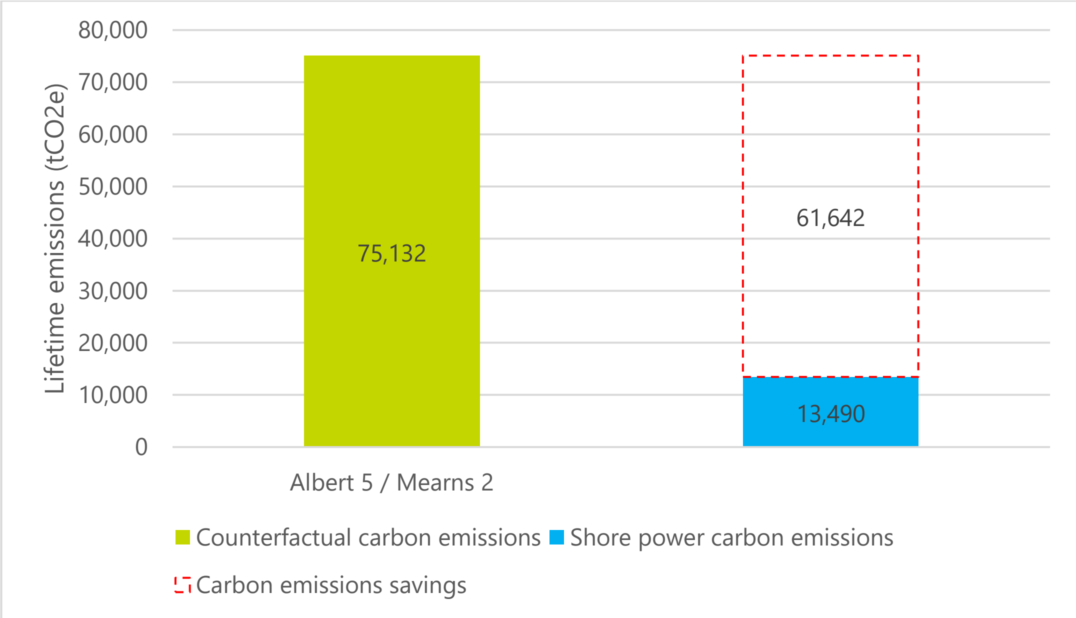


Figure 1—9 Lifetime emissions comparison vs counterfactual

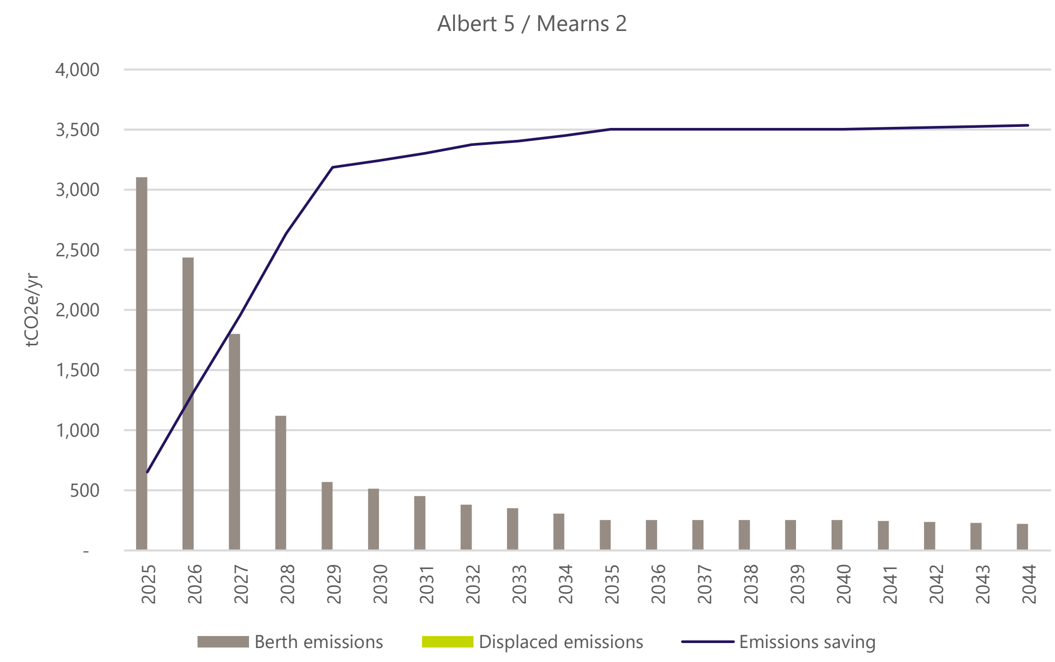


Figure 1—10 Annual emissions comparison vs counterfactual

1.2.3. Commercial Case

1.2.3.1. Overview

The commercial case must demonstrate that the project will result in a viable procurement and contractual strategy and provide a sustainable basis for the long-term operation of the system.

1.2.3.2. Roles

A commercial strategy needs to ensure that the project delivers an optimal return while aligning with the key low carbon objectives for the Aberdeen shore power deployment. As such it needs to consider the commercial arrangements between principal parties including vessel operators (the customers i.e. BP, Total), quayside operators (i.e. ASCO), potential funders / investors, contractors and suppliers. The allocation of these roles is dependent on the allocation of risks, ability to fund and requirements for participation and control. The key roles are summarised in Table 1—2.

Table 1—2 Key roles associated with a shore power system

Role	Explanation
Asset owner	The party that owns the physical assets, such as the shore power system and associated infrastructure.
System Operator	Responsible for the technical operation of the shore power system.
Retailer	The party responsible for the retailing of energy, i.e. purchasing electricity from the Distribution Network Operator and arranging transportation to the shore power system.
Port User	Considered to be the customer and critical for the operational viability of the system

1.2.3.3. Key considerations

From discussions with Aberdeen Harbour it became evident that creating a shore power network and sustainable economic model are highest priorities for the scheme. There is however some tension between relatively high procurement and maintenance costs associated with the construction of the shore power network infrastructure versus the historically lower energy solution using marine fuel. However, Aberdeen Harbour is mindful of the need to provide a carbon reduction solution which is fit for the future, which not only satisfies early connection requirements but also provides a basis for future development at the port.

The above key considerations led to a simplified commercial structure with AHB holding a direct commercial relationship with a wholly owned SPV to deliver the project. This is illustrated in Figure 1—11. This indicates the proposed funding from UK Government via the CMDC grant scheme. It is currently proposed that commercial arrangements will be formalised with the following:

- **Professional services**: yet to be confirmed but likely to include ongoing legal and technical support and possibly project management if Aberdeen Harbour decides to outsource management of the scheme.
- **DB Contractor**: to be appointed via competitive tender following completion of the current design and responsible for the detailed design, complete installation and commissioning.
- **Operate contractor**: dependant on shore power system component. Charging cable operations are likely to be operated in-house or by vessel operators. System operations are likely to be appointed to quayside operators.
- **Maintenance contractor**: maintenance contract likely to be provided by DB contract and / or taken up by quayside operators.
- **Electricity customers**: customer supply and connection agreements
- **Electricity providers**: power supply agreements

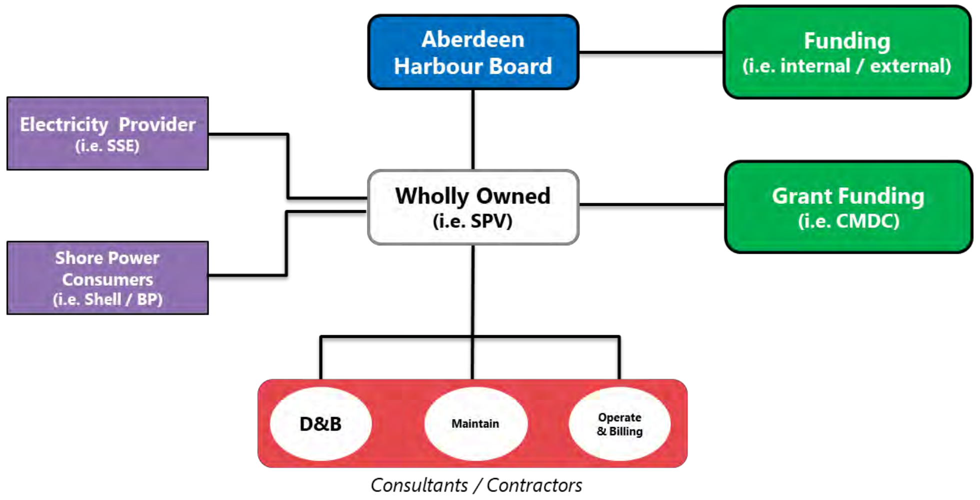


Figure 1—11 Anticipated commercial structure

1.2.3.4. Heads of terms

During the completion of the DPD, Heads of Terms (HoTs) were drafted for the following stakeholders with input from Aberdeen Harbour:

- Aberdeen Harbour (shore power operator)
- BP (shore power customer)
- TotalEnergies (shore power customer)
- Harbour Energy (shore power customer)
- Ithaca Energy (shore power customer)
- Shell (shore power customer)
- Other smaller Energy Operators (shore power customer)

The latest version (at time of writing this document) of the full heads of terms for the main stakeholders is included in Appendix D.

1.2.3.5. Stakeholder Relationships

Whilst the stakeholder relationships are further detailed in the commercial structure and procurement arrangements below, the allocation of key roles can be summarised in Figure 1—12 below.

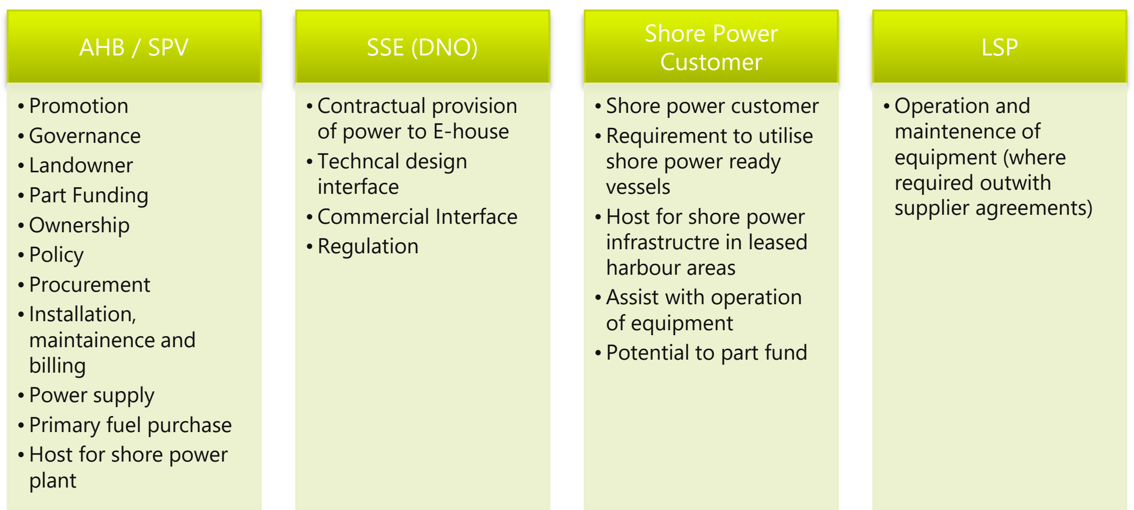


Figure 1—12 Stakeholder Key Roles

1.2.4. Financial Case

1.2.4.1. Overview

A full cashflow financial model was completed by QMPF (qualified accountants) once the economic and commercial elements were agreed.

1.2.4.2. Capex

The capital cost breakdown for the base case is shown in Table 1—3 indicating a total cost of ~£8M exc. VAT.

Table 1—3 Capital cost requirement summary

Cost Element	Capital Cost Estimate, £k
Shore Power connections	2,754
Cable management	676
Port side connection	248
LV Network costs	1,839
Network ancillary equipment	141
Cable storage building	135
Electricals	200
Additional costs	1,995
Total CAPEX exc. VAT	**7,988**
Net VAT funding during construction	**133**
Total construction inc. Net VAT	**8,121**

The main funding sources for the project are a grant for 50% of the total capital costs and the rest will be met by Aberdeen Harbour using its own capital. It is assumed that the grant funding is drawn as required. Sensitivities have been run varying the level of grant funding available (section 6.8). Capital costs are assumed to be incurred in twelve equal monthly payments across the construction year

Table 1—4 Sources and uses to 31 December 2024

Sources of Funds to 31 December 2024	£k	%
Grant Funding (50% of capex)	3,994	49.18 %
Equity	1,032	12.70 %
Intercompany Loan	3,095	38.11 %
Total	8,121	100.00 %

Uses of Funds to 31 December 2024	£k	%
Construction Costs	7,988	98.36 %
Construction Cost VAT	1,598	19.67 %
Construction Period VAT Reimbursement	(1,464)	(18.03)%
Total	8,121	100.00 %

1.2.4.3. Revenue

Revenue is generated for the project through the sale of shore power. There is no standing charge / fixed tariff charged to the offtakers. The shore power sale price will be calculated by adding a mark-up to the cost Aberdeen Harbour import electricity from the grid. For the base case, the mark-up was solved to meet an IRR target of 9%. Table 1—5 shows a summary of the base case offtake and electricity cost assumptions. The demand from the offtakers that is met by shore power is assumed to gradually step up over the first 5 years of operations, reaching 100% in 2029.

Table 1—5 Starting electricity price and offtake associated with each phase

Maximum Annual Offtake (MWh/annum)	Base Electricity Import Cost (£/MWh)	Mark-up (£/MWh)	Base Shore Power Electricity Sale Price (£/MWh)
5,747	150	114	264

1.2.4.4. Overall project cash flow

Overall the project generates £4M cash surplus and is financially viable over the 20-year appraisal period. Project IRR for the base case is show in Table 1—6. In operational terms, the revenues generated from shore power sales covers the total construction and operating costs and the interest and capital of the sub debt provided by Aberdeen Harbour. The project IRR before grant funding is 2.2%. With the addition of grant funding the project IRR is 9.84%.

Table 1—6 Project cash flows over 20-year operational life

Project Cashflows	Nominal £k	NPV March 2022 at 6.09%, £k
Income		
Shore Power Sales	37,869	16,718
Expenditure		
Input Fuel Cost	(23,232)	(10,315)
O&M costs	(386)	(178)
Business Costs	(140)	(65)
Equipment Costs	(484)	(223)
Corporation Tax Paid	(2,668)	(955)
Net Income	10,958	4,982
Construction Cost	(7,988)	(6,787)
Component Replacement Costs	(2,054)	(294)
Net Income after Capex	916	(2,099)
Funding Drawdown and Repayment		
Grant Drawdown	3,994	3,394
Harbour Sub Debt	3,095	2,630
Harbour Equity	1,032	877
Cashflows after Sources of Funding	9,037	4,802
Interest		
Interest Paid on Harbour Interco Loan	(2,430)	(847)
Surplus Cash Available to the Harbour	6,607	3,954

1.2.4.5. Sensitivities

Sensitivity analysis has been completed and indicates a financially viable project that is robust to all but the most extreme sensitivities which have been investigated. The financial model has been prepared on the basis of prudent assumptions and in the case of most of the downside sensitivities, although AHB may be required to provide extra funding for early year deficits (overdraft) subject to confirmed contributions from grant funding sources, the project does ultimately pay back and generate an overall project cash surplus. This is described in more detail in section 6.8.

One of the key risks to the project is the potential lack of operator uptake to use shore power which could negatively impact shore power sales and the financial viability of the scheme. While the modelling has accounted for a gradual uptake in shore power demand to 2029 as operators retrofit their vessels, should vessels not incur or recognise any carbon cost (or they recognise a cost significantly below the assumption used in the modelling) from the continued use of marine fuel when berthed in the harbour, then the direct financial incentive for the vessels to connect to the onshore power is not evident.

However, as discussed elsewhere in the business case there is a wider general incentive for the operators to decarbonise from a climate change, environmental, social, governmental and public relations perspective which is likely to support a level of demand for the use of onshore power and has been considered in determining the base case offtake assumptions.

1.2.5. Management Case

The roles undertaken from the stakeholders involved in the project are crucial for its delivery and mitigation of associated risks. The roles suggested for the shore power demonstrator are presented in the commercial case. It should be noted that following commercial workshops and communication with the stakeholders it is assumed that AHB will have the leading project governance role.

The key stages, timing assumption and milestones are summarised in Table 1—7.

Table 1—7 Proposed timeline and key milestones

Item	Date Assumption	Key Milestones
Full design complete and stakeholder contractual agreements in place	Q4 2022	All parties contractually engaged and final spatial coordination of infrastructure (i.e. following additional GPR surveys) complete.
Funding secured	Q3/4 2023	Grant funding and internal funding sources secured
Contractor tendering and appointment	Q3/4 2023	Enables all construction to begin
Construction start date	January 2024	D&B contractor contract award
Operations start date	January 2025	Sales of shore power commence with gradual increase in sales to 2029

1.3. Benefits Realisation

Benefits realisation should also be included in the aforementioned project management plan. Ensuring the project delivers its low carbon/sustainability goals is of vital importance to all stakeholders. The benefits of the project are in line with the project objectives presented in section 2.2. The following arrangement/actions are suggested to be planned to mitigate risks that might affect meeting the desired goals:

- The DBM contracts should include monitoring of the technologies' performance and review future technology advancements to optimise even further the operation of the shore power infrastructure, by replacing old and/or less efficient equipment at the end of its lifetime.
- AHB should actively manage utility costs for primary electricity supplied to the shore power e-house.
- AHB should complete a formal review of the economic performance every 6 months (minimum) to consider improvements required to meet required financial targets
- AHB should develop an information pack to help engage future shore power off-takers.

1.4. Risk Management

Risks and suggested mitigation measures have been included within the risk register included in Appendix C, along with probability and impact weighting before and after mitigation action.

The risk register should be handed to the D&B contractors who will then act as Principal Designer and Principal Contractor under CDM regulations 2015. There will be a shared responsibility between AHB (the Client) and the D&B Contractor to keep it updated in the following implementation and operation and communicate potential issues to the stakeholders. The overall responsibility for the project still remains with AHB. Therefore, clauses should be included in the contract for AHB to be able to intervene in case risks are not mitigated or communicated timely and properly. The key risks associated with committing to the shore power development have been identified as follows, with proposed mitigation below each:

1. **AHB fail to gain wider political support**
   a. *AHB to submit OBC and DPD information to applicable funding body for additional funding signoff which could potentially support up to 50% of capital costs of infrastructure and consult with government departments to test basis for system procurement and delivery is transparent and according to best practice.*
2. **Failure to attract participating shore power users or delay in implementing shore power infrastructure therefore resulting in reduced revenue leads to revenue gap to repay any borrowing / investment.**
   a. *Investigate alternative revenue grants including sharing of risk until further participating operators (and revenue) are sufficient to cover operating costs including any borrowing costs.*
3. **Failure to identify funding sources adequate to meet the capital costs of the scheme, particularly the grant funding to meet the 50% of CAPEX base case**
   a. *AHB should continue to engage with potential funding bodies such as the DfT and keep track of the development of the Clean Maritime Plan 2023 as well as other potential funding opportunities. Operator / off taker contribution to infrastructure deployment should also be considered Should <50% of the CAPEX cost be covered through grant funding then shore power sales price would need to increase if the base case IRR is to be met. A series of sensitivities have been undertaken around this in the financial case.*
4. **Costing estimates increase during design development on award of D&M contracts**
   a. *Market testing and bespoke cost consultancy input has been undertaken to refine the cost plan - this should be revisited at later stages. This engagement process will highlight any cost hotspots which require further design development. Cost sensitivity has been tested to +/-20% in financial case.*
5. **Shore power consumption estimates vary vs actual consumption**
   a. *Power demand sensitivity has been completed as part of a detailed vessel movement analysis and modelled as a sensitivity, but risks remain due to inherent variability between design and operation. Continued refinement of the model may be required if a significant change in predicted operator use becomes apparent.*

1.5. Contingency Plans

Although there are no critical aspects of the project that could lead to an unavoidable project failure, which in turn would impact the development on site, it is worth mentioning that as described in the Strategic case the project is seen as a catalyst and a pilot leading to both environmental and social benefits for the area, with Point Law Peninsula being a flagship location for delivering a shore power demonstrator project.

Steps that could however mitigate the risk of failure are the following:

- Minimising the number of design, build, operate and maintain contractors for the project, and associated interface risks between construction and operation.
- Ensuring that vessel power equipment is resilient in case of shore power operational issues.

It is important for AHB to have step-in rights for the event that the appointed contractors contract becomes untenable. In that case, clauses in the contract should be included that allow AHB to take over the project in order to be delivered.

2. Introduction

2.1. Purpose of report

Countries and organisations around the world have declared a climate emergency in light of increasingly overwhelming scientific evidence of the detrimental effects humans are having on our planet. The UK and Scottish Governments have made a legal commitment to reach Net Zero by 2050 and 2045 respectively. To support continued economic growth, the UK and Scottish Governments have declared significant investment is to be made to support these Net Zero commitments.

To achieve these carbon targets, reliance on fossil fuels must be significantly reduced, especially within the transport sector which accounts for the largest proportion of carbon emissions in the UK (24% of greenhouse gas emissions in 2020). Within this sector domestic shipping accounted for 5.3 $MtCO2_e$ and international shipping accounted for 6.1 $MtCO2_e$ in 2020.[4] Additionally, shipping makes significant contribution to air pollution which contributes to adverse human health effects, as well as environmental damage.

It is widely acknowledged that shore power can make an important contribution to decarbonising the shipping sector and improving the air quality for local communities. Currently, vessels run their onboard diesel engines whilst at berth, to power amenities such as lighting, air-conditioning and lifting equipment. Shore power would allow vessels to turn off their engines and plug into onshore power sources when berthed, reducing carbon emissions, noise and air pollution. Shore power technology is established in many ports across the globe, particularly in regions such as Scandinavia where lower cost of electricity, supporting policies and capital funding mechanisms for shore power allow for greater adoption of this technology.

In May 2021 Buro Happold and Tyndall Centre for Climate Change Research completed a feasibility study on the decarbonisation strategy of Aberdeen Harbour. It was estimated ca. 44,000 tCO_2/a of carbon emissions are produced throughout the port every year. The study determined that 78% of emissions were derived from ships using marine fuels while at berth, 19% for vessels in transit within port limits (2km) and just 3% from use of electricity and gas on the port estate i.e. buildings. Therefore, it is evident that reducing vessel emissions whilst at berth, by building shore power capability at Aberdeen Harbour, should be the priority focus area to reduce port emissions.

The societal cost associated with the carbon emissions and air pollutants that are generated by ships whilst at berth was calculated to be in the region £7.5M per annum. However, with recent changes to the Government's methodology for calculating carbon value (June 2021), the societal cost is estimated to be in the region of £14M per annum in 2024 (see section 4.13 for methodology).

As a result of the initial investigation, Aberdeen Harbour applied and was successful in obtaining an award from the Clean Maritime Demonstration Competition to develop plans for a shore power demonstration project within the harbour. There are limited examples of shore power infrastructure projects in the UK (Royal Navy base at Portsmouth, Orkney and Southampton)[5]. The project aims to develop a blueprint for shore power implementation within Aberdeen Harbour and the rest of the UK.

The structure of the report leans on the Green Book Supplementary Guidance on 'Delivering Public Value from Spending Proposals'' whereby the overarching purpose of the OBC is to:

- Identify the spending option which optimises value for money (VFM)
- Prepare the scheme for procurement
- Put in place the necessary funding and management arrangements for the successful delivery of the scheme

This Outline Business Case (OBC) uses a Five Case Model as set out in the Green Book (Figure 2—1).

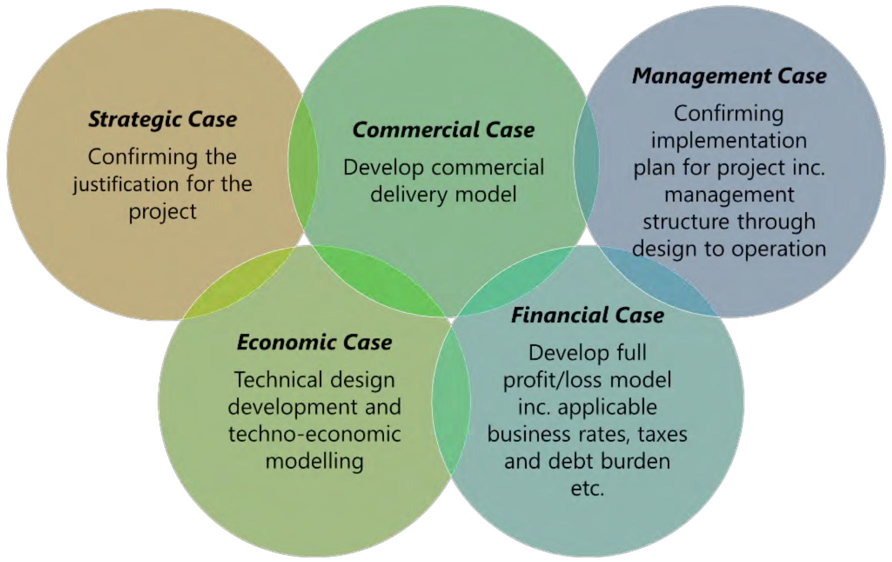


Figure 2—1 Green Book Five Case Model

2.2. Objectives

The key objectives of the shore power development project are:

1. Develop a business case for shore power which provides a low carbon solution to burning marine fuel whilst at berth for operators and Aberdeen Harbour that reduces the overall carbon emissions of Aberdeen Harbour by 10%.
2. Demonstrate a proof-of-concept shore power design and project blueprint for roll-out across the Harbour and other UK ports.
3. Provide evidence to inform future policy development on shore power within Scotland and the UK including the "Call for Evidence on Shore Power".
4. Contribute towards the Scottish/UK Government and Aberdeen Harbour's sustainability policies and carbon reduction targets.
5. Reduce carbon emissions and air pollutants into the local community, delivering a social benefit to Aberdeen.
6. Provide a shore power solution at Albert and Mearns Quay that minimises operational impact.
7. Provide shore power to users at a cost competitive to marine fuel.

2.3. Scope of work

Aberdeen Harbour Board alongside Connected Places Catapult (CPC) were awarded over £400,000 through the Clean Maritime Demonstration Competition (CMDC) to develop a "Feasibility Study for Shore Power in Aberdeen Harbour". The project description was as follows:

"This project will undertake a Feasibility Study for a next-phase demonstration project for a green shore power scheme in Aberdeen's existing North Harbour. Key outputs will be an Outline Business Case for the scheme and plans for the demonstration project. The project builds on a recently completed study commissioned by Aberdeen Harbour Board which produced an initial system design for shore power to AHB's berths and completed initial emissions and business modelling. This demonstrated substantial reductions in GHG emissions and a viable business model. This confirmed the findings of a recent Clusters Research Project undertaken for DfT which stated that Aberdeen was one of two priority ports in the UK for adopting this technology. Shore power to avoid vessel emissions at berth is an established technology, but significant technical differences exist with the appropriate physical infrastructure and associated system specifications. Its application in

[4] DEPRATMENT FOR BUSINESS, ENERGY & INDUSTRIAL STRATEGY, 2022, 2020 UK Greenhouse Gas Emissions, Final Figures.

[5] https://www.britishports.org.uk/content/uploads/2021/02/Shore-power-Tyndall-FINAL-DEC-2020.pdf [Accessed 4th March 2022]

this project is for vessels involved in a wide array of activities, including small to medium vessels such as Offshore Service Vessels. Whilst the system design and associated Outline Business Case will be at the core of this project, work by Connected Places Catapult will take a broader 'system of systems' approach, considering how the shore power developments will fit into full decarbonisation of the existing and new Aberdeen harbours, the vessels using it and its linkages to the wider Aberdeen city region. This complementary part of project will add substantial value to the focused study by using it to develop a transferable blueprint for implementation of shore power which can be replicated in other UK regional ports. It will help develop a long-term vision of a Net Zero Aberdeen port and how that fits into the broader regional decarbonisation initiatives."

Within this project scope Buro Happold were engaged to complete the Outline Business Case with support from various sub-consultants. Within the OBC these consultants were responsible for different scopes of work:

- Buro Happold
  - Overall project management
  - Develop strategic case including understanding critical success factors
  - Engage with suppliers to identify best solution
  - Techno-economic analysis
  - Economic case development including long list to short list options assessment
  - Commercial case development
  - Management case development
- Tyndall Centre for Climate Change Research
  - Specialist maritime expertise
  - Shore power demand analysis and quantifying vessel power demands
- QMPF
  - Financial case development including full profit/loss model
- Thomson Bethune
  - Cost consultant reviewing supplier quotes and providing knowledge to develop a cost plan
- 3D-TD
  - Spatial coordination of civils infrastructure including identification of key hazards

2.4. Methodology

The proposal set out in this report presents a significant opportunity for Aberdeen Harbour Board to reduce its future carbon emissions and enhance its reputation, whilst acting as a demonstration of how a transition to a low carbon future could be achieved. This opportunity is also a way to future proof the site against the need for future works. The combination of ambitious stakeholders, clear long-term masterplan and significant shore power opportunity make Aberdeen Harbour the ideal place for a shore power demonstration project.

Figure 2—2 shows the methodology followed to deliver the project objectives and create an OBC for shore power within Aberdeen Harbour.

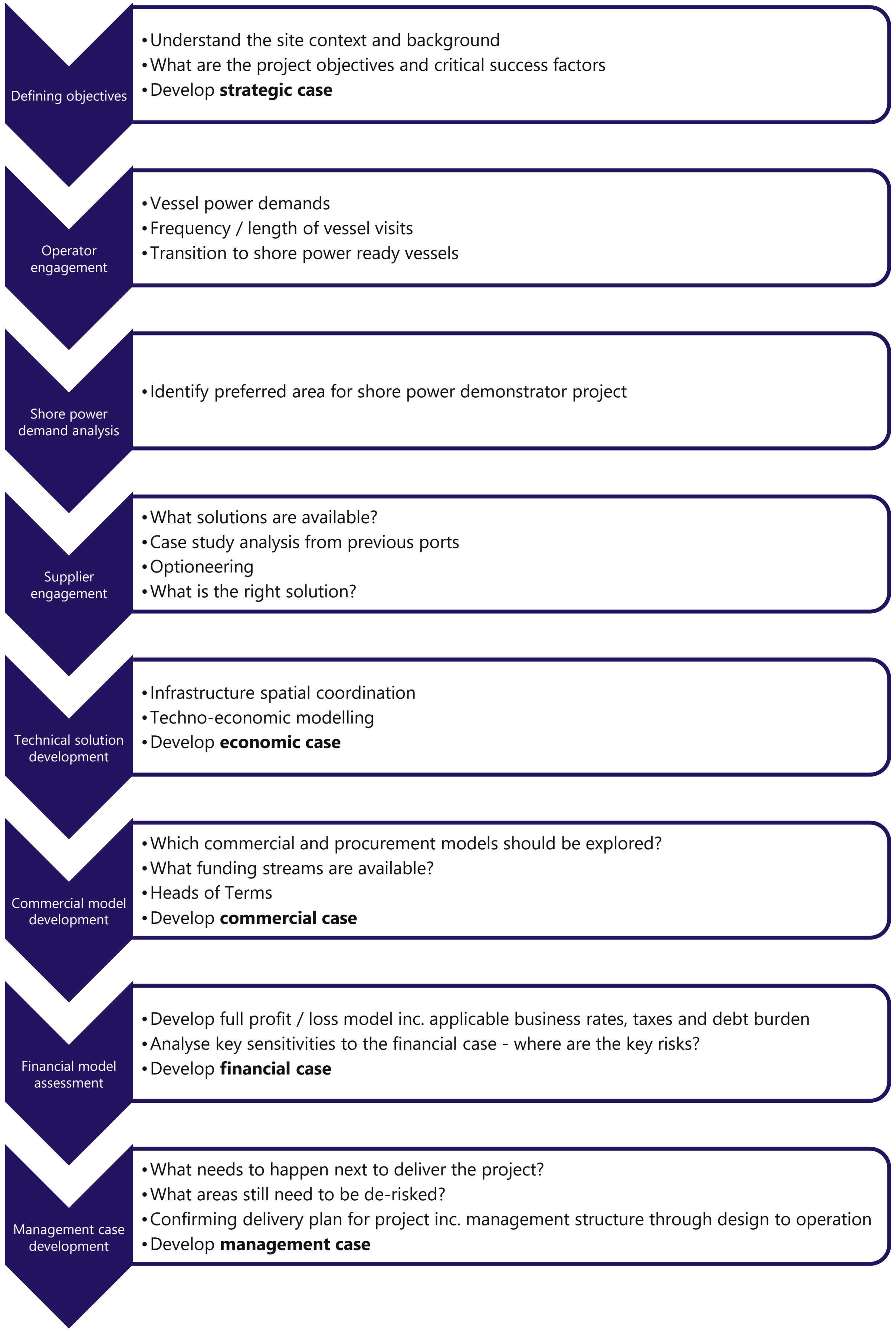


Figure 2—2 Aberdeen Harbour shore power OBC methodology

3. Strategic Case

3.1. Introduction

This section outlines the strategic case for the project, its key features and how the objectives align with local and national policies. The process for implementation is also explained.

3.2. Overview of strategic case

Scotland is recognised as a world leader in its ambition to tackle climate change. After declaring a climate emergency, the Scottish Government has set a target to reach net zero greenhouse gas (GHG) emissions by 2045, in order to end Scotland's contribution to climate change within a generation[6]. Acknowledging that responding to the climate emergency will not be easy, Scotland's transition to a net zero society requires collaboration, with every industry working together to ensure all opportunities are seized.

For shipping, the International Maritime Organisation (IMO) has set an initial climate change strategy, with a target of at least 50% reductions in international shipping emissions on 2008 levels by 2050 and this target is due for revision in 2023. However, the UNEP emissions gap report[7] states that this target is not consistent with the Paris Climate Agreement's 1.5°C goal and it is described as "critically insufficient" by independent analysts, Climate Action Tracker[8]. The IMO has recently recognised the need to strengthen its ambition. Their 2050 target would require tightening to zero emissions before 2050 to be 1.5°C compatible[9].

In many respects, action on shipping at international level is being driven instead not by the IMO, but by other factors such as:

1) the UK Government explicitly including emissions from international shipping, as well as domestic shipping, within in its carbon budgets[10]
2) the Department for Transport launching UK SHORE, providing £206 million in funding to support zero emissions sailing and skilled maritime jobs
3) the 22 nation Clydebank Declaration on green shipping corridors
4) the EU acting to include shipping in the EU Emissions trading scheme
5) the Getting to Zero Coalition of the maritime sector
6) the financial community's Poseidon Principles
7) proposals from ship charterers Trafigura and the International Chamber of Shipping for a strong international carbon price for marine fuels.

In 2020 the UK's net territorial greenhouse gas emissions were 405.5 million tonnes carbon dioxide equivalent. Figure 3—1 shows the transport sector accounted for the largest proportion of carbon emission in the UK (24% of greenhouse gas emissions in the UK in 2020). Domestic shipping in 2020 accounted for 5.3 $MtCO2_e$ and international shipping in 2020 accounted for 6.1 $MtCO2_e$.[11] Additionally, shipping makes significant contribution to nitrogen oxides (NOx), sulphur dioxide (SO_2) and primary $PM_{2.5}$ and PM_{10} (particulate matter, PM with diameter less than 2.5 micrometres and 10 micrometres respectively) emissions. These primary and secondary pollutants derived from shipping emissions contribute to adverse human health effects in the UK and elsewhere (including cardiovascular and respiratory illness and premature death), as well as environmental damage through acidification and eutrophication.

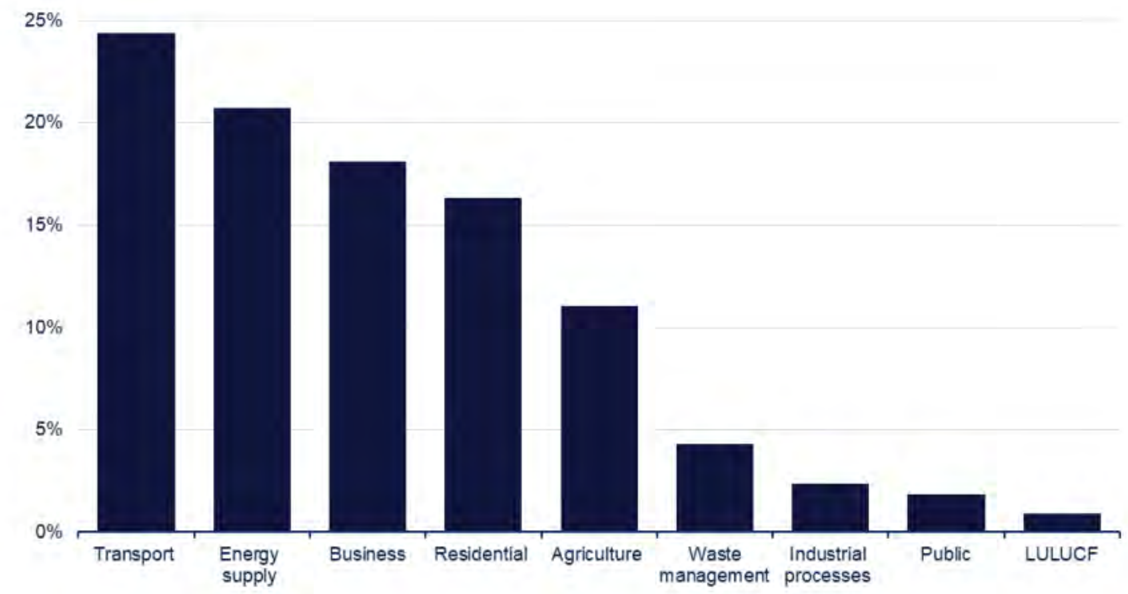


Figure 3—1 Net territorial UK greenhouse gas emissions by sector. Figure reproduced from [11]

The Clean Air Strategy (CAS) published in January 2019 aims to cut down air pollution in the UK across all sectors to protect public health and the environment. Previously the priority has been to tackle the biggest individual sources of pollution, but as these major sources of emissions have decreased, due to intervention, the relative contribution of smaller and more diffuse sources of air pollution has increased.

The Maritime section of the CAS sets out a number of commitments focussed on opportunities to reduce emissions from domestic shipping and port activities. This includes guidance on Port Air Quality Strategies and the production of a Clean Maritime Plan (CMP) which was published by the Department for Transport in July 2019 and sets out the UK Government's aim for a transition to a future of zero emission shipping. This CMP strategy is due for revision in the next two years.

The shipping sector can assist with reducing its global impact in the various ways including:

- Assessing and developing decarbonisation strategies for ports
- Electrification of maritime vehicles where possible
- Electrification of mobile machinery and land-vehicles used to facilitate shipping operations
- Investment in low carbon heating solutions for shipping buildings
- Improved efficiency of maritime vehicles
- Development of zero/low carbon fuels for maritime vehicles

It is widely acknowledged that shore power can make an important contribution to decarbonising the shipping sector and improving the air quality for local communities. Currently, vessels run their onboard diesel engines whilst at berth, to power amenities such as lighting, air-conditioning and lifting equipment. Shore power would allow vessels to turn off their engines and plug into onshore power sources when berthed, reducing carbon emissions (when using low or zero carbon power), noise and air pollution. It is also a technology which can be deployed now, whereas other decarbonisation options will take longer to materialise or do not yet have recognised existing supply chains, e.g. hydrogen or biofuels.

In June 2021, the UK's Sixth Carbon Budget explicitly included emissions from international shipping, as well as domestic shipping, within in its carbon budgets process for the first time. The UK Government projects that in order to achieve net

[6] SCOTTISH GOVERNMENT. 2020. Securing a green recovery on a path to net zero: climate change plan 2018–2032 – update. https://www.gov.scot/publications/securing-green-recovery-path-net-zero-update-climate-change-plan-20182032/ [Accessed 2nd March 2022]
[7] UNITED NATIONS ENVIRONMENT PROGRAMME. 2020. Emissions gap report 2020. https://www.unep.org/emissions-gap-report-2020 [Accessed 2nd March 2022]
[8] CLIMATE ACTION TRACKER. 2020. https://climateactiontracker.org/sectors/shipping/ [Accessed 2nd March 2022]
[9] BULLOCK, S., MASON, J. & LARKIN, A. 2021. The urgent case for stronger climate targets for international shipping. Climate Policy, 1-9.
[10] CLIMATE CHANGE COMMITTEE, 2020, Sixth Carbon Budget, https://www.theccc.org.uk/publication/sixth-carbon-budget/ [Accessed 2nd March 2022]
[11] DEPRATMENT FOR BUSINESS, ENERGY & INDUSTRIAL STRATEGY, 2022, 2020 UK Greenhouse Gas Emissions, Final Figures.

zero by 2050, approximately 13% of emissions reduction in shipping would be delivered through efficiency and electrification, with the remaining emissions saving delivered through the development of zero-carbon fuels (Figure 3—2). The Sixth Carbon Budget projects that by 2050, 3 TWh/a of electricity would be used in electric propulsion and shore power, compared to 0.2 TWh/a in the baseline.

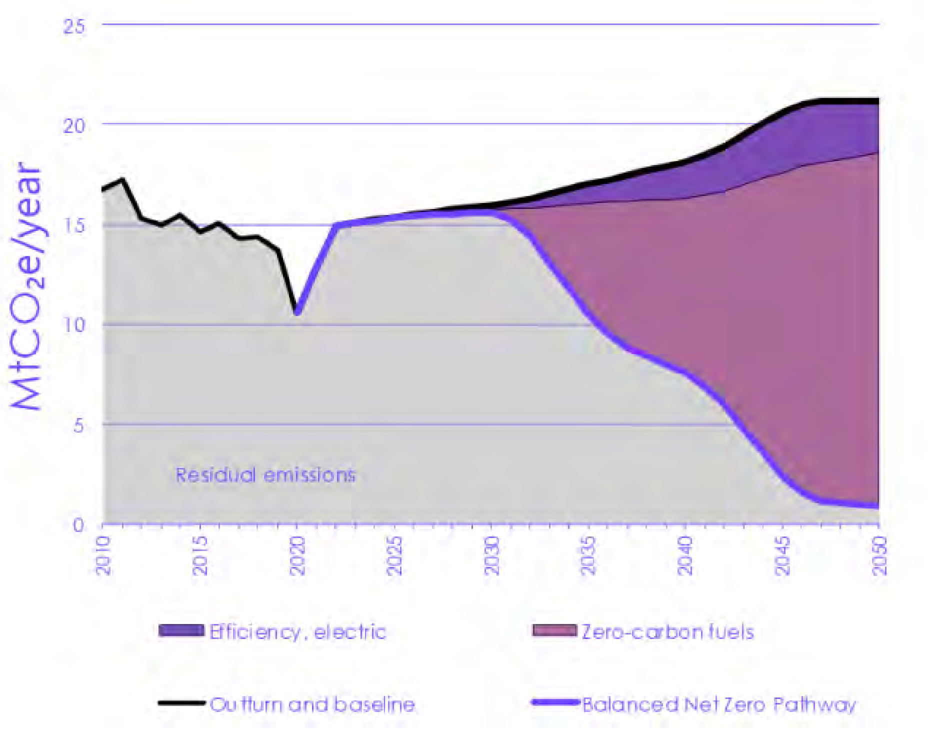


Figure 3—2 The Sixth Carbon Budget projections for Net Zero Pathway for the shipping sector. Figure reproduced from [10]

Although ports have a pivotal role to play in shipping decarbonisation, they also need policy support. Marine fuel oil is currently untaxed internationally and therefore holds a competitive price advantage over low-carbon fuels and shore power. In the medium-term this can be solved at an international level through carbon pricing on marine fuel oil and incentivising low carbon alternatives. However, in its absence, in the short-term national governments and port authorities can work together to incentivise low carbon initiatives such as shore power.

Aberdeen Harbour alongside CPC has been awarded more than £400,000 from the UK Government, through the Department for Transport's Clean Maritime Demonstration Competition, to fund a demonstration project providing shore power within Aberdeen North Harbour. The initiative demonstrates the ambitions of Aberdeen Harbour to become a net zero port and leading port in the net zero energy transition.

3.3. Site context and background

A recent feasibility report (May 2021) completed by Buro Happold and Tyndall Centre for Climate Change Research on the decarbonisation strategy of Aberdeen Harbour estimated ca. 44,000 tCO_2/a of carbon emissions are produced throughout the port.

The study determined that 78% of emissions were derived from ships using marine fuels while at berth, 19% for vessels in transit within port limits (2km) and just 3% from use of electricity and gas on the port estate i.e. buildings (Figure 3—3). Therefore, it is evident that reducing vessel emissions whilst at berth, by building shore power capability at Aberdeen Harbour, should be the priority focus area to reduce port emissions.

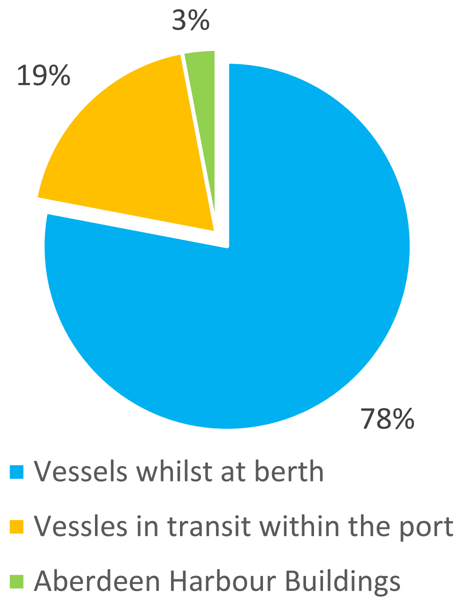


Figure 3—3 Aberdeen Harbour Carbon Emissions

The societal cost associated with the carbon emissions and air pollutants that are generated by ships whilst at berth was calculated to be in the region £7.5M per annum. However, with recent changes to the Government's methodology for calculating carbon value (June 2021), the societal cost is estimated to be in the region of £14M per annum in 2024 (see section 4.13 for methodology).

As a result of the initial investigation, Aberdeen Harbour applied and was successful in obtaining an award from the Clean Maritime Demonstration Competition to develop plans for a shore power demonstration project within the harbour. There are limited examples of shore power infrastructure projects in the UK (Royal Navy base at Portsmouth, Orkney and Southampton)[12]. However, the technology is established in many ports across the globe, particularly in regions such as Scandinavia where lower cost of electricity and supporting policies and capital funding mechanisms for shore power allow for greater adoption of this technology[13].

Following initial energy demand analysis the following criteria were used to analyse priority berth areas for shore power within Aberdeen Harbour:

1. Energy demand of the berthing areas.
2. High berth occupancy by a small number of high frequency visitors, to increase the likelihood of all vessels being equipped for shore power connection
3. Attitude/interest in shore power from the ship operator/owner. Working with operators/owners who want shore power and agree to install the connection infrastructure to their vessels is a high priority for choice of berth.
4. Ease and cost of connection to green grid electricity.
5. Benefits for local air and noise pollution. A major co-benefit of shore power is the reduction in local air pollution and noise. This benefits onboard and landside crews in every berth, but the wider benefits are greater where there is a higher population density nearby.

Following an assessment of the energy demand and multi-criteria analysis, each berthing area was assessed and it was deemed that Albert Quay and Mearns Quay (located within the Point Law Peninsula) are among the most suitable areas for positioning a demonstration shore power infrastructure project within Aberdeen Harbour. Vessels at Albert Quay (1-5)

[12] https://www.britishports.org.uk/content/uploads/2021/02/Shore-power-Tyndall-FINAL-DEC-2020.pdf [Accessed 4th March 2022]

[13] https://www.britishports.org.uk/content/uploads/2021/10/BPA_Shore_Power_Paper_May_2020.pdf [Accessed 4th March 2022]

and Mearns Quay (1&3) were calculated to have an overall energy consumption of ~5,700 MWh/a (11% of the overall vessel energy consumption within Aberdeen Harbour whilst at berth) and carbon emissions of 3,750 tCO2/a.

Additionally, some of the high-frequency users of these berths have their own climate change commitments. BP has signed a memorandum of understanding with Aberdeen Harbour to explore opportunities that could reduce carbon emissions, including shore power. BP and TotalEnergies have also set targets to become net zero by 2050 or sooner. Harbour Energy, another large user of these berths has committed to a net zero goal of 2035. Also, Shell, who is scheduled to transition from Torry Marine Base berths to Albert and Mearns berths both has a net zero commitment of 2050.

3.4. Guiding principles for AHB

Aberdeen Harbour's strategy sets out the harbour's purpose, mission and vision:

- Purpose – creating prosperity for generations
- Mission – to connect our customers to what they need, where and when they need it
- Vision – to become Scotland's premier port, offering world class facilities to national and international customers and stakeholders

Additionally Aberdeen Harbour's strategy states the following in relation to the climate and emissions:

- We have a significant responsibility to protect the natural resources of the harbour and adjacent coastal region, protecting these environmental assets, to deliver benefits to the community and ensure long-term sustainability in all its dimensions
- We aim to become an exemplar in environmental stewardship and sustainability leadership, pioneering green port innovation and facilitating energy transition solutions
- We aim to encourage port business to adopt sustainable approaches and to encourage innovation in design, operation towards net zero and reduce all the dimensions and metrics of the environmental footprint
- We will continually strive to improve and grow our services.

It is evident that developing shore power capability within Aberdeen Harbour is consistent with the Port's strategy:

- Many port users of the Harbour are requesting shore power infrastructure within the port. Therefore, implementing shore power would align with the mission to connect customers to what they need, where and when they need it. It would also align with the Port's vision to offer world class facilities.
- Shore power delivers a clear carbon benefit and air quality benefit to the community and environment and helps meet the objectives of the Scottish and UK Government's Climate Change strategies.
- Shore power is a mature technology but underutilised within the UK. Aberdeen Harbour could use this technology to create a blueprint for decarbonising ports across the UK and further reduce the carbon footprint.
- Shore power increases the low carbon service offering available at Aberdeen Harbour.

3.5. "Do nothing approach"

The do-nothing approach for Aberdeen Harbour would means vessels continue using marine fuel oil whilst at berth, as no low carbon alternative would be available.

Implementing shore power infrastructure at the Albert and Mearns Quay berths within Aberdeen Harbour makes strategic sense for the following reasons and the alternative do-nothing approach would be a significant opportunity missed for the Port:

1. Albert and Mearns Quays have a large energy demand and a small number of high frequency visitors, who are committed to climate change commitments and are willing to implement the appropriate infrastructure on their vessels.
2. Operators within both quay's have requested shore power infrastructure within Aberdeen, meaning there would be a high likelihood that shore power would be heavily utilised.
3. A shore power development project could form the basis of a blueprint for the decarbonisation of ports across the UK.
4. Implementing shore power within Albert and Mearns Quay could reduce the Harbour's emissions by ~3,500 tCO2/a and presents a societal value of £800,000 per annum.
5. Marine fuel oil has approximately doubled in price within the last year[14]. Marine fuel could further increase in price if carbon taxation is applied, narrowing the price gap with electricity.

3.6. Key stakeholders

The shore power development project is led by Aberdeen Harbour, however there are various other interested stakeholders:

- Aberdeen Harbour (shore power development lead)
- SSE (electricity grid reinforcement)
- BP (vessel operator and shore power customer)
- TotalEnergies (vessel operator and shore power customer)
- Harbour Energy (vessel operator and shore power customer)
- Ithaca Energy (vessel operator and shore power customer)
- Shell (vessel operator and shore power customer)
- Other smaller operators (shore power customer)
- Vessel owners (installation of ship-side equipment for shore power for operators)
- Scottish/UK government (shore power policy)

3.7. Objectives

The key objectives of the shore power development project are:

1. Develop a business case for shore power which provides a low carbon solution to burning marine fuel whilst at berth for operators and Aberdeen Harbour that reduces the overall carbon emissions of Aberdeen Harbour by 10%.
2. Demonstrate a proof-of-concept shore power design and project blueprint for roll-out across the Harbour and other UK ports.
3. Provide evidence to inform future policy development on shore power within Scotland and the UK including the "Call for Evidence on Shore Power".
4. Contribute towards the Scottish/UK Government and Aberdeen Harbour's sustainability policies and carbon reduction targets.
5. Reduce carbon emissions and air pollutants into the local community, delivering a social benefit to Aberdeen.

3.8. Constraints and dependencies

There are a number of key constraints and dependencies which have been and will continue to be considered in the further progression of the project, these are summarised as follows:

[14] https://shipandbunker.com/prices#MGO [Accessed 4th March 2022]

3.8.1. Key constraints

1. Electricity grid constraints – There are currently no significant costs impacting the project related to upgrades within the electricity grid. However, this could be an issue for the Harbour in the future if they look to expand their shore power offering to all areas within the port.
2. Cable routing constraints – various hazards were identified when completing a spatial coordination assessment of existing utilities and proposed cable routing for shore power infrastructure. These include crossing the mains sewer on North Esplanade East, crossing fuel lines on Albert Quay and North Esplanade East and crossing drainage channels on Albert Quay. Additionally, an overground solution is suggested for Mearns Quay, due to the deck being of suspended construction. Further detail of these constraints, risks and mitigations are provided within Appendix E.

3.8.2. Key dependencies

The success of the shore power project is dependent upon the following:

1. Formal commitment for usage of shore power by vessel operators on Albert and Mearns Quay.
2. Securing suitable grant funding to allow for a competitive shore power sales price to be achieved vs marine fuel.
3. Identifying a delivery partner(s) whose internal rate of return (IRR) expectations for the project allows for cost competitive shore power sales prices to be offered to users.
4. Procuring shore power infrastructure from suppliers at a competitive capital cost that allows for competitive shore power sales prices to be offered to users.
5. Procuring an electricity purchase price from the UK grid that allows for competitive shore power sales prices to be offered to users.
6. Future marine fuel oil prices and carbon taxation.

4. Economic Case

4.1. Overview

This section examines the economic case for shore power within Aberdeen Harbour. A thorough supplier engagement process was conducted to ensure the correct solution was chosen. Following this, a spatial coordination exercise was completed to arrive at the appropriate technical solution. Finally, a detailed techno-economic modelling was carried out to inform the economic case.

4.2. Critical success factors

Following the ongoing discussions with Aberdeen Harbour the below critical success factors are considered essential for the successful delivery of the shore power demonstration project:

1. Develop a business case for shore power which provides a low carbon solution to burning marine fuel whilst at berth for operators and Aberdeen Harbour that reduces the overall carbon emissions of Aberdeen Harbour by 10%.
2. Provide a shore power solution at Albert and Mearns Quay that minimises operational impact.
3. Provide shore power to users at a cost competitive to marine fuel.
4. Develop a blueprint for shore power implementation within Aberdeen Harbour that can be applied to the rest of the UK.
5. Provide fair and transparent allocation of shore power costs.
6. Transfer the delivery risk of the project where possible and mitigate risk as much as practicable.
7. Reduction of capital investment where possible, whilst ensuring project quality.
8. Transfer of operating risk where possible through O&M procurement.
9. Develop a resilient low carbon shore power supply to the site.
10. Futureproof for potential increased power requirements i.e. battery charging capability

4.3. Site status

Aberdeen Harbour is situated in a central location within the city of Aberdeen. Aberdeen Harbour contains approximately 50 berthing area for a wide variety of vessels including multi-purpose supply vessels (MPSVs), diving support vessels (DSVs), cargo vessels and ferries.

Following an assessment of the energy demand and multi-criteria analysis, as part of a feasibility study completed by Buro Happold and Tyndall Centre, Albert Quay and Mearns Quay located within the Point Law Peninsula (Figure 4—1), were deemed the most suitable areas for a demonstration shore power infrastructure project within Aberdeen Harbour. This was primarily due to:

- Heavy vessel utilisation of the berths, with fewer operators
- External operator intent to move operations to the area in future
- Net zero aspirations of existing Point Law Peninsula operators. which has resulted in good buy-in
- Good duration of typical vessel visits, meaning less handling of shore power equipment per vessel charge

Vessels at Albert Quay (1-5) and Mearns Quay (1&3) were calculated to have an overall energy consumption of ~5,700 MWh/a (11% of the overall vessel energy consumption within Aberdeen Harbour whilst at berth) and carbon emissions of 3,750 tCO_2/a.

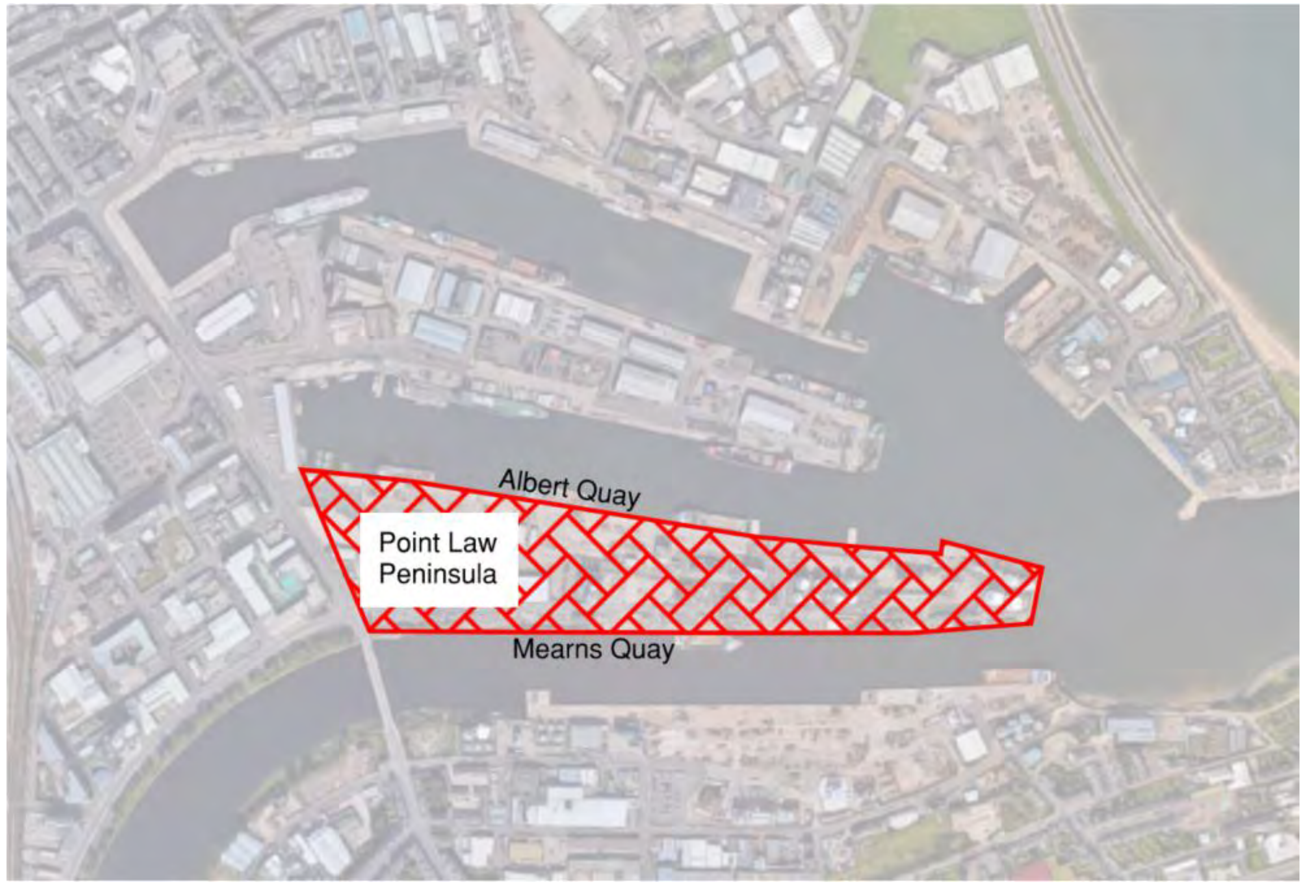


Figure 4—1 Aberdeen Harbour and Point Law Peninsula

4.4. Project "Business as Usual"

Traditionally, when ships are in port, they use their auxiliary engines to provide power for the ship's operations. This is also known as cold ironing.

Business as usual (BAU) for Point Law Peninsula would involve the ships leaving their engines running whilst in berth to ensure power is available for the ship systems. This engine operation would mean greater emissions from the vessels whilst in port, contributing to global warming, as well as noise and air pollution within Aberdeen, which negatively impacts vessel crews, landside operators and the wider community.

4.5. Energy demand for shore power

A detailed analysis of the energy demand for shore power at Albert and Mearns berths is provided in Appendix I. Briefly, berthing data for Albert and Mearns Quay from Aberdeen Harbour, as well as interviews with ship owners and operators were used to determine the time vessels spent at berth and power demand of these vessels. Further analysis was completed to understand the high-frequency vessels and operators of the port area. Using this information an anticipated phased demand profile for shore power was developed that recognised the shore power demand of large operators who frequently used the berths and were invested in using shore power.

Table 4—1 Summary of energy demand at Albert and Mearns Quay

	Total demand MWh/a	Phase 1 (2024) MWh/a	Phase 2 (2025)	Phase 3 (2026)	Phase 4 (2027)	Phase 5 (2028)
Average energy demand (Albert 1-5 Mearns 1&3)	821	172 (21%)	345 (42%)	517 (63%)	689 (84%)	821 (100%)
Total energy demand	5,744	1,206 (21%)	2,413 (42%)	3,619 (63%)	4,825 (84%)	5,744 (100%)

4.6. Shore power technology

To ensure ships can use the electrical power from a shore power unit, the voltages and frequencies need to match and a set level of safety and control functionality needs to be in place. Figure 4—2 shows the equipment required by the standard BSEN80005-3 to connect a ship to a shore power supply system when the frequencies of ship and shore are the not the same.

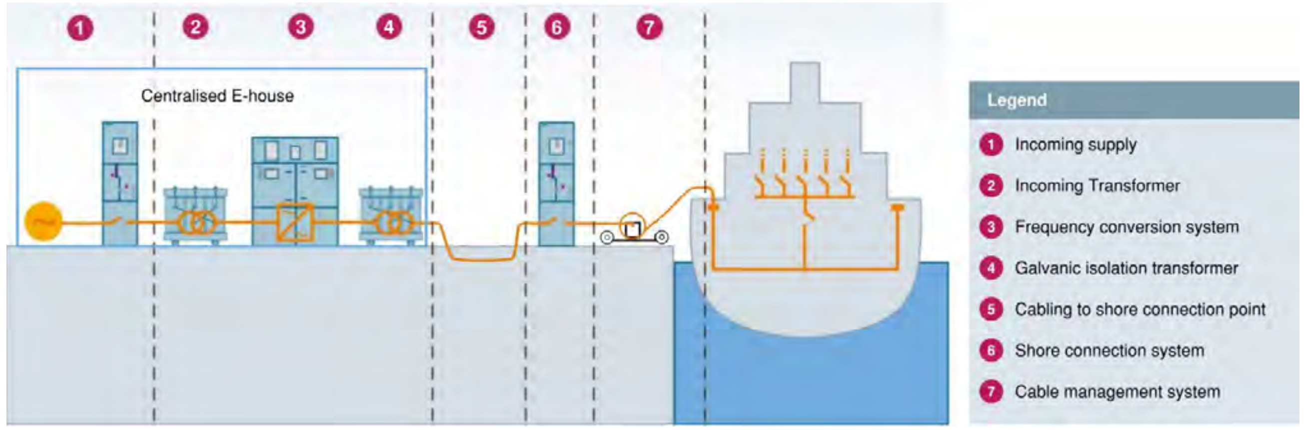


Figure 4—2 Block diagram of typical Low Voltage shore power connection system

The fundamental parts of the system that would be required at Aberdeen port are described in Table 4—2.

Table 4—2 -Shore connection system fundamental parts and descriptions

Item Number	Name	Description
1	Incoming supply	This is the electrical supply from the grid connection point from the Distribution Network Operator, in this case SSE. Due to the power requirements for the shore power system the network connection voltage would be required to be at 11 kV. The incoming supply would connect into an MV switch panel or Ring Main Unit depending on switching requirements on the network.
2	Incoming transformer	Power electronics become very costly when working with voltages above the low voltage range of 1000V. To ensure the costs of the system are maintained at a sensible level, the incoming voltage is required to reduce from 11 kV down to a voltage that can be used by the frequency converter (typically 400/440/690 V).
3	Frequency conversion system	The frequency of a ships power supply can be either 50 or 60 Hz with 50 Hz predominantly being the standard throughout Europe. During consultation with the ship operators currently active in Aberdeen, it was highlighted that the most common power frequency adopted for use on offshore platforms and the multi-purpose supply vessels (MPSV) using the Albert/Mearns Quay area of the harbour is 60 Hz. This means that a frequency conversion system is required to utilise the UK grid standard of 50 Hz. For the purpose of this economic case we haven't considered the requirements of the vessel. A ship must be equipped with a set level of functionality to be able to incorporate shore power in line with the international standard BSEN 80005-3: Utility connection in port – Part 3. To allow a ship running on 60 Hz to connect to the 50 Hz UK energy grid, a frequency conversion system is required to change between the two. This frequency conversion is achieved by first converting the voltage from an Alternating Current AC source to a Direct Current DC source before converting back to an AC voltage at the new frequency of 60 Hz.
4	Galvanic isolation transformer	To ensure the electrical systems are not directly connected, a galvanic isolation transformer is used on the shore side equipment prior to shore connection system. This transformer comes complete with neutral earth resistor to restrict the fault current available at the point of connection.
5	Cables to shore connection unit	The cables between the galvanic transformer and the shore connection unit is a fixed piece of LV infrastructure that is installed in the ground and sized to accommodate the current carrying capacity, volt drop and fault clearance requirements associated with the system.
6	Fixed shore connection point	This is a fixed piece of infrastructure that serves as the point of connection for the ship and is sized to accommodate the quantity of cables that will be connected to it and comes complete with safety features such as emergency stop and information display. The shore connection units are sized in accordance with BSEN 80005-3 that limit the operating current for each connector to 350A. When considering the operating voltages of the system, maximum power capacities for each connection point are as shown below in Table 4—3.
7	Cable management system	The cable management system connects the ship to the shore with the required number of connections as per the power requirements. The cable management system can be either fixed or mobile depending on requirements of the port. Examples of fixed and mobile connections are shown below in as shown below in Figure 4—3 and Figure 4—4.

Table 4—3 Cable power capacities for different voltages

Operating Voltage	Maximum current	Power capacity
400 Volts	350 Amps	242 kVA
440 Volts		266 kVA
690 Volts		418 kVA

Figure 4—3 Connection with fixed cable management system. Figure reproduced from [15]

Figure 4—4 Connection with mobile cable management system. Figure reproduced from [16]

4.7. Supplier engagement

To assist with the technical and financial elements of the project, Buro Happold undertook soft market testing for the shore power and connection systems to understand the different solutions available for implementation at the port. The suppliers contacted for shore power systems is shown Table 4—4 and Table 4—5 for the cable management systems.

All the suppliers listed held meetings with Buro Happold to discuss the project and potential solutions available. As a result of this, the long list of options as shown in Table 4—6 was generated.

To ensure like-for-like costs were received, the technical requirements for the three system types (decentralised, semi-centralised and centralised) were issued to the suppliers and the responses received are noted in Table 4—4 & Table 4—5. The spatial coordination and overview schematics of the different shore power configurations is also provided in Appendix A.

Table 4—4 Summary of supplier engagement for Shore power systems

Company	Response
ABB	Costs issued for centralised solution
CNE	Costs received for energy storage solution
DYG	No information received
GE	Costs issued for centralised and de-centralised solutions
Power Con	Costs issued for centralised solution
Power Systems International	Costs issued for centralised and De-centralised solutions
Schneider	Unable to provide technical input as below their threshold of 5 MVA frequency conversion capacity

Table 4—5 Summary of supplier engagement for shore power connection systems

Company	Response
Cavotec	No information received
Igus	Costing information issued for mobile cable management
Power Con	Costing information issued for mobile cable management
Shore-Link	Costing information issued for mobile cable management
Wabtec	Costing information issued for mobile cable management

A summary of the quotes received from the suppliers for their solutions is included in Appendix F.

4.8. Long list options

Following discussion with various shore power providers, in order to identify the preferred option for Aberdeen Harbour all options were considered within a multi-criteria analysis (MCA) assessment. Separate MCA assessments were completed for the shore power E-house systems, the fixed shore connection points and the cable management solutions. Principally there are three main design architecture for the shore power E-house, two types of fixed shore connection point and five main types of cable management system. Each option is described below in Table 4—6, alongside the pros and cons of each solution. The spatial coordination and overview schematics of the different shore power configurations is also provided in Appendix A.

[15] https://shore-link.eu/vessel-to-port/ [Accessed 31/03/2022]

[16] http://www.powercon.dk/ [Accessed 31/03/2022]

Table 4—6 Summary of the available shore power options

Shore Power E-House	Description	Pros / Cons
Decentralised	High voltage distribution to individual berthing area / connection point. All the required equipment at each berth for connection to the ships.	This system allows higher power quantities to be distributed around the site with lower losses, however it also takes up more space on the quayside and requires frequency conversion and transformation at each berth.
Semi-centralised	Centralised incoming high voltage supply and frequency conversion system that distributes at high voltage around the port to each individual berthing area / connection point. Transformation down to the voltage required for use by the ships at each connection point.	This system has the benefit of being able to distribute a higher quantity of power around the site via a reduced number of cables due to being at higher voltage and would be suitable when distribution in low voltage would lead to significant power losses (>15%)
Centralised	Centralised incoming high voltage supply, frequency conversion system and isolating transformers. Distribution at low voltage around the port to each individual berthing area / connection point for use by the ships.	This system allows all the technology to be incorporated into a single building, reducing construction costs and space take on the quayside. This system works well when operating at 690 V as the cable losses due to voltage drop are reduced vs 400/440 V.
Fixed shore connection point	**Description**	
Fixed above ground connection point	Fixed unit above ground approx. 1m × 1.2m space take. Unit would be protected by barriers and positioned at the front of the vessel, limiting the operational impact of the crane.	This system is relatively inexpensive and easy to operate and maintain. Operational movements need to be careful considered alongside buried service coordination to develop a practical solution.
Fixed below ground connection point	Fixed unit installed below ground within a chamber that would be accessible when connection is required. Unit connection would be positioned toward the front of the vessel, limiting the operational impact of the crane.	This system would require more maintenance due to the buried construction and would be more difficult to operate with due to manual handling risks. Solution can provide benefit to reducing impact on operations if designed to allow for crane movements over the access chamber during operation.
Cable management	**Description**	
Shore side fixed cable management point	Fixed cable management solution typically utilised for berthing area that is visited by the same vessel. Solution would have limited movement and be a fixed above ground structure.	This system allows for quick connection / disconnection but has limited flexibility to service multiple types of vessel with different connection points and acts as a constant obstruction to quayside operations.
Shore side flexible cable reel	Mobile cable reel solution on quayside that can be moved into place and connect the fixed connection point to the ship.	This system allows for maximum flexibility but does have slower connection / disconnection times. Used for vessels that has long durations at berths (>6h).
Ship side flexible cable reel	Cable reel solution on sip side that would be lowered to connect to fixed connection point at each berth.	This system would minimise the equipment on the quayside but would be a much larger capital expenditure as a cable reel would be required for each vessel.
Shore side port tracking connection	Moveable cable reel solution that can track along the edge of the quay wall to multiple connection points.	This system has lots of flexibility to move up and down the quayside and wouldn't impede operations on the quay but the integration of this type of system with the quay wall and berthing vessels would need to be carefully considered.
Shore side buried cable reel	Below ground cable reel solution fixed per berthing area / connection point	This system would require more maintenance due to the buried construction and would be more difficult to operate with due to manual handling risks. Solution can provide benefit to reducing impact on operations if designed to allow for crane movements over the access chamber during operation.

Table 4—7, Table 4—8 and Table 4—9 are the summary MCA tables for the shore power E-house, fixed shore connection points and cable managements solutions. Full MCA assessments are provided within Appendix B. The following criteria were considered within the MCA assessment with the corresponding weighting:

- Cost – 20%
- Maintenance – 15%
- Quality of design solution – 10%
- Inherent risk – 15%
- Supplier track record – 10%
- Effect on port operations – 10%
- Flexibility – 10%
- Lifetime / futureproofing – 10%

Table 4—7 MCA summary for shore power E-house options

Option	Cost matrix number	Maintenance matrix number	Quality of design matrix number	Inherent risk matrix number	Supplier track record matrix number	Effect on port operations matrix number	Flexibility matrix number	Lifetime / future proofing matrix number	Weighted matrix number	Rank
Decentralised	3	3	3	3	2	3	1	3	2.7	3
Semi-centralised	2	2	2	2	1	2	2	1	1.8	2
Centralised	2	1	1	1	1	1	2	2	1.4	1

Table 4—8 MCA summary for fixed shore connection point options

Option	Cost matrix number	Maintenance matrix number	Quality of design matrix number	Inherent risk matrix number	Supplier track record matrix number	Effect on port operations matrix number	Flexibility matrix number	Lifetime / future proofing matrix number	Weighted matrix number	Rank
Fixed above ground connection point	1	2	2	2	1	2	2	1	1.6	1
Fixed below ground connection point	2	3	2	3	2	2	2	2	2.3	2

Table 4—9 MCA summary for cable management options

Option	Cost matrix number	Maintenance matrix number	Quality of design matrix number	Inherent risk matrix number	Supplier track record matrix number	Effect on port operations matrix number	Flexibility matrix number	Lifetime / future proofing matrix number	Weighted matrix number	Rank
Shore side fixed cable management point	1	2	2	1	1	3	2	2	1.65	2
Shore side flexible cable reel	1	1	2	2	1	2	1	1	1.35	1
Ship side flexible cable reel	3	2	2	2	1	1	1	1	1.8	3
Shore side port tracking connection	3	3	1	1	2	1	1	2	1.9	4
Shore side buried cable reel	3	2	1	2	2	1	2	2	2	5

4.9. Preferred option

The MCA assessment showed that the preferred option for Albert and Mearns Quay is a:

- Centralised shore power E-house
- Fixed above ground connection point
- Trenched LV cabling from the E-house to the shore power connection points
- Shore side flexible cable reel

The centralised shore power E-house option is feasible at a distribution voltage of 690 V, as this voltage reduces the cable losses encountered during distribution to the shore connection points. At this voltage shore connection points have power output up to 836 kVA, which provides a level of future proofing for battery charging or larger vessel power demand.

A fixed shore connection point was chosen to the ease of maintenance and operability. Also, if the location of this infrastructure is specifically designed to minimise operational impact it is deemed to be a more preferred solution for Aberdeen Harbour.

The mobile cable reel connection system was preferred due to the flexibility this offered and to reduce space take on the quayside that could limit or constrain crane operations whilst not in use.

Figure 4—5 is an illustration of the shore power infrastructure on Albert and Mearns Quay, with a centralised shore power E-house that would likely be a containerised solution with a space take of 10m × 6m. Power would be distributed underground to seven fixed connection points, that would be connected to vessel via a mobile cable reel. This cable reels would be stored in a central storage area while not in use. For the preferred solution the following points should be noted:

1. To reduce excavations through the reinforced concrete deck slab fixed connection points at Albert Quay are positioned in three locations (see section 4.10. This allows for the cabling of two connection points to be completed within the same excavation channel. Therefore, there is a proposed berthing arrangement for the ships if they were connecting to shore power.
2. The fixed shore connection points on Albert Quay are as close to the quay edge as practicably possible, enabling the quayside crane to move up and down the quay. However, due to the suspended deck construction on Mearns Quay these connection points have to be set back on the quay, as excavations within the suspended deck could impact the structural integrity of the quay. Therefore, shore power connections points have been positioned at either end of the quay to allow for movements of the crane whilst in operation.
3. Spare ducting capacity has been designed to allow for future shore power expansion.

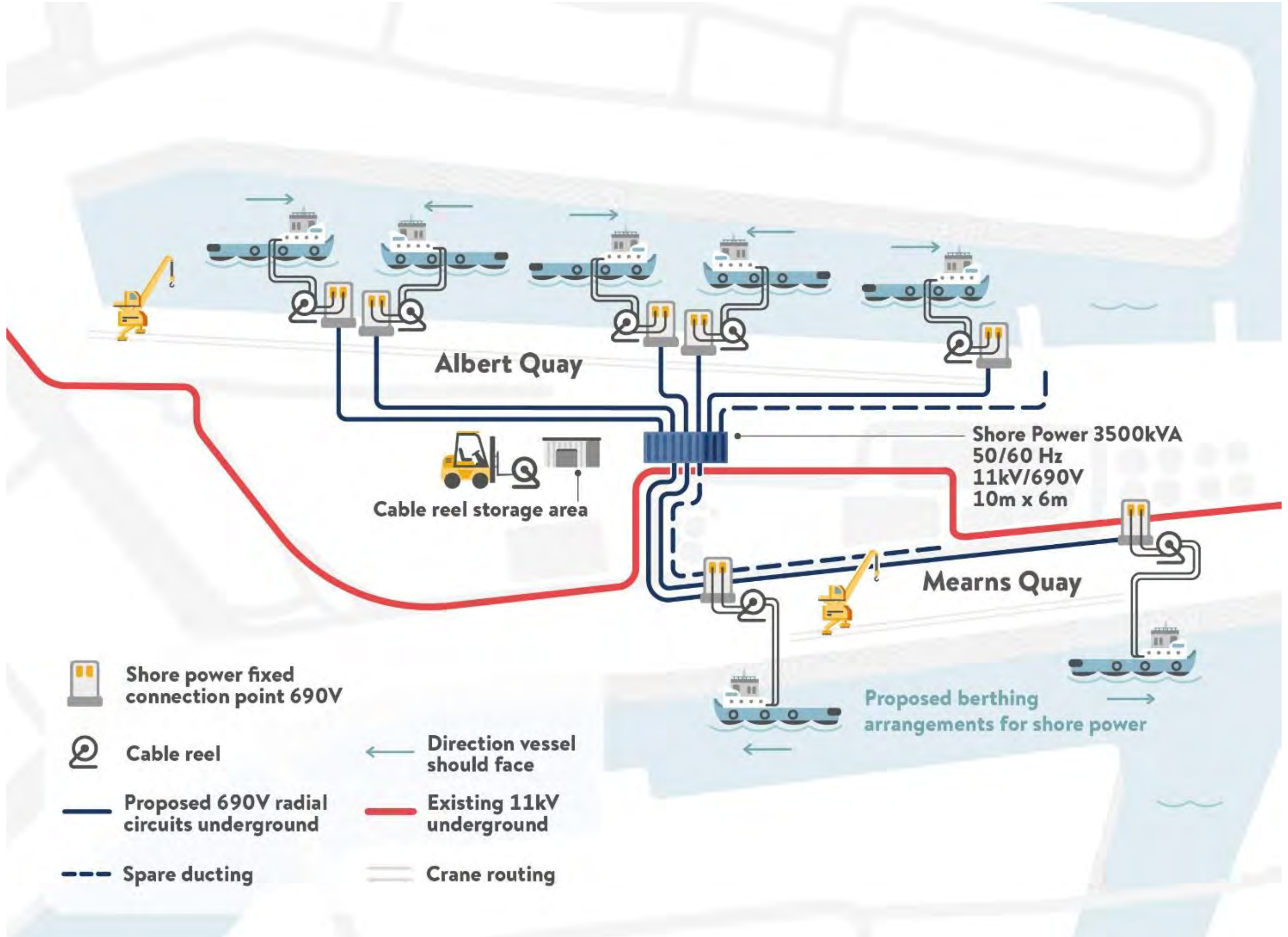


Figure 4—5 Illustration of shore power infrastructure at Albert and Mearns Quay

In addition to the illustration 3D renders were generated to visualise the shore power infrastructure and space take. Figure 4—6 shows the shore power infrastructure layout on Albert Quay and Figure 4—7 shows the infrastructure on Mearns Quay. Figure 4—8 and Figure 4—9 show the centralised shore power E-house and cable management storage area respectively.

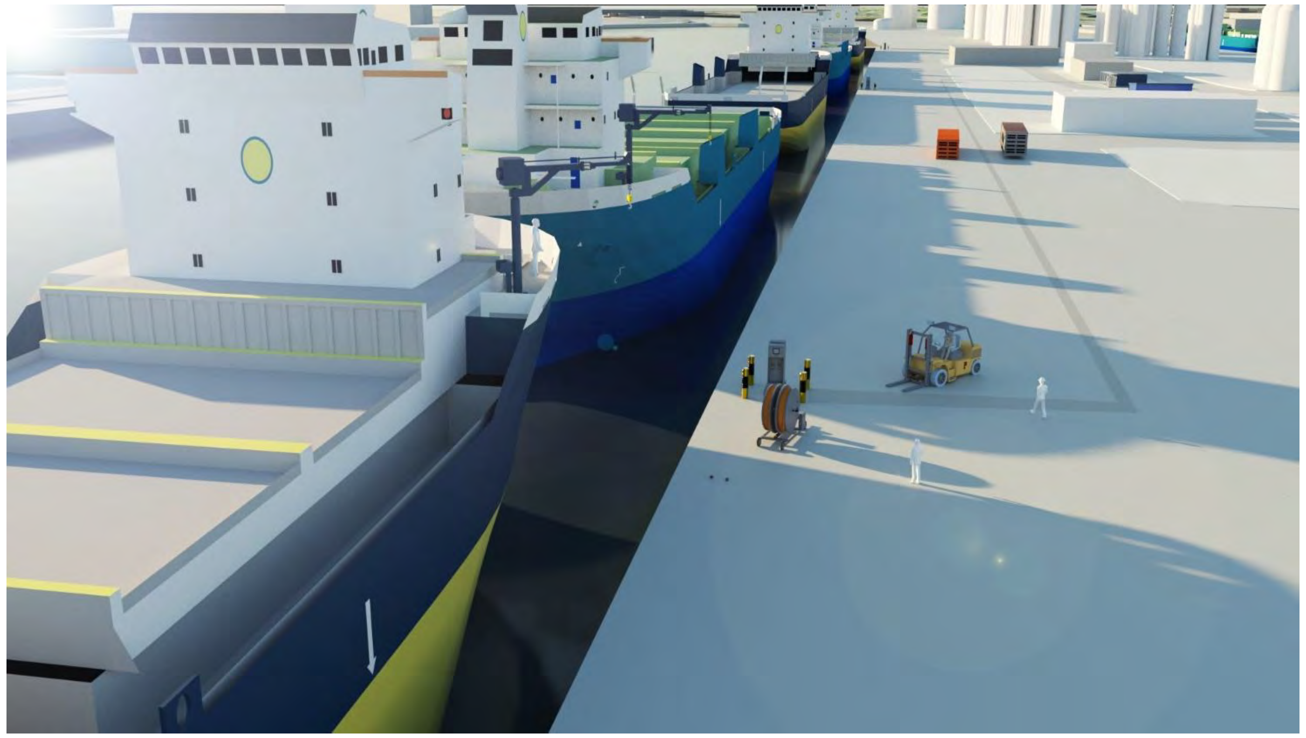


Figure 4—6 3D render shore power infrastructure Albert Quay

Figure 4—8 3D render shore power E-house

Figure 4—7 3D render shore power infrastructure Mearns Quay

Figure 4—9 3D render cable management storage area

3D renders were also used to demonstrate the shore power connection/disconnection process. This occurs in three stages:

1. Cable reel delivered to berthing area during the ship berthing process (Figure 4—10)
2. Cable reel lifting towards the ship side connection using the vessels onboard crane or quayside crane (Figure 4—11)
3. Shore connection made with ship and fixed connection point (Figure 4—12)

Figure 4—10 3D render shore power connection process stage 1 - Cable reel delivered to berthing area during the ship berthing process

Figure 4—11 3D render shore power connection process stage 2 - Cable reel lifting towards the ship side connection using the vessels onboard crane or quayside crane

Figure 4—12 3D render shore power connection process stage 3 - Shore connection made with ship and fixed connection point

4.10. Spatial coordination report

Following the identification of the preferred option a spatial coordination exercise was completed to investigate how the new infrastructure would integrate with existing services. A list of the high priority hazards identified from the spatial coordination report are provided below. The full spatial coordination report is provided within Appendix E.

1. Utility information and spatial coordination: More detailed information regarding the position of existing services is required to progress the design. It is recommended that GPR and topographical surveys are carried out in relevant areas to determine more exact service positions to inform design. Following the completion of a utility survey and identification of pinch points, trial holes may be required at some locations to confirm service positions, material, condition, and depth of cover.
2. Concrete deck slab excavation: A reinforced concrete deck slab of significant thickness is present at Albert Quay, with additional reinforced concrete being present around surface drainage channels located along the deck slab. Due to difficulty of excavation and reinstatement, the proposed routes have been positioned to minimise excavation in this area. Part of this strategy includes the location of some of the route segments within the Albert Quay Road instead of the deck slab (Figure 4—13). During early discussions with the client, the number of trenches located within the deck slab has been reduced. An optional route has been identified based on available as-built drawings that could reduce the excavation costs (Figure 4—14).

Figure 4—13 Proposed LV cabling route avoiding excavation of the reinforced concrete deck slab at Albert Quay.

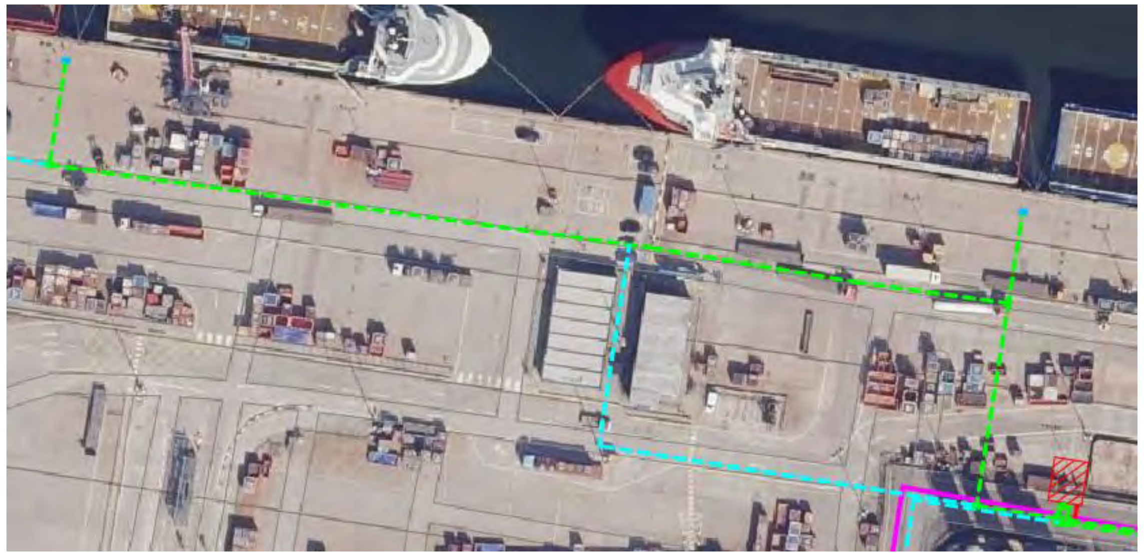


Figure 4—14 Proposed route in cyan may allow easier excavation. Based on available as-built drawings, there is a possibility that the surfacing in this area may be less substantial than the 275mm thick reinforced concrete slab present in the surrounding area.

3. Large sewers at North Esplanade East: The feasibility of crossing above the two large-diameter sewers located at North Esplanade East (Figure 4—15) is critical for allowing the connection between Albert Quay and Mearns Quay. Additional information regarding the exact depth, condition, and construction of the sewers should be obtained to progress the design, including consideration for carrying out trial holes.

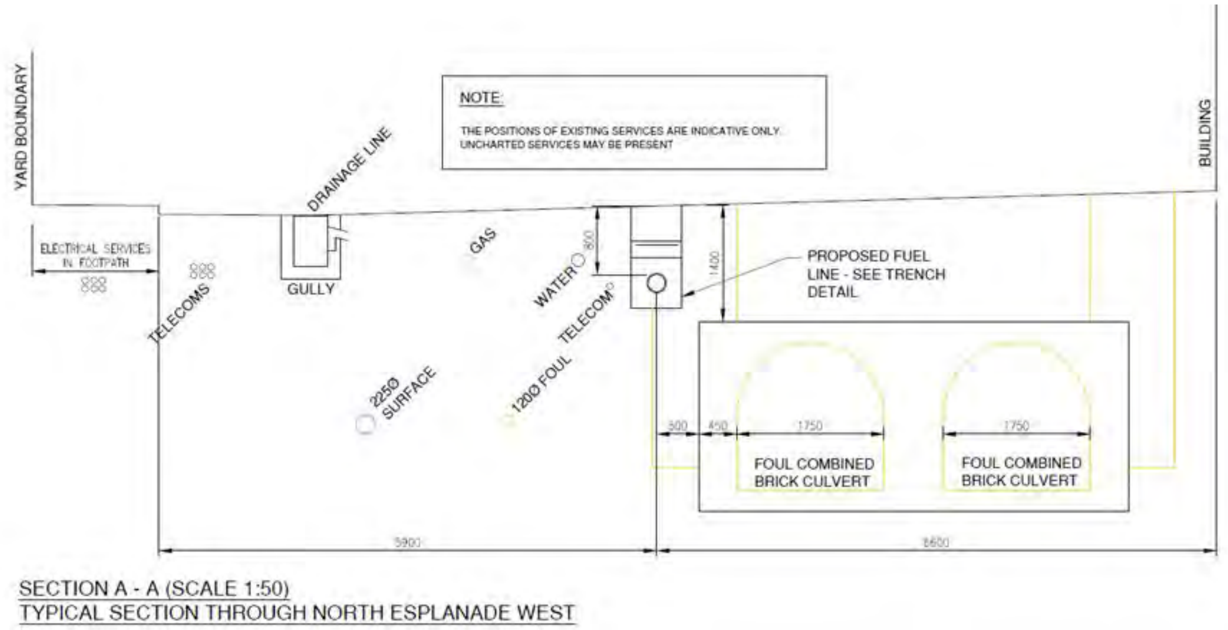


Figure 4—15 Two large sewers shown to run along North Esplanade East.

4. Fuel line crossings: The proposed cable routes cross a number of fuel lines at Albert Quay and at North Esplanade East (Figure 4—16). The feasibility of these crossings and the crossing details should be established at an early stage.

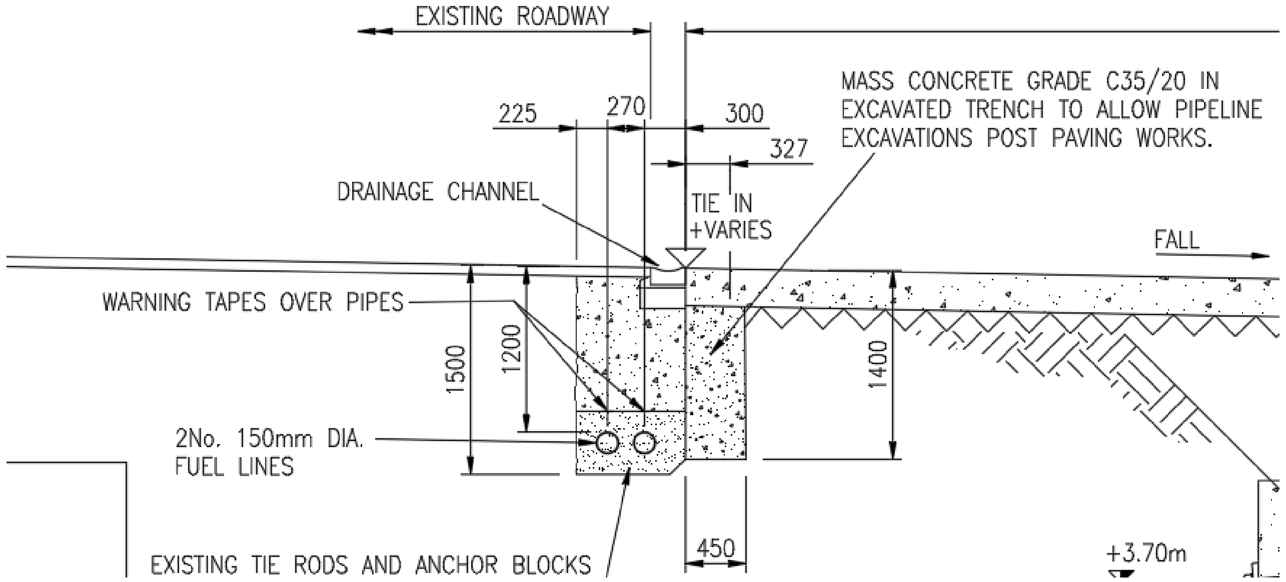


Figure 4—16 Example of 150mm diameter fuel lines positioned along the southern edge of the Albert Quay deck slab, with 1.2m of cover above the pipes. The drawing shows sand surrounding the pipes and an adjacent buried mass concrete wall. The mass concrete wall has been constructed to act as a temporary retaining wall during excavations of the fuel lines. The backfill above the sand surround appears to be mass concrete, although it has not been annotated in the drawing.

5. Redundant service trenches: During the site visit, it was noted that some of the concrete service trenches at Albert Quay have been infilled with concrete and are therefore assumed to be redundant. It should be confirmed at an early stage which trenches have been made redundant and whether all of these have been infilled. Although the trenches do not align with the proposed positions of shore power connection points, they may be used to allow easier crossing of the deck slab as no excavation below the 300mm drainage channel would be required, and any underlying services would be crossed by these trenches.

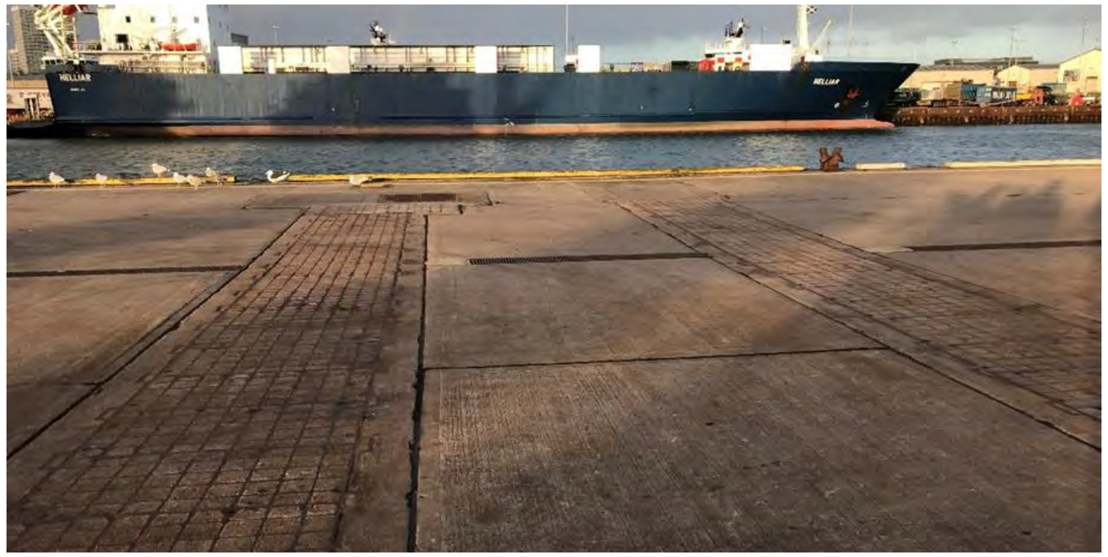


Figure 4—17 Site visit photograph showing concrete service trenches at Albert Quay. It is noted that the trench on the right of the photo has been infilled with concrete and is therefore assumed to be redundant.

6. Optional route segments: Further development of the optional route segments by identification of pinch points from utility surveys and review of any other available as-built drawings could allow the reduction of the number of crossings over existing services, and the reduction of excavation of reinforced concrete at Albert Quay. This includes the optional route at the western side of the quay, the optional route passing between two buildings located centrally at Albert Quay (Figure 4—13) and the optional route of passing through a yard between Albert Quay Road and North Esplanade East (Figure 4—18).

Figure 4—18 An optional route has been identified which could allow connection between the route segments along Albert Quay and North Esplanade East by passing through a yard which is abutted by both of these roads. Statutory utility maps consulted for this report do not show services crossing the yard. Additionally, the as-built drawings provided by the client at this stage do not show a significant density of services located in this area.

7. Albert Quay crane: A mobile crane operates at Albert Quay, generally positioned on the quayside area of the deck slab. Water mains service fire hydrants and cable ducts located at the northern edge of the quayside deck slab may require placement of shore power connection points further south from the cope beam (Figure 4—19). There is a risk of encroachment on the typical operating area of the mobile crane and therefore a risk of impact on typical harbour operations by installation of above-ground shore power cables. Depths and alignments of water mains and cable ducts need to be identified as well as ownership of the water main and any required consents at an early stage. It may be feasible to install power cable ducts near and above existing hydrant water mains with a suitable design for the shore power connection point chamber. Possible modifications to harbour operations or alternative designs should be considered at an early stage if this isn't feasible.

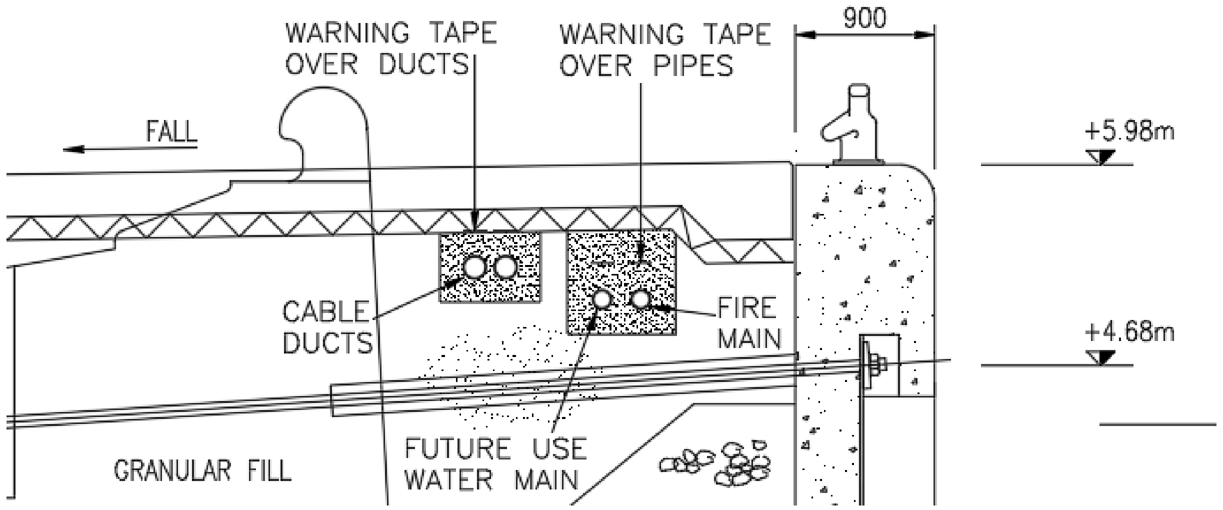


Figure 4—19 : Extract from Arch Henderson as-built drawing 03012-29 showing two water mains and cable ducts adjacent to the cope beam.

Figure 4—20 and Figure 4—21 show the provisional suggested cable routing and spatial coordination of infrastructure on Point Law Peninsula.

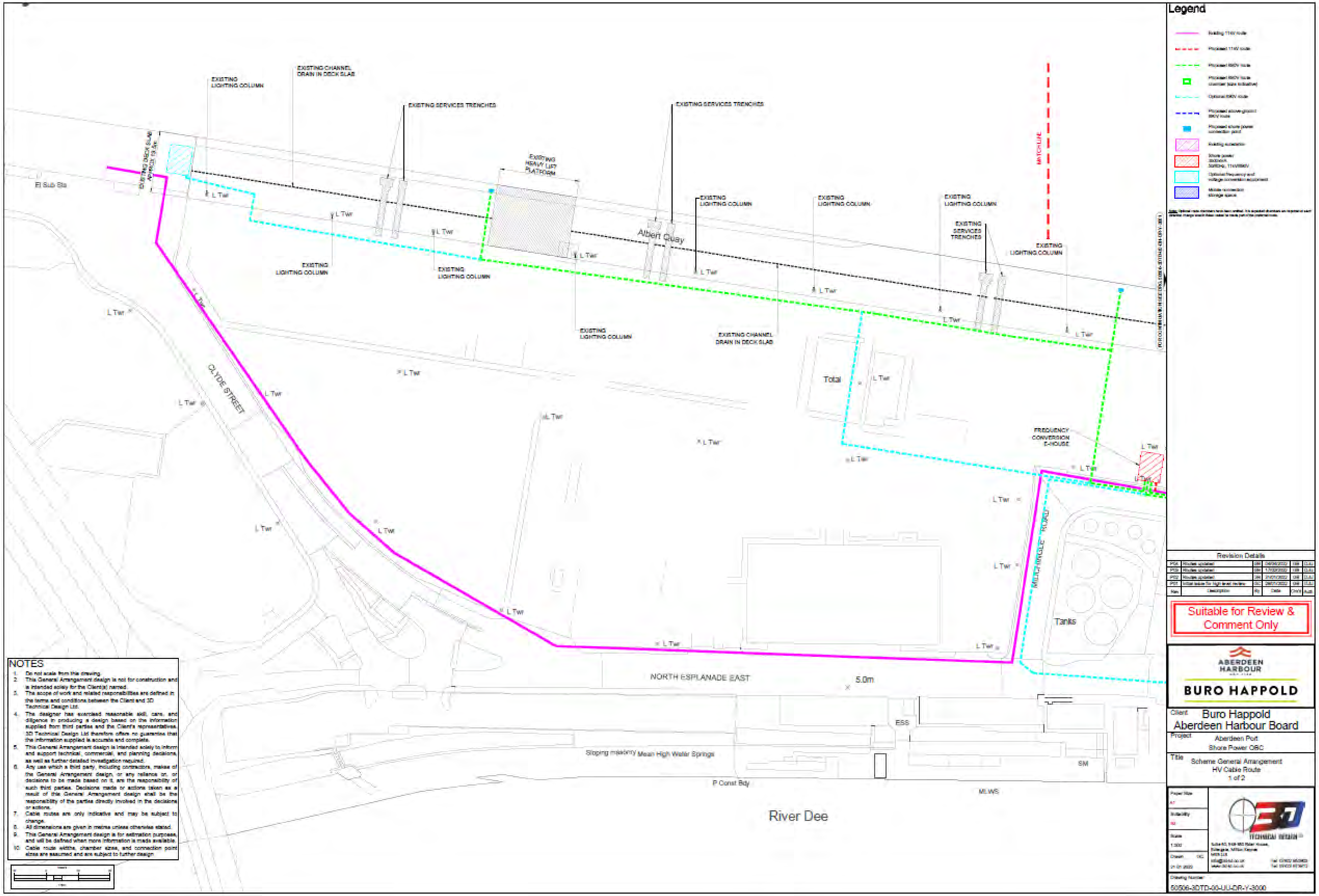


Figure 4—20Part 1 of 2 - Spatial coordination overview drawing with OS map underlay showing provisional suggested cable routing and spatial coordination of infrastructure.

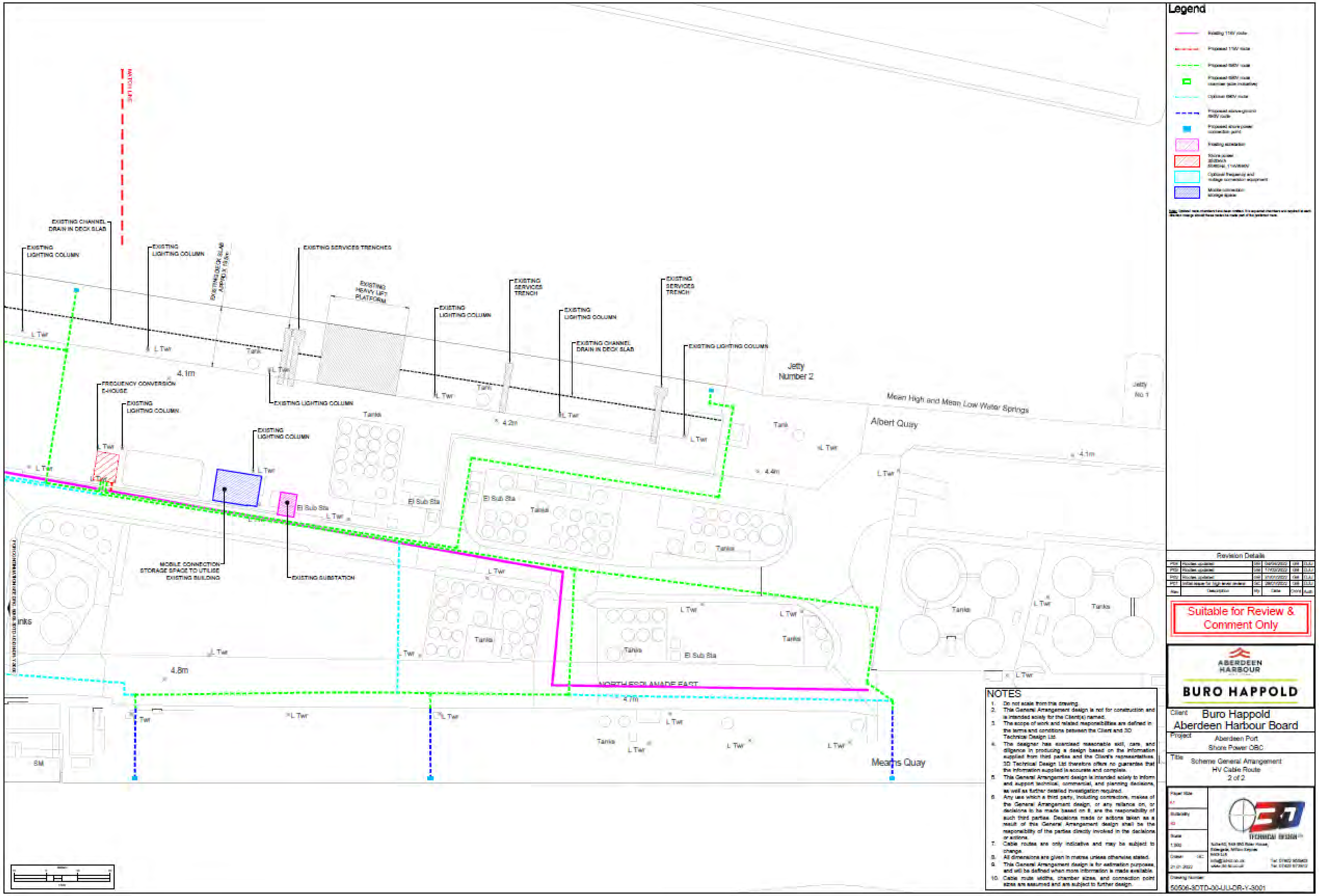


Figure 4—21 Part 2 of 2 - Spatial coordination overview drawing with OS map underlay showing provisional suggested cable routing and spatial coordination of infrastructure.

4.11. Techno-economic modelling

A techno-economic cashflow model (TEM) has been set-up to assess the possible return on investment which each scenario can achieve over a 20-year time period. The chosen scenario to consider was for a total of 7 shore power connection points, 5 at Albert 1-5 and 2 at Mearns 1&3.

A TEM was built in MS Excel combining the technical details of the scheme (capital and operational) with appropriate cost/price inputs to generate an annual cash flow. This enabled an assessment of viability (pre-tax) using Net Present Value (NPV) and Internal Rate of Return (IRR) as key indicators.

The key assumptions included:

- The shore power provider would own, operate and maintain the whole shore power network
- Shore power is sold to consumer at a variable rate. There are no standing changes occurred by any users due to the number of users and variety in frequency of equipment for each user. The fixed costs on the project are absorbed into the variable rate charged.
- Uptake of shore power is modelled across five phases (operational years). It is assumed that the shore power demand increases linearly every year, with 100% shore power uptake occurring after 4 years of operation (see section 4.5).
- The demand was assumed to be the same across all berths, due to the difficulties in projecting future usage within Albert and Mearns locations (see section 4.5).

4.11.1. Modelling assumptions

Table 4—10 shows the various modelling assumptions within the techno-economic model.

Table 4—10 Modelling assumption for the TEM

Assumption	Value	Source	Comment
Electricity import price	15.02 p/kWh	17	Non-domestic small/medium consumer band inc. climate change levy (CCL) Q4 2021
Electricity carbon factor	0.102 kgCO2e/kWh (2020) 0.027 kgCO2e/kWh (2064)	18	Electricity emissions factor decreasing over time due to the decarbonisation of the electricity grid in-line with BEIS projections
Marine fuel price	15.33 p/kWh	19,20	Rotterdam marine gas oil (MGO) price in March 2022 $1002/t; conversion to GBP 0.75 £/$; Fuel efficiency 0.204 t/MWh
Marine fuel carbon factor	0.654 kgCO2e/kWh	20	Specific fuel consumption 0.204 kg/kWh; mass of CO2 produced whilst burning 3.206 kgCO2/kg
Parasitic losses	10%		Calculated electrical losses through cabling and within unit conversion from 11kV/50Hz to 690V/60Hz
Commercial appraisal lifetime	20 years		
Scheme start year	2024		
Discount rate	3.5%	21	HM Treasury, The Green Book
Grant funding	25%-100%		Sensitivity variable to be considered within the financial case

[17] Department for Business, Energy & Industrial Strategy, Gas and electricity prices non-domestic sector, 2021.
[18] Department for Business, Energy & Industrial Strategy, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, 2021.
[19] https://shipandbunker.com/prices#MGO [Accessed 30th March 2022]

4.11.2. Counterfactual

The counterfactual scenario to the shore power scenario is "business as usual", whereby vessels continue to use marine fuel for their power requirements whilst at berth. The TEM compared the carbon and other pollutant emissions of the counterfactual with the shore power scenario, to determine the emissions saving and social impact (see sections 4.13 and 4.14).

4.11.3. Mark-up sales price

The base case TEM taken forward to full financial modelling utilised the "goal seek" function to determine the mark-up price needed (difference between the electricity import price and shore power sales price) to deliver a set IRR of 9%. The mark-up price was deemed to be a more useful metric for Aberdeen Harbour compared with the shore power sales price, due to the fluctuations seen in current energy prices[22]. Therefore, it is recommended that Aberdeen Harbour should arrange to maintain a consistent mark-up price (pre inflation) to allow for security in generating a return.

4.11.4. Capital cost

Various industry suppliers were engaged to receive quotes for specialist shore power infrastructure equipment. Quotes from various suppliers are provided within Appendix F. Additionally, a sub-consultant (Thomson Bethune) was engaged to evaluate the capital cost assumptions of the project. The cost plan produced by Thomson Bethune is also provided within Appendix F. Table 4—11 shows the capital cost breakdown associated with the shore power project. Please note an allowance for inflation has been included assuming a site start of first quarter 2023 and with an overall 12-month construction period. The inflation allowance is based on the current tender price indices published by the Building Cost Information Service of The Royal Institution of Chartered Surveyors which indicate a predicted increase in tender prices over this period of 5.71%.

The overall capital cost of the project was calculated to be approximately £8M. The largest single cost is related to the shore power unit (£2.8M). The difference in quotations between suppliers for the shore power unit equipment varied substantially (£1M - £2.8M) and therefore overall CAPEX could reduce by ~20% if alternative suppliers were chosen.

[20] International Maritime Organization, Forth Greenhouse Gas Study 2020, 2020.
[21] HM Treasury, The Green Book Central Government Guidance on Appraisal and Evaluation, 2020
[22] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators [Accessed 9th March 2022]

Table 4—11 Capital cost breakdown

CAPEX item	Details	Source	Cost
Shore power unit	Centralised shore power connection unit and outlet points. Based on ABB quotation plus requirement for 3500kVA system. Includes transformer (11kV/690V), frequency conversion (50/60 Hz), housing, groundworks and reinforced concrete foundations for shore power unit	Various project specific quotes. Thomson Bethune for foundations and associated builder work.	£2,754,000
Cable management	7nr cable reel cable management solutions.	Various project specific quotes	£676,000
Port side connection	7nr above ground port side connection boxes with 2 cable connections for cable reel. Plinths and associated builder work for final connection positions.	Various project specific quotes. Thomson Bethune for builder work	£248,000
Low voltage network costs	Trenching and reinstatement for proposed duct and cable routes from centralised shore power location to serve 7nr connection points at the quayside. Plastic ductwork with draw wires all laid in trenches to accept cabling network. LV cabling pulled into ducts and connected to shore power location and final outlet connection points. Data cabling pulled into ducts and connected to shore power location and final outlet connection points.	Thomson Bethune following cable routing provided by Buro Happold	£1,839,000
Network ancillary equipment	Recommended list of spares and cable protection barrier solution for cable reel on Mearns Quay	Various project specific quotes and Thomson Bethune for cable protection solution	£141,000 (Recommended spares total £119,000; critical spares total £59,000. See Appendix G)
Cable storage building	Central cable storage building. Steel framed structure with insulated metal cladding to walls and roof (8m × 8m footprint)	Thomson Bethune	£135,000
Electricals	Upgrade to existing Distribution Network Operator mains electrical system to serve shore power design. Trenching and reinstatement of ground for mains upgrade.	Specific DNO quote	£200,000 (See Appendix H for details)
Additional costs	An allowance for design fees by the Contractor assuming a design and build procurement route has been included at 2% of the works value. The preliminaries allowance for the Main Contractors site set up and site management costs has been set at 11% of the work value. This percentage reflects the nature of the works and the expected duration that would be required to complete operations on a development of this type. An allowance of 10% of the works value has been included for Main Contractor overheads and profit. The contingencies allowance has been set at 10%. This figure is the minimum prudent allowance that should be allowed for works of this nature at this stage of the design process.	Thomson Bethune	£1,995,000
Total			**£7,988,000**

Operating costs

The ongoing operational costs within the model are categorised as follows:

- Operation and maintenance costs
- Fuel costs
- Replacement costs

4.11.4.1. Operation and maintenance costs

Operating expenditure (OPEX) for equipment was modelled as a percentage of CAPEX or as a cost per unit/connection.

	Units	Cost	Comments
Shore power unit	% of CAPEX per year	0.5%	After discussion with the supplier, maintenance costs were suggested to be low for this equipment. Maintenance costs will typically be around 1 day per year including: Visual inspection on the outside. Visual inspection of container for damage to gaskets and rust protection. Visual inspection of container inside for penetrating water and dirt. Inspection of electrical components and connections inside the system. Inspection of wear on components (fan, switch, pump and coolant).
Cable management	% of CAPEX per year	1%	Supplier suggested maintenance costs would be low due to limit moving/complicated parts. General maintenance of the equipment.
Metering and billing	£/connection per year	£1,500	Cost involved with processing the billing inc. software system integration and maintenance, invoicing etc.

4.11.4.2. Fuel costs

Figure 4—22 shows the pre-inflation electricity purchase price over the modelled period starting at 15.7 p/kWh in 2024 and falling to 13.6 p/kWh in 2035. BEIS prices for non-domestic small/medium consumer band inc. CCL for Q4 2021 were indexed throughout the model in-line with BEIS projections for future fuel costs, which provides a forecast out to 2035. After this point, it is assumed that the electricity cost stays the same, in the absence of reliable forecasts.

The most recent published BEIS data on electricity prices[22] were used to account for the recent increases in wholesale gas and electricity prices within the modelling approach. However, with the absence of further short-term price forecasts and the fact this study considers network opportunity across the scheme lifetime (20 years), long-term price projections published annually by BEIS were used for future price forecasting. The recent increase in electricity prices demonstrates the current dependence on gas for electricity production, particularly when renewable electricity output is lower than expected. However, these prices will begin to decouple as the UK transitions away from combined cycle gas turbine (CCGT) electricity generation and towards renewables. This transition is captured within the future BEIS projections, whereby gas and electricity prices begin to show more independence by the mid-2020s.

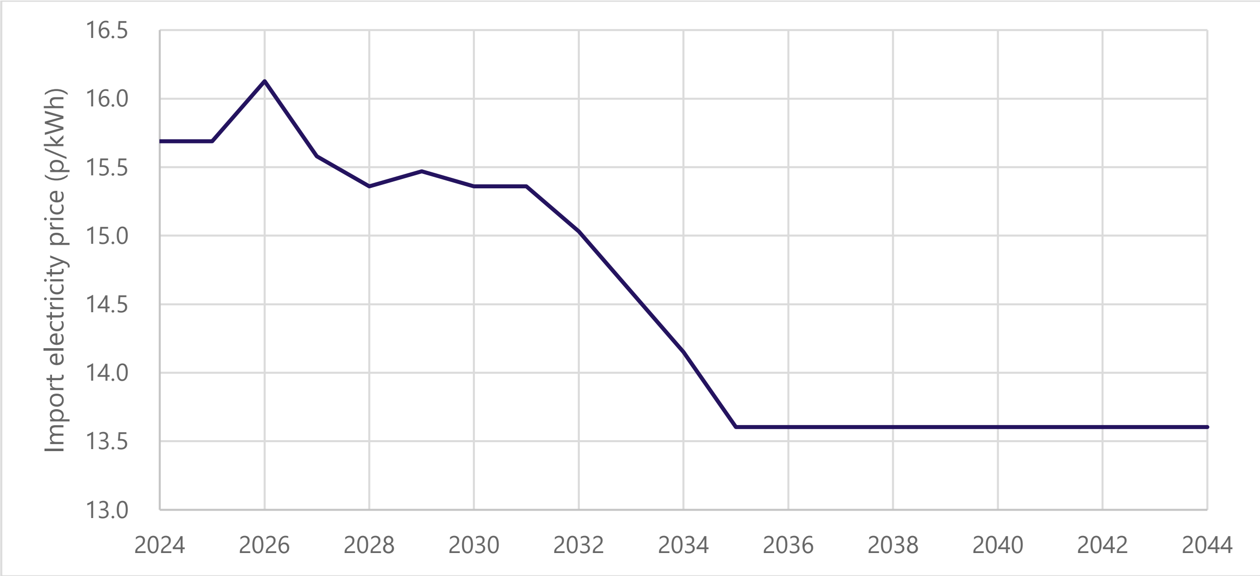


Figure 4—22 TEM import electricity price

Figure 4—23 shows the cost of marine gas oil (MGO) has increased approximately 90% between March 2021 and March 2022 ($526/mt March 2021; $1,002/mt March 2022) and reached a high of $1,468/mt on 9th March 2022 (170% increase). The significant increase in fuel oil cost improves the economics of shore power, as electricity becomes more cost competitive. In March 2021 the cost of MGO per kWh was ~8p/kWh (fuel efficiency of 0.204 t/MWh from IMO study[20]). In March 2022 this price has risen to ~15p/kWh and therefore in-line with the anticipated import electricity price of the harbour. During the initial feasibility study completed there was shown to be limited economic benefit for consumers to use shore power. With current geopolitical pressures and musings on carbon taxation within the shipping sector, it appears that marine fuel prices will continue to rise, demonstrating the economic benefit of shore power, as well as the social/carbon benefit.

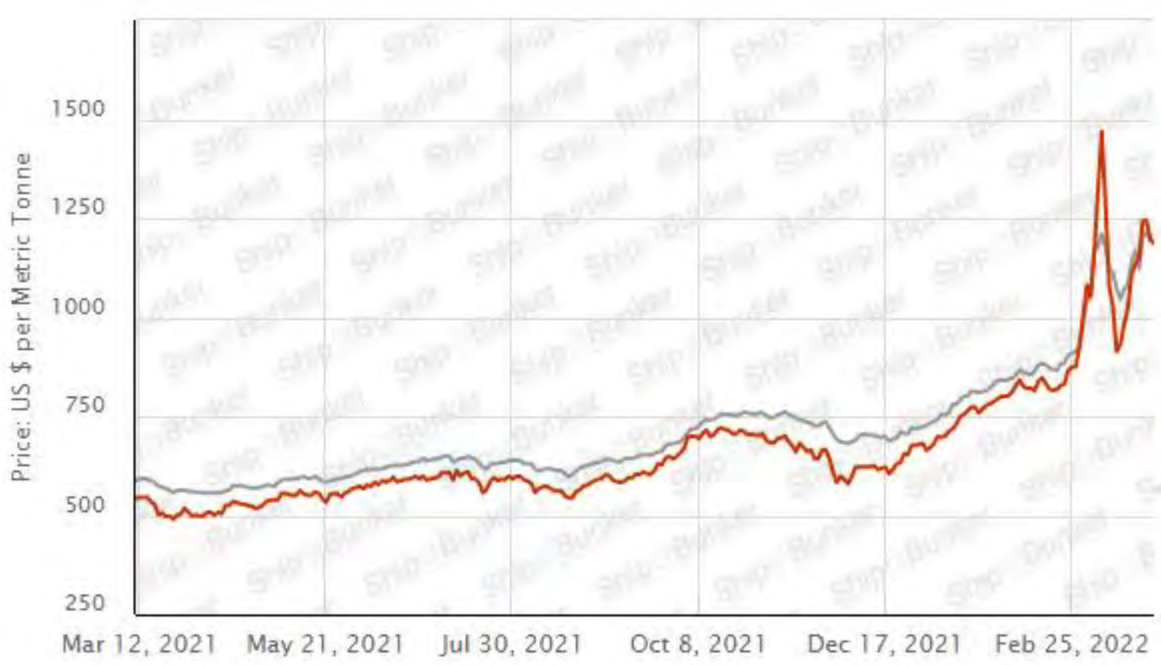


Figure 4—23 Ship and bunker price marine gas oil (MGO) March 2021 - March 2022. Figure reproduced from [14]

4.11.4.3. Replacement costs

Table 4—12 shows the lifetime replacement period assumed for the major capex items that will need to be replaced over the modelled 20-year period. Within the model an 80% charge is incurred as a replacement cost at the end of the asset lifetime.

Table 4—12 Replacement period assumptions

	Replacement period	Comments
Shore power unit	Full project lifetime	Fixed electrical equipment modelled to operate as run to failure. Cost of spares has been included within CAPEX. Electrical infrastructure expected to last the whole scheme lifetime under normal operating conditions.
Cable management	15 years	Moving infrastructure would need replacing during the scheme lifetime. Current infrastructure not operational long enough to truly understand equipment lifetime.
Port side connection	Full project lifetime	Fixed electrical equipment modelled to operate as run to failure. Electrical infrastructure expected to last the whole scheme lifetime under normal operating conditions.

4.11.5. Revenue

Revenue is generated for the project through the sale of shore power. There is no standing charge/fixed tariff charged to the consumers. The shore power sale price was calculated by adding a mark up to the cost to Aberdeen Harbour of importing electricity from the grid (see section 4.11.3).

4.12. Results

Below in Table 4—13 is a summary of the results from the TEM results (pre-tax and inflation). The results show that to achieve an IRR exception of 9% the mark-up price needed would be 14.02 p/kWh, equating to a shore power sales price of 29.05 p/kWh.

A full financial model was completed following the results of the economic model to refine the mark-up and shore power sales price, following tax and inflation adjustments (see section 6).

Table 4—13 Summary of techno-economic results

	Scenario – Albert 5 / Mearns 2
Total CAPEX	£7.99M
Average OPEX per year	−£0.81M
Average REPEX per year	−£26k
Average revenue per year	£1.40M (£360k Y1; £730k Y2; 1.07M Y3; 100% utilisation Y4-Y20)
Shore power sales price	29.05 p/kWh (26.95 p/kWh for a 40-year term)
Mark-up price	14.02 p/kWh (11.92 p/kWh for a 40-year term)
Grant funding[23]	50%
NPV at 10 years	−£0.55M
NPV at 20 years	£3.23M
IRR at 20 years	9.0%
Discounted payback	12 years

Figure 4—24 shows the associated cash flow curve of the chosen scenario.

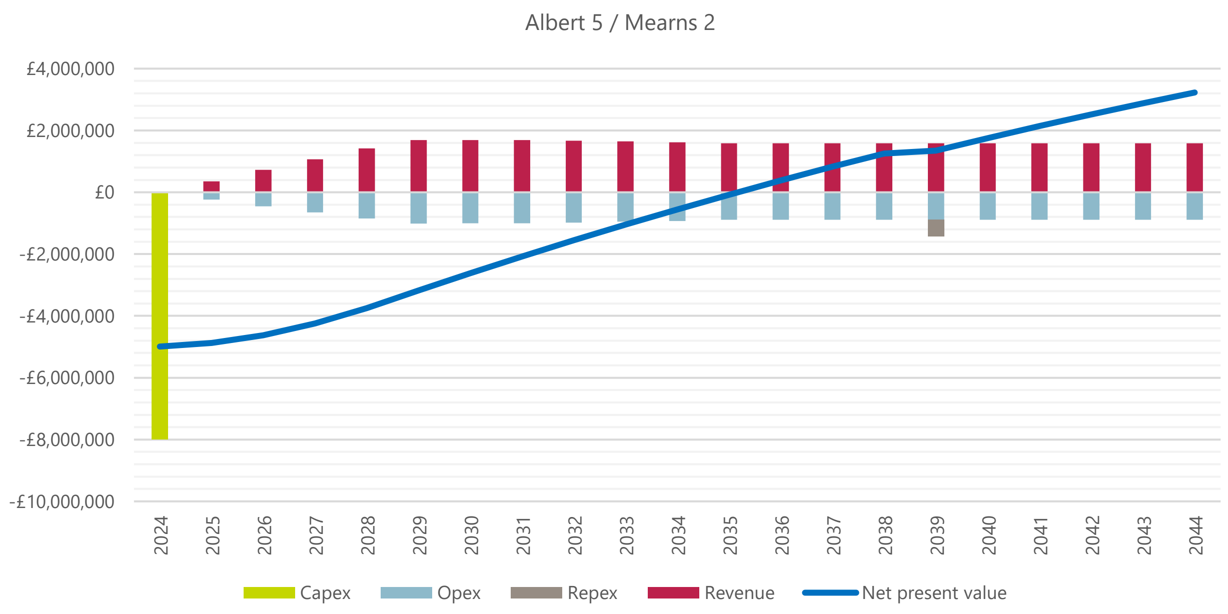


Figure 4—24 Cash flow curve of chosen scenario (5 shore power connection points at Albert and 2 at Mearns).

4.12.1. Sensitivity analysis

Sensitivity analysis has been carried out as part of the techno-economic analysis to illustrate the key modelling inputs of the scheme and their impact on project NPV and project IRR. Various modelling inputs were varied by ±30%:

- Fuel cost (electricity import price)
- Capital cost
- Shore power sales price
- Annual demand

Figure 4—25 shows that all four chosen inputs have a large impact of the scheme economics. The largest sensitivity is shore power sales price, where the NPV at 20 years changed by ±£6.0M for a 30% change in the shore power sales price.

To reduce the risk associated with the project, the shore power sales price was separated into two elements within the financial model: the fuel cost element and the mark-up price element. The mark-up price is the difference needed between the electricity import price and shore power sales price to generate a specified return on the shore power infrastructure investment (see section 4.11.3).

Further analysis into the sensitivity of different input variables on the mark-up price is provided within section 6.

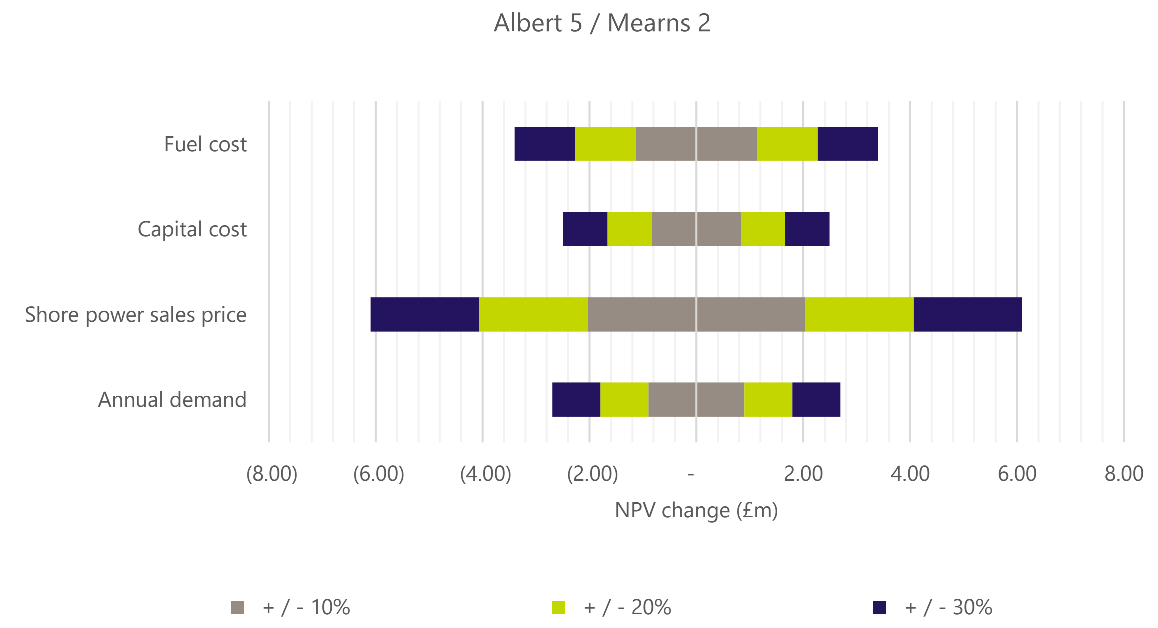


Figure 4—25 Sensitivity curves for chosen scenario (5 shore power connection points at Albert and 2 at Mearns).

4.13. Social impact

As well as looking at the economics of the scheme it is also important to consider the social benefit. The social benefit of shore power was assessed by two measures:

1. Carbon abatement value
2. Air quality impact value

[23] 50% grant funding assumed within base case. Impact of grant funding assessed between 25%-100% within financial model.

Using the monetary value associated with preventing the release of one tonne of carbon equivalent into the atmosphere[18], the social value of carbon abatement by utilising shore power was calculated for the project and compared with the counterfactual.

Implementing shore power on Albert and Mearns berths is expected to save approximately 62,000 $tCO2_e$ over the 20-year project lifetime compared with the "business as usual" case. This equated to a yearly emissions saving of ~3,100 $tCO2_e$.

Using the carbon values published by BEIS to achieve net zero by 2050, this equates to a carbon abatement value of £604,000 per year or £12.7M over the scheme lifetime.

It is also important to consider the air quality impact associated with other pollutants e.g. NOx, SOx and particulate matter through the burning of marine fuel, whilst at berth in Aberdeen.

The IMO recently published typical pollutant emissions per tonne of marine fuel burned within their greenhouse gas study[20]. This information was combined with the Department for Environment Food & Rural Affairs publication on the air quality damage cost of certain pollutants[24] to generate an air quality damage cost associated with marine fuel, which was compared with electricity (Appendix J).

It can be seen that marine fuel has approximately 50 times more air quality damage impact cost compared to electricity (9.85 p/kWh vs 0.21-0.31 p/kWh). This equates to approximately £325,000 social value addition a year in air quality damage reduction costs, or £6.8M over the lifetime of the project.

Overall the scheme has a social benefit of £19.5M, demonstrating the significant value of the project to society as a whole.

Social value addition	Lifetime value addition	Average yearly value addition
Carbon abatement vs counterfactual	£12.7M	£604,000
Air quality impact vs counterfactual	£6.8M	£325,000
Overall social value vs counterfactual	**£19.5M**	**£929,000**

4.14. Carbon emissions

Figure 4—26 and Figure 4—27 show the lifetime and annual carbon emissions of the shore power project compared with the counterfactual scenario.

Implementing shore power in Albert and Mearns Quay saves 62,000 tonnes of CO2e over the scheme lifetime (20 years). This equates to an 82% reduction in carbon emissions compared to the counterfactual of burning marine fuel whilst at berth.

Due to the phased projected rollout and uptake of shore power there is expected to be a phased emissions reduction over the first 5 years of the scheme lifetime (Figure 4—27). Following the full rollout of shore power and subsequent decarbonation of the UK grid, emission reductions per year are estimated to be in the region of 3,500 tCO2/a.

The initial decarbonisation strategy feasibility study for Aberdeen Harbour estimated ca. 44,000 tCO_2/a of carbon emissions are produced throughout the port. Of these emissions 78% (34,000 tCO2/a) were derived from ships using marine fuels while at berth. Therefore, developing shore power infrastructure at Albert and Mearns Quay could reduce Aberdeen Harbour's overall emissions by approximately 8% and reduce berthing emissions by 11%.

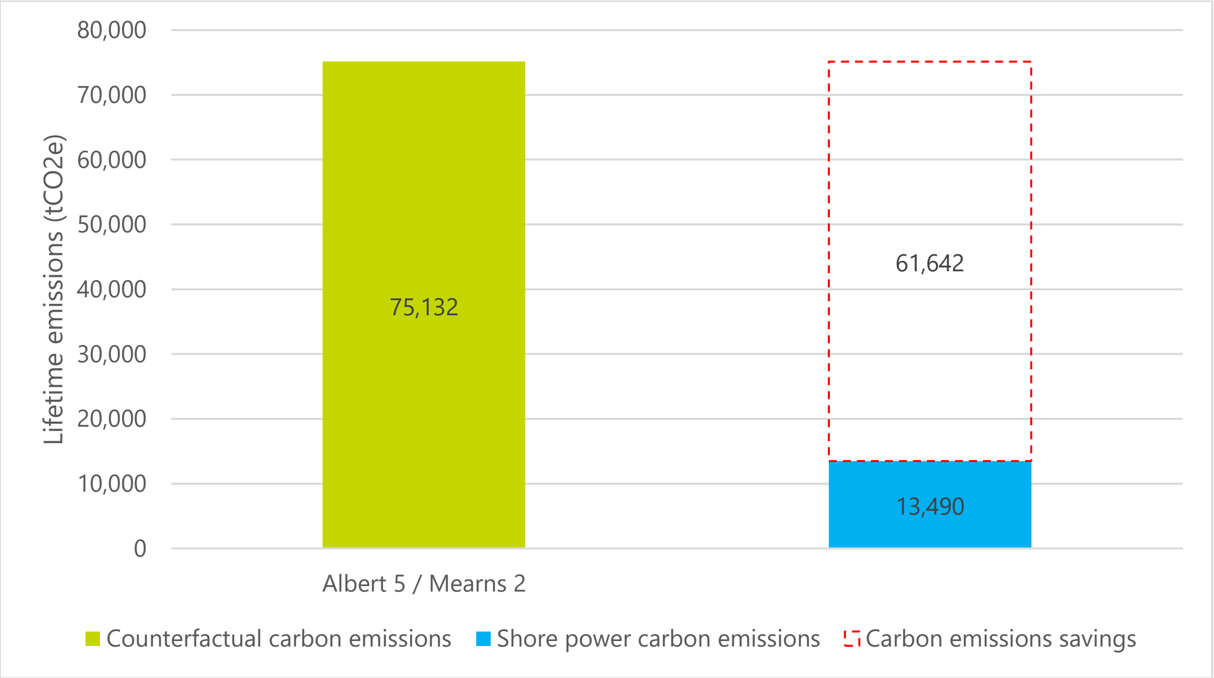


Figure 4—26 Lifetime emissions comparison vs counterfactual

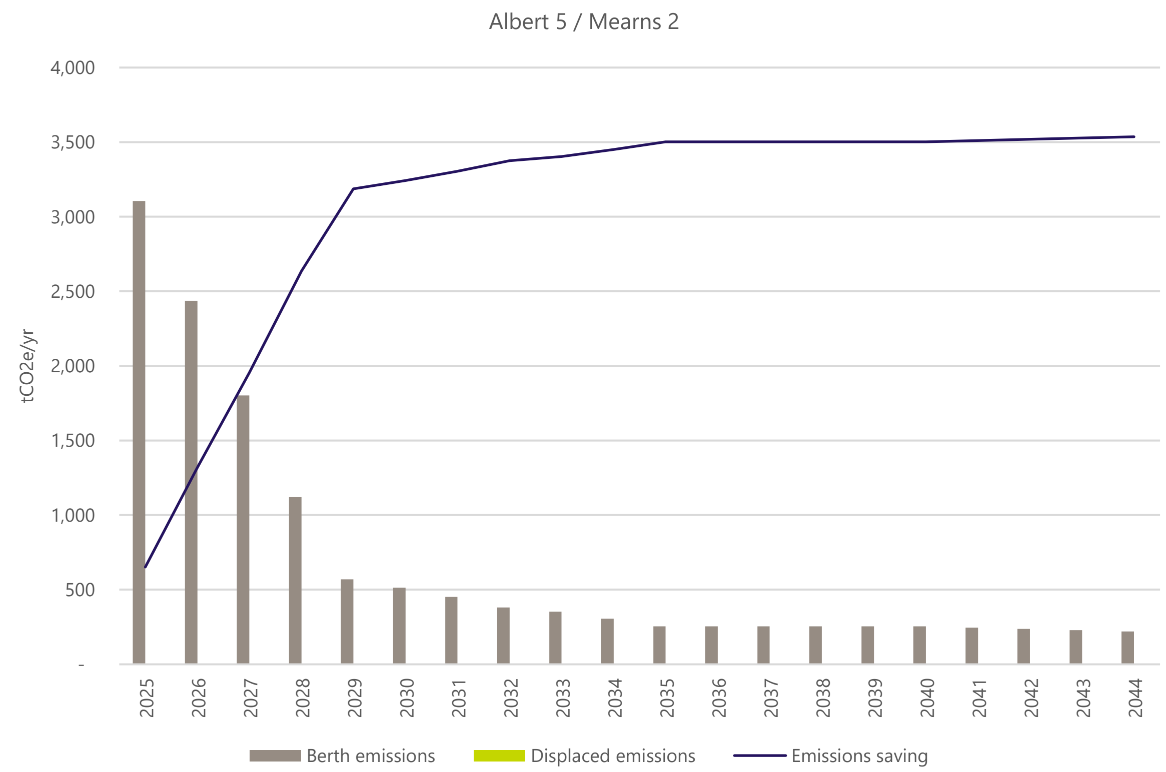


Figure 4—27 Annual emissions comparison vs counterfactual

[24] https://www.gov.uk/government/publications/assess-the-impact-of-air-quality/air-quality-appraisal-damage-cost-guidance#annex-a-updated-2020-damage-costs [Accessed 14th March 2022]

5. Commercial Case

5.1. Overview

The commercial case must demonstrate that the project will result in a viable procurement and contractual strategy and provide a sustainable basis for the long-term operation of the shore power system.

The objective of this Commercial Case is to summarise the developed commercial model of the preferred option for delivery of the project for all stakeholders. The Commercial Case is part of the overarching Five Business Case Model and should be viewed in conjunction with the Strategic, Economic, Financial and Management Business Cases.

The primary purpose of the Aberdeen Harbour Port Decarbonisation Strategy presented in this Outline Business Case is to provide a carbon emissions reduction strategy for vessels 'hotelling' at the Albert and Mearns berths, and to highlight the drawbacks of the energy source traditionally associated with this process. The scheme is expected to realise benefits that support Aberdeen Harbour as a pioneer in the development of a reasonably priced, reliable and carbon reducing shore power energy systems across the United Kingdom.

A commercial strategy must ensure the project delivers an optimal return for the level of risk being taken, while aligning with the key carbon reduction objectives for the harbour and its port users. The scheme needs to consider the commercial structure in which Aberdeen Harbour wants to deliver the system, considering the various roles of the energy operators, port users, service companies, suppliers, contractors, and any investor(s) that may be attracted to the project. The key roles for the development of a shore power system are usually allocated as shown in Table 5—1. The allocation of these roles is dependent on the allocation of risks, ability to fund and requirements for participation and control.

Table 5—1 Key roles associated with a shore power system,

Role	Explanation
Asset owner	The party that owns the physical assets, such as the shore power system and associated infrastructure.
System Operator	Responsible for the technical operation of the shore power system.
Retailer	The party responsible for the retailing of energy, i.e. purchasing electricity from an electricity supplier and arranging transportation to the shore power system.
Port User	Considered to be the customer and critical for the operational viability of the system

From discussions with the harbour to date it is evident that creating a shore power system and sustainable economic model are highest priorities for the scheme. There is however some tension between relatively high procurement and maintenance costs associated with the construction of the systems infrastructure versus the historically lower energy solution using marine fuel. However, Aberdeen Harbour is mindful of the need to provide a carbon reduction solution which is fit for the future and which not only satisfies early connection requirements, but also provides a basis for future development at the port.

This chapter summarises the following:

- Heads of Terms, developed with input from Aberdeen Harbour and drafted for the main stakeholders
- Stakeholder Roles
- Key Objectives
- Proposed commercial structure
- Proposed charging mechanism
- Risk allocation
- Procurement requirements
- Contract and procurement strategy

5.2. Heads of Terms

During the completion of the DPD, Heads of Terms (HoTs) were drafted for the following stakeholders with input from Aberdeen Harbour:

- Aberdeen Harbour (shore power operator)
- BP (shore power customer)
- TotalEnergies (shore power customer)
- Harbour Energy (shore power customer)
- Ithaca Energy (shore power customer)
- Shell (shore power customer)
- Other smaller Energy Operators (shore power customer)

The latest version (at time of writing this document) of the full heads of terms for the main stakeholders is included in Appendix D.

5.3. Stakeholder roles

The stakeholders and their roles within the shore power system must be identified to ensure a successful delivery of the project. The commercial structure shown in Figure 5—2 details the contractual relationship and procurement arrangements of each of the parties within the shore power system delivery. The key roles can be summarised as the following:

- Aberdeen Harbour – project sponsor and enabler
- Funding bodies both locally and nationally - The project may qualify for CMDC Phase II, LCITP or Marine Fund funding which will improve the financial and commercial performance of the project
- Potential customers – BP, TotalEnergies, Shell, Harbour Energy etc.
    - A minimum activity level will be required to ensure the commercial viability of the project. Initial interaction suggests a willingness to use shore power and a desire to help reduce carbon emissions. Table 6—12 in the Financial Case shows the effects varying demand has on the project's financial returns. Table 4—1 shows the energy demand findings at Albert and Mearns Quay.
- SSE – needed to enable power for the project.
- Logistics Service Providers – quayside operators who will have an interest in the operation of shore power (i.e. handling of cable management systems)

5.4. Key objectives

The stakeholders recognise that there are a number of objectives that would need to be either addressed or positively contribute to the shore power project. Conversations and workshops were held with the key stakeholders where their objectives were explored and their critical success factors considered. Following these consultations, it was agreed that the following objectives should be prioritised:

- Delivery of a carbon reducing energy solution for Aberdeen Harbour
- Delivery of reasonably priced power to the ships when at berth

5.5. Commercial structures

There are several ways in which Aberdeen Harbour could set up and deliver the shore power system. Feasibility work has been undertaken to identify the harbours objectives and to determine the commercial option which best achieves those objectives, including choice of commercial structure, preferred procurement delivery model, physical scope of the scheme, nature of services and economic viability.

Ultimately, because Aberdeen Harbour is the sole investor (excluding grant funding) and instigator of the shore power system, they have the ability to decide what formal role they want to take in the design, installation, commissioning, and long-term operation of the network. Aberdeen Harbour has access to cash from their balance sheet which aids the ability to fund the scheme, however, this results in the harbour holding the financial risk (lessened with grant funding) but would also benefit from the forecasted revenue generation of the scheme and therefore future returns.

The possible structures that are available for Aberdeen Harbour are summarised in Table 5—2.

Table 5—2 Potential commercial structures

Commercial structure	Description
3rd Party concession	Common approach whereby a private 3rd party company installs, owns and operates the shore power system and acts as the energy service provider. The scheme must be commercially attractive to a private company but does not necessarily remove the burden of financial investment, installation, operation, and maintenance from the harbour
Aberdeen Harbour Joint Venture	Aberdeen Harbour partners with a 3rd party to establish a Joint Venture. Both entities will be responsible for funding the shore power system and will share control of the managing of contractors and sale of electricity. The 3rd party can bring in external expertise and equity and requires a level of strategic control but reduces Aberdeen Harbours exposure to risk. The project must be seen as economically viable to attract a JV partnership.
Wholly Owned (Aberdeen Harbour)	It is unlikely that Aberdeen Harbour will deliver the shore power system directly. This is more likely to be done via a corporate vehicle such as a Special Purpose Vehicle, which will be responsible for administering contracts to 3rd party experts. The use of a corporate vehicle allows the harbour to maintain strategic control over the contractors, the sale of electricity and benefit from any financial rewards. However, Aberdeen Harbour would be responsible for funding the project and will be exposed to project risks unless transferred to the contractors.
Self-Delivery (direct involvement)	Aberdeen Harbour undertakes delivery and operation of the project in its entirety. This will include sourcing all necessary funds, undertaking procurement, and owning and operating the scheme including acting as an electricity supplier to end customers. Aberdeen Harbour gains more strategic control but more risk, but equally can benefit from the revenue generation.

The fundamental issue facing the client in determining whether they invest directly in the shore power system, is what relationship is required with a 3rd party. The evaluation of the options usually resolves around a number of considerations as summarised in Table 5—3.

Table 5—3 Considerations for Aberdeen Harbours involvement

Consideration	Explanation
Control vs. risk	The tensions between the desire for control over project outcomes and the willingness to take on project risk.
Commercial attractiveness	The rate of return the project will actually support and whether this will be acceptable to the 3rd party.
Cost of raising capital	Cost of capital drives rate of return needed for a project and different organisations have different costs of capital which can result in differing levels of expected returns needed.
Availability of capital	The availability of capital to both private sector and 3rd party is limited but is also closely linked to the degree of risk involved and the organisations' understanding of the risks involved.

The amount of control that Aberdeen Harbour requires over the scheme is important in achieving their overall objectives. Similarly, drivers to participate for the stakeholders need to be sufficiently strong to ensure agreements for connection and supply are reached. For port users it is likely that some form of compulsion will be required to ensure connection, through government levies which require the ships to connect to the shore power system as opposed to using the existing, high polluting, marine fuel energy source. Figure 5—1 illustrates the level of control, risk and reward associated with the 4 commercial structures.

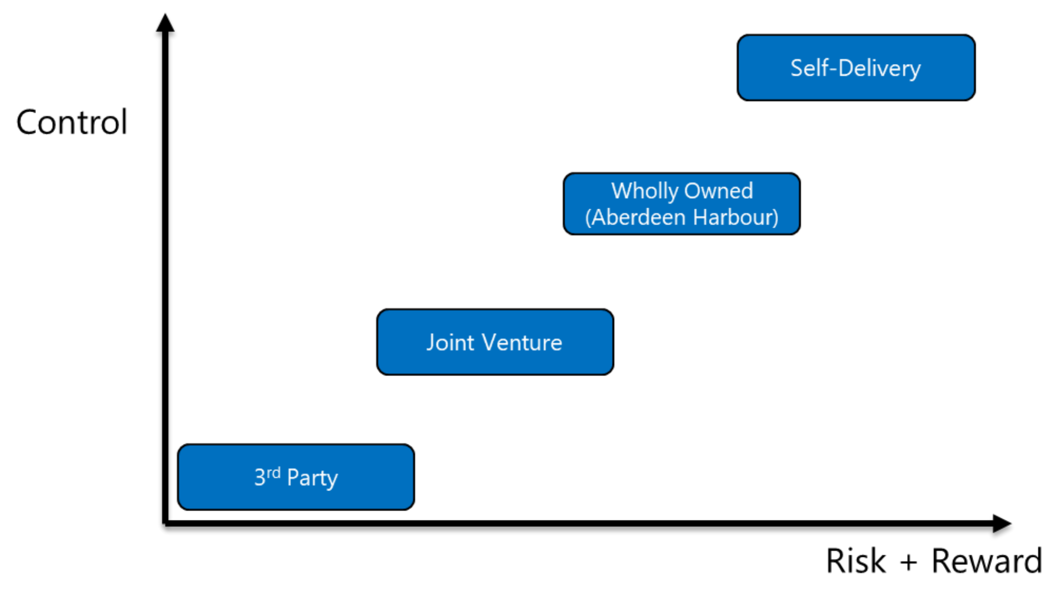


Figure 5—1 Risk, reward and control associated with commercial structures

The approach to ensure connection to the shore power system for future customers has yet to be confirmed but is envisaged to include:

- Supplying reasonably priced electricity to the ships when at berth.
- Providing an alternative, carbon reducing energy source to ships when at berth.

Aberdeen Harbour and supporting consultant team have reflected on the available options and agreed that progressing with a simple structure was preferred, that does not rely on securing 3rd party interest in return for risk transfer or investment. This can be achieved by the harbour owning the shore power system and network assets and using standard contractual forms for the delivery of the project, whilst accepting operating risk and the longer return on investment associated with the system.

5.5.1. Proposed commercial structure and delivery

It was therefore proposed a Wholly Owned (Aberdeen Harbour) led approach to deliver, own and operate the shore power system using a combination of internal funding and external grant funding. A wholly owned corporate vehicle, such as an SPV, would be established so that AHB can own the assets and maintain strategic control of the operations. Through this commercial structure the harbour is able to fund the project via the SPV with their own internal finances as well as external grant funding.

As the sole investor and creator of the SPV, the harbour board will be the primary shareholder and decision maker. A shareholder's agreement between the board and the corporate vehicle legal entity would initially be established so that any decision making can be regulated. The creation of a corporate vehicle provides a simple mechanism for administering contracts to 3rd party experts when external knowledge and experience is required. Aberdeen Harbour would ultimately be responsible for the delivery and operation of the project including the appointment and management of consultants/ contractors and the sale of electricity to port users.

Once the shore power system has been established, the wholly owned commercial structure would not impact the potential future sale of shares in the SPV and the subsequent transfer of ownership to 3rd party investor(s). Further connections beyond the Albert and Mearns Quay berths would result in lower risk and improved value proposition. Sale of the corporate vehicle would need the system to be seen as profitable, but should this happen, the harbour would need to consider a saleable value which is attractive to the buyer. The shore power system must also ensure all outstanding debt burden can be covered. Equally, all stakeholders would need to be engaged to review any time related contracts and ensure the new owner had assured future costs and income. Table 5—4 summarises the benefits and drawbacks of the proposed wholly owned commercial structure.

Table 5—4 Advantages and disadvantages associated with a wholly owned commercial structure.

Advantages	
	Aberdeen Harbour maintains ownership of assets and strategic control of the operations.
	Exist strategy through the sale of shares in corporate vehicle.
	Easier to accommodate expansion.
	Benefit from generated revenue.
Disadvantages	
	More overhead to administer, need to draw on market experts.
	Exposure to risk unless passed down to consultants/ contractors.
	Aberdeen Harbour solely responsible for projects funding/ securing funding.
	reputational damage if poor service

The anticipated commercial structure for the first power off takers is illustrated in Figure 5—2. This indicates the proposed funding from the UK Government via the CMDC grant scheme as well as internal capital. It is currently proposed that commercial arrangements will be formalised with the following:

- Professional services: yet to be confirmed but likely to include ongoing legal and technical support and possibly project management if the harbour decides to outsource management of the scheme.
- DBM Contractor: to be appointed via competitive tender following completion of the current design, and responsible for the detailed design, complete installation and commissioning.
- Operations and Maintenance contractor(s): either kept in-house, contracted or sub-contracted depending on element of shore power system. Training to be provided by equipment supplier on a negotiated basis.
- Billing: likely to be kept in-house.
- Electricity customers:
  - o customer supply and connection agreements
- Electricity providers:
  - o power supply agreements

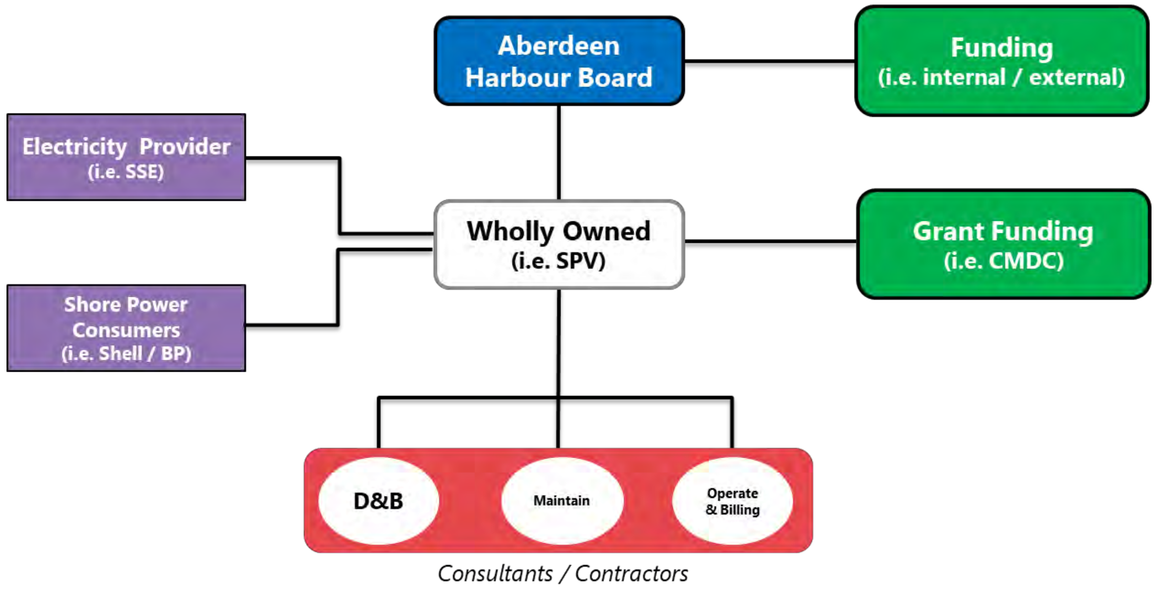


Figure 5—2 Anticipated commercial structure

5.5.2. Proposed avenues for funding

In 2020, £20 million in investment into the Clean Maritime Demonstration Programme was announced as part of the Ten Point Plan for a Green Industrial Revolution. Following on from the funding released through the CMDC to undertake feasibility studies, the DfT is presently running a call for evidence on shore power to support the interventions announced for the Clean Maritime Plan, which is anticipated to be rolled out in 2023. Any funding announced as part of the Clean Maritime Plan could be a key source of funding for the shore power scheme in Aberdeen Harbour.

The wholly owned commercial structure provides flexibility around the funding sources. Aberdeen Harbour could finance the project directly via the corporate vehicle, either using their own internal capital, a combination of internal capital and external grant funding, or external funding awarded directly to the SPV.

5.5.3. Proposed services and service levels

Ships berthed at the port will utilise the power service to supply all of their electricity, therefore the service must:

a) be of sufficient capacity, reliability, and resilience to meet the electrical needs of all connected customers at all times.
b) be reasonably priced to encourage uptake; and
c) support the corporate aspirations for reduced carbon operations.

Service Levels are set out in the heads of terms and includes minimum availability of electricity supply, power capacity and response times to restore power due to unplanned outages. These will also be included in back-to-back arrangements with any system operators and service providers employed by the harbour.

5.6. Proposed charging structure approach

The proposed charging structure for the port users uses a hybrid tariff (p/kWh) in which the connection charge and electricity supply charge are blended into one single delivered unit rate. To mitigate risk from market volatility, the unit rate will be a consistent mark-up price (pre-inflation and tax) compared to the current market pricing.

Due to the nature of the quayside operations, it is most likely the harbour will adopt a monthly invoice billing mechanism to contracted port users. This approach sits well with the physical connection points, which have the capability to record the metered data as well as connect to any billing software that the harbour should wish to use. The recorded consumption data is stored and can be shared as a CSV-file which ensures easy integration into most billing system applications.

5.7. Risk allocation

The proposed commercial structure as presented in Figure 5—2 comes with the risk to Aberdeen Harbour of acting as an electricity supplier. The employment of Design, Build and Maintain (DBM) contractors shifts the design and construction risk from the harbour to the contractors. However, Aberdeen Harbour are the project sponsor and would remain subject to the financial and operational risk associated with the project's delivery.

Best practice dictates that the general principle is that risks should be passed *to 'the party best able to manage them'*. This is usually considered to be subject to a *'value for money'* (VFM) test since the party to which the risk is being transferred will in most cases value that risk in pricing the works or services appertaining to that risk. Provision will be made in the contracts to identify the short, medium and long-term risks, handover procedures at each stage and to define the relevant responsibilities and liabilities. The contracts should also detail the associated liquidated damages relevant to underperformance (at design, installation and operation stages), as well as any residual asset value and potential exit strategies at each stage.

Through the selection of suitably qualified and experienced organisations, Aberdeen Harbour will need to transfer risk to contractors where appropriate in line with the risk matrix set out in Table 5—5. This will need to be updated depending on the final selected commercial structure. Indicative organisations are shown based on the current stage of project development. No shared risk has been identified at this stage, possible options for shared risk include operational risk due to training being provided to quayside operators / Aberdeen Harbour personnel and vessel operators by the DBM contractors and equipment suppliers and availability and performance risk, whereby both the harbour and appointed contractors are incentivised to ensure energy efficiency and performance is maintained/ improved.

Table 5—5 Risk transfer matrix

Risk Category	Allocation	
	Aberdeen Harbour	**Other**
1. Design risk	Aberdeen Harbour project management and tender of suitably experience team	Consultant and Contractor D&B
2. Construction risk	Aberdeen Harbour project management and tender of suitably experienced contractor and supervision	Contractor
3. Transition and implementation risk	Aberdeen Harbour project management and technical oversight	Contractor (commissioning)
4. Availability and performance risk	Aberdeen Harbour systems manager and tender of contract for Maintenance and Billing/ Metering	Maintenance contractor
5. Operating risk	Aberdeen Harbour system operating personnel and use of contractor training	DBM contractor and equipment supplier
6. Variability of revenue risks (development risk)	Aberdeen Harbour project manager and business case modelling	Investigate opportunities for funding to help share / mitigate development risk
7. Energy market price volatility	Aberdeen Harbour project management and operational project management.	
8. Termination risks	Aberdeen Harbour and O&M contractor due diligence	
9. Technology and obsolescence risks	Aberdeen Harbour project manager and technical oversight	Engineering consultant (through detailed specification) and contractor (through supplier/ manufacturer choice)
10. Financing risks	Aberdeen Harbour funding, and operational project management	TBC
11. Legislative risks	Aberdeen Harbour to manage	Maintenance contractor legislative alignment to latest site and technology operations

Key commercial risks and current mitigation are summarised below. A full risk register is provided in Appendix C. The numbering below corresponds with the number referencing in the risk register:

2.1.1 Failure to identify funding sources adequate to meet the capital costs of the scheme

Mitigation:

Aberdeen Harbour continues to engage with UK Gov to confirm additional funding opportunities via the Clean Maritime Demonstration Competition. Scheme has been tested without grant funding, but this puts undue pressure on the economic viability of the project

2.1.2 Unable to develop business case to allow scheme to progress. Lack of political will to continue as owner and operator

Mitigation:

Current intention is to progress with DBM with Aberdeen Harbour retaining ownership and strategic control. Engagement with senior Aberdeen Harbour officials has continued and OBC forms basis of current project position for final sign-off

2.3.1 Failure to attract predicted demand at the port therefore resulting in reduced revenue leads to revenue gap for Aberdeen Harbour to repay borrowing/ investment.

Mitigation

Investigate alternative grants including sharing of risk until further customers (and therefore connections to the shore power system) and resulting revenue sufficient to cover operating costs including Aberdeen Harbour borrowing costs.

2.3.2 Fail to obtain economic value from electricity sales

Mitigation:

Further sensitivity testing has been carried out over variety of electricity prices (wholesale) and long-term economic sustainability of the scheme. There will be a need to ensure customer supply contracts reinforce viability of agreed shore power electricity prices and changes in electricity purchase price are backed off to customers

2.3.7 Failure to meet power on date requirements for port users leading to delays in ships connecting.

Mitigation

Continued consultation has been undertaken with port users throughout the completion of the OBC. During this process mitigation approaches should be agreed including the use of incumbent marine fuel energy supply as a last resort.

2.3.9 Failure to meet project completion deadlines set by project funders.

Mitigation

Aberdeen Harbour will confirm milestones at the outset of the construction programme with the CMDC board and manage any delays through regular consultation. There are precedents for delays on previous projects funded through this means so close collaboration will be key.

4.1 Power consumption estimates vary vs actual consumption

Mitigation:

Power demand sensitivity has been completed during DPD phase and modelled as a sensitivity, but risks remain due to inherent variability between design and operation.

5.1 Aberdeen Harbour fail to secure cable route through their demise

Mitigation

Aberdeen Harbour is consulting their records to ensure route feasibility and trial holes and/or GPR surveys will be conducted if necessary

5.2 Aberdeen Harbour fails to obtain agreement with the Distribution Network Operator for the provision of power to the shore power system.

Mitigation

The DNO is obliged to 'provide a connection upon request' as its statutory duty. Third parties can be used (ICP/IDNO) to reduce the capital cost to connect

5.8. Procurement requirements

The works and services required to deliver the shore power project can be categorised as follows. This does not include any ongoing activity to support the procurement of enabling works.

1. Enabling works:
    a. GPR and topographical surveys
    b. Development of Employer Requirements for tender
    c. Shore power contract formalisation
2. Implementation works
    a. Implementation Management
        i. Professional Services
    b. Design and Build
        i. 11kV connection to the DNO network
        ii. Shore power E-house
        iii. Low voltage cable routing along Albert and Mearns Quay
        iv. Cable management including fixed connection points and storage area
3. Operational services for power supply and service agreements
    a. Electricity supply
    b. Metering and billing
4. Maintenance services for shore power equipment
    a. Shore power E-house
    b. Cable management.

Figure 5—3 below shows the range of agreements and procurements that may be required.

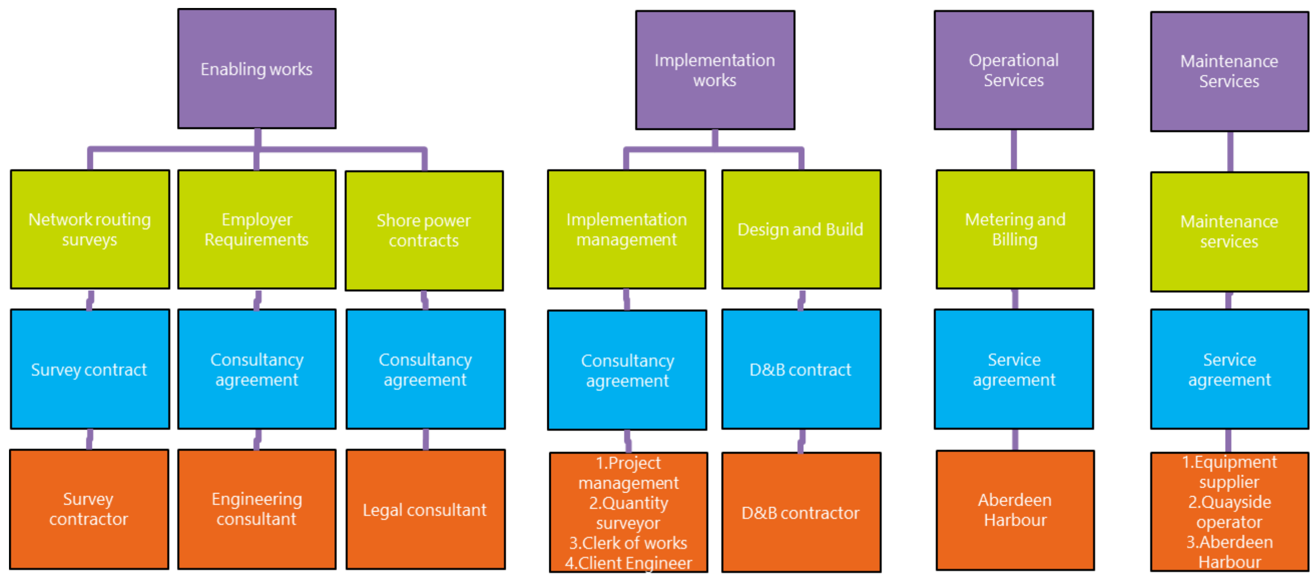


Figure 5—3 Procurement requirements

5.9. Procurement strategy

For the procurement strategy it has been assumed a formal procurement process will be followed to ensure fair value for money, competitiveness, and reliability. The recommended strategy is to procure as follows:

5.9.1. Professional services

The professional services required by Aberdeen Harbour for the implementation phase can be obtained through open tender during the enabling phase and it is recommended to be made up of four potential lots:

1. Project Management
2. Commercial (covering cost and quantity surveying)
3. Client Engineer (covering client representative role and/or may also fulfil duties under NEC4,or equivalent, contract route if chosen)
4. Clerk of Works

To undertake the client project management role a qualified professional project manager should be recruited or assigned to the project from the existing in-house team. Ideally this person should have experience of project managing utility work.

5.9.2. Distribution Network Operator connection

The power connection can be broken down into two separate components, the contestable and non-contestable works, where the latter can only be carried out by the local Distribution Network Operator, SSE.

SSE will be approached for the procurement of both sets of works, however, it is unlikely their contestable works quotation will be competitive. A soft market testing exercise will therefore be used for the procurement of the contestable works. During this exercise at least 3 Independent Connection Providers will be approached to quote the costs of the civil works, electrical design, jointing, laying Cable Laying and substation instillation. Once a utility infrastructure strategy has been agreed, with input from the harbour and gained market knowledge, a full procurement exercise will be carried out to appoint a contractor for the contestable works.

5.9.3. Shore power infrastructure

Initial soft market testing with suppliers was held for the procurement of the shore power infrastructure. Figure 5—4 shows the possible contractual arrangements and responsibilities for the shore power infrastructure. The proposed approach is to provide contractors with a technical brief of the Design and Build aspects, whilst also giving the option to include the Maintenance element which is offered by numerous shore power equipment suppliers. This particular contractual relationship would fall under a Design, Build and Maintain procurement model (DBM).

From previous soft market testing it was understood that a maintenance contract for the shore power equipment, i.e., shore power E-house, cable management system could be offered by the respective suppliers or maintained by quayside operators/ vessel operators. Aberdeen Harbour may also be interested in maintaining the equipment in-house where some level of training would be provided by the equipment supplier. In addition, it is suggested that maintenance contracts include KPI's for efficiency, capacity availability and reliability. Depending on how Aberdeen Harbour should wish to designate responsibility, the entity responsible for the maintenance could fall under the harbour itself, the contractors/ suppliers or quayside or potentially vessel operators as illustrated in Figure 5—4. If the maintenance aspect was to be taken up by the harbour, AHB may want to pass risk to a 3rd party contractor.

Typically, the quayside operators and vessel operators will be responsible for the operation of the shore power cable management systems, i.e. delivery to the berthing area and connection of the shore power charging cables to the individual ships points of connection.

The billing element is likely to be the responsibility of Aberdeen Harbour as they are the primary shareholder of the corporate vehicle, further discussion on billing and metering is provided in section 5.9.4.

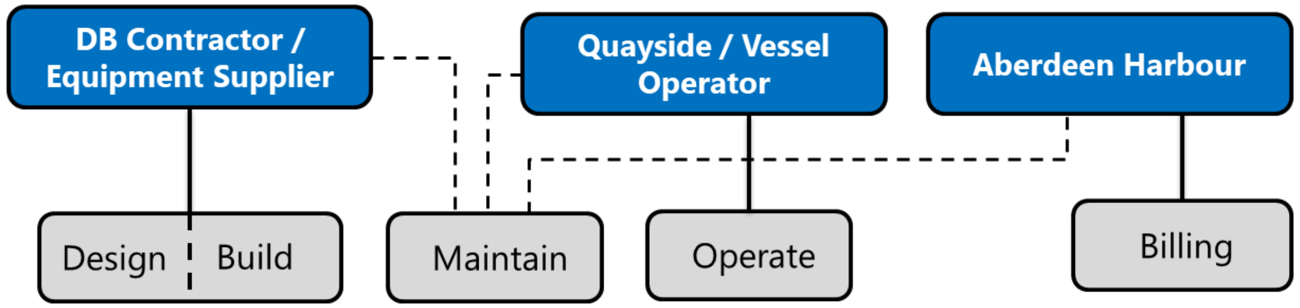


Figure 5—4 Contractual agreements and responsibilities

The DBM contract must also include a role for design review and construction monitoring of the system works and performance targets

There are many different standard form contracts for the design and build elements used in the energy sector. JTC and NEC are common forms used for construction projects and are likely to be the most appropriate as they cover both the civils work elements and the installation and commissioning of system and equipment. As an example, and in the case of power infrastructure, NEC forms generally achieve a very high level of risk transfer or a more collaborative cost sharing regime depending on the option chosen. The use of NEC is more likely to be acceptable to a wider range of market participant for procurement.

The operate and maintain contracts are likely to be bespoke rather than a standard form but will contain terms which are generally expected for a project of this type and in line with market precedent.

5.9.4. Billing and metering

The success of the project will also require a high level of customer service and accurate, regular metering and billing. Due to the capability of the shore power equipment being able to capture metered data, it is proposed that the billing is provided by the harbour via an in-house resource. This reduces the project OPEX and simplifies the procurement exercise. These services could also be provided by a 3rd party that could be procured on a negotiated basis under a metering & billing and customer services contract for an initial term of circa 5 years.

6. Financial Case

6.1. Introduction

Building upon the Commercial Case, the Financial Model has been developed for the Aberdeen Harbour Shore Power project. This has been modelled under the assumption that Aberdeen Harbour Board ("Aberdeen Harbour") owns the Shore Power network through a wholly owned SPV. The financial model forecasts the financial performance of the system, assuming a third party is procured to install and build the project, with the capital expenditure being funded from a combination of internal Aberdeen Harbour funding and external grant support. Aberdeen Harbour intends to operate the shore power system in house. The key assumptions and financial model outputs are presented in this chapter with further detail provided in Appendix K. All values are shown in nominal terms unless noted otherwise.

6.2. Key dates

The dates used in the financial model are shown in Table 6—1, these are the same dates which are included in the techno-economic model.

Table 6—1 Financial model key dates

Item	Assumption
Construction Start Date	1st January 2024
Operations Start Date	1st January 2025
Operations End Date	31st December 2044

6.3. Capital cost requirements

Capital costs for the project are provided in Table 6—2 below. The estimated total Capex amounts to £8.0M excluding VAT (£9.6M including VAT). These costs are based on those included in the techno-economic model. For the purposes of the financial model, these capital costs are assumed to be incurred in twelve equal monthly payments across the construction year. VAT on construction costs is assumed to be at a rate of 20% and is charged on the total capital costs as shown in the table below. VAT is assumed to be fully recoverable and is reclaimed one month after it is paid. Due to this, the final VAT recovery is in the first months of operation, which means that an additional funding requirement equal to one month's VAT payment is required.

Table 6—2 Capital cost requirement summary

Cost Element	Capital Cost Estimate, £k
Shore Power connections	2,754
Cable management	676
Port side connection	248
Low voltage network costs	1,839
Network ancillary equipment	141
Cable storage building	135
Electricals	200
Additional costs	1,995
Total CAPEX exc. VAT	7,988
Net VAT funding during construction	133
Total construction inc. Net VAT	8,121

6.4. Affordability and funding

This Financial Case has been prepared on the assumption that the commercial structure is a wholly owned Aberdeen Harbour SPV project. The main funding sources for the project are a grant for 50% of the total capital costs and the rest will be met by Aberdeen Harbour using its own capital.

For the base case model we have assumed that Aberdeen Harbour will provide funding in the form of 25% equity and 75% debt as an intercompany loan to the SPV. This provides an optimal financial return as the intercompany loan allows profits generated in the early years to be distributed back to the harbour. We have also run a comparable sensitivity which assumes Aberdeen Harbour contributes 100% of the funds as equity. This results in a lower rate of return as dividend distributions would be restricted in the initial years of the project, due to an opening negative retained earnings balance after construction. In this scenario, dividends would only be distributed once the project had made an overall net profit taking account of capex outlay. The results of this sensitivity can be found in section 6.8 below.

The financial model retains a minimum cash balance throughout the operating period which has been sized to meet three months' worth of operating expenditure, as agreed with Aberdeen Harbour. This balance is built up using operating cash flows from the start of operations.

The funding sources and uses for the period to the end of construction, 31 December 2024, is shown in Table 6—3.

Table 6—3 Sources and uses to 31 December 2024

Sources of Funds to 31 December 2024	£k	%
Grant Funding (50% of capex)	3,994	49.18 %
Equity	1,032	12.70 %
Intercompany Loan	3,095	38.11 %
Total	8,121	100.00 %

Uses of Funds to 31 December 2024	£k	%
Construction Costs	7,988	98.36 %
Construction Cost VAT	1,598	19.67 %
Construction Period VAT Reimbursement	(1,464)	(18.03)%
Total	8,121	100.00 %

It is assumed that the grant funding is drawn as required and covers 50% of the eligible construction costs. Sensitivities have been included varying the level of grant funding available (section 6.8). Harbour funding is drawn as required to fund the remainder of the Capex in the construction year.

The Harbour intercompany loan is assumed to be available immediately prior to the start of construction (1st January 2024) to the end of construction (31st December 2024) with repayment commencing following the commencement of operations (1st January 2025). An interest rate of 6.0% is charged on the loan and repayment is on a cash sweep basis, with any available cash in excess of the minimum retention being used to repay any remaining outstanding intercompany loan.

6.5. Component replacement costs

Component replacement costs are assumed to be £1.08m (in real terms) over the operational life of the project using the assumption of 80% of the relevant construction costs and asset useful lives of components. The component replacement costs are indexed at RPI using the inflation assumption agreed with the Harbour (see Appendix K). Operational cash flows are utilised to meet component replacement expenditure and a retention balance accumulated in advance to cover component replacement costs, where operational cash flows in the same year are insufficient. This avoids an overdraft or additional funding having to be utilised to meet in-year component replacement costs. The retention amount required is built up evenly over the five years prior to the replacement cost occurring.

6.6. Operations - revenue and operating costs

The nominal and Net Present Value (NPV), using a discount rate of 6.09% as agreed with the Harbour, of the revenue and operating costs for the project over the 20-year operational life are shown in Table 6—4.

Table 6—4 Project cash flows

Project Cashflows	Nominal £k	NPV March 2022 at 6.09%, £k
Income		
Shore Power Sales	37,869	16,718
Expenditure		
Input Fuel Cost	(23,232)	(10,315)
O&M costs	(386)	(178)
Business Costs	(140)	(65)
Equipment Costs	(484)	(223)
Corporation Tax Paid	(2,668)	(955)
Total Expenditure	(26,911)	(11,735)
Net Income	10,958	4,982

6.6.1. Revenue

Revenue is generated for the project through the sale of shore power. There is no standing charge / fixed tariff charged to the offtakers. The shore power sale price will be calculated by adding a mark-up to the cost to Aberdeen Harbour of importing electricity from the grid. For the base case, the mark-up was solved to meet an IRR target of 9%. To illustrate how a change in Aberdeen Harbour's return requirement would impact the mark-up, and therefore affordability to offtakers, we have included sensitivities showing the mark-up to achieve a 6% and 12% IRR. Table 6—5 shows a summary of the base case offtake and electricity cost assumptions and the results of the three scenarios can be seen below in Table 6—6. The rest of this finance case assumes the 9% IRR as the base position.

Table 6—5 Starting electricity price and offtake associated with each phase

Maximum Annual Offtake (MWh/annum)	Base Electricity Import Cost (£/MWh)	Mark-up (£/MWh)	Base Shore Power Electricity Sale Price (£/MWh)
5,747	150	114	264

Table 6—6 Shore power price mark-up based on IRRs

Shore Power Price Mark Up (£/MWh)	Electricity Sale Price (£/MWh)	AHB IRR
92	242	6.0 %
114	264	9.0 %
139	289	12.0 %

The demand from the offtakers that is met by shore power is assumed to gradually step up over the first 5 years of operations, reaching 100% in 2029. The variable shore power price is assumed to increase in line with the BEIS – Electricity Services Prices and then adjusted by a factor to maintain the same real mark-up from the purchase price year on year.

Inflation is reflected on the electricity purchase prices using the assumption as set out in Appendix K. Inflation has also been applied to the Shore Power sales price as the comparative cost of marine fuel to the offtakers will also increase with inflation, therefore the real cost in monetary terms is maintained throughout the lifetime of the project. The affect which inflation has on the annual mark-up is demonstrated in Appendix L and sensitivities outlining the impact of inflation on returns is shown in in section 6.8.

Revenue is generated in the first year of operations (2025) and gradually increases over the first 4 years whilst the demand profiles step up. Following this, the project revenue increases with inflation. The revenue generated over operations is shown in Figure 6—1.

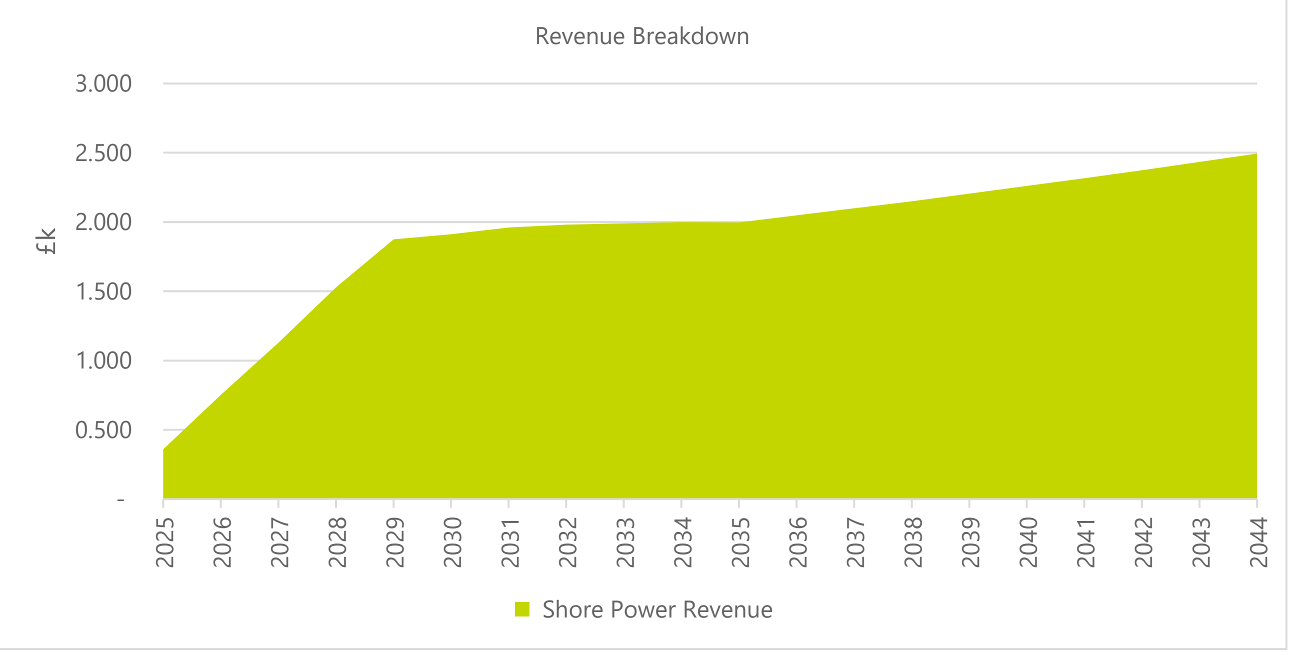


Figure 6—1 Revenue generated over the operational life of the project

6.6.2. Operating costs

The financial model includes operating costs, noted in the Table 6—7 below. The operating costs included within the financial model are based on the costs within the techno-economic model. QMPF has also been advised by Aberdeen Harbour to include £5,000 annually for tax and audit fees and corporation tax at 19%, which rises to 25% in April 2023.

Electricity is purchased at a base cost of £150/MWh as set out in Table 6—5 increasing with the BEIS service index and inflation.

Table 6—7 Annual operating costs

Annual Operating Costs	£k p.a.
Shore Power maintenance	7
Metering and Billing	11
Cable management	14
Audit & Tax	5
Total	36

The operational costs over the project life are shown in Figure 6—2.

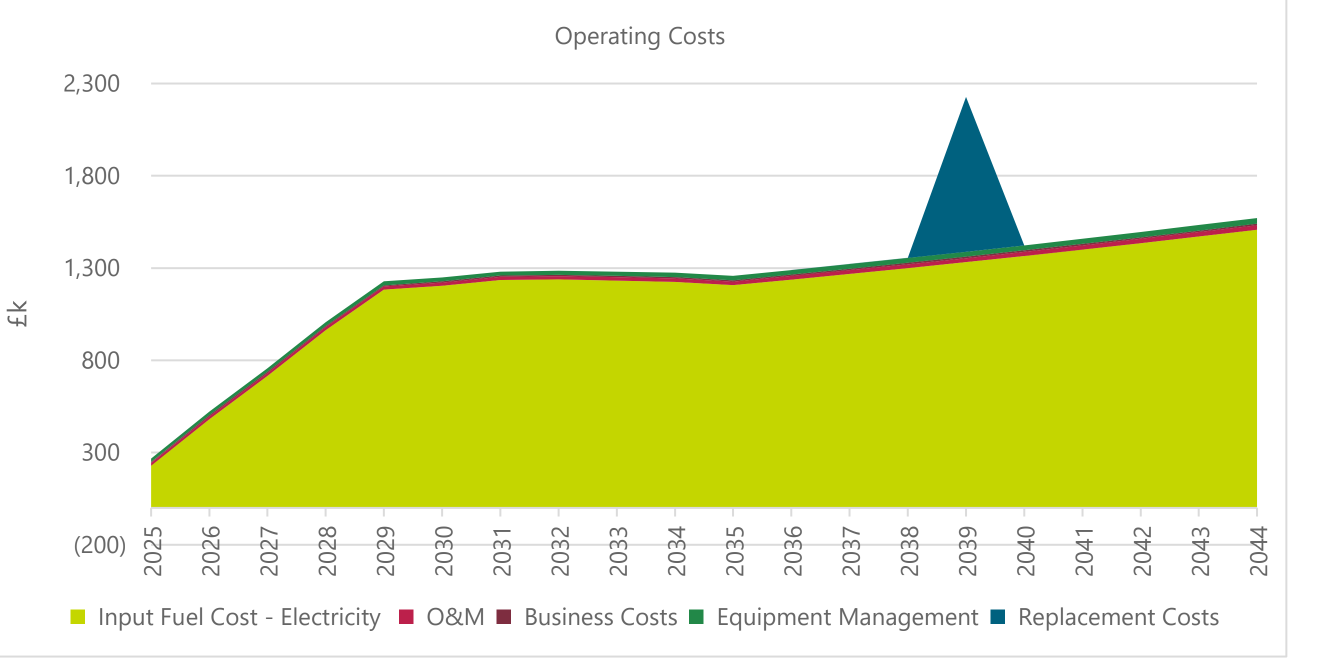


Figure 6—2 Operating cost over the operational life of the project

All operating costs are assumed to inflate by RPI. Electricity import costs also increase with the relevant BEIS forecasts, further details provided below.

Figure 6—3 demonstrates the total Aberdeen Harbour expenditure over the life of the project compared to the total revenue which is generated by the shore power sales. The difference between these two cashflows is the profit margin receivable to Aberdeen Harbour.

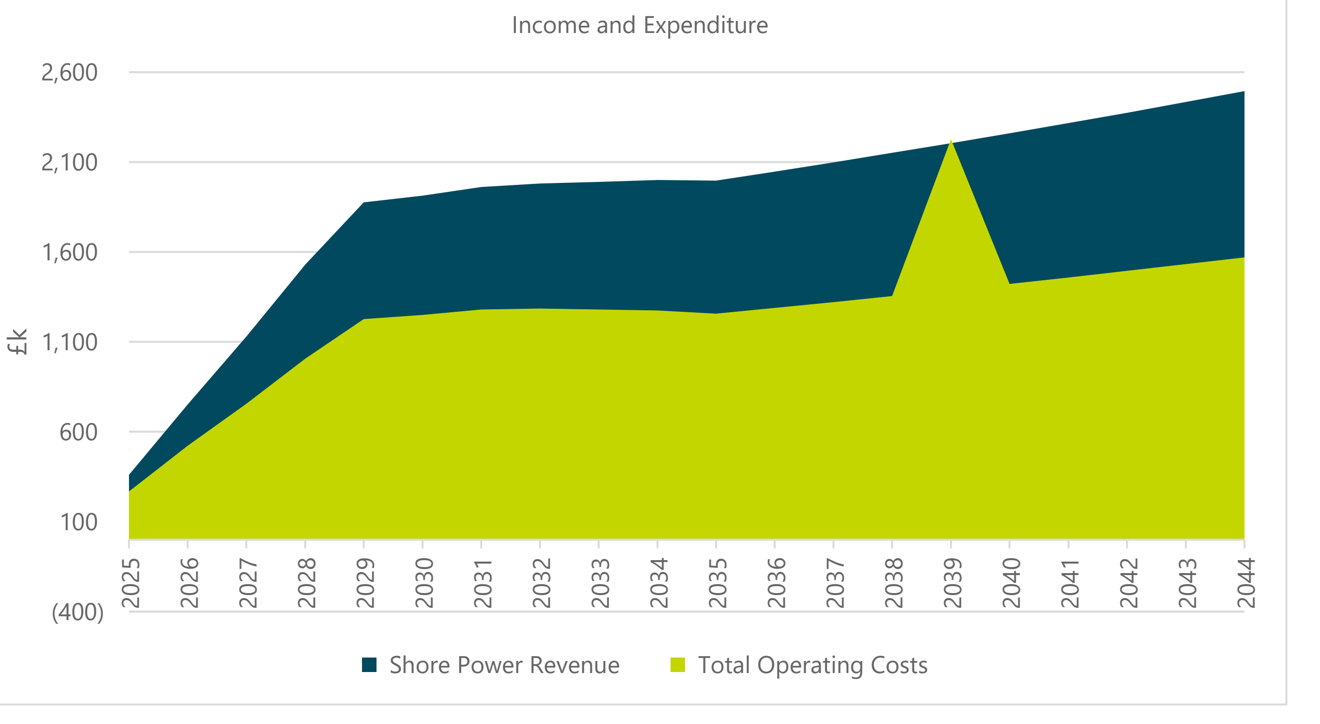


Figure 6—3 The income and expenditure over the project life.

The main operating cost incurred by the project is the import electricity cost that Aberdeen Harbour purchases from the grid. The starting price for electricity from the grid is 15.02 p/kWh from the BEIS quarterly published energy prices[17]. The starting fuel cost has been increased in line with the relevant BEIS Electricity Services forecasts (published in December 2020) and indexed at RPI.

6.6.3. Overall project cash flow

Table 6—8 Project cash flows over 20-year operational life

Project Cashflows	Nominal £k	NPV March 2022 at 6.09%, £k
Income		
Shore Power Sales	37,869	16,718
Expenditure		
Input Fuel Cost	(23,232)	(10,315)
O&M costs	(386)	(178)
Business Costs	(140)	(65)
Equipment Costs	(484)	(223)
Corporation Tax Paid	(2,668)	(955)
Net Income	10,958	4,982
Construction Cost	(7,988)	(6,787)
Component Replacement Costs	(2,054)	(294)
Net Income after Capex	916	(2,099)
Funding Drawdown and Repayment		
Grant Drawdown	3,994	3,394
Harbour Sub Debt	3,095	2,630
Harbour Equity	1,032	877
Cashflows after Sources of Funding	9,037	4,802
Interest		
Interest Paid on Harbour Interco Loan	(2,430)	(847)
Surplus Cash Available to the Harbour	6,607	3,954

Overall the project generates a £4M cash surplus and is financially viable over the 20-year appraisal period. Project IRR for the base case is show in Table 6—9. In operational terms, the revenues generated from shore power sales cover the total construction and operating costs and the interest and capital of the sub debt provided by Aberdeen Harbour. The project IRR before grant funding is shown below at 2.2%. With the addition of grant funding the project IRR is 9.84%. Table 6—9 below shows the total equity IRR (combining equity and intercompany loan returns) at 9.0%.

Table 6—9 Project IRR over 20-year operational life

Project IRR (after tax)	%
Before grant funding of 50% capex	2.2 %
After grant funding	9.8 %
Equity IRR	**%**
Total Nominal Equity IRR (share capital only)	12.7%
Total Nominal Equity IRR (incl. s/h debt)	9.0%

6.7. Business as usual and counterfactual

The business as usual (BAU) for the Harbour would involve no additional costs, as the vessels would continue to burn marine fuel to meet vessel power needs while at berth. The sale of marine fuel does not happen through Aberdeen Harbour. The carbon cost associated with the vessels continuing to use marine fuel, rather than onshore power, is assumed to reside with the vessels and is addressed in the counterfactual case below. There are no socioeconomic costs linked to the burning of fossil fuel considered in the finance case, as there is no financial cost or liability identifiable to associate with it, however this has been discussed in the techno-economic case (see section 1.1).

To understand the costs and benefits to the offtakers, we have run a comparative counterfactual case from the vessel (or vessel owners) perspective. The analysis compares the electricity costs for vessels connected to the shore power network versus the counterfactual costs that they would incur by burning marine fuel to generate electricity whilst at berth. A base cost for marine fuel has been assumed, using market rates from ship and bunker[19] as at the 3rd March 2022, which are assumed to increase at RPI. An additional carbon cost to the of-takers has been added for burning fossil fuel using the HMT Treasury forecast cost of carbon[18] published in 2021 and increased at RPI. The assumptions are listed in Table 6—10. The cost or benefit of the scheme for each of the offtakers in turn can also be seen in Table 6—10. For the purpose of the counterfactual comparison no additional capital / operational costs have been considered for offtakers.

Table 6—10 Counterfactual assumptions & cost / saving for customers

Counterfactual Comparison			
Technology		Marine Fuel	Shore Power
Variable Base Price (2025) plus inflation	£/MWh	168	299
Carbon Tax Cost	£/MWh	187	0
Variable Base Price plus inflation plus carbon tax	£/MWh	355	299
NPV exc. Carbon costs	£k	11,730	18,690
NPV inc. Carbon costs	£k	26,541	20,340
(Cost) / Saving: Shore Power compared to Counterfactual exc. Carbon tax	**£k**		**(6,960)**
(Cost) / Saving: Shore Power compared to Counterfactual inc. Carbon tax	**£k**		**6,201**

Carbon Tax implications to make marine fuel competitive with Shore Power over 20 years.			
Technology		Marine Fuel	Shore Power
Variable Base Price (2025) plus inflation	£/MWh	168	299
Carbon Tax Cost	£/MWh	108	0
Variable Base Price plus inflation plus carbon tax	£/MWh	277	299
NPV exc. Carbon costs	£k	11,730	18,690
NPV inc. Carbon costs	£k	20,340	20,340

(Cost) / Saving: Shore Power compared to Counterfactual exc. Carbon tax	**£k**		**(6,960)**
(Cost) / Saving: Shore Power compared to Counterfactual inc. Carbon tax	**£k**		**(0)**

Carbon Tax implications to make marine fuel competitive with Shore Power in the first year of operations.			
Technology		Marine Fuel	Shore Power
Variable Base Price plus inflation	£/MWh	168	299
Carbon Tax Cost	£/MWh	131	0
Variable Base Price plus inflation plus carbon tax	£/MWh	**299**	**299**
NPV exc. Carbon costs	£k	11,730	18,690
NPV inc. Carbon costs	£k	22,098	20,340
(Cost) / Saving: Shore Power compared to Counterfactual exc. Carbon tax	**£k**		**(6,960)**
(Cost) / Saving: Shore Power compared to Counterfactual inc. Carbon tax	**£k**		**1,758**

The marine fuel counterfactual shows that with the considerations of carbon tax added onto the cost of marine fuel, it is financially economical for the offtakers to switch to using shore power when berthed at the port. The table above shows that overall, the vessels could save over £6 million over the lifetime of the project by using shore power rather than burning marine fuel. As the price for marine fuel excluding cost associated with carbon is lower than that for shore power, there is no saving for the offtakers if no carbon cost is accounted for.

A starting carbon tax on marine fuel of £108/MWh (40% less than the Green Book carbon valuation) would mean that shore power is cost comparable to marine fuel over the 20-year project life. Similarly, if carbon tax was introduced to make the shore power price competitive with marine fuel in the first year of operations, the carbon tax would have to be £131/MWh so that marine fuel plus carbon tax in the first year of operations was the same as shore power price at £299/MWh.

However, with current geopolitical pressures as well as musings on carbon taxation within the shipping sector, there is a high likelihood marine fuel prices will continue to rise, which could alter the current cost for offtakers in the counterfactual scenario and reduce the influence of a separate carbon cost on the economics of the project.

Nevertheless, it is assumed that offtakers will be willing to switch to shore power to reduce their carbon footprint regardless of economic incentives, due to the incremental social cost which is attributed to the burning of marine fuel.

6.8. Sensitivity testing

Various sensitivities have been completed which show how different levels of grant funding affect the IRR or mark-up price. Further sensitivities have also been completed which solve the IRR for 6%, 9% and 12% by flexing the mark-up for shore power on the electricity purchase cost. These sensitivities and outcomes are shown in Table 6—11 below.

In order to assess the financial risks associated with the project we have undertaken a number of sensitivities in respect of the offtaker demand, power purchase cost, operational cost and inflation. Table 6—12 shows the impact on returns to Aberdeen Harbour, maintaining the electricity sale mark-up from the base case. Table 6—13 shows the change in mark-up required to maintain the base case IRR of 9%.

The analysis flexes the mark-up on the purchase price of electricity to analyse shore power revenue as the mark-up is independent on purchase price of the electricity. The shore power price tracks the purchase price with any real price increase forecasts and then applies the mark-up to cover the costs related to the shore power installation and operation. AHB will be able to set the mark-up at the outset (and throughout) of the project. Therefore, in our sensitivity analysis, we have looked at the effect that the sensitivities have on the shore power mark-up.

The key sensitivities which affect the markup price are the percentage of grant funding, increases or decreases in the CAPEX costs, altering the target IRR of Aberdeen Harbour and changes to the power demand.

The grant funding amount has a considerable impact on the required mark-up when holding the IRR at 9%. Grant funding of 25% would mean the mark-up price needs to be £156/MWh (£42/MWh increase vs. base case) to deliver 9% IRR. For 75% grant funding the mark-up price would reduce to £72/MWh to deliver 9% IRR (vs. base case £114/MWh).

A 20% increase/decrease in CAPEX would mean the mark-up price to deliver a 9% IRR is £131/MWh and £97/MWh respectively (±£17/MWh vs. base case £114/MWh). Therefore is it imperative to minimise the capital expenditure where possible, whilst maintaining design safety and quality.

If the required IRR is reduced from 9% to 6% then the mark up can also be reduced by £22/MWh (£92/MWh vs. base case £114/MWh). The IRR and the mark-up will move in conjunction with each other as the IRR determines the required project return and the markup is then adjusted to achieve this.

Another key element which will affect the IRR or the mark-up price is any changes in demand quantity. If the demand changes by 30% then the shore power mark-up changes by £43/MWh (£157/MWh +30% demand; £91/MWh −30% demand).

The shore power price is more competitive with the counterfactual costs of power to the vessels when CAPEX costs decrease, the percentage of grant funding increases or there is an increase in shore power demand. Another key variable which Aberdeen Harbour can alter to bring the mark-up down is the return IRR. If Aberdeen Harbour reduces the required IRR expectation, then the shore power price mark-up can also be reduced, making the price of shore power more competitive with the price of bringing marine fuel for the vessels.

Additionally we have run a 10-year project sensitivity (shown in Table 6—13), which maintains the 9% IRR. Reducing the operational period by 50%, means that Aberdeen Harbour is generating less revenue over the life of the project, therefore the mark-up must be significantly increased by £179/MWh to maintain the same level of return.

We have also run a sensitivity which moves the start of construction to 2023, with operations ending at the end of 2043. This requires a fairly modest increase to the mark up of £2 or 1.8% (£116/MWh vs £114/MWh), to retain an IRR of 9%.

Table 6—11 Financial returns – sensitivity results IRR and grand funding

Scenario					Project IRRs After Tax		Equity IRR								
	Mark-up of sale vs import price	Total Project Funding Requirement	AHB Funding Requirement	Grant funding	Before grant funding	After grant funding	All Equity (inc. SHL)	Pure Equity only	Overall cash generation from project after repayment of debt	Nominal Net Operating Cashflow	NPV of Net Operating Cashflow	Income	Opex	Net Income	Construction Costs
	£/MWh	£k	£k	£k	%	%	%	%	£k	£k	£k	£k	£k	£k	£k
Base Case - 9% IRR	**114**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,306	12,787	2,747	37,869	(25,081)	12,787	(7,988)
IRR 6%	**92**	8,121	4,127	3,994	0.0 %	6.7 %	**6.0 %**	6.8 %	7,927	9,617	2,065	34,698	(25,081)	9,617	(7,988)
IRR 12%	**139**	8,121	4,127	3,994	4.5 %	12.9 %	**12.0 %**	18.1 %	13,028	16,414	3,527	41,495	(25,081)	16,414	(7,988)
Grant Funding 25% of capex, maintain mark up	**114**	8,121	6,124	1,997	2.6 %	5.6 %	**5.1 %**	4.8 %	10,811	12,787	2,747	37,869	(25,081)	12,787	(7,988)
Grant Funding 75% of capex, maintain mark up	**114**	8,121	2,130	5,991	1.7 %	19.5 %	**17.6 %**	28.3 %	9,803	12,787	2,747	37,869	(25,081)	12,787	(7,988)
Grant Funding 100% of capex, maintain mark up	**114**	8,121	133	7,988	1.2 %	162.3 %	**111.5 %**	209.5 %	9,312	12,787	2,747	37,869	(25,081)	12,787	(7,988)
Grant Funding 25% of capex, maintain 9% IRR	**156**	8,121	6,124	1,997	6.3 %	9.6 %	**9.0 %**	12.7 %	15,306	18,779	4,036	43,860	(25,081)	18,779	(7,988)
Grant Funding 75% of capex, maintain 9% IRR	**72**	8,121	2,130	5,991	0.0 %	10.5 %	**9.0 %**	12.7 %	5,332	6,832	1,466	31,913	(25,081)	6,832	(7,988)
Grant Funding 100% of capex, maintain 9% IRR	**30**	8,121	133	7,988	0.0 %	37.3 %	**9.0 %**	13.4 %	296	802	169	25,884	(25,081)	802	(7,988)

Table 6—12 Financial returns – sensitivity results IRR impact

Scenario					**Project IRRs After Tax**		**Equity IRR**								
	Mark-up of sale vs import price	Total Project Funding Requirement	AHB Funding Requirement	Grant funding	Before grant funding	After grant funding	All Equity (inc. SHL)	Pure Equity only	Overall cash generation from project after repayment of debt	Nominal Net Operating Cashflow	NPV of Net Operating Cashflow	Income	Opex	Net Income	Construction Costs
	£/MWh	£k	£k	£k	%	%	%	%	£k	£k	£k	£k	£k	£k	£k
Base Case - 9% IRR	**114**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,306	12,787	2,747	37,869	(25,081)	12,787	(7,988)
100% equity, no intercompany loan	**114**	8,121	4,127	3,994	2.2 %	9.8 %	**6.6 %**	6.6 %	10,449	12,787	2,747	37,869	(25,081)	12,787	(7,988)
Power demand +10%	**114**	8,121	4,127	3,994	3.2 %	11.1 %	**10.2 %**	15.0 %	11,404	14,251	3,056	41,656	(27,405)	14,251	(7,988)
Power demand -10%	**114**	8,121	4,127	3,994	1.1 %	8.5 %	**7.7 %**	10.2 %	9,208	11,324	2,438	34,082	(22,758)	11,324	(7,988)
Power demand +30%	**114**	8,121	4,127	3,994	5.0 %	13.4 %	**12.5 %**	19.0 %	13,602	17,178	3,675	49,229	(32,051)	17,178	(7,988)
Power demand -30%	**114**	8,121	4,127	3,994	0.0 %	5.4 %	**4.8 %**	3.8 %	7,011	8,396	1,820	26,508	(18,112)	8,396	(7,988)
Capex +20%	**114**	9,745	4,953	4,793	0.6 %	7.8 %	**7.1 %**	9.1 %	10,444	12,787	2,747	37,869	(25,081)	12,787	(9,586)
Capex -20%	**114**	6,497	3,302	3,195	4.3 %	12.5 %	**11.5 %**	17.3 %	10,168	12,787	2,747	37,869	(25,081)	12,787	(6,390)
Utility Purchase Cost +25%	**114**	8,121	4,127	3,994	1.8 %	9.3 %	**8.5 %**	11.8 %	9,898	12,244	2,631	43,133	(30,889)	12,244	(7,988)
Utility Purchase Cost -25%	**114**	8,121	4,127	3,994	2.6 %	10.3 %	**9.5 %**	13.6 %	10,718	13,337	2,864	32,610	(19,273)	13,337	(7,988)
Opex (exc. repex + utility) +15%	**114**	8,121	4,127	3,994	2.1 %	9.7 %	**8.9 %**	12.5 %	10,244	12,704	2,717	37,937	(25,233)	12,704	(7,988)
Opex (exc. repex + utility) -15%	**114**	8,121	4,127	3,994	2.3 %	10.0 %	**9.1 %**	12.9 %	10,363	12,863	2,777	37,793	(24,930)	12,863	(7,988)
Repex +15%	**114**	8,121	4,127	3,994	2.1 %	9.8 %	**8.9 %**	12.5 %	10,211	12,661	2,732	37,869	(25,207)	12,661	(7,988)
Repex -15%	**114**	8,121	4,127	3,994	2.3 %	9.9 %	**9.1 %**	12.8 %	10,400	12,913	2,763	37,869	(24,956)	12,913	(7,988)
Inflation +1%	**114**	8,121	4,127	3,994	3.4 %	11.1 %	**10.2 %**	14.8 %	11,709	14,655	3,051	43,395	(28,740)	14,655	(7,988)
Inflation -1%	**114**	8,121	4,127	3,994	1.0 %	8.6 %	**7.8 %**	10.5 %	9,093	11,173	2,477	33,091	(21,918)	11,173	(7,988)

Table 6—13 Financial returns – sensitivity results mark-up impact

Scenario					Project IRRs After Tax		Equity IRR								
	Mark-up of sale vs import price	Total Project Funding Requirement	AHB Funding Requirement	Grant funding	Before grant funding	After grant funding	All Equity (inc. SHL)	Pure Equity only	Overall cash generation from project after repayment of debt	Nominal Net Operating Cashflow	NPV of Net Operating Cashflow	Income	Opex	Net Income	Construction Costs
	£/MWh	£k	£k	£k	%	%	%	%	£k	£k	£k	£k	£k	£k	£k
Base Case - 9% IRR	**114**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,306	12,787	2,747	37,869	(25,081)	12,787	(7,988)
Power demand +10%	**105**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,322	12,808	2,746	40,213	(27,405)	12,808	(7,988)
Power demand -10%	**125**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,292	12,768	2,749	35,527	(22,758)	12,768	(7,988)
Power demand +30%	**91**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,357	12,855	2,745	44,906	(32,051)	12,855	(7,988)
Power demand -30%	**157**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,256	12,721	2,750	30,832	(18,112)	12,721	(7,988)
Capex +20%	**131**	9,745	4,953	4,793	2.1 %	9.7 %	**9.0 %**	12.7 %	12,273	15,224	3,271	40,305	(25,081)	15,224	(9,586)
Capex -20%	**97**	6,497	3,302	3,195	2.3 %	10.0 %	**9.0 %**	12.7 %	8,336	10,346	2,222	35,428	(25,081)	10,346	(6,390)
Utility Purchase Cost +25%	**118**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,306	12,787	2,748	43,676	(30,889)	12,787	(7,988)
Utility Purchase Cost -25%	**110**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,308	12,790	2,747	32,064	(19,273)	12,790	(7,988)
Opex (exc. repex + utility) +15%	**115**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,341	12,834	2,745	38,067	(25,233)	12,834	(7,988)
Opex (exc. repex + utility) -15%	**113**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,271	12,741	2,751	37,671	(24,930)	12,741	(7,988)
Repex +15%	**115**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,276	12,747	2,750	37,955	(25,207)	12,747	(7,988)
Repex -15%	**113**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,336	12,827	2,744	37,783	(24,956)	12,827	(7,988)
Inflation +1%	**105**	8,121	4,127	3,994	2.4 %	9.8 %	**9.0 %**	12.6 %	10,588	13,161	2,739	41,900	(28,740)	13,161	(7,988)
Inflation -1%	**124**	8,121	4,127	3,994	2.0 %	9.8 %	**9.0 %**	12.8 %	10,033	12,425	2,755	34,344	(21,918)	12,425	(7,988)
Start Year 2023 IRR 9%	**116**	8,121	4,127	3,994	2.2 %	9.8 %	**9.0 %**	12.7 %	10,256	12,720	3,091	37,383	(24,663)	12,720	(7,988)
10 Years IRR 9%	**293**	8,121	4,127	3,994	0.0 %	9.3 %	**9.0 %**	13.9 %	7,385	9,200	2,975	26,003	(16,802)	9,200	(7,988)

6.9. Conclusion

The Financial Case demonstrates a financially viable project that is robust to the sensitivities that have been investigated. The financial model has been prepared on the basis of the inputs from the techno-economic model and prudent assumptions. Even with the application of the downside sensitivities presented, the project still delivers a pay back to Aberdeen Harbour and generates an overall project cash surplus and positive IRR.

The project is funded by grant funding, an intercompany loan from the Harbour to the wholly owned SPV and equity from Aberdeen Harbour. Revenue is generated in the project through the sale of shore power electricity to offtakers at a mark-up to the import cost of electricity. The majority of revenue is generated after 2029, when 100% of the offtaker demand is met by the shore power supply.

Following the sensitivities discussed above, the key drivers in this project which increase the overall IRR, or mark-up price on the shore power sales price to customer are: CAPEX, grant funding, shore power mark-up on the purchase price of electricity from the grid, IRR expectation and shore power demand.

It should be highlighted that if the vessels that are assumed to use shore power do not incur or recognise any carbon cost (or they recognise a cost significantly below the assumption used in the modelling) from the continued use of marine fuel when berthed in the harbour, then the direct financial incentive for the vessels to connect to the onshore power is not evident using the fuel and power costs in the counterfactual case.

This could impact demand and therefore the viability of the finance case. However, as discussed elsewhere in the business case there is a wider general incentive for the operators to decarbonise from a climate change, environmental, social, governmental and public relations perspective which is likely to support a level of demand for the use of onshore power and has been considered in determining the base case offtake assumptions.

7. Management Case

7.1. Introduction

The roles undertaken from the stakeholders involved in the project are crucial for its delivery and mitigation of associated risks. The roles suggested for the implementation of shore power have been presented in section 5.2 of the commercial case. It should be mentioned that following the commercial workshops and communication with the stakeholders it is assumed that AHB will have the leading project governance role.

7.2. Infrastructure delivery timeline

The proposed phased delivery of the shore power infrastructure on Point Law Peninsula has been assumed to commence in early 2024 to allow power sales to vessels to begin on all selected berths by 2025. This time period will allow for funding to be secured from DfT following the call for evidence for the Clean Maritime Plan which is anticipated to be rolled out in 2023 as well as for finalised design, contractor appointment to take place.

There may be scope to bring construction commencement forward to 2023, which is heavily dependent on finalising stakeholder agreements and funding being secured. A modelling sensitivity has been undertaken around a 2023 construction start date as outlined in section 6.8 which suggests a small increase to the markup shore power sales price of £2/MWh on the base case for a 9% IRR to be achieved after 20 years operation This increase in markup represents a <2% change on the base case mark-up power sales price of £114/MWh and very minimal impact to the delivery of the scheme.

A potential programme for delivery of shore power infrastructure is presented in Table 7—1.

Table 7—1 Proposed timeline and key milestones

Item	Date Assumption	Key Milestones
Full design complete and stakeholder contractual agreements in place	Q4 2022	All parties contractually engaged and final spatial coordination of infrastructure (i.e. following additional GPR surveys) complete.
Funding secured	Q3/4 2023	Grant funding and internal funding sources secured
Contractor tendering and appointment	Q3/4 2023	Enables all construction to begin
Construction start date	January 2024	D&B contractor contract award
Operations start date	January 2025	Sales of shore power commence with gradual increase in sales to 2029

7.3. Change and contract management arrangements

It is suggested that AHB develop a programme management plan, in which risks are monitored and risk mitigation actions are recorded, as well as key milestones throughout the project. In order to ensure a variety of stakeholder needs are properly met, it is necessary that appropriate governance over the project is in place and the group continues to work as a team on the project.

Change and contract management should be informed and communicated to the relevant stakeholders, along with how this affects costs and timeline. Therefore, it is also recommended for the people monitoring and managing change and contracts to be experienced project managers with APM and/or PRINCE2 qualifications.

7.4. Benefits realisation arrangements

Benefits realisation should also be included in the aforementioned project management plan. Ensuring the project delivers its low carbon/sustainability goals is of vital importance to all stakeholders. The benefits of the project are in line with the project objectives presented in section 2.2. The following arrangement/actions are suggested to be planned to mitigate risks that might affect meeting the desired goals:

- The DBM contracts should include monitoring of the technologies' performance and review future technology advancements to optimise even further the operation of the shore power infrastructure, by replacing old and/or less efficient equipment at the end of its lifetime.
- AHB should actively manage utility costs for primary electricity supplied to the shore power e-house.
- AHB should complete a formal review of the economic performance every 6 months (minimum) to consider improvements required to meet required financial targets
- AHB should develop an information pack to help engage future shore power off-takers.

7.5. Risk Management Arrangements

Risks and suggested mitigation measures have been included within the risk register included in Appendix C, along with probability and impact weighting before and after mitigation action.

The risk register should be handed to the D&B contractors who will then act as Principal Designer and Principal Contractor under CDM regulations 2015. There will be a shared responsibility between AHB (the client) and the D&B Contractor to keep it updated in the following implementation and operation and communicate potential issues to the stakeholders. The overall responsibility for the project still remains with AHB. Therefore, clauses should be included in the contract for AHB to be able to intervene in case risks are not mitigated or communicated timely and properly. The key risks associated with committing to the shore power development have been identified as follows, with proposed mitigation below:

1. **AHB fail to gain wider political support including additional funding**
    a. *AHB to submit OBC and DPD information to applicable funding body for additional funding signoff which could potentially support up to 50% of capital costs of infrastructure and consult with government departments to test basis for system procurement and delivery is transparent and according to best practice.*
2. **Failure to attract participating shore power users or delay in implementing shore power infrastructure therefore resulting in reduced revenue leads to revenue gap to repay any borrowing / investment.**
    a. *Investigate alternative revenue grants including sharing of risk until further participating operators (and revenue) are sufficient to cover operating costs including any borrowing costs.*
3. **Failure to identify funding sources adequate to meet the capital costs of the scheme, particularly the grant funding to meet the 50% of CAPEX base case**
    a. *AHB should continue to engage with potential funding bodies such as the DfT and keep track of the development of the Clean Maritime Plan 2023 as well as other potential funding opportunities. Operator / off taker contribution to infrastructure deployment should also be considered Should <50% of the CAPEX cost be covered through grant funding then shore power sales price would need to increase if the base case IRR is to be met. A series of sensitivities have been undertaken around this in the financial case.*
4. **Costing estimates increase during design development on award of D&M contracts**
    a. *Market testing and bespoke cost consultancy input has been undertaken to refine the cost plan - this should be revisited at later stages. This engagement process will highlight any cost hotspots which require further design development. Cost sensitivity has been tested to +/-20% in financial case.*
5. **Shore power consumption estimates vary vs actual consumption**
    a. *Power demand sensitivity has been completed as part of a detailed vessel movement analysis and modelled as a sensitivity, but risks remain due to inherent variability between design and operation.*

Continued refinement of the model may be required if a significant change in predicted operator use becomes apparent.

7.6. Contingency arrangements and plans

Although there are no critical aspects of the project that could lead to an unavoidable project failure, which in turn would impact the development on site, it is worth mentioning that as described in the Strategic case the project is seen as a catalyst and a pilot leading to both environmental and social benefits for the area, with Point Law Peninsula being a flagship location for delivering a shore power demonstrator project.

Steps that could however mitigate the risk of failure are the following:

- Minimising the number of design, build, operate and maintain contractors for the project, and associated interface risks between construction and operation.
- Ensuring that vessel power equipment is resilient in case of shore power operational issues.

It is important for AHB to have step-in rights for the event that the appointed contractors contract becomes untenable. In that case, clauses in the contract should be included that allow AHB to take over the project in order to be delivered.

Appendix A Quayside Configurations

Appendix A1 – Decentralised

Appendix A2 Semi-centralised

Appendix A3 - Centralised

Appendix B Multi-Criteria Analysis

Option	Cost	Cost matrix number	Maintenance	Maintenance matrix number	Quality of design solution	Quality of design matrix number	Inherent risk	Inherent risk matrix number	Supplier track record	Supplier track record matrix number	Effect on port operations	Effect on port operations matrix number	Flexibility	Flexibility matrix number	Lifetime / futureproofing	Lifetime / future proofing matrix number	Weighted matrix number	Rank
Decentralised	Highest cost	3	Higher maintenance cost as more units to service	3	Design not a simple or cost-effective solution	3	More HV cabling to protect	3	Less supplier options for fully decentralised	2	Most likelihood to effect operations	3	Flexibility to use shore power and cable management across the port	1	Good lifetime for equipment. Not futureproofed	3	2.7	3
Semi-centralised	Lowest cost than decentralised due to savings around single frequency converter and also minimising flexible plant around port	2	Lower maintenance costs but more units than centralised	2	For purpose of the port where LV solutions work the 2nd best quality design	2	Risk of HV transformers on dock side	2	Multiple suppliers able to offer	1	Some likelihood for operations impact	2	Centralised frequency converter mean other berthing area would need this too.	2	Good lifetime for equipment. Futureproofed	1	1.8	2
Centralised	Intermediate cost option due to centralised plant but need infrastructure for all berths	2	Lowest maintenance cost	1	Best quality design for the purpose	1	Least risk	1	Multiple suppliers able to offer	1	Minimal likelihood to effect operations	1	Infrastructure cannot be used on other berths without additional infrastructure	2	Not fully futureproofed due to cable size limits	2	1.4	1

Option	Cost	Cost matrix number	Maintenance	Maintenance matrix number	Quality of design solution	Quality of design matrix number	Inherent risk	Inherent risk matrix number	Supplier track record	Supplier track record matrix number	Effect on port operations	Effect on port operations matrix number	Flexibility	Flexibility matrix number	Lifetime / futureproofing	Lifetime / future proofing matrix number	Weighted matrix number	Rank
Fixed above ground connection point	Lowest cost option	1	General maintenance costs, easy maintenance access. Potential to get damaged by quayside operations	2	Has minimal impact to quayside operations if located close to quay edge	2	Risk involved in damaging the fixed connection point whilst in use. Construction of bollard around the connection point	2	Multiple suppliers able to offer	1	Has minimal impact to quayside operations if located close to quay edge. At the front of the ship to minimise disruption	2	Fixed solution	2	Good lifetime for equipment, fixed no moving parts	1	1.6	1
Fixed below ground connection point	Higher cost option	2	Higher maintenance cost due to buried construction. Access chamber could get damaged by quayside operations.	3	Access chamber would have to be closed to allow normal operations to continue	2	Risk involved in manual lifting the access chamber, water ingress into the chamber and crane movements around the access chamber	3	Fewer suppliers able to offer, often bespoke solutions	2	Access chamber would have to be closed to allow normal operations to continue. At the front of the ship to minimise disruption	2	Fixed solution	2	More moving parts, lower lifetime on equipment	2	2.3	2

Option	Cost	Cost matrix number	Maintenance	Maintenance matrix number	Quality of design solution	Quality of design matrix number	Inherent risk	Inherent risk matrix number	Supplier track record	Supplier track record matrix number	Effect on port operations	Effect on port operations matrix number	Flexibility	Flexibility matrix number	Lifetime / futureproofing	Lifetime / future proofing matrix number	Weighted matrix number	Rank
Shore side fixed cable management point	Low-cost option	1	Some mechanical aspects to maintain	2	Has an impact of the port	2	Bespoke for connection	1	Multiple suppliers able to offer	1	Most likelihood to effect operations	3	Flexibility to use shore power and cable management across the port	2	Good lifetime for equipment. Not futureproofed as may need new infrastructure	2	1.65	2
Shore side flexible cable reel	Low-cost option and flexible	1	Low maintenance cost	1	Has an impact of the port	2	Cables to be moved	2	Multiple suppliers able to offer	1	Some likelihood for operations impact with long durations at port	2	Centralised frequency converter mean other berthing area would need this too.	1	Good lifetime for equipment. Futureproofed as cable can be easily replaced	1	1.35	1
Ship side flexible cable reel	More units required as on ship	3	Low maintenance cost but difficult to monitor maintenance	2	Has an impact of the port	2	Cables to be moved and dropped	2	Multiple suppliers able to offer	1	Minimal likelihood to effect operations	1	Infrastructure cannot be used on other berths without additional infrastructure	1	Not fully futureproofed due to cable size limits	1	1.8	3
Shore side port tracking connection	Very expensive	3	Highest maintenance costs as moving parts	3	Neat solution	1	Minimal safety risk	1	Fewer options available	2	Minimal likelihood to effect operations	1	Most flexible option	1	Would need to replace infrastructure if you were to change operations	2	1.9	4
Shore side buried cable reel	Buried service expensive and multiple required	3	Maintenance issues with buried solution	2	Neat solution	1	Cables running across the port	2	Buried option not a typical offer	2	Minimal likelihood to effect operations	1	No flexibility to move if required	2	Would need to replace cable for buried service if you were to change operations	2	2	5

Appendix C Risk Register

Item Ref.	CORE SCHEME ITEM	Pre mitigation Prob. 1-5 P	Impact 1-5 I	Risk 1-25 R = P x I	Action M/T/R	M- MANAGE T - TRANSFER R - REDUCE Actions required	Lead By	Post mitigation Prob. 1-5 P	Impact 1-5 I	Risk 1-25 R = P x I
1	**1.0 Stakeholders**									
1.1	AHB fail to gain support internally to develop shore power infrastructure	3	5	15	M	AHB to achieve sign off from internal decision makers with completion of OBC to agree on formal policy approach and procurement route for shore power infrastructure.	AHB / SPV	1	5	5
1.2	AHB fail to gain wider political support	4	5	20	R	AHB to submit OBC and DPD information to applicable funding body for additional funding signoff which could potentially support up to 50% of capital costs of infrastructure and consult with government departments to test basis for system procurement and delivery is transparent and according to best practice.	AHB / SPV	3	5	15
1.3	Harbour tenants / operators do not wish to participate or push back on required planning requirements for implementation of shore power infrastructure.	3	5	15	R	Heads of Terms (HoTs) to be agreed in principle with participating operators including spatial planning. Suggested enhancement of electric take-off contract to include shore power spatial requirements	AHB / SPV	2	5	10
1.4	Vessel owners do not transition their vessels to accommodate shore power, particularly in cases where vessels are rented or leased by harbour users.	3	5	15	R	Harbour areas where operators have decarbonisation targets and good relationships with vessel owners have been selected. Continued engagement between vessel users and owners must take place to promote the retrofitting of vessels to accept shore power, else alternative leasing arrangements should be sought.	AHB / SPV & operators	2	5	10
2	**2.0 Business Case**									
2.1	**2.1 Funding and Procurement**									
2.1.1	Failure to identify funding sources adequate to meet the capital costs of the scheme, particularly the grant funding to meet the 50% of CAPEX base case	4	5	20	R	AHB should continue to engage with potential funding bodies such as the DfT and keep track of the development of the Clean Maritime Plan 2023 as well as other potential funding opportunities. Operator / off taker contribution to infrastructure deployment should also be considered Should <50% of the CAPEX cost be covered through grant funding then shore power sales price would need to increase if the base case IRR is to be met. A series of sensitivities have been ran around this in the financial case.	AHB / SPV	3	5	15

		Pre mitigation						Post mitigation		
	CORE SCHEME	Prob. 1-5	Impact 1-5	Risk 1-25	Action M/T/R	M- MANAGE T - TRANSFER R - REDUCE		Prob. 1-5	Impact 1-5	Risk 1-25
Item Ref.	ITEM	P	I	R = P x I		Actions required	Lead By	P	I	R = P x I
2.1.2	Unable to develop business case to allow shore power infrastructure to progress. Lack of political will to continue as owner and operator	2	5	10	R	OBC to inform commitment required from associated parties. Current intention is to progress with D&B contracts with AHB retaining ownership. Engagement with senior Aberdeen Harbour officials has continued and OBC forms basis of current project position for final sign-off	AHB / SPV	3	5	15
2.2	**2.2 Capital costs**									
2.2.1	Costing estimates increase during design development on award of D&M contracts	4	4	16	M	Market testing and bespoke cost consultancy input has been undertaken to refine the cost plan - this should be revisited at later stages. This engagement process will highlight any cost hotspots which require further design development. Cost sensitivity has been tested to +/-20% in financial case.	AHB / SPV	3	4	12
2.2.2	Budget underestimated during construction due to unforeseen issues	3	5	15	M	Appropriate contingency has been added to OBC cost estimates and should be considered during contractor awards and funding applications. Key risks identified during feasibility study and continuing design development to be actively managed and mitigated at appropriate time. Key surveys have been identified to progress prior to D&B contractor award.	AHB/ Consultant	3	4	12
2.3	**2.3 Revenues/ Operating Costs**									
2.3.1	Failure to attract participating shore power users or delay in implementing shore power infrastructure therefore resulting in reduced revenue leads to revenue gap to repay any borrowing / investment.	5	5	25	R	Investigate alternative revenue grants including sharing of risk until further participating operators (and revenue) are sufficient to cover operating costs including any borrowing costs.	AHB / SPV	4	5	20
2.3.2	Fail to obtain economic value from power sales	3	5	15	R	Further sensitivity testing has been carried out over variety of electricity prices (wholesale) and long-term economic sustainability of the scheme. There will be a need to ensure customer supply contracts reinforce viability of agreed shore power electricity prices and changes in electricity purchase price are backed off to customers	AHB / SPV	2	4	8
2.3.3	Exposure to fluctuations in future energy prices leading to AHB exposed to funding shortfall versus operator power sales	3	4	12	R	Future energy price scenario from BEIS tested in financial model to understand sensitivity to future fuel cost fluctuations. To be reviewed and updated during design development. Power sales have been index linked to primary energy prices. Protection from increases in power prices should be considered for AHB power purchase from supplier. Shore power sales prices may need to temporarily increase and this should be considered within operator contracts.	AHB / SPV	2	3	6

		Pre mitigation						Post mitigation		
	CORE SCHEME	**Prob. 1-5**	**Impact 1-5**	**Risk 1-25**	**Action M/T/R**	**M- MANAGE T - TRANSFER R - REDUCE**		**Prob. 1-5**	**Impact 1-5**	**Risk 1-25**
Item Ref.	**ITEM**	**P**	**I**	**R = P x I**		**Actions required**	**Lead By**	**P**	**I**	**R = P x I**
2.3.4	Resulting cost of shore power is too high for participating operators	3	5	15	M	AHB could obtain additional capital funding to minimise power cost; tight control of costs for infrastructure rollout is required and index linking of power cost to counterfactual marine fuelling solution which may incur carbon taxes in the future. Power rate to be remodelled on realisation of funding provision before proceeding.	AHB / SPV	2	4	8
2.3.5	Purchase price of power to supply shore power units becomes too high in future in comparison to alternatives (e.g. marine fuel)	3	5	15	R	AHB to consider long term contracts for energy purchase	AHB / SPV	2	2	4
2.3.6	Information not forthcoming from potential shore power consumers. Estimates have been made for future shore power sales based on best available information.	2	3	6	R	Early engagement with operators has been completed to update models with anticipated future power demands using best available information. Gradual uptake in power demands for vessels has been factored into early years of shore power operation to reflect vessels being retrofitted to accept shore power and operator buy-in. This should be continually reviewed and may require re-run of model should they be a significant deviation from base case demands.	AHB / SPV	1	3	3
2.3.7	Failure to meet "power on" date requirements for leading to loss of power sales over modelled lifetime	3	5	15	R	Continued consultation has been undertaken with port users throughout the completion of the OBC. During this process mitigation approaches should be agreed including the use of incumbent marine fuel energy supply as a last resort. Sensitivity testing indicates minimal impact to project commercial feasibility if power on dates are delayed.	AHB / SPV	2	3	6
2.3.8	Some shore power off takers (customers) do not value carbon costs as high as has been assumed in the base case and therefore do not regard utilisation of shore power as economically worthwhile vs. Cost of marine fuel	3	5	15	M	Prevailing sentiment from most operators engaged as part of the OBC process is to decarbonise their operations in order to meet self-set net zero targets. Continued engagement with operators to promote the use of shore power at Point Law and possible contractual obligations to utilise shore power whilst alongside at selected berths or based on anticipated duration of stay.	AHB / SPV	2	4	8
2.3.9	Failure to meet project completion deadlines set by project funders.	3	5	15	R	Aberdeen Harbour will confirm milestones at the outset of the construction programme with the funding board and manage any delays through regular consultation. There are precedents for delays on previous projects funded through this means so close collaboration will be key.	AHB / SPV	2	3	6
2.3.10	Operating costs exceed expectations as modelled in the base case.	3	4	12	M	A series of sensitives against the impact of mark-up price and IRR have been ran as part of the financial case to assess the impact of operating costs, these sensitivities also cover the impact of tax burden.	AHB / SPV	2	4	8

		Pre mitigation						Post mitigation		
	CORE SCHEME	Prob. 1-5	Impact 1-5	Risk 1-25	Action M/T/R	M- MANAGE T - TRANSFER R - REDUCE		Prob. 1-5	Impact 1-5	Risk 1-25
Item Ref.	ITEM	P	I	R = P x I		Actions required	Lead By	P	I	R = P x I
3	**3.0 Planning Consents, Permitting and Environment**									
3.1	Fail to obtain planning / operational permission for shore power infrastructure and associated power connections	2	5	10	R	AHB will need to continue to manage planning / operational concerns for infrastructure through engagement with operators and local stakeholders. Understanding is AHB are the landowners of areas where new infrastructure is being implemented.	AHB / SPV	1	5	5
3.2	High levels of visual impact from infrastructure	1	4	4	R	Thought to be low risk due to industrial nature of the site.	AHB/ consultant	1	4	4
4	**4.0 Technical and design issues**									
4.1	Shore power consumption estimates vary vs actual consumption	4	4	16	M	Power demand sensitivity has been completed as part of a detailed vessel movement analysis and modelled as a sensitivity but risks remain due to inherent variability between design and operation. Continued refinement of the model may be required if a significant change in predicted operator use becomes apparent.	AHB/ contractor	3	4	12
4.2	In short to medium term (i.e. before the shore power systems are developed) operators install own equipment reducing potential for shore power sales for AHB	1	5	5	M	Dialogue will be maintained with key stakeholders to discuss shore power opportunity and ensure HoTs are agreed. Understanding is that permission would have to be granted from AHB to operators to develop own solutions.	AHB / SPV	1	3	3
5	**5.0 Utilities**									
5.1	Service cabling requires service diversions to accommodate new power cabling	3	5	15	R	Record asset survey information has been collected and appraised to determine best estimate of utility locations and pinch points for coordination of new infrastructure. Areas of concern have been identified where further investigation has been recommended (i.e. GPR surveying). Contingency costs for buried services in concrete quays have been factored in to cost model and should be considered during contractor appointment.	AHB/ contractor	2	3	6
5.2	Aberdeen Harbour fails to obtain agreement with the Distribution Network Operator for the provision of power to the shore power system.	3	5	15	R	The DNO is obliged to 'provide a connection upon request' as its statutory duty. Third parties can be used (ICP/IDNO) to reduce the capital cost to connect.	AHB/ DNO	2	3	6

		Pre mitigation						Post mitigation		
	CORE SCHEME	Prob. 1-5	Impact 1-5	Risk 1-25	Action M/T/R	M- MANAGE T - TRANSFER R - REDUCE		Prob. 1-5	Impact 1-5	Risk 1-25
Item Ref.	ITEM	P	I	R = P x I		Actions required	Lead By	P	I	R = P x I
5.3	Lack of capacity locally to supply electricity or significant reinforcement required to provide capacity	2	5	10	R	Early engagement with the DNO (SSE) has been made to understand any reinforcement requirements and costs to serve shore power areas. SSE (DNO) has indicated that extension of nearby 11kV cabling to the E-House is feasible with no requirement for upstream reinforcement. DNO costs to make shore power connection have been received and factored into the model with contingency. A formal quote and timescales should be secured from the DNO at later stages. Intelligent controls to minimise coincident peak demands on shore power systems should be considered if required.	AHB/ contractor	1	5	5
6	**6.0 Construction and procurement**									
6.1	Design responsibility and temporary termination for live building sites	3	3	9	M	AHB appointed consultant/ contractor to manage construction work in conjunction with contractors, developers and other potential shore power consumers.	AHB / Main contractor	2	2	4
6.2	Risk of discovering unexpected material in the ground such as contaminated land, archaeology or unexploded ordinances	2	4	8	M	Low risk given harbour owned and operated areas. Spatial coordination of new infrastructure to avoid impacting existing harbour services and or structural integrity of quays has been considered. Undertake suitable ground investigation prior to commencement of procurement; hold suitable level of contingency within budget.	AHB/ development project engineers	2	2	4
6.3	Impact of COVID and future pandemics causing unforeseen risks to programme.	3	4	12	M	Employers Requirements to request the D&B contractor to confirm safe means of working,	AHB/ development project engineers	2	2	4
7	**7.0 Operations and maintenance**									
7.1	Power delivery failure	2	5	10	R	Incoming electrical supply includes resilience by being fed via a ring arrangement from the grid meaning if either incoming leg Is faulty, the remaining leg can accommodate the electrical supply. Outgoing supplies to the berths are arranged in a radial formation meaning if an outgoing cable/frequency converter/transformer fails, then this will render that specific berth unusable, however the remaining berths will remain in operation	AHB/ DNO	1	3	3

		Pre mitigation						Post mitigation		
	CORE SCHEME	Prob. 1-5	Impact 1-5	Risk 1-25	Action M/T/R	M- MANAGE T - TRANSFER R - REDUCE		Prob. 1-5	Impact 1-5	Risk 1-25
Item Ref.	ITEM	P	I	R = P x I		Actions required	Lead By	P	I	R = P x I
7.2	Default of O&M contractor (where used)	1	4	4	M	Careful selection of contractor / supplier; setup handover procedures; hold funds for replacement etc.	AHB/ contractor	1	3	3
8	**8.0 Future Phases**									
8.1	Future operators of the harbour do not wish to participate	3	5	15	M	Early engagement with operators has been undertaken indicating net zero aspirations and good buy in for shore power offtake in future. Enhancement of lease agreements could include shore power use obligations. Future carbon taxes on marine fuels could help justify case for shore power	AHB / SPV	2	4	8
8.2	Later phases do not go ahead	1	5	5	M	Scheme has been tested and baseline scenario has attractive commercial and financial results. Installation timeline has been assumed as 1 year as a single phase.	AHB / SPV	3	5	15
9	**9.0 Legal**									
9.3	to be added									

Appendix D Draft Heads of Terms

Draft Heads of Terms for the Power Connection & Supply Agreement

Parties	
Shore Power Operator	Aberdeen Harbour Board
Port User	[]

Interpretation	
Approved Shore Power Operator Transferee	any party in which the Shore Power Operator holds an interest of no less than 50%; or any party over which the Shore Power Operator retains contractual control for that party's quality of service or standards of performance; or any major utility provider; or any party with the skills, resource and experience required to manage the supply of electricity similar to the Electricity Supply governed by the terms of this Contract.
Approved Port User Transferee	Any of the Port User's affiliates or any person to whom the Port User transfers the head lease(s).
Connection	The physical connection of the Ship to the Shore Power Network (or temporary plant as the case may be) to enable the Shore Power Operator to provide, and the Port User to receive, Power.
Connection Capacity	Expressed in KVA and being the maximum instantaneous power capacity that the Connection can supply to the Ship.
Connection Charges	The charge (if any) payable by the Port User to the Shore Power Operator being calculated as the Connection Capacity multiplied by the Connection Charge Rate per kWh as set out in the connection particulars in these Heads of Terms.
Shore Power Network	The network assets, including all pipes, wires, control and monitoring equipment on the network, which enables power to be supplied to the Port User.
Effective Date	The date when the Conditions Precedent are first satisfied or waived.
Electricity Meter	The meter or equipment measuring the amount of power supplied as electricity as the case may be to each connection point.
Minimum Supply Voltage	The minimum supply voltage shall be set according to the requirements agreed with the Port User excluding variations lasting for less than 20 minutes.
Planned Connection Date	The date requested by the Port User and agreed by the Shore Power Operator by which the Connection is to be completed and power made available.
Point of Supply	The point(s) at which the Supply is delivered to the Port User.
Ship	The agreed vessel to be connected to the Shore Power Network.
Service Charges	A fixed charge payable (if any) in each period based on the fixed cost associated with supplying electricity to the Ship.
Supply Charges	A variable charge in each period based on the amount of power supplied in that period.

Port User Obligations	
Technical requirements	The Port User shall ensure their ship side installation conforms to the technical requirements of IEC 80005-3 Low Voltage Shore connection (LVSC) Systems. Any deviations from this standard must first be discussed with the shore power operator before connection is made.
Security	Notify the Shore Power Operator immediately should the Port User become aware of any damage to any part of the Shore Power Network. Not to allow or cause interference with, attempted removal of, or otherwise damage the Shore Power Network. Pay for any damage to the Shore Power Network unless such is caused by the Shore Power Operator or has arisen from fair wear and tear.
Power Use	Not obtain a power supply other than from the Shore Power Network and not install or operate any independent power production equipment during the term.
Payment	Pay in accordance with the Payment Terms all Connection Charges, Supply Charges and Service Charges, including any VAT properly owed to the Shore Power Operator.
Payment terms	1) Connection Charges: 100% on execution of the Connection Agreement 2) Supply Charges - 100% within 30 Days of Invoice

Shore Power Operator Obligations	
Technical requirements	The shore power operator shall ensure the shore side installation conforms to the technical requirements of IEC 80005-3 Low Voltage Shore connection (LVSC) Systems. Any deviations from this standard must first be discussed with the Port User before connection is made.
Connection Capacity	Ensure that the connection and network design is capable of delivering the required Connection Capacity (as defined in the Supply Particulars to this Heads of Terms) at the Point of Supply.
Connection Works	Installation and commissioning of the Shore Power Network.
Delay Mitigation	Take all commercially reasonable steps to mitigate any delay in the completion of the Connection Works in the event that the Connection Works are delayed whether as a result of a Legitimate Excuse or otherwise.

Power Availability — Ensure that Power is supplied to the Ship with not less than the Minimum Supply Voltage & frequency and sufficient capacity to meet the demand provided that demand does not exceed the Connection Capacity.

Metering — The Shore Power Operator shall accurately meter the power used and maintain, repair, and replace the associated metering equipment in accordance with good industry practice, relevant legislation.

Faults & Maintenance — If there is a fault or maintenance work that requires a reduction in supply capacity or, where unavoidable, an interruption in supply, the Network Operator shall where possible provide prior notice of such fault or work to the Port User and carry out such remedial work as is necessary to correct the fault or otherwise return the network to full capacity as soon as reasonably possible having regard to the nature of the cause of the fault or maintenance work.

Planned maintenance works shall be carried out as far as practical in periods of low demand for power and in such a way that the supply is not interrupted.

Guaranteed Standards — TBC

Key Terms

Term of Agreement — Not less than [X} years from the date of completion of the Connection Works.

Charges & Indexation — The Connection Charges are subject to adjustment by the Construction Output Price Index for Infrastructure as published by the Office for National Statistics.

The Service Charges shall be indexed annually against the Consumer Price Index.

The Supply Charges shall be indexed against the electricity price (being the delivered price for electricity payable by the Network Operator for the supply of electricity to the Ship.

Legitimate Excuses

(a) Breach of the Connection Agreement by the Port User;
(b) Force Majeure (including adverse weather conditions, industrial action, inability to obtain access to any premises, delay of competent authority, unavailability of gas, water, electricity or telecommunications, Shore Powers, illegality, civil emergency or act of terrorism; pandemics or epidemics and government response to them or other circumstances of an exceptional nature beyond the Shore Power Operator's control and which the Shore Power Operator has taken reasonable steps to prevent);
(c) Third party action e.g. vandalism.

Ownership — The Shore Power Network shall remain the property of the Shore Power Operator.

Novation & Sub-Contracting — The Shore Power Operator may:

(a) sub-contract any of its obligations under this Connection & Supply Agreement to any other party (but remains liable for the proper execution of those obligations) and may novate its rights and obligations to an Approved Shore Power Operator Transferee without consent of the Port User; and
(b) novate its rights and obligations to any other party subject to the Port User's consent.

The Port User may novate its rights and obligations to an Approved Port User Transferee without consent of the Shore Power Operator's or to any other party subject to the Shore Power Operator's consent.

Termination — Either party shall be entitled to terminate this Agreement by giving [X] months written notice after the initial Term of Agreement.

By Shore Power Operator if:

(a) Material or persistent un-remedied breach by Port User;
(b) Port User insolvency, administration etc.
(c) Force Majeure lasts > 6 months.

By Port User if:

(a) Material or persistent un-remedied breach by Shore Power Operator;
(b) Shore Power Operator insolvency
(c) Force Majeure lasts > 6 months;
(d) Shore Power Operator fails to complete the Connection by the longstop date (120 days after the Planned Connection Date).

Automatically if:

(a) Conditions precedent (if any) are not satisfied or waived.

Consequences of Termination — At the Port User's discretion:

(a) Shore Power Operator removes the right to connect to the Shore Power Network.

Limitation of Liabilities — Liabilities:

(a) Death or injury – unlimited
(b) Public liability - £5,000,000 per incident or series of related incidents
(c) Damage to property - £5,000,000 per incident or series of related incidents

No liability for:

(a) loss caused by strikes or industrial disputes involving employees of any third party, natural disaster or compliance with any law or governmental order, rule, regulation or direction;
(b) indirect loss, loss of profit, revenue, contract or goodwill (or third-party claims for the same);
(c) any loss caused by corruption or damage to electronic data or software;
(d) loss arising from force majeure.

Change in Law — Each party to comply with any relevant Change in Law and where the effect of such change is to increase or reduce the Shore Power Operator's costs such change shall be reflected in the Charges but only to the extent that the Shore Power Operator is returned to the position that existed before such Change in Law came into effect.

Other Legal Boilerplate Provisions — Other standard legal provisions including but not limited to insurance, confidentiality, novation and dispute resolution are to be included.

Governing Law — This Connection and Supply Agreement is subject to the laws of Scotland and to the exclusive jurisdiction of the courts of Scotland.

Connection & Supply Particulars

1) The Conditions Precedent are:
   a. [●]

b. [●]
c. [●]

2) The Connection Capacity is [●] KVA.
3) The Planned Connection Date is the later of [●] days after the Effective Date and [*insert date*].
4) The Connection Charge Rate at the date of this Heads of Terms is £ [●] - [●] per kWh
5) The Service Charge Rate at the date of this Heads of Terms is £ [●] per kWh.
6) The Supply Charge Rate at the date of this Heads of Terms is £ [●] per kWh.

These Heads of Terms set out the principles for connection to a Shore Power System and supply of Power to the Ship which the Port User and the Shore Power Operator propose to formally agree and document in the Connection and Supply Agreement. Save in respect of keeping the content of these Heads of Terms confidential, neither the Port User nor the Shore Power Operator intend that these Heads of Terms create any legally binding rights or obligations between them and no legally binding obligations shall arise under these Heads of Terms.

Signed on behalf of Aberdeen Harbour	)	**Name:**
	)	
	)	
	)	
	)	
	)	**Authorised Officer**

Signed on behalf of the Port User	)	**Signed:**
	)	
	)	
	)	**Name:**
	)	
	)	**Position:**

Appendix E Services Coordination Report

Appendix provided separately from the report. Appendix includes:

- Appendix E1 – Aberdeen Port Shore Power OBC Cable Routes Advanced Feasibility Study
- Appendix E2-E13 – Associated CAD drawings of spatial coordination
- Appendix E14 - Spatial coordination HAZID Register

Appendix F Supplier Quote Summary and Cost Plan

F.1 Shore power system quote summary

For the initial 2500 kVA design that only included Albert quay, the following prices were received back from the above suppliers.

F.1.1 Decentralised system for 2500 kVA

Company	Costs	Pros	Cons
CNE	£4.7m per year to lease a 24 MWh energy storage system	Very flexible solution, Lease/hire capability to reduce CAPEX outlay, Doesn't require civils works on the dock, Capable of harnessing generated renewable energy if available	Very costly solution on OPEX Fixed output voltages
GE	£1.6m for equipment costs not including housing	Good flexible solution supplying two connection points per system If installed in containers, then these can be moved around the port	More expensive, Price does not include housing Fixed output voltages
Power Systems International	£1.3m for equipment including containerised housing	Cheapest option Containers can be maneuvered around site if required	Fixed output voltages

F.1.2 Semi centralised and Centralised system for 2500 kVA

Company	System type	Costs	Pros	Cons
ABB	Centralised	£1.6m Including housing	Well known OEM	More expensive than rivals
GE	Semi Centralised	£1m Not including housing	Larger transformer and frequency converter for potential future proofing	Most expensive option Requires construction of housing, not included
Power Con	Centralised	£685k Including housing	Cheap turnkey system including incoming switchgear Capable of different output voltages for each connection increased flexibility	Futureproofing if supply increases
Power Systems International	Semi Centralised	£400k Not including housing	Cheapest option excluding housing	Requires construction of housing, not included

F.1.3 Centralised systems for 3500 kVA

Based on the above information, we contacted a select few suppliers to provide costs for a larger 7 connection 3500 kVA system that incorporated both Albert and Mearns quay for a centralised solution. The following costs were returned:

Company	Costs	Pros	Cons
GE	£1.6m for equipment costs not including housing or shore connection points	Well known OEM Larger transformer and frequency converter for potential future proofing	More expensive, Price does not include housing Fixed output voltages
Power Con	£975k for full system including housing and shore connection points	Cheap turnkey system including incoming switchgear Capable of different output voltages for each connection increased flexibility	Futureproofing if supply increases

F.2 Connection system quote summary

The suppliers contacted for shore power connection systems were:

Company	Response	Costs – Connection box	Costs – Cable management
Cavotec	No information received	£8.5k	£75k
Igus	Costing information issued for mobile cable management	Included in design costs	£35k
Shore-Link	Costing information issued for mobile cable management	N/A	£78k
Wabtec	Costing information issued for mobile cable management	£22k	£78k

Additional appendix items provided separately from the report:

- Appendix F1 – ABB quote
- Appendix F2 – Carbon Neutral quote
- Appendix F3.1 – GE quote technical proposal 2.5 MVA
- Appendix F3.2 – GE quote tender price schedule 2.5 MVA
- Appendix F4 – Power con quote and proposal 2.5 MVA
- Appendix F5 – Power systems international quote
- Appendix F6 – Igus quote
- Appendix F7 – Wabtec quote
- Appendix F8.1 – GE quote technical proposal 3.5 MVA
- Appendix F8.2 – GE quote tender price schedule 3.5 MVA
- Appendix F9.1 – Power con SLD 3.5 MVA
- Appendix F9.2 – Power con quote and proposal 3.5 MVA
- Appendix F10 – Thomson Bethune Cost Plan

Appendix G Recommended Spares

G.1 Supplier recommended list of spares. Red denotes critical spares and black denotes other required spares. Recommended spared provided be GE.

Description
LVL LV3 1250A 1200Vd.c. V6 Build
~~Heat Exchanger B120THx090~~
~~Air/Water Heat Exchanger, Large~~
~~Air/Water Heat Exchanger, Small~~
Pump TPD50-300/2-X-F-A BQQE 690V 60Hz
Flow Sensor SI5000
Combined Pressure Sensor PN2094
~~Quickpanel HMI~~
~~PC CPU 1.4GHZ GE-IP RXI-042 Standard~~
~~Resistor BC6 1.5ohm (no tapping)~~
~~Resistor, W/W, PE380, 1Kohm, Non-Ind~~
Toroidal Control Transformer 3kVA 690:230V
Fuse 400A 690V SIZE 30 DIN110 Blades
RCTi-3ph AC Current Transducer 500A
Capacitor 68uF
~~AF460 Contactor,100-250V,50-60Hz,1NO1NC~~
~~Contactor, SPST-NC, 30A, 24VDC~~
Fan Coil Monitor/Controller
Amplifier Switch
Module,Buffer,24VDC 0.2s 20A
Power Supply Unit, 24V DC, 10A
~~MCB 2P-D-20A Ref 686894~~
~~MCB 2P-D-10A Ref 686966~~
~~Mains Filter 10A~~
Relay,W\Suppression,14-Pin 5A 220\240Vac
Diode Suppression Relay, 24vdc
~~Optical Smoke Detector~~
~~Optical Smoke Detector Base~~
Total

Appendix H SSE Quote

Appendix provided separately from the report. Appendix includes:

- Appendix H1 – SSE Design Documents
- Appendix H2 – SSE Quote Letter

Appendix I Power Demand Assessment

Shore power demand is a function of three variables:

- The total number of hours each ship spends at berth, summed over all ships
- Which of those ships have the capability to use shore power
- The power requirements of those ships at berth

This appendix sets out estimates for shore power demand based on these three variables, using berthing data from Aberdeen Harbour Board, and interviews with ship owners and operators. It starts with berthing analysis in the year from 1/11/2020 to 31/10/21 at the Albert 1-5, Mearns 1-3 and Torry 3-6 berths, used by multi-purpose supply vessels operated by oil companies, and then focusses on the proposed shore power installation areas of Albert 1-5, Mearns 1 and 3.

Core data:

In total, the 12 berths were occupied for 48,244 hours, with an average visit length of 12.9 hours

Albert 1-5, Mearns 1-3, Torry 3-6 core data	
Visits/yr	3,744
Average length of visit	12.9 hours
Total hours at berth/yr	48,244 hours

These 48,244 hours are concentrated in a small number of vessels. 97 vessels visited these berths in total, but just 30 of them had multiple-visits and comprised 77% of the total hours at berth. The other vessels tend to be those hired for short-periods on the spot-market, rather than those on year or multi-year contracts.

It is assumed here that frequent-visit vessels would be the priority for shore power installation and connection. Based on operator interviews on future plans, and berthing data for these operators in the last year, the following table summarises likely future annual berthing hour requirements for frequent-visit vessels. Major operators are defined here as those with total annual hours from frequent-use vessels totalling more than 2,000: Harbour, BP, Shell, Total, Ithaca, Repsol. Smaller operators include TAQA. CNR, CNOOC, Neptune, Dana, Hurricane.

	Likely future requirements, annual average	**Total annual hours**
6 Major operators	*21 vessels, 1000-2000 hours each*	*26,600*
Smaller operators:	*8 vessels, 700-1100 hours each*	*7,400*
Total	***29 vessels***	***34,000***

This analysis is for 12 berths across Albert, Torry and Mearns. The proposal is to install shore-power connections to service 7 of these berths: at Albert 1-5 and Mearns 1 and 3 (i.e. not Mearns 2 or the Torry berths).

This study assumes a phased increase in shore power utilisation, based on the ship operators gradually deploying shore power on their frequent-visit vessels. Phase 1-4 assume a linear increase until the 7 berths would each supply electricity for on average ~3,000 hours a year to such vessels; this would be equivalent to around 4 of the major operators and one of the smaller operators using shore-power on their frequent-visit vessels. 3,000 hours represents 84% of the current time occupied by all vessels at these berths (Albert 1-5 and Mearns 1 and 3 average 3,560 hours occupied a year).

In Phase 5 it is assumed that shore power is used by all vessels at these 7 berths, assuming current levels of berth occupancy: this was 24,915 hours in the last year. Providing power for more vessels (as the frequent use visits estimate is 34,000 hours) would require either greater average berth occupancy at these berths, or provision of new shore power facilities at Torry 3-6 and Mearns 2.

Power demand:

The average length of berth visits across the Albert, Torry, Mearns berths was 12.9 hours. Assuming 1 hour loss for connection/disconnection for each visit, this equates to a 7.8% loss.

So, a 24,915 hours/year of potential shore-power time would mean actual shore power demand was 24,915 x 0.922 = 22,972 hours.

Over 98% of the berth visits were from multi-purpose supply vessels. Data received from 15 vessel owners confirmed that the average power demand at berth for these vessels is 250kW. This leads to power demand of 5,744 MWh/yr (phase 5). We assume this demand is average equally across the 7 berths, so 821 MWh/berth/yr (phase 5).

MWh/year	**Phase 1**	**Phase 2**	**Phase 3**	**Phase 4**	**Phase 5**
Average per berth	172	345	517	689	821
All 7 berths	1,206	2,413	3,619	4,825	5,744

Further details on assumptions and calculations are available on request.

Appendix J Air Quality Impact Assessment

Air quality input	***Unit***	***Source***	**Value**
Energy marine fuel	*t/MWh*	*20*	0.204
N20 emissions	*kg/tfuel*	*As above*	0.18
NOx emissions	*kg/tfuel*	*As above*	56.71
SOx emissions	*kg/tfuel*	*As above*	1.37
VOC emissions	*kg/tfuel*	*As above*	2.40
PM cost	*kg/tfuel*	*As above*	0.90
PM2.5 cost	*kg/tfuel*	*As above*	0.83
Nox cost	*£/t*	*24*	6,358
SO2 cost	*£/t*	*As above*	13,206
VOC cost	*£/t*	*As above*	102
PM cost	*£/t*	*As above*	46,611
PM2.5 cost	*£/t*	*As above*	73,403
Nox cost	*p/kWh*	*Calculated*	7.38
SO2 cost	*p/kWh*	*Calculated*	0.37
VOC cost	*p/kWh*	*Calculated*	0.00
PM cost	*p/kWh*	*Calculated*	0.86
PM2.5 cost	*p/kWh*	*Calculated*	1.24
Marine fuel p/kWh	*p/kWh*	*Sum of above*	9.85
Electricity p/kWh	*p/kWh*	*18*	0.21

Appendix K Financial Model Assumptions

Item	Date
Construction Start Date	1st January 2024
Operations Start Date	1st January 2025
Operations End Date	31st December 2044
Length of Operations Period	20 years

Electricity Offtake / Supply (p.a.)	MWh
Uses of Electricity	
Customer Offtake Requirement	5,744
Loss in System	637
	6,381
Sources of Electricity	
Main electricity source supply	Import electricity from the Harbour's grid connection

Phasing of Construction Costs	
Construction Period	12 months
Start of Construction	01 January 2024
End of Construction	31 December 2024
Spend Profile	costs are all incurred evenly over 12 months.

Sources of Funds to 31 December 2024	£k	%
Sources of Finance		
Grant Funding	3,994	49.18 %
Drawdown (sized for construction) - Equity	1,032	12.70 %
Drawdown - Subordinated Debt	3,095	38.11 %
Net Income during construction	8,121	100.00 %

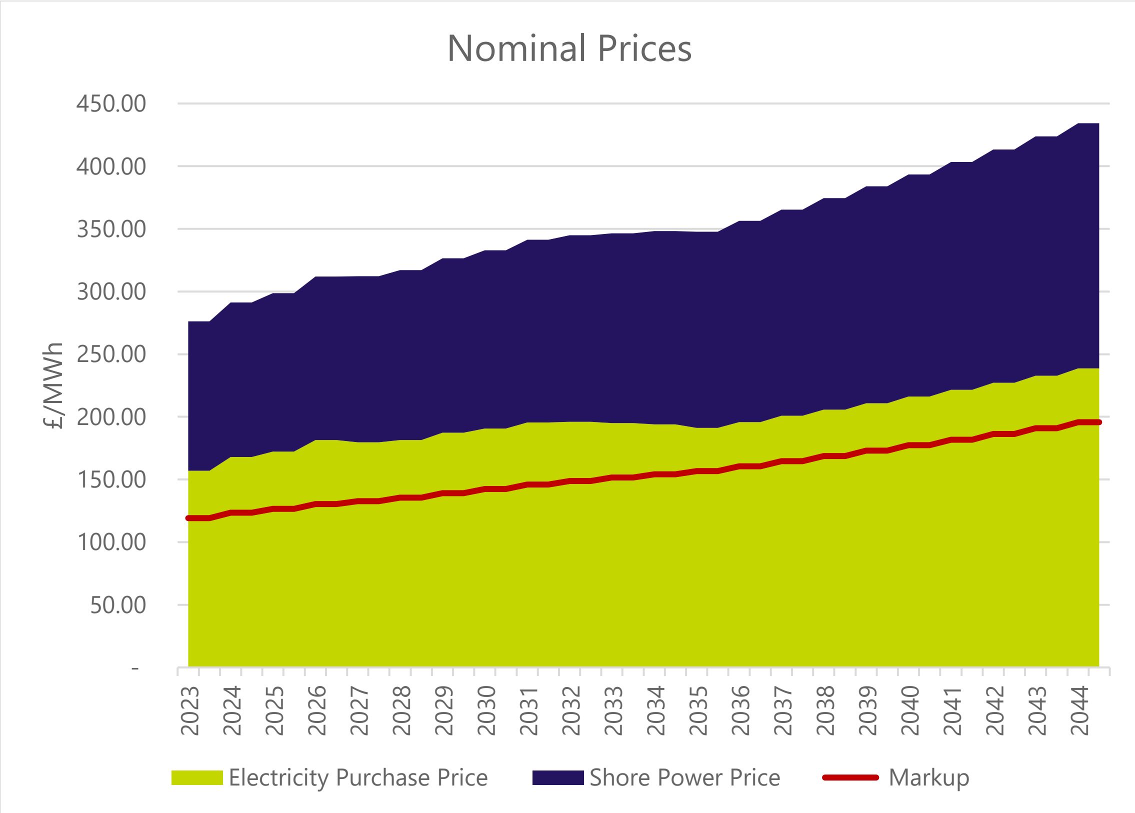
Uses of Funds to 31 March 2028	£k	%
Uses of Finance		
Construction Costs	7,988	98.36 %
Construction Cost VAT	1,598	19.67 %
Construction Period VAT Reimbursement	(1,464)	(18.03)%
Total	8,121	100.00 %

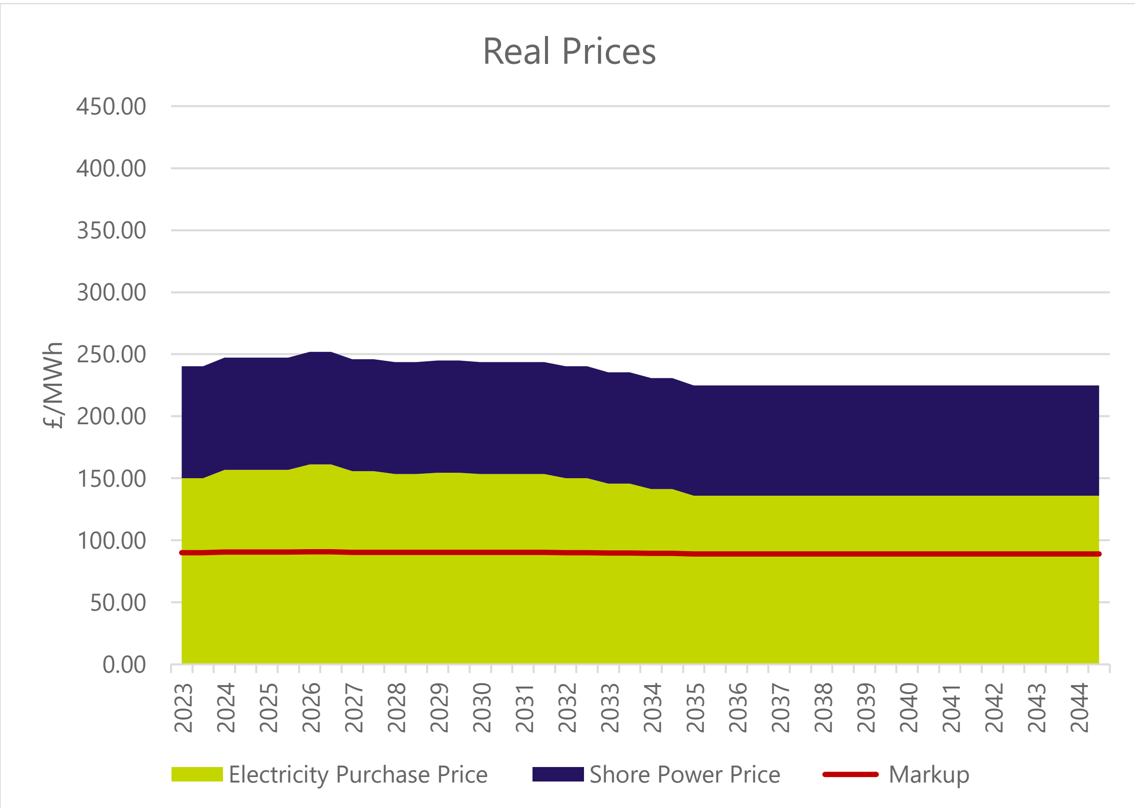
Working Capital	
Creditors	30 days
Debtors	30 days

Assumption	
Commercial Structure	
Structure	Aberdeen Harbour Wholly Owned (SPV)
Funding Assumptions	
Ultimate funding provider	Accessed from Harbour balance sheet
Funding type	Grant funding plus in house funds(cash)
Repayment profile	Intercompany loan and dividends repaid over 20 years.
Interest rate for intercompany loan	6.00 %
Drawdown profile	Drawdown on construction cost profile.
Fees	None assumed
Grant funding	50% of eligible Capex in base case
Tax and Accounting Assumptions	
Fixed asset depreciation	Straight line over asset useful life
Component replacement expenditure	not capitalised
Corporation Tax rate	19% (rising to 25% in Apr 2023)
[Construction] VAT Rate:	20.00 %
VAT recovery timings:	1 month
Creditor days	30 days

Debtor days	30 days
Business Rates	No additional business rate burden expected.
Other Assumptions	
Year-end date	December
Interest on cash balances	1.25% to 2024 then reducing
RPI	7% 2022, 4.5% 2023, 2.5% thereafter.
Indexation	RPI for all operating expenditure, capital expenditure and revenues.
Real discount rate	3.50 %
Nominal Discount Rate	6.09%
Costs in addition to those detailed in the TEM	Audit fees assume £5k per annum including tax advice
Cash buffer	3x monthly expenditure

Appendix L Financial Model Electricity Real Prices and Nominal Prices





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BURO HAPPOLD

Port of Aberdeen - Port Zero

Port Zero Feasibility Report

0053988

9 August 2023

Revision P03

Revision	Description	Issued by	Date	Checked
P01	WP2 WIP Draft Issue v1 – covering energy demand analysis, low carbon infrastructure sizing and coordination and alternative fuel requirements. Full techno-economic analysis and carbon assessment to be provided in subsequent submission	Luigi Piani	02/06/2023	JC
P02	WP2 Draft Issue v2 – covering energy demand analysis, low carbon infrastructure sizing and coordination, alternative fuel requirements, full techno-economic analysis and carbon assessment – for comment	Luigi Piani	16/06/2023	JC
P03	WP2 Final issue – integration of residual comments and expansion of appendix L content	Luigi Piani	09/08/2023	JC

Report Disclaimer

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author	**Luigi Piani**
date	**16/06/2023**
approved	**James Crossan**
signature	
date	**09/08/2023**

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Contents

Table of Tables

Table of Figures

Glossary

Term	Definition
BAU	Business as usual
BESS	Battery storage power station
BESS	Battery energy storage systems
CAPEX	Capital expenditure
CAS	Clean Air Strategy
CMS	Cable management system
COMAH	Control of Major Accident Hazards
CPC	Connected Places Catapult
CSV	Construction support vessel
DESNZ	Department for Energy Security and Net Zero.
DNO	Distribution Network Operator
DPD	Detail Project Development
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
DSV	Diving support vessel
EMSA	European Maritime Safety Agency
ESC	Energy Systems Catapult
ETZ	Energy Transition Zone
EU	European Union
EV	Electric vehicles
FAME	Fatty acid methyl esters
GHG	Greenhouse gases
GSP	Grid Supply Point
HGV	Heavy goods vehicles
HV	High voltage
HVO	Hydrotreated vegetable oil
HVSC	High voltage shore connection
IDNO	Independent Distribution Network Operator
IMO	International Maritime Organisation
IRR	Internal rate of return
IUK	Innovate UK
LHEES	Local Heat and Energy Efficiency Strategies
LHV	Lower heating value
LNG	Liquified natural gas
LOHC	Liquid organic hydrogen carrier
LV	Low voltage
LVSC	Low voltage shore connection
MCA	Multi-criteria analysis
MGO	Marine gas oil
NPV	Net present value
NZTC	Net Zero Technology Centre
OBC	Outline Business Case
OPEX	Operational expenditure
OSV	Offshore Support Vessels
PoA	Port of Aberdeen
PV	Solar Photo Voltaic
REPEX	Replacement expenditure
SFC	Specific fuel consumption
SSE	Scottish and Southern Electricity Networks
TEM	Techno economic model
TX	Transformer

1 Executive Summary

1.1 Project context

Port of Aberdeen (PoA) has recently completed the first phase of the South Harbour Development, accounting for 80% of the total berthing capacity, which will eventually reach 1.5km when complete.

The Port Vision and aspiration is to become a strategic maritime example for cutting emissions within the site boundaries and eventually eliminating emissions from vessel operations by 2040, in line with national legal requirements on net zero targets. PoA is therefore investigating opportunities to cut their own emissions and become an enabler for their clients' carbon reduction targets.

This study has been delivered following funding secured from the "Clean Maritime Demonstration Competition – Phase 2" developed by Innovate UK (IUK),

Buro Happold has worked closely with project partners, Energy System Catapult (ESC) and Connected Places Catapult (CPC) to develop an initial feasibility study which considers technical, cost and carbon implications of a new shore power system to serve vessels at the south harbour. Onsite renewable generation and storage solutions have also been considered as well as generation, storage, and provision of alternative low carbon fuels to vessels.

1.2 Report purpose and content

This report focuses on an initial investigation around the opportunity for the installation of a shore power system and onsite renewable generation trough Solar Photo Voltaic (PV) and wind turbines at the South harbour. The report covers the following:

- **Scenario assessments**
  - o Together with ESC, three scenarios have been investigated and compared. These are:
    - ▪ **Baseline**. The baseline scenario considers grid power only (no on-site renewables) to serve a new shore power system for the south harbour. The carbon emissions of the system are reliant on the carbon intensity of grid supplied power. The cost of power and subsequent pass-through costs to vessels is subject to agreed grid import prices.
    - ▪ **Stretch**, The stretch scenario considers on site renewables and storage, as well as grid power to serve a new shore power system. Renewably generated power would offset grid import requirements and be sold back to the grid during periods of excess generation, creating an additional revenue stream for the port. The stretch scenario configuration is presented in Figure 1—1.
    - ▪ **Pioneering**, The pioneering scenario expands on the scope of on the stretch scenario to further consider how the PoA enables vessel operators to decarbonise their operation while at sea trough alternative low carbon fuels (i.e. methanol) The scenario considers spatial and energy requirements for the generation, storage and supply of low carbon fuel to vessels to vessels
- **Demand analysis:**
  - o Analysis of current and projected vessel power demands (peak & annual) while at berth as well as of the landside demands (buildings, Electric Vehicles (EV's) etc)
  - o Determination of worst case coincident peak power demand to inform infrastructure sizing
- **Existing infrastructure assessment:**
  - o Appraisal of site constraints including grid electrical capacities and existing cabling / servicing tunnels which could be used for new shore power infrastructure

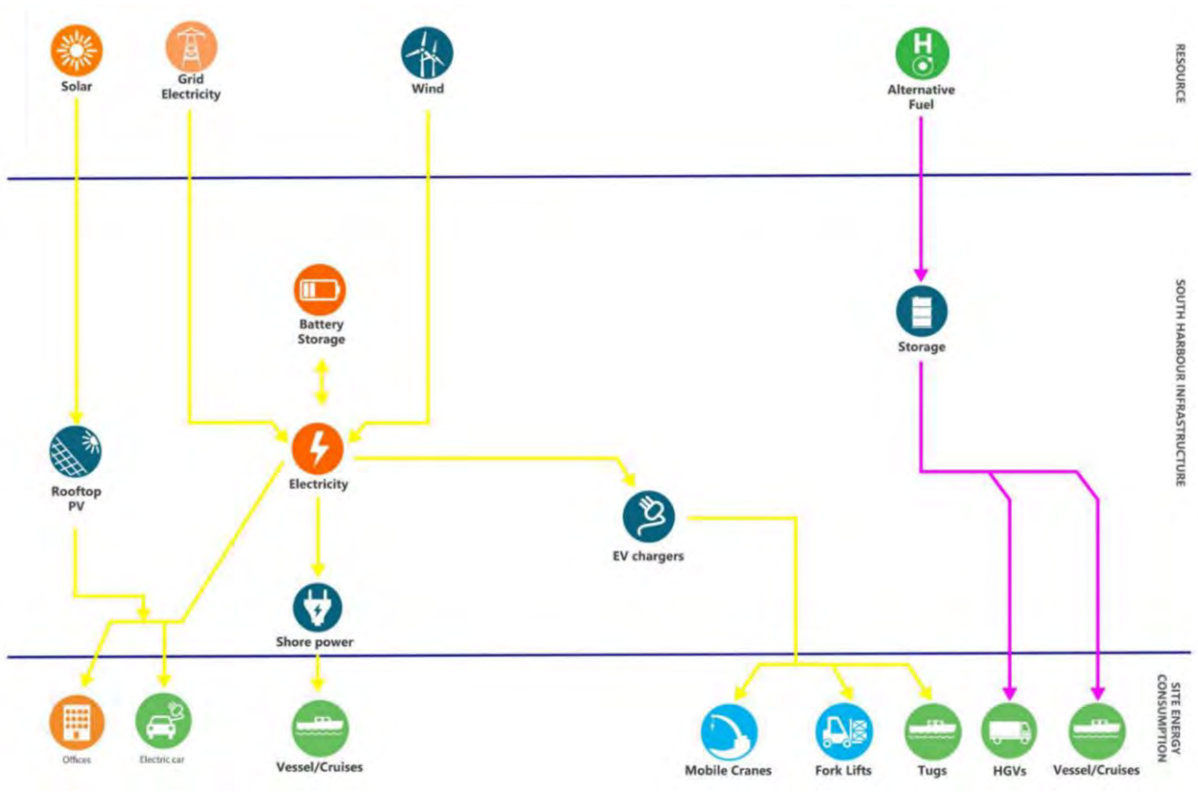

Figure 1—1 Stretch scenario system map

The stretch scenario has been taken to detailed infrastructure assessment since it aligns with PoA ambition and targets for net zero. It contains equipment sizing, related placement within the south harbour and the Technoeconomic modelling to assess financial performance.

In particular, this includes:

- **Proposed system infrastructure for the preferred scenario:**
  - o Initial design of the High Voltage (HV) power network and electrical network integration for shore power
  - o Initial sizing of the solar PV system and wind turbine to support the South Harbour electrical demands
  - o Spatial coordination of proposed infrastructure including primary substations, shore power connection points wind turbine, Solar PV and cable connections
- **Alternative fuel potential:**
  - o Overview of methanol production for vessel consumption while at sea and spatial requirements for storage, renewable energy generation, hydrogen and CO2 production.

- **Techno economic modelling and environmental impact:**
  - Cash flow modelling of the preferred scenario against the baseline
  - Vessel shore power sales rates, CAPEX, OPEX, REPEX and grant funding considerations and how this impacts the required markup price of shore power to deliver an attractive IRR over the operational lifetime to shore power installer and operator (assumed to be PoA)
  - Sensitivity analysis around the key variables notes above. Comparison of social benefits and CO2eq reduction of shore power to vessels vs. combustion of traditional Marine Gas Oil (MGO) fuels

1.3 Key findings and recommendations

Given the high anticipated electrical demands should a shore power system be implemented, and the level of flexibility required by PoA with regards to berthing points accommodating different vessel types, a dedicated electrical network to support the shore power system has been proposed. The main findings are:

- **Existing infrastructure assessment**
  - An 800kVA substation currently supplies power requirements at the South Harbour. Therefore, significant additional capacity is required to meet projected shore power demands and facilitate new renewable infrastructure.
    - Low Voltage (LV) networks distribute the power from the 800 kVA substation to the buildings, pumps and external lighting.
  - Extensive berthing point service trenches running along the quaysides, currently hosting potable water mains, could be used to accommodate shore power cabling.
- **Projected Demand analysis**
  - Detailed analysis of number of calls and their duration for different types of vessel has been carried out. Sensitivity analysis over these parameters has provided a range of potential power demands for the shore power system
  - An annual power demand of ~28 GWh/year has been estimated by 2030, assuming a gradual uptake in vessel consumption of shore power starting in 2025 of 11.2 GWh/yr. Consumption profiles for landside and shipside demands have been estimated based on provided information
  - A coincident peak demand of 22.6 MVA by 2030 has been calculated to supply vessels at berth, based on 7 vessels at berth simultaneously
- **Proposed infrastructure for the stretch scenario -** Figure 1—2
  - A new primary substation with 24 MVA of capacity alongside HV/LV distribution cabling and shore power infrastructure (including. transformers, frequency conversion and cable reels) is required to meet the projected 2030 demands. Additional space is included within the substation for potential expansion due to future adjacent developments i.e. the Energy Transition Zone (ETZ) development

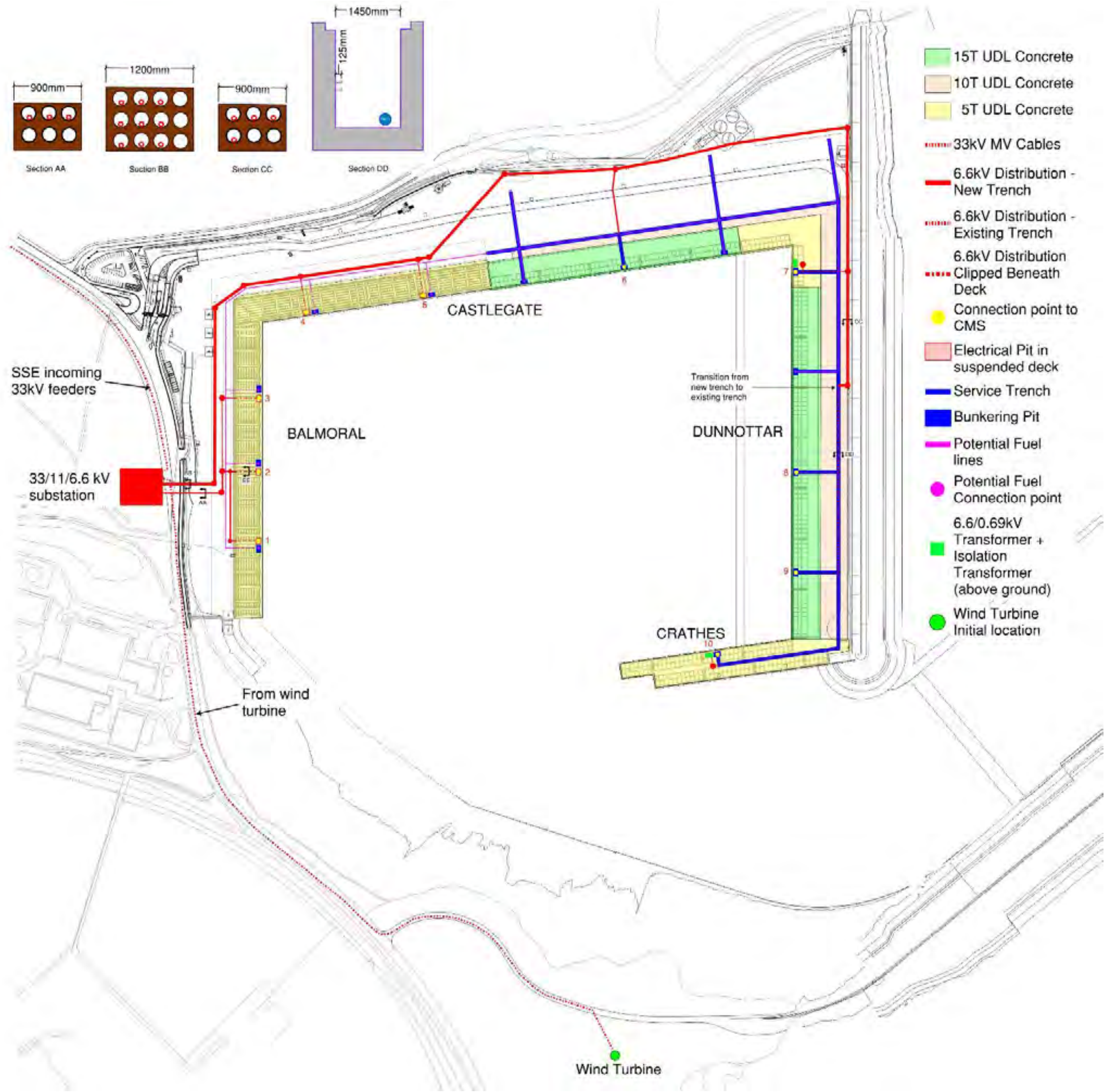

Figure 1—2 Proposed electrical infrastructure for the stretch scenario

- A new shore power system is required within the South harbour:
  - Up to ten HV shore power connection points are proposed along all quaysides areas to allow for greater flexibility with up to seven vessels potentially supplied simultaneously
  - Two LV shore power connection points have been designed to cover the demands of smaller vessels
    - The LV connections require above ground infrastructure on the deck but these have been strategically located at Crathes and Dunnottar quayside to minimize operation disruption
  - HV and LV cable routing have been identified to utilize as much as possible the existing services trenches and mitigate any major civil work i.e. hard digging of the large portion of the decks
  - Existing bunkering pits have been identified to potentially host shore power connection points due to the expected available space

- **On site renewable generation**
  - The total annual demand is ~28 GWh/yr. At full build out 60% of this demand is met through on site renewable generation and storage. The remaining 40% is met through direct grid import. The total annual generation from the renewables is ~24 GWh/yr. Of this generation ~17GWh is consumed on site while ~7GWh would be exported to grid
  - The onsite renewable generation consist of:
    - A 6 MW wind turbine is proposed nearby to the south breakwater to cover the shore power demands
    - A total of 268kWp solar PV system is proposed on top of the existing and future building to meet the landside demands
  - A Battery Energy Storage System (BESS) optimal sizing has been investigated to maximise renewable energy use on site and the modelling shows that a BESS may not be required. However, an allowance for BESS of 3.85 MWh is made to cover the uncertainty over the demand and generation profiles. More detail in section 6.5

- **Alternative fuel deployment**
  - The pioneering scenario shows that an e-methanol production facility would require a footprint significantly in excess of available land areas within the harbour. Furthermore, significant grid reinforcement would be required to meet electrical demands
  - A detailed description of the different steps required to produce e-methanol and related demands and space take is presented in the pioneering scenario (section 7) to allow PoA for any future decision and discussion with other stakeholders
  - Comparison of emissions between Marine Gas Oil (MGO), Hydrotreated Vegetable Oil (HVO) and methanol as stored fuel at port is included to illustrate the difference in carbon benefit.

- **Techno economic modelling and environmental impact**
  - Within the techno-economic modelling, two scenarios are modelled to capture the impact of renewable technology on the price of shore power and PoA's overall carbon emissions. The two scenarios modelled are as follows:
    - Baseline Scenario
    - Stretch Scenario (alternative fuel not included)
      - The total CAPEX investment for the scheme has been estimated at £43M. However, the port is unlikely to incur the full extent of these costs due to provision of grant funding and DNO absorption of elements of the grid upgrade costs (which account for £13m of the overall CAPEX)
      - The markup required on the base shore power sales price, above the electricity import cost, is highly dependent on the Capital costs of the project
      - When considering the CAPEX for the Stretch Scenario the addition of Solar PV and an onshore Wind Turbine does not provide additional economic benefit to when compared to the base case. This is due to the additional ~£15M required on the equipment and supporting infrastructure
  - Techno-economic modelling indicates a shore power markup price of 52.83 p/kWh and 56.27 p/kWh for the Baseline and Stretch scenarios respectively is required to achieve an 8% IRR without grant funding over the 40 year modelled lifetime (Figure 1—3 and Figure 1—4). This markup can be lowered to 42.62 p/kWh and 39.66p/kWh when 50% grant funding is applied.

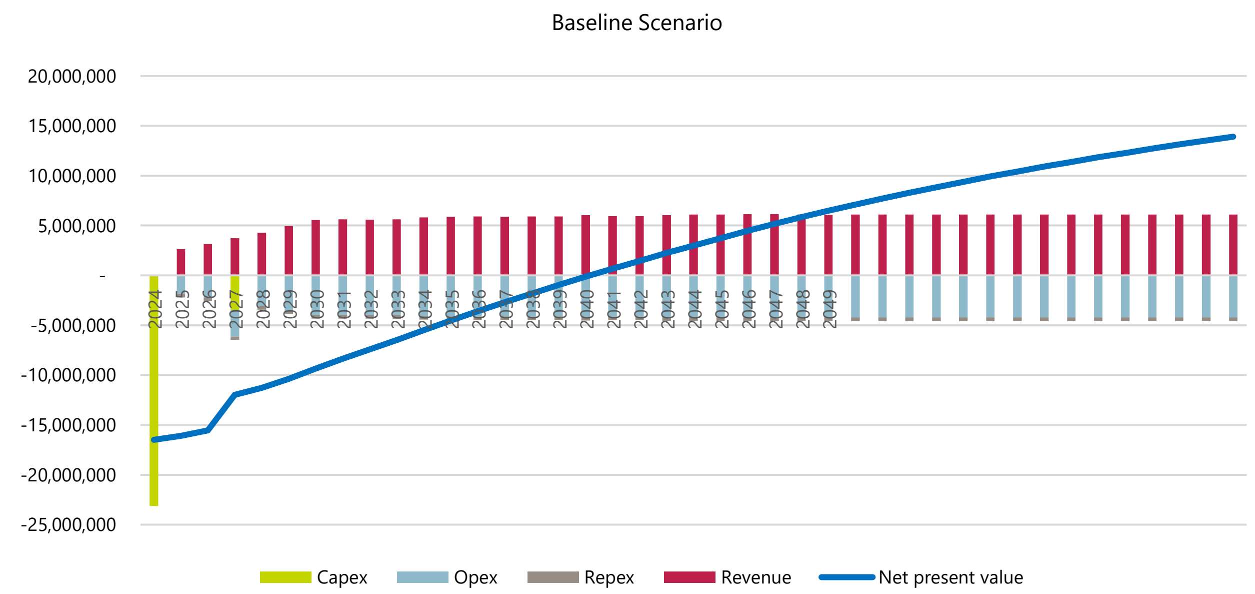

Figure 1—3 Cash flow curve for Baseline Scenario - With grant funding

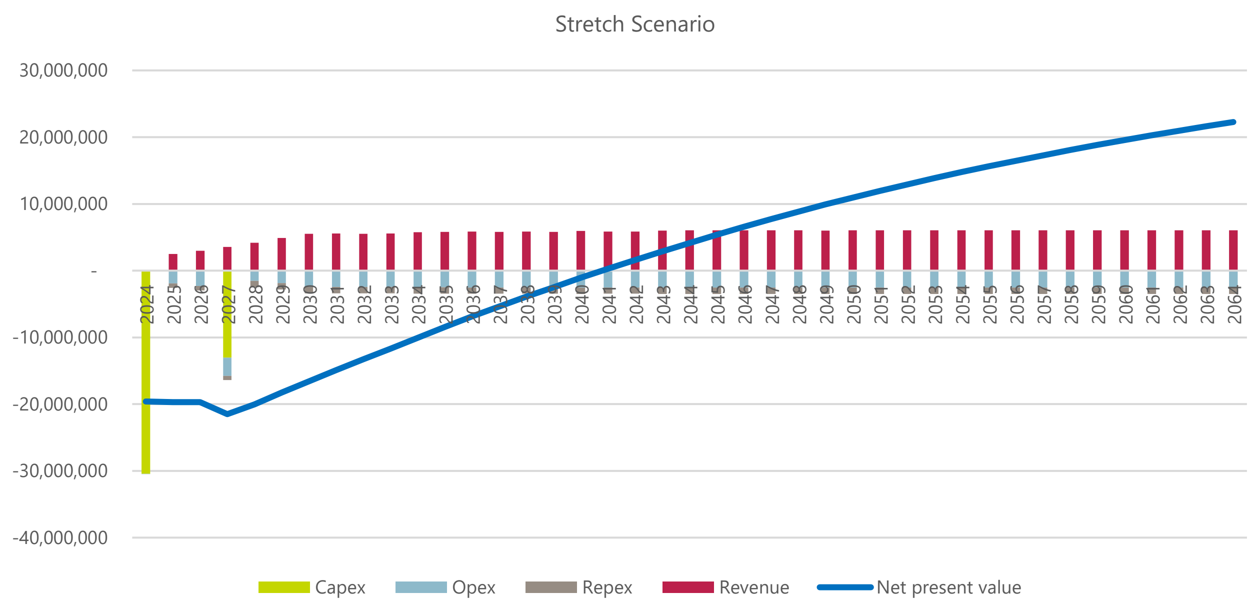

Figure 1—4 Cash flow curve for stretch scenario - With grant funding

- The stretch scenario is highly sensitive to the capex. It is possible that SSE would cover the CAPEX for the required primary substation through the Access SCR policy change. This capex reduction would further cut to the shore power sales price to a markup of 25.55 p/kWh for the Stretch Scenario with grant funding applied. A lower markup could lead to increased berthing traffic hence higher shore power sales with further improvement of the scheme's economics.
- Modelling indicates the solar PV system does not offer an economic benefit to the scheme. When comparing the shore power prices, with DNO costs removed in combination with grant funding, the inclusion of the PV systems results in a reduction of 1.38p/kWh of power sold.
- The PV system offers an additional carbon saving of 160 tCO2e over the project lifetime, offering a return of > 0.00001 tCO2/£ spent while the Wind turbine leads a saving of 8,800 tCO2e when compared to the Baseline Scenario, offering a return of 0.0006 tCO2/£ spent. This is based on the projected the carbon intensity of the grid assumed to drop significantly in the next future. If this projection was to be optimistic then the savings from renewable energy would be much higher.
- Current TEM indicates that on site renewable technologies provide a tiny benefit from an economic or carbon perspective to the scheme. The estimated reduction within the stretch scenario (when DNO costs are excluded and grant funding applied) from onsite renewables is ~4p/kWhp compared to the baseline scenario.
- Wind turbine and PV could still guarantee low carbon power supply in the case of the grid not following Green Book forecasted prices and carbon intensity.
- Despite a reduction in shore power prices, further investigation is recommended to reduce the uncertainties outlines throughout the report and test again the TEM to verify if the current results are still applicable and whether a wind turbine can provide a significant benefit to the scheme or not.

1.4 Comparison of the three scenarios to include space take, power consumption and emission reduction

Table 1-1 presents the main results and comparison of results. The key observations are:

- **Baseline**
  - Significant emissions under PoA scope are anticipated when considering the baseline scenario due to grid imported electricity. Land take requirements include for a new primary substation, BESS, LVSC which is slightly less than the stretch scenario due to implementation of renewable generation system such as wind turbine and solar PV. Fuel storage requirements are the same as the stretch scenario due to similar density of MGO and biofuels
- **Stretch**
  - The stretch scenario has the same electrical consumption as the baseline scenario. Spatial requirements are slightly greater (0.01Ha) than the baseline due to due to implementation of renewable generation system such as wind turbine and solar PV. Lifetime emissions for marine operations are reduced vs. the baseline scenario due to introduction of biofuel (HVO/FAME) as alternative fuel to MGO
- **Pioneering**
  - The pioneering scenario is significantly more energy and spatially demanding than the baseline and stretch scenarios due to the scale of e-methanol production requirements for vessels. Methanol would require roughly double the storage volume of MGO and HVO, due to its lower energy density, This is based on MGO, HVO and methanol respectively for baseline, stretch and pioneering scenario

Table 1-1 Three scenarios comparison

Scenario	Annual electrical consumption at 2030 (GWh/year)	Annual Renewable generation GWh/year	Total land take (ha)	Fuel storage req. at the harbour m³	Lifetime emissions within PoA scope (tCO2e)	Lifetime emissions for marine operations at sea (tCO2e)
Baseline	28	0	0.16	576	18,568	23,093,972
Stretch	28	24	0.17	576	9,608	734,620
Pioneering	4,256	4,268	7,290	1,345	9,608	~0

1.5 Key risks

A risk register has been provided as part of Appendix P. Key risks associated with the proposed design include:

1. **PoA fail to gain wider political support for shore power system**
    a. *PoA to develop design to OBC and DPD level applicable funding body requirements which could potentially support up to 50% of capital costs of infrastructure and consult with government departments to test basis for system procurement and delivery is transparent and according to best practice.*
2. **Failure to attract participating shore power users or delay in implementing shore power infrastructure therefore resulting in reduced revenue leads to revenue gap to repay any borrowing / investment.**
    a. *Investigate alternative revenue grants including sharing of risk until further participating operators (and revenue) are sufficient to cover operating costs including any borrowing costs.*
3. **Failure to identify funding sources adequate to meet the capital costs of the scheme, particularly the grant funding to meet the 50% of CAPEX base case**
    a. *PoA should continue to engage with potential funding bodies such as the DfT and keep track of the development of the Clean Maritime Plan 2023 as well as other potential funding opportunities. Operator / off taker contribution to infrastructure deployment should also be considered. Should <50% of the CAPEX cost be covered through grant funding then shore power sales price would need to increase if the base case IRR is to be met. A series of sensitivities have been undertaken around this in the financial case.*
4. **Costing estimates increase during design development**
    a. *Quantity Surveyors have been engaged to produce the cost plan - this should be revisited at later stages. This engagement process will highlight any cost hotspots which require further design development.*
5. **Shore power consumption estimates vary vs actual consumption**
    a. *Power demand sensitivity has been completed as part of a detailed vessel movement analysis and modelled as a sensitivity, but risks remain due to inherent variability between design and operation. Continued refinement of the model may be required if a significant change in predicted operator use becomes apparent.*
6. **Electrical grid capacity availability following DNO engagement**
    a. Early engagement should be made with the Distribution Network Operator (DNO) to determine grid reinforcement requirements and associated cost responsibilities with difference stakeholders. Independent Distribution Network Operators (IDNO) could be consulted to once commercial approaches are agreed, potentially offering cost saving over provision of infrastructure from the DNO
7. **Space provision for the primary substation to be secured**
    a. Engagement with nearby developers should be undertaken as a priority to agree locations for new primary substations adjacent to PoA land
8. **Renewable generation:**
    a. TEM results appear to suggest renewable generation on site don't provide significant economic benefits while they still contribute to reduce the carbon emission offsetting the carbon intensity of the grid
    b. Phasing and installation of shore power system and wind turbine on site shall be further investigated and agreed. Earlier introduction of the turbine could lead to higher benefits from economic and carbon perspective
    c. Engagement with development in the vicinity of the south harbour is recommend and it could result in a better financial performances i.e. private wire connection to BP solar farm or Power Purchase Agreements

1.6 Next steps

Further work is required to develop this study to achieve a level of design and economic / commercial analysis in line with an Outline Business Case. Key next steps include:

- Refinement of the energy demands and infrastructure requirements, as follows:
    - **HV/LV and shore power infrastructure**
        - Engagement with SSE and nearby developers around provision of a new primary substation and supply arrangement
            - Soft market testing with utilities to determine electricity import price for shore power connection
        - Engagement of IDNO's to gauge interest in delivering contestable elements of the electrical infrastructure
        - Engagement with CMS manufacturers to confirm shore to vessel interfacing can be satisfied for LVSC at a reasonable cost
        - Engagement with shore power system suppliers to "stress test" current designs and assumptions
        - Refinement of vessel traffic estimates trough the project lifetime based on recorded data at South Harbour
        - Obtain final "as-built" drawings and information for the south harbour including proposed fuel lines.
    - **Commercial**
        - Discussions with key stakeholders to identify optimal commercial structures for the landside and shipside systems and related renewable generation. Investigate potential alternative commercial structures such as Power Purchase Agreements for renewable power
        - Further analysis around the upper limit to the shore power sales price. Workshops with potential end users to assess competitive pricing structure

2 Project Overview

Buro Happold has been appointed by the PoA to contribute to the Port Zero Feasibility study with an investigation of net zero technologies and opportunities at the South Harbour.

This report considers three scenarios to implement a shore power system, on site renewables and alternative low carbon fuel infrastructure to curb carbon emissions and other air pollutants from buildings and vessels at the south harbour.

2.1 Purpose of the project

The study responds to the "Clean Maritime Demonstration Competition – Phase 2" developed by Innovate UK (IUK).

The Port Zero Project aims to investigate the steps that PoA is required to take to reach the target of achieving net zero status as a port by 2040. Three different scenarios have been considered to show the baseline, stretch and pioneering actions.

In agreement with PoA, a preferred scenario in addition to the baseline has been considered further and taken to electrical design, spatial planning, and high-level Techno-economic modelling.

The report considers the following:

- **Scope emission boundaries and carbon reduction plan by PoA – section 2.3**
  - Overview of PoA targets and actions planned on the north harbour and applicability to the South Harbour
- **Regional Initiatives and overview on decarbonisation of the shipping sector – section 2.2 and 2.4**
  - Overview of adjacent developments to the south harbour with integration potential
  - Overview of shipping sector future projections for decarbonisation
- **Site investigation and demands assessment – section 3**
  - Site spatial and utility constraints
  - Landside and shipside current and projected demands with related indicative consumption profiles
- **Scenarios definition and implementation – section 4**
  - Description of the three scenarios investigated
  - Further investigation for each of them
- **Detailed analysis of the preferred scenario – section 6**
  - On site Renewable generation deployment
  - Initial Electrical design and spatial coordination
  - Carbon emission reduction
- **Initial Techno-economic and commercial model analysing financial viability of the system – section 8**

The report is a prelude towards a more detailed investigation of the best techno-economic option which should be more fully explored through full outline business case development.

The report shall be also read in conjunction with the material produced by the other partners as listed below:

- ESC00796-D1.3 Future Energy and Scenario Planning by Energy System Catapult.

2.1.1 Scope

This study has been subdivided in five main work packages with the following objectives:

- **Work Package 0: Project Management**

  Buro Happold is not involved in this work package

- **Work Package 1: Future Demand Scenarios**
  - Develop initial scenario configuration following supplier engagement process to determine technology readiness state
  - Energy demand and supply analysis to support further economic viability activity
  - Review regulatory requirements, any barriers and opportunities to drive regulation discussions to support future developments

  Buro Happold contributed to this work package through the assessment of the future demands and energy infrastructure assessments, as well as development of the 3 preferred scenarios.

- **Work Package 2: Future Demand Scenarios**
  - Develop initial scenario configuration, TRL, energy demand and supply analysis to support economic viability
  - Understand regulatory requirements, barriers and opportunities to drive regulation discussions to support future developments.

  Buro Happold contributed to this work package through the energy modelling, preferred scenario development, spatial coordination and electrical design for costing purposes (not for tender) and associated recommendations. The initial techno economic modelling structure has been provided.

- **Work Package 3: System Roadmap**
  - Complete Roadmap to 2040 as part of a net zero emission port of the future, including transferability analysis in North Harbour
  - Outline scope, cost and business model for future implementation

  This work package has not started yet for Buro Happold but we will provide the complete TEM and the initial structure for the Outline Business Case (OBC)

- **Work Package 4: Dissemination and Event**
  - Organise a dissemination event
  - Prepare documentation package for dissemination across port community, IUK and other relevant parties

  Buro Happold will contribute in prepare the required material for any dissemination activity.

Refer to Appendix A for detail task breakdown.

2.1.2 Partners

The Port Zero project has been set up by PoA in partnership with Energy Systems Catapult (ESC) and Connected Places Catapult (CPC) to deliver the feasibility study to Innovate UK (IUK) in the contest of the "Clean Maritime Demonstration Competition – Phase 2".

All partners have closely worked together for the overall deliverable under the coordination of Port Of Aberdeen. Buro Happold deliverables represent the technical information for the different scenarios related to the south harbour site, the current status/constraints and the possible integration of different technologies and solution.

ESC within the ESC00796-D1.3 Future Energy and Scenario Planning has provided a detailed understanding of the overall shipping sector as well as investigation of any regional initiatives close to Aberdeen that can help PoA in their goal toward net zero.

2.2 Shipping Decarbonization Pathway

This section presents a summary of ESC detailed investigation. Refer to ESC00796-D1.3 Future Energy and Scenario Planning for further detail.

2.2.1 Government ambition

In late 2020, the UK Government released the Energy White Paper, which recognised the critical role the transport sector must play in the UK's journey to Net Zero. It highlights six strategic priorities for Transport such as decarbonisation of vehicles, the growth of the UK as a hub for green transport technology and innovation, and the reduction of carbon in the global economy.

This White Paper integrates The Transport Decarbonisation plan, which sets out several key commitments across the applicable industries; including a commitment to accelerate maritime decarbonisation with the wider challenges for the UK's Energy System and the UK Government's Net Zero aspirations.

Prior to this, in 2019, the UK Government set out its initial vision specifically for maritime decarbonisation through the release of Maritime 2050: Navigating the Future. The report identified the UK's potential to be the world leader in clean maritime growth and ultimately utilise the economic benefits of early adoption. Subsequently, the Clean Maritime Council was established, and the Clean Maritime Plan was released with a more detailed roadmap identifying key milestones such as:

- The availability of energy efficient shipping options by 2025
- The establishment of clean maritime clusters by 2035
- Culminating in a zero-emissions shipping industry by 2050

It also emphasised the importance of investment in clean maritime growth. The goals of the Clean Maritime Plan encompass the findings of the previously issued Clean Air Strategy which outlines the UK's stringent air pollution reduction targets for 2020 and 2030. This strategy recognises the significant contribution that emissions from the transport sector play in overall air quality in the UK and includes the requirement for UK maritime ports to develop and implement air quality strategies that reflect the specific challenges of their region.

During 2021, the UK Government issued the UK Hydrogen Strategy, which highlights the critical role that Hydrogen will play in conjunction with electrification to aid the wider transport decarbonisation goals towards 2050. This strategy estimates that by 2050 there could be 75-95TWh of demand for hydrogen-based fuels (principally in the form of ammonia) from UK domestic and international shipping.

Most recently, the Net Zero strategy has been issued and coalesces the UK Government's ambitions for Transport decarbonisation with the broader systemic challenges of achieving Net Zero across multiple areas such as heating and green investment. Additionally, it is understood that the UK Government will release a 2050 Net Zero Transport Strategy in the future.

It is also currently understood that the UK Government are seeking to establish a UK Shipping Office for Reducing Emissions (UK SHORE) within the Department of Transport based on the outcomes of the £20million Clean Maritime Demonstration Competition held in 2021 which has yielded a range of projects focussed on furthering the development of zero emissions marine vessels via combined academic and industrial partnerships.

The International Maritime Organisation (IMO) is a United Nations specialised agency which supports the UN sustainable government goals by working to prevent and reduce marine and atmospheric pollution from the global shipping industry and plays a key role in ensuring that standards in shipping are adopted evenly across the international maritime community.

The UK is included as a member state within the scope of the IMO's activities. Most notably the IMO developed MARPOL; the International Convention for the Prevention of Pollution from Ships which was created in 1973. It includes six annexes that cover key pollutants from noxious gases to waste products from on board shipping activities.

On reflection of the IMO study and the Paris Agreement, The Clydebank Declaration was launched at COP26 in November 2021. It is an initiative aimed at further recognising the internationally interconnected nature of shipping and to facilitate the formation of "green shipping corridors" across the international maritime community for "end to end" decarbonised shipping routes of which the UK Government is a signatory.

The aim of the collective of signatories is to support the establishment of at least 6 green corridors by 2025, while aiming to scale activity up in the following years. Amongst other things it aims to support the establishment of more routes, longer routes and/or having more ships on the same routes.

In November 2022, the COP27 conference held in Sharm El-Sheikh, Egypt, international zero-emission shipping routes came one step closer to becoming a reality. The UK made a major pledge alongside the US, Norway, and the Netherlands to roll out green maritime links between them.

In particular, the UK and the US have agreed to launch a special Green Shipping Corridor Task Force focussed on bringing together experts in the sector, encouraging vital research and development, and driving other important work and projects to see these initiatives come to life as quickly as possible.

The Knowledge Transfer Network (KTN) is a UK wide organisation grant funded by Innovate UK and have recently launched the Decarbonising Ports and Harbours Innovation Network which consists of a range of stakeholders from industry and academia.

The network is relatively new and a key finding from initial meetings with stakeholders has identified that as UK ports have relatively unique profiles due to their varying relationships with different industries both domestically and internationally, this presents a key challenge in developing a standardised industry level approach to port decarbonisation.

The Government's ambition to phase out the sale of ICE and hybrid cars and vans by 2030 and 2035 respectively will also influence the future energy demands around the port. Staff and visitors will be using EVs which raises the need to consider what opportunities for an EV charging infrastructure would need to be made available at the port.

The sale of non-zero emission heavy goods vehicles (HGV) is set to end by 2040, which influences the way freight is being moved in and out of the port. Considerations will have to be made regarding the recharging and refuelling of these vehicles during the transition period, creating challenges, but also opportunities for the port.

Finally, the Scottish Government has developed their own decarbonisation targets, separate to the UK Government. This includes the targets to achieve net zero by 2045, and higher level of growth for technologies like hydrogen, marine energy and offshore wind.

Regional actions taken under the Local Heat and Energy Efficiency Strategies (LHEES) have been reflected in a higher level of uptake of low carbon heating technologies. New policy announcements in 2021 have included the updated Climate Change Plan, Scotland's own Heat and Building Strategy and a draft national planning framework to deliver net zero.

2.2.2 Decarbonisation Methods

Figure 2—1 shows estimated fractions of decarbonisation potential according to the 1.5°C Scenario modelled by IRENA.

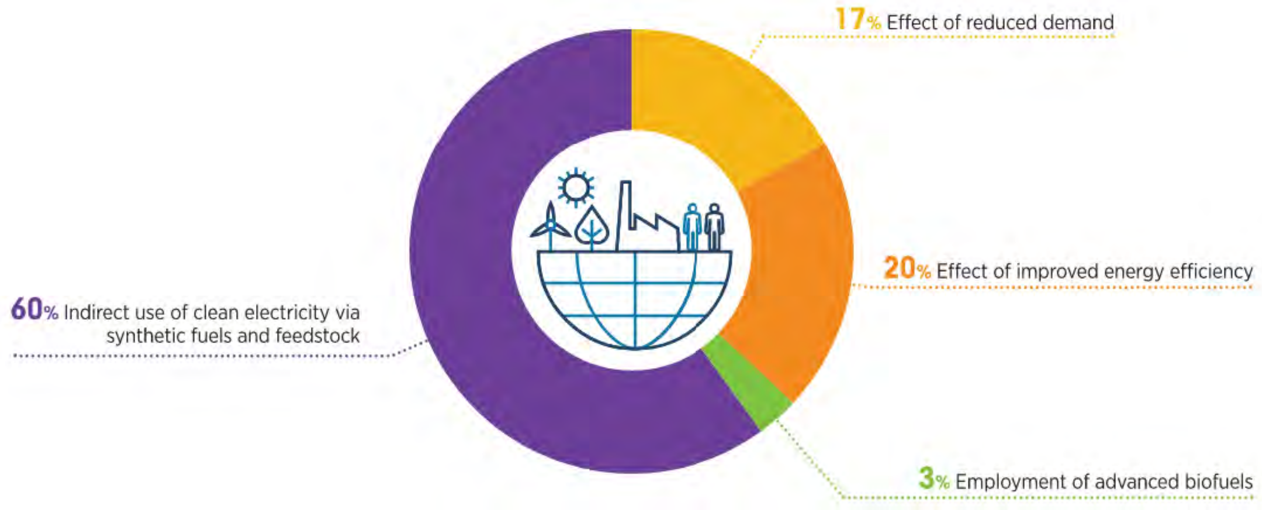

Figure 2—1 Estimated roles of key CO2 emission reduction measures associated with IRENA 1.5C° Scenario, reproduced from [1]

The largest benefit therefore will probably come from the use of alternative fuels. There is potential for fuel switching in shipping to hydrogen or ammonia, both of which would need to be produced in a low- or zero-carbon way (i.e., from zero-carbon electricity or with CCS).

These options also have the advantage that they can be retrofitted to existing ships. The potential development of an international market in hydrogen (e.g., as ammonia, methanol) shipped from countries with low costs of low-carbon hydrogen production, does raise the possibility of this being the primary way of supplying low-carbon fuel for refuelling at ports. Biofuels are technically feasible in shipping but not likely to be a priority given other competing uses for this resource. Electrification is possible for ships but is likely to be limited to relatively short routes given the energy and therefore battery requirements.

Efficiency improvements

Improvements to fuel efficiency are possible including through measures to reduce water resistance (e.g., more efficient hull coatings), measures to improve energy efficiency (e.g. recovery of waste heat), and through use of alternative sources of propulsion (e.g. kites, Flettner rotors, and sails).

Additional benefits can be seen by changing certain ship operations. Reducing speeds at which ships travel can significantly reduce fuel use. This saves fuel even if the journey takes longer. Other operational measures include use of software to plan the most efficient route given expected weather conditions and to optimise ballast and trim.

A more exhaustive list of solutions that aid decarbonisation (other than switching fuels for vessels) has been provided by IRENA:

Operational solutions

Some of the operational improvements that could be made involve managing the voyage performance through methods such as just-in-time arrival, ship speed optimization, weather routing, autopilot improvements and optimising trim, draft and ballast. Energy management systems can also be employed which reduce onboard power demand with the additional benefit of fuel quality and consumption reporting. Vessel maintenance measures managing the roughness of the hull and the propeller can also improve the energy efficiency.

Design solutions

For newer vessels, there is potential to increase energy efficiency by design improvements. These can be done by changing the hull and superstructure affecting the ship's size and weight, but also the propulsion systems by optimizing the propeller, propulsion drives and air lubrication systems. Power systems improvements can also be made to the main engines and auxiliary equipment, and even assisting propulsion by wind and solar energy.

Infrastructure solutions

Terminal infrastructure can be improved at the inland waterway connection between the port and the main waterway as well as at the docking areas. Changing fuels will also require rethinking the bunkering facilities, which can also see themselves affected by a greater push for cold ironing. ICT/digital infrastructure improvements can help the port and hinterland operations.

Operational equipment that has an energy demand that can be looked at more specifically include: the road transport connection from port to the main highway, equipment for maritime access i.e., dredging and tugboats, terminals in the port area and dry ports outside the port area, rail transport connection from port to main line and equipment for transport flows within the port area i.e., cranes.

2.3 Port Of Aberdeen emissions boundaries and Carbon reduction plan

PoA has ambitious targets in place to become an exemplar green port and reach Net Zero by 2040. PoA has also recently finalised to catalogue in the different scope and to define a clear path reducing their emission.

Generally, the majority of the Port's emission are a result of visiting vessels and as such PoA has the ability to influence rather than directly control their activities.

Despite being focused on the North Harbour operations, it is assumed that the scope boundaries and similar trends are applicable to the South Harbour.

Table Table 2-1 lists the main emissions and the related weight over the different scopes. The decarbonisation of the port is fully dependent on the client's vessel and any action to limit their emissions will have the greater impact. Figure 2—2 graphically shows the different categories and their scopes considered at the north harbour.

[1] A pathway to decarbonise the shipping sector by 2050, IRENA 2021

Table 2-1 North Harbour emissions breakdown by scope and weights, reproduced from [2]

Emission Source	Scope	Percentage of overall emissions	Percentage of emissions within scope 1 & 2	Percentage of emissions within scope 3	Applicable to South Harbour
Fuel burnt in Port Vessels	Scope 1	0.70%	17.5%	-	Y
Fuel burnt in Port owned equipment and machinery	Scope 1	0.10%	1.9%		Y
Company vehicles	Scope 1	0.01%	0.9%		Y
F-gas (aircon)	Scope 1	0.00%	0.7%		Y
Natural gas	Scope 1	0.70%	18%		N
Procured electricity	Scope 2	2.50%	61%		Y
Client visiting vessels	Scope 3	91.34%		95.1%	Y
Business travel	Scope 3	0.01%		0.0%	Y
Waste	Scope 3	0.00%		0.0%	Y
Water	Scope 3	0.00%		0.0%	Y
Leased assets	Scope 3	4.64%		4.8%	N
Employee commute	Scope 3	0.06%		0.07%	Y
WFH	Scope 3	0.00%		0.0%	N

Generally, the emission breakdown for north harbour is applicable to the south harbour with the exception of the natural gas (not planned) and the lack of tenant's assets as the only buildings are under PoA ownership and operations.

PoA has also produced a carbon reduction plan which aims to:

- Achieve Net Zero within scope 1 and 2 emission sources by 2035 with a reduction of 82.93%
- Achieve a reduction of scope 3 sources by 57% by 2040

A detail summary of the plan is included in Appendix G. The key actioned outlined are the following:

- Deploy shore power system
- Deploy on site renewable generation
- Replace diesel/petrol vehicles
- Electrification of pilot boats
- Electrification of machinery

Some of the actions planned (or not) for the North Harbour are likely to be of easier implementation at south harbour such as electric vehicle fleet which could be directly purchased as electric rather than replaced.

It is also recommended that PoA investigates how it can facilitate the decarbonisation of their clients' operation trough supply of low/zero emission fuels.

[2] Port Of Aberdeen – Carbon Reduction Strategy & Target setting, Sealand projects (2023)

Overall, at the south harbour there is an opportunity to reach higher emission reductions for each scope and also for PoA to provide essential infrastructure for vessel operator and significantly contribute at the reduction of their emissions.

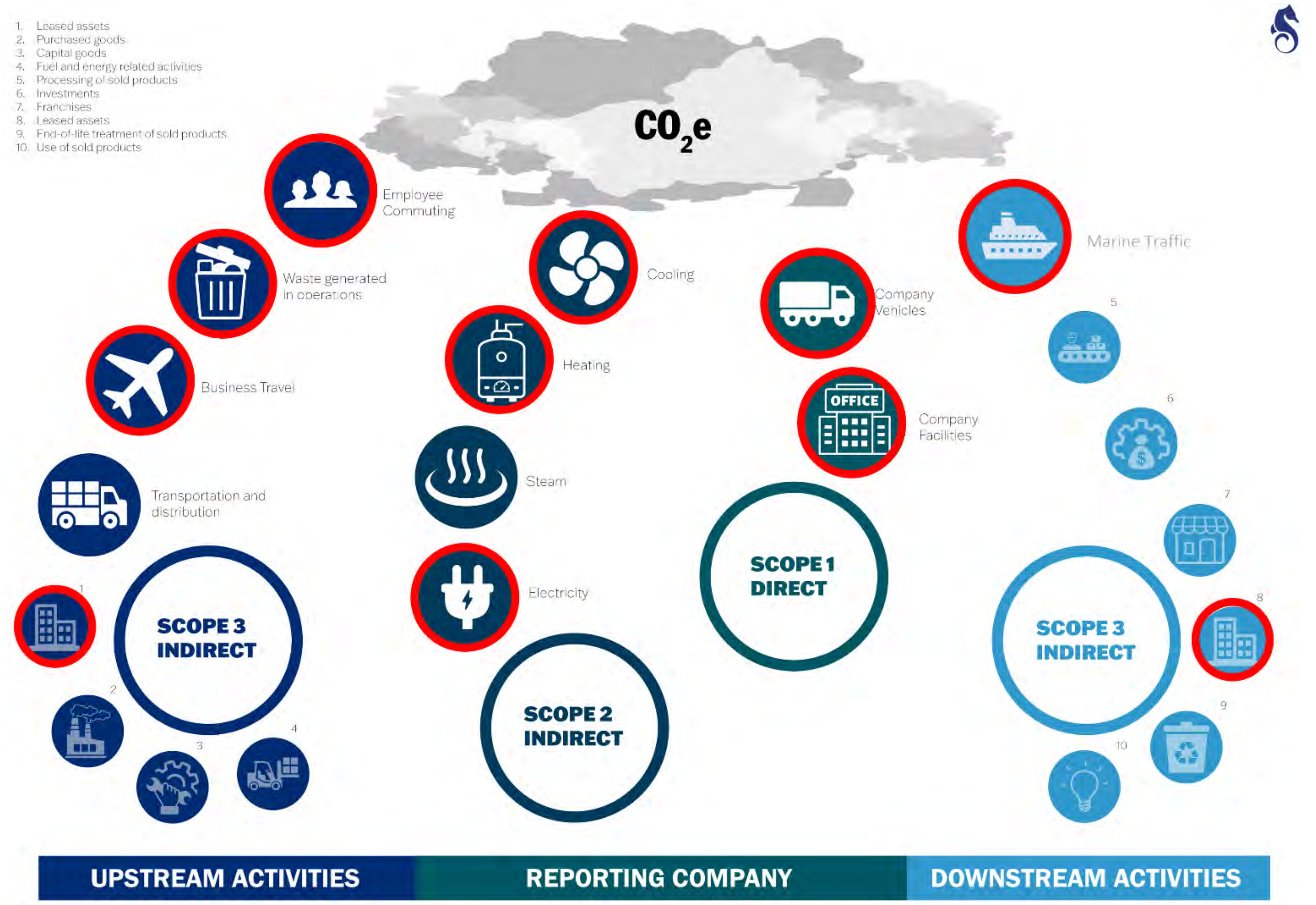

Figure 2—2 North Harbour scope emission breakdown, reproduced from [3]

2.4 Regional Energy Initiatives

ESC00796-D1.3 Future Energy and Scenario Planning provides in depth understanding of the commissioned or planned renewable energy project in Scotland.

Table 2-2 lists the main wind projects near Aberdeen and any related plans for hydrogen generation.

Figure 2—3 shows all the planned hydrogen projects in Scotland.

It is clear that close to PoA there is a significant amount of planned infrastructure leading towards the production of cleaner energy which could be beneficial for PoA. In particular, the off-shore wind farm could lead to a faster decarbonisation of the Scottish electrical grid.

Hydrogen production is also expected to increase in near future as evident from the latest funding from UK government which includes the Dolphine project for the deployment of a 10MW green hydrogen production site in front of Aberdeen coast.

Energy Transition Zone (ETZ) is another project adjacent to the south harbour with proposed development of areas in St.Fittick's and Gregness as well as significant on site renewable generation. It is recommended to engage with ETZ to minimise the investment from both party of the required grid upgrade as well as potential share of onsite generation.

[3] Port Of Aberdeen – Port of Aberdeen GHG emissions inventory report, 2020 reporting period, Sealand projects (2023)

Table 2-2 Existing and planned offshore wind projects near Aberdeen

Wind farms within SOV distance from Aberdeen	Capacity, MW	Fixed or floating	Full commissioning date	Development stage	Plans for H2
Aberdeen EOWDOC	97	Fixed	-	Fully commissioned	Yes
Kincardine	48	Floating	2021	Fully commissioned	Yes
Cluaran Deas Ear	1,008	Fixed	2032	Concept / early planning	No
Muir Mhòr	798	Floating	-	Concept / early planning	No
Campion Wind	2,000	Floating	-	Concept / early planning	No
Bellrock	1,200	Floating	2030	Concept / early planning	No
Ossian	3,600	Floating	2031	Concept / early planning	No
Morven	2,907	Fixed	2030	Concept / early planning	No
Seagreen	1,140	Fixed	2023	Consent authorised	No
Seagreen 1A	500	Fixed	2026	Partial generation / under construction	No
Hywind Scotland Pilot Park	30	Floating	2017	Fully commissioned	No
Salamander	100	Floating	2029	Concept / early planning	Potentially
Beech North	1,500	Floating	2029	Concept / early planning	No
Green Volt	480	Floating	2027	Concept / early planning	No
Orcadian Microgrid	105	Floating	2026	Concept / early planning	No
MarramWind	3,000	Floating	-	Concept / early planning	No
Buchan Offshore Wind	960	Floating	-	Concept / early planning	No
Broadshore	900		2029		No
Stromar	1,000		2030		No
Cluaran Ear- Thuath	1,000		2033		No
Beatrice	588		2019		No
Moray East	950		2022		No
Moray West	882		2025		No
"Caledonia					
Offshore Wind Farm"	2,000		2029		No
Inch Cape	1,080		2026		No
Neart na Gaoithe	448		2024		No
Berwick Bank	4,100		2030		No
Beech South	1,500		2029		No

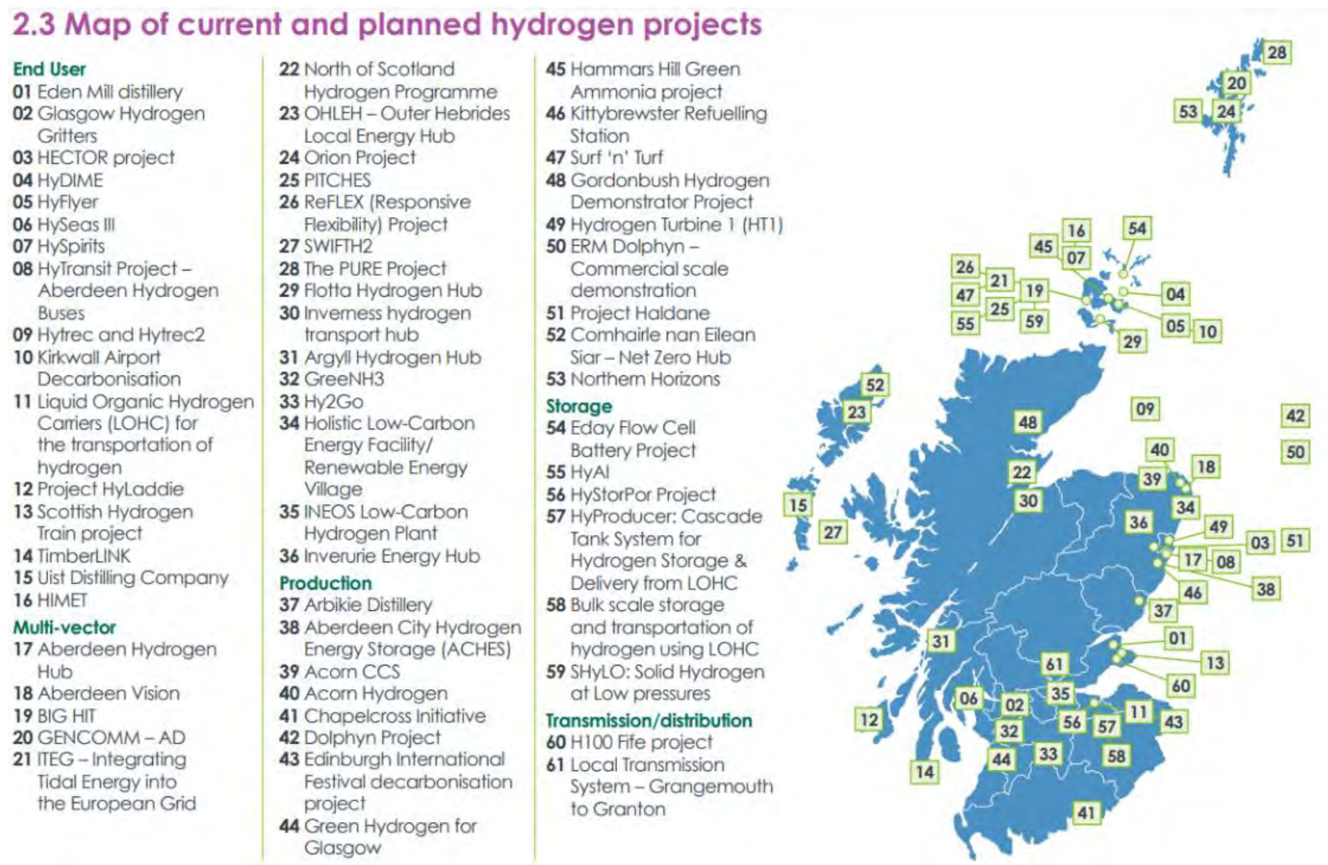

Figure 2—3 Map of current and planned hydrogen projects in Scotland

3 Port of Aberdeen South Harbour overview

3.1 Site overview/boundary

The PoA South Harbour is located in North East Scotland and is south of the north harbour entrance, adjacent to the Balnagask golf course on the north with St. Fittick park on the west. Figure 3—1 shows the boundary of the harbour and the areas under PoA control (with the blue and yellow areas showing areas that are under PoA control).

Figure 3—1 South harbour boundary

The South harbour has been partially operational since July 2022, with Balmoral Quay and parts of Castlegate Quay still under construction and due for completion by Q2 2023. Figure 3—2 shows the detailed structural layout of the harbour and identifies the different typologies of the decks.

This shall be considered as indicative only since it is not representative of the as built harbour which is currently still to be finalised. The quays will be referred as follows throughout the report.

Table 3-1 - Quay naming terminology

West Quay	Balmoral Quay
North Quay	Castlegate Quay
East Quay	Dunnottar Quay
South Quay	Crathes Quay

A site visit undertaken in March 2023 clarified harbour civil and infrastructure layouts. During the visit it was observed that all suspended deck structures remain under construction (Balmoral and part of Castlegate).

Only Security and control buildings are envisaged to be within the site but it is known that an additional warehouse and terminal building could be introduced by PoA.

There is no heating nor gas networks installed at the South Harbour, but a significant potable water network owned by PoA serves 13 connection points via bunkering pits complete with bollard protection.

There is currently no provision for fuel storage or refuelling pipelines within the port. Vessels are supplied and serviced via trucks or barge vessels. PoA are currently planning to introduce a fuel storage facility to supply the ships at berth and PoA provided an indicative estimate of 180,736 tMGO/year required by 2028 and assumed constant after.

It is not clear if the fuel demand provided includes the current needs for vessel at berth i.e. fuel used to run engines to produce power, which could be avoided trough a shore power system.

PoA is investigating potential for future alternatives to maritime diesel and how their integration within landside supply system may impact the current harbour configuration.

Current understanding is that PoA will not own or operate any heavy-duty vehicles except for forklifts, as quayside operational requirements are based on individual vessel/project needs, and under the responsibility of each vessel operator, supported by the appointed ship agents.

No fixed equipment is envisaged on the quayside of the harbour to facilitate ease and flexibility of operations

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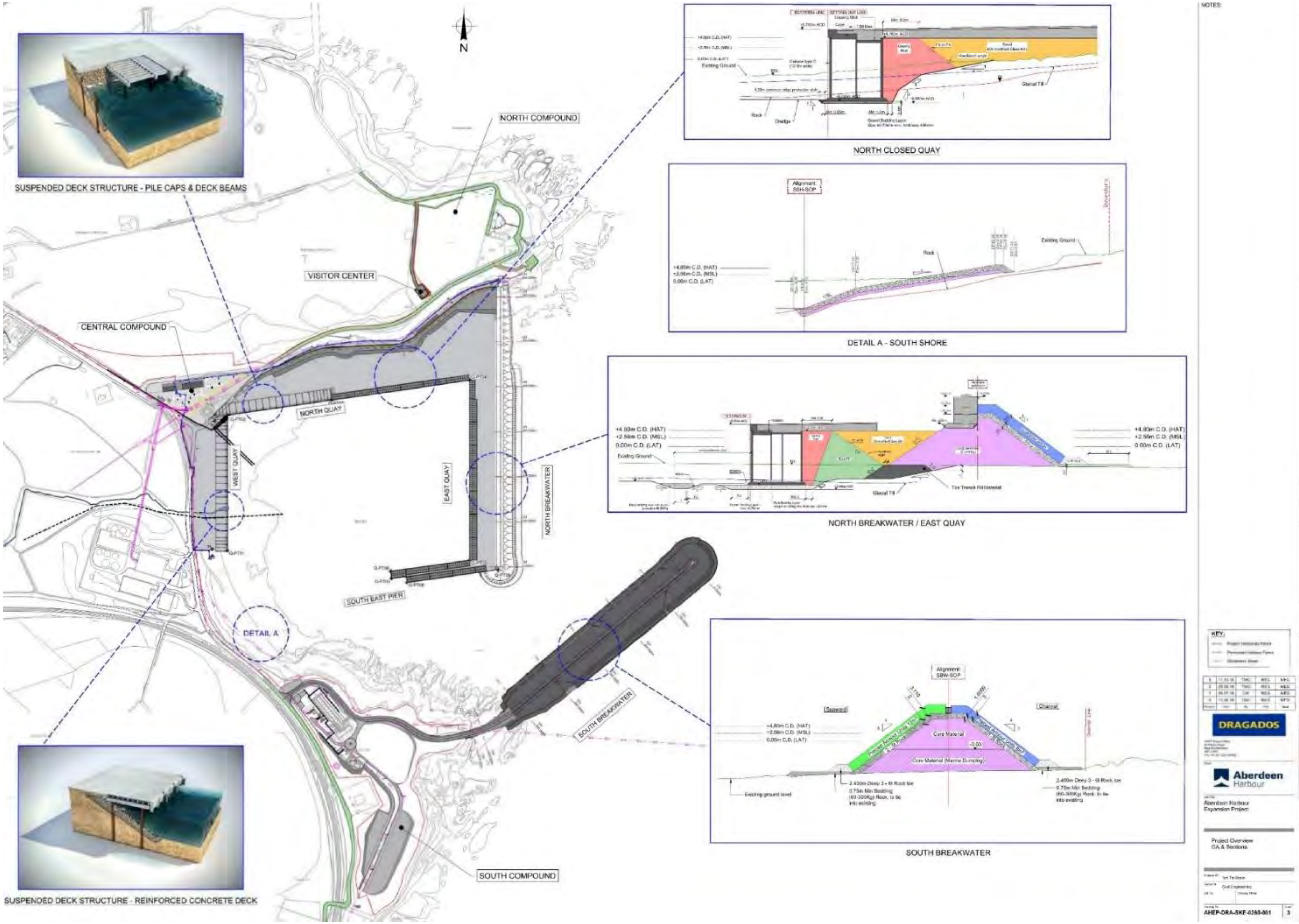


Figure 3—2 Indicative layout of Port Of Aberdeen South Harbour

3.2 Power infrastructure

PoA has provided Buro Happold with multiple drawings related to the overall infrastructure design as well as the electrical networks. However, these do not represent the as built package due to ongoing construction. Therefore, all information contained within the report will require validation when as built drawings and details are available.

The utility networks currently deployed within the South harbour are the following:

- LV power network
- Potable water network
- Sewage network
- ICT network

The existing power infrastructure at the South harbour is an LV voltage system (400V) connecting to SSE's (11kV) network through an 800kVA substation. A schematic is provided in section 5.6 for more information.

3.2.1 Scottish and Southern Electricity (SSE) grid

SSE is the local Distribution Network Operator (DNO) supplying the South harbour and Aberdeen city and the assumed supplier of the additional electricity required for the shore power system.

To assess the existing grid capacity in the area, data was retrieved through SSE's website. The data contains geographic information related to their network as well as primary substation demand headroom.

It is important to review this information to continuously assess the level of network reinforcement that would be required to connect additional loads to SSE network. The level of reinforcement required will then give an indication of the upgrade cost prior to engagement with the DNO.

As shown in Figure 3—3, there are 4 primary substations within proximity to the South harbour. These primaries are supplied by Grid Supply Points (GSPs) and step the voltage down from 33kV to 11kV. Each primary has a demand headroom which is the DNO's estimation on how much additional power load can be connected to each substation, based on its existing connected loads.

Table 3-2 shows the worst-case and best-case demand and generation headroom at each of these primary substations, taken from SSE's forecasts. These provide a demand value for each year (up to 2050) and for each of the National Grid's future energy scenarios.

Figure 3—3 also shows that there are two GSPs in the area: Clayhills and Redmoss. These grid supply points are fed by the national grid at 132kV and step the voltage down to 33kV and they could serve as supply points for the South Harbour.

Redmoss GSP is labelled as a restricted supply point and is relatively far from the harbour so is very unlikely to act as a supplier. Clayhills GSP however has a 60MVA transformer rating with a maximum load of 32.7MW, which it is estimated as leaving ~23.6MVA of headroom.

This headroom should be sufficient to supply the estimated demands for shore power, especially when considering peak power demand diversification between vessels and the opportunity to add peak shaving technologies both onshore and onboard the vessels.

Engagement with SSE is still required to confirm that they are aligned with Buro Happold's assumptions on their supply.

Figure 3—3 SSE substations within proximity to PoA south harbour

Table 3-2 SSE primary substation demand and generation headroom

ID	Primary Substation Name	Grid Supply Point	Minimum Generation Headroom (MVA)	Minimum Demand Headroom (MVA)	Maximum Generation Headroom (MVA)	Maximum Demand Headroom (MVA)
1	Balnagask	Clayhills	10.90	2.32	14.67	8.00
2	Craiginches	Clayhills	20.14	8.44	38.23	18.44
3	Clayhills	Clayhills	21.64	-16.03	32.59	13.16
4	Kincorth	Redmoss	9.56	-8.05	20.29	5.94

3.2.2 South harbour infrastructure

Currently, the power infrastructure has only been deployed in part of the port and it mainly consists of one 11/0.4kV distribution substation. The 11kV feeders are fed from SSE and the LV network is then distributed throughout the site in ducts or as direct buried.

The distribution substation has a contracted capacity of 722kVA and it is equipped with an 800kVA ONAN TX.

Due to the expected high demands of the vessels, the existing electrical network is likely not functional for the shore power system, therefore it will be considered as any other utility i.e. verifying any main clash, limitations with the new proposed network.

There is also a substation located in the NorthEast corner of the site fully dedicated to Marine Scotland whose actual capacity is not known at the time of writing this report.

Figure 3—4 shows the electrical infrastructure within the South Harbour as well as the utility trench which is currently hosting the potable water distribution network (max 250mm OD) as well as n.2 of 200mm Ductile Iron pipes for Marine Scotland running along Castlegate East only.

The service trench is 1400mm wide and varies between 1985mm and 1650mm in depth. The water network then connects to the vessel through 6.4x4m or 6.4x3.4m bunkering pits.

The service trench only runs along Crathes, Dunnottar and Castlegate East while any service along the suspended deck quaysides is or will be direct buried.

The service trench has also been envisaged to host fuel pipelines in the future, as indicated by PoA. The type of fuel is currently unknown and it will depend on the next development in the sector and decision made in coordination with vessel operators.

PoA have indicated that one import and two export lines are currently envisaged even though the requirements in terms of location, sizes, safety and integration with other utilities are not known.

Therefore, any additional infrastructure within design proposal will aim to limit any run of HV/LV cables within the trench as well limiting any significant hard digging of the existing quaysides.

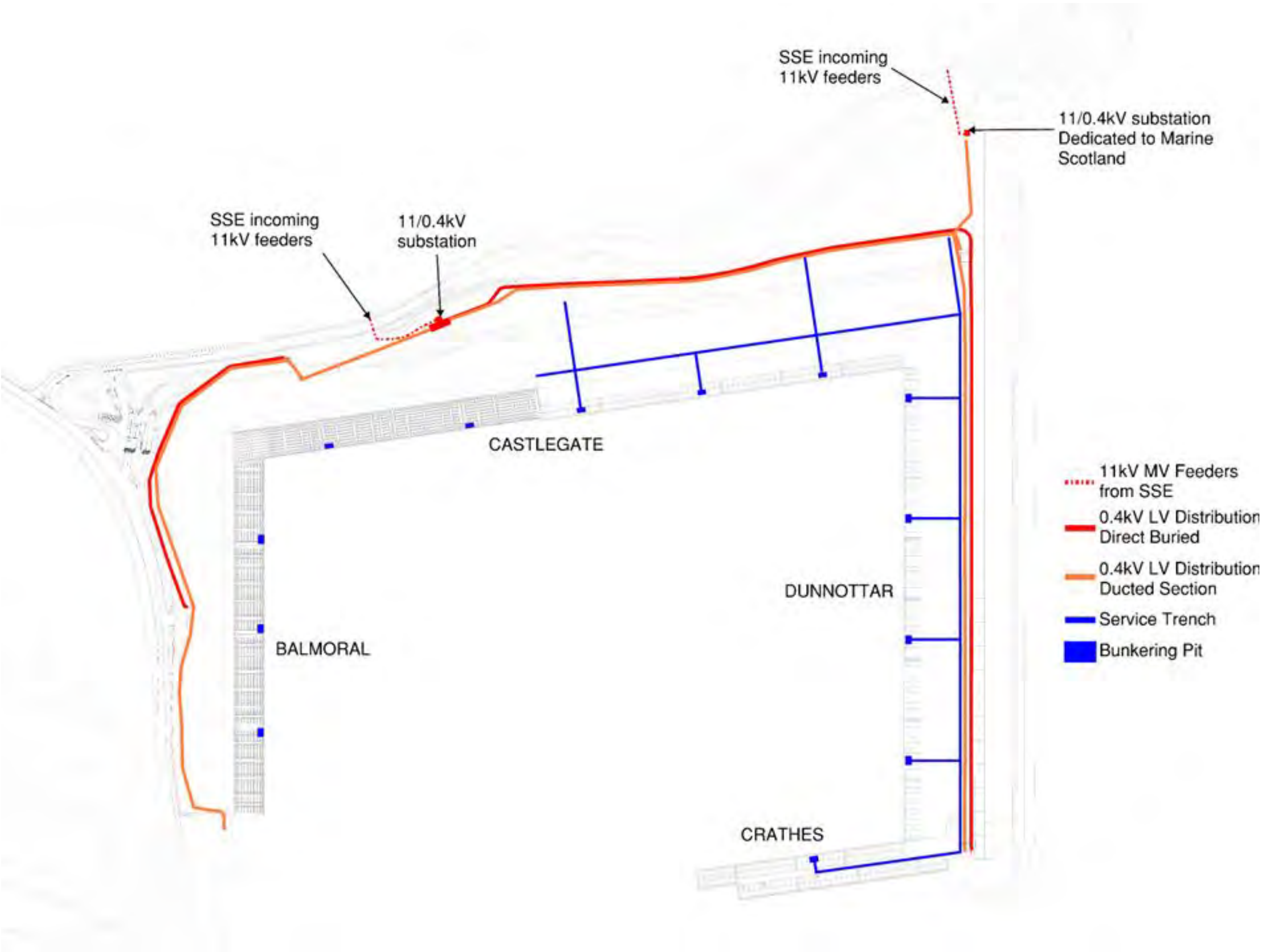


Figure 3—4 Existing electrical and civil infrastructure at South Harbour

3.3 Berthing analysis

An extensive analysis of the current and estimated vessel traffic and the duration of the calls to the south harbour has been carried out in coordination with PoA.

PoA has provided the expected calls for each ship typology expected to berth at the south harbour between 2023 and 2030, Table 3-3.

Table 3-3 expected number of calls per year

	Calls/year		
year	**2023**	**2027**	**2030**
General Cargo	29	75	94
DSV	59	153	193
CSV	24	61	77
Cruise	15	87	101
Offshore Rig	2	2	2
Total	127	367	465

The calls after 2030 are treated as constant as agreed with PoA.

The berthing hours for each call has been determined as average values since the duration of each vessel call depends on multiple factors (maintenance, weather, equipment/material supply etc). For cruise ships, PoA confirmed that these would call between 8am-6pm, i.e. 10 hours per call while the rigs are expected to berth for 30-90 days.

To account of the variation of call length, low and high values for CSV and DSV have been estimated as per Table 3-4.

Table 3-4 Range of DSV and CSV call's duration

	Range of call length (hours)		
	CSV	CSV	Rig
Low	76	87	720
High	79	98	2160

It is also understood that the longer calls for CSV and DSV are likely to happen during winter rather than during summer and this assumption has been used to shape the power consumption profiles.

Discussions with PoA also noted that not all vessels that call at the port will utilise shore power. Therefore, an indicative percentage of expected shore power uptake from 2025 to 2030 has been applied as agreed with PoA. Two sets of data were used; a high uptake scenario and a low uptake scenario. The percentage uptake for both scenarios is displayed in

Table 3-5.

Table 3-5 Shore power utilisation uptake

Scenario	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Low uptake	30%	35%	40%	45%	50%	55%
High uptake	50%	60%	70%	80%	90%	90%

Figure 3—5 and Figure 3—6 show the annual call's duration growth in both the best and worst case scenarios. These data sets exclude Cargo vessels due to uncertainty regarding their port calls at the POA.

Therefore cargo vessels were excluded from further analysis and not included in the final berthing hours illustrated in Figure 3—5 and Figure 3—6.

Please refer to Appendix B for additional information.

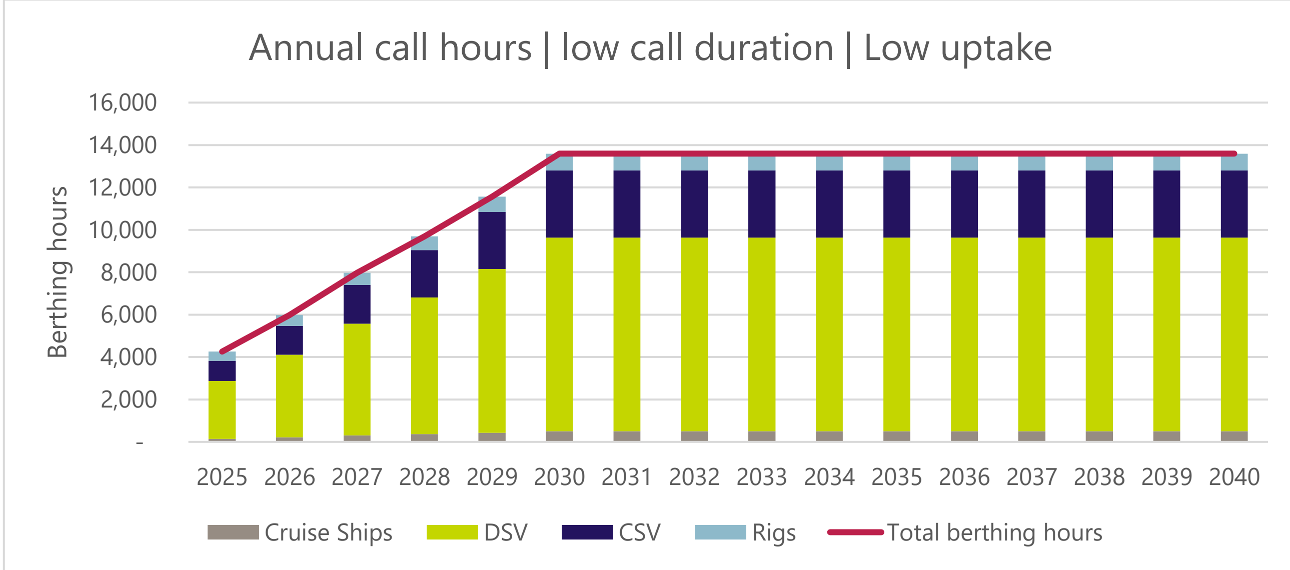


Figure 3—5 Annual Berthing calls growth – Low call duration | low uptake

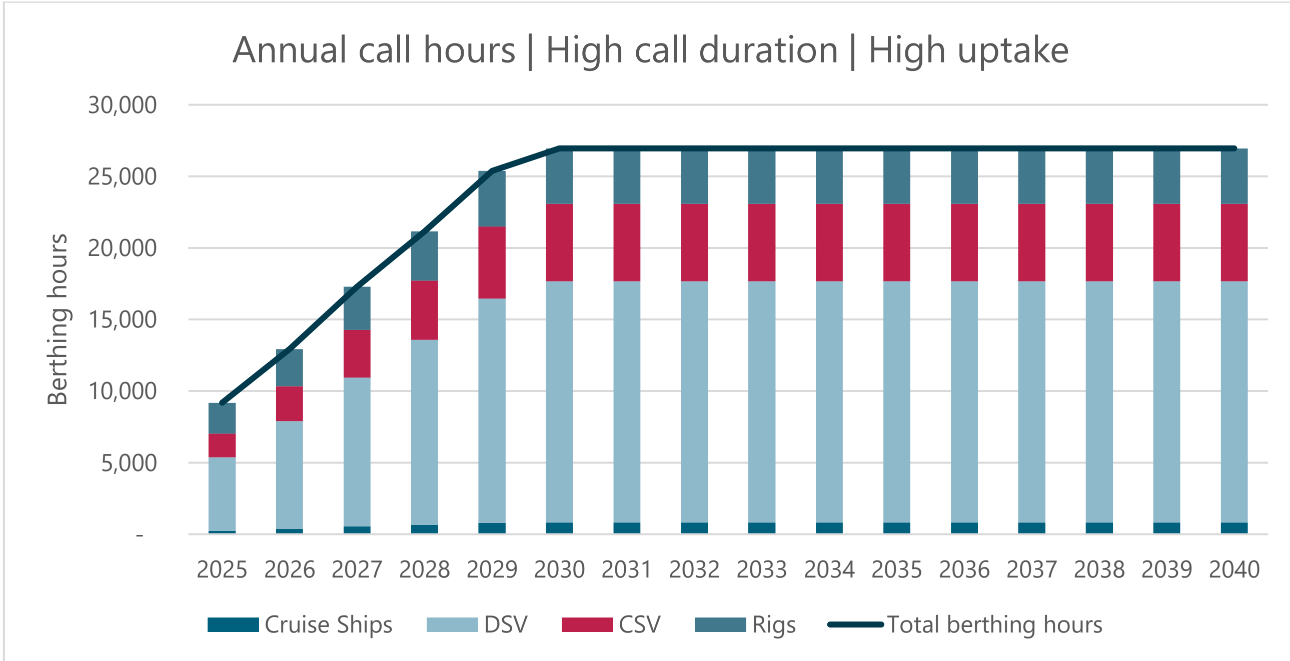


Figure 3—6 Annual Berthing calls growth – High call duration | High uptake

3.4 Power demands

Power demands have been computed based on provided information by PoA, vessel operators and applicable standards and they can be divided in two main categories:

- **Shipside demands**: power supply requirements of different type of vessels while at berth, informing the size of any proposed shore power system.
- **Landside demands**: reflects the buildings demands as well as sitewide infrastructure such as EV chargers, external lighting, ICT etc.

For both landside and ship side power demands profiles have been generated to allow a in depth investigation of any renewable sizing and their contribution/offset to the energy consumption. and taken forward for further analysis.

3.4.1 Landside

The landside demands can be summarised by the categories outlined in Table 3-6. The associated power demands have been derived through a combination of drawings and information provided by PoA:

Table 3-6 Estimate of landside power demands

End use	Power demand (kW)
Gatehouse (called Welfare Building 1 in the schematics)	73kW
Security building (called Welfare Building 2 in the schematics)	40kW
EV charging points	150kW
New terminal building	35kW
New warehouse	75kW
Sitewide infrastructure (pumps, security lighting, CCTV etc)	Various equipment sizes

At the time of this study there was no electrical schematics or design available for the potential new terminal or warehouse buildings. Therefore, an estimation of the electrical loads for both buildings has been agreed with PoA.

The provided electrical schematics do not represent the actual as built information. Utilising them to estimate the power demands for the landside assets poses a high level of uncertainty and risk. Therefore, an alternative methodology was used to estimate the peak consumption of the port's landside assets.

Based on electric schematics provided, the onsite substation is currently sized at 800kVA and, as confirmed by PoA, the current contracted capacity with SSE is for 722kVA - including a future allowance for the additional buildings.. A high level assumption has been made that ~90% of substation capacity would be utilised. This assumption suggests 716kVA of the 800kVA substation capacity being utilised which is within the contracted capacity outlined by SSE.

Representative annual power profile for the landside demands has been determined using a "Non - domestic unrestricted customer" Elexon profile as a template. The landside demand profile for January only is displayed in Figure 3—7. January was chosen for the graphical display as it represents the month with the highest power demand due the higher heating demands.

Based on the outlined assumptions, the annual power demand for the landside loads was estimated at 2.6 GWh/a. The peak demand was estimated at 680kW (716 kVA). The annual

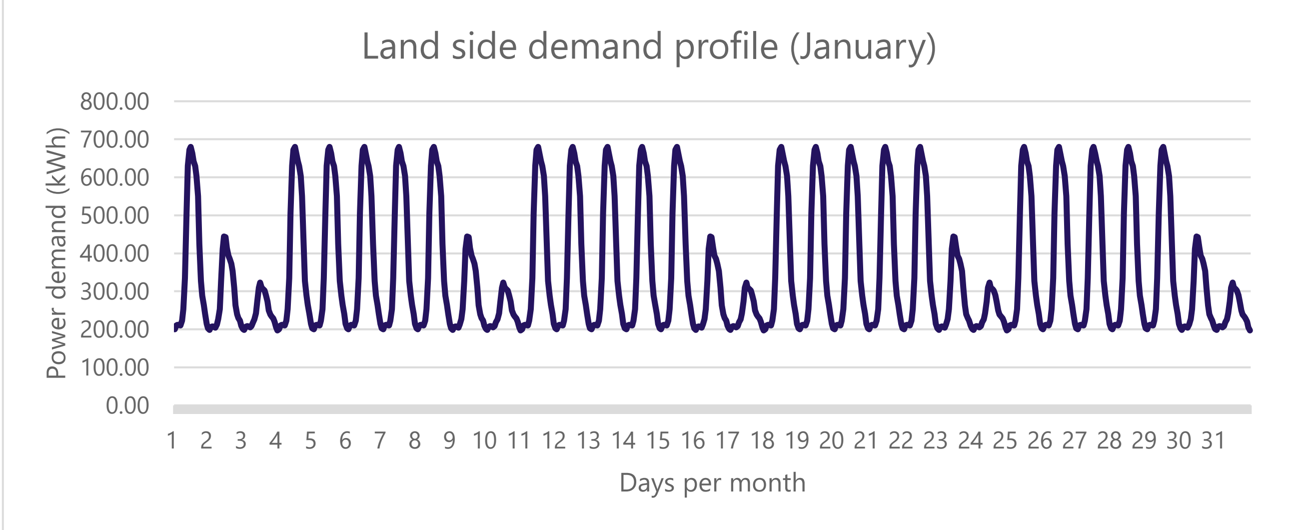


Figure 3—7 Landside energy demand profile January

As built information is not yet available since part of the port is under construction. It is recommended to confirm all the findings of this report when these information are available together with metered data for the electrical consumption which should be used for a better profile definition.

3.4.2 Shipside

Shipside demands related to the power consumption of vessel while at berth due to their operation i.e. maintenance etc

Consumption profiles were generated for the annual shore power consumption to inform the renewable energy technology sizing and the techno-economic analysis. The creation of these demand profiles enabled a greater understanding of the base and peak loads for each call, as they captured the historical berthing data, detailed power demand profiles for vessels and various discussions with the client.

Therefore, the generated profiles aim to capture variations in call duration and related power demands, building upon the berthing analysis carried out in section 3.3..

Two profiles were generated, one for 2025 and one for 2030, as well as the related estimated demand trajectory. This is to capture the initial build out of the shore power system between these years. The generated demands were treated as a realistic case while still fitting in the range of the four scenarios estimated in the berthing analysis

The generated representative profiles show alignment of the number of port calls per vessel type with the berthing analysis described in section 3.3. Assumptions were made regarding the seasonal distribution of the calls as per discussions with the PoA and historical berthing patterns, where higher number of calls are expected in summer rather than winter.

This is mainly due to the seasonality of the cruise ships primarily operating doing the summer months and rigs berthing mostly in winter. This distribution pattern was captured within the generated profiles. The annual demand trajectory from the generated profiles is displayed in Table 3-7 and Figure 3—8.

Table 3-7 Shore power generated annual consumption

Year	2025	2026	2027	2028	2029	2030
Shore power profile consumption projection (GWh/year)	11.28	14.15	17.03	19.90	22.78	25.65

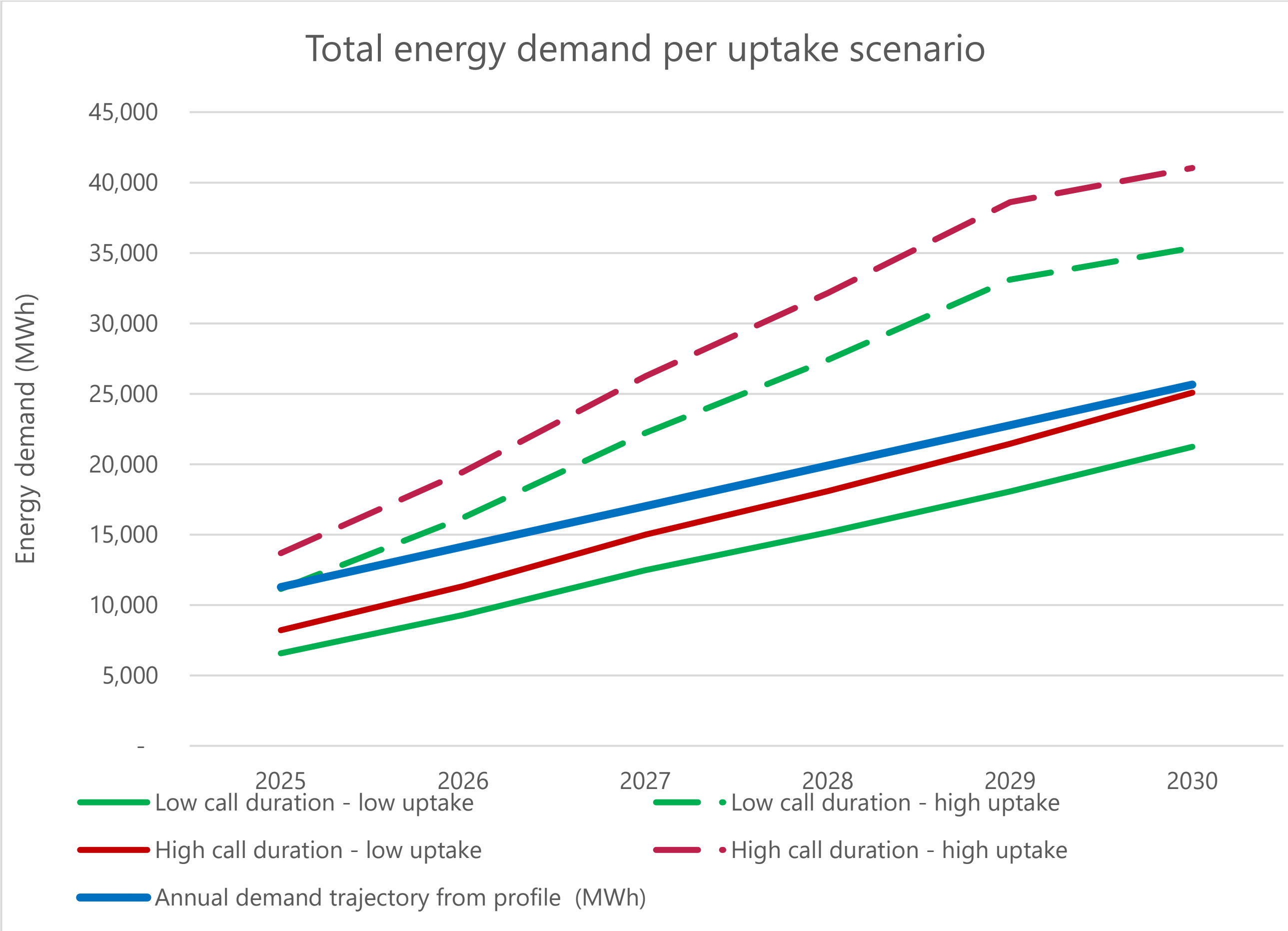


Figure 3—8 Shore power demand comparison between scenarios

The annual consumption profiles for 2025 and 2030 are displayed in

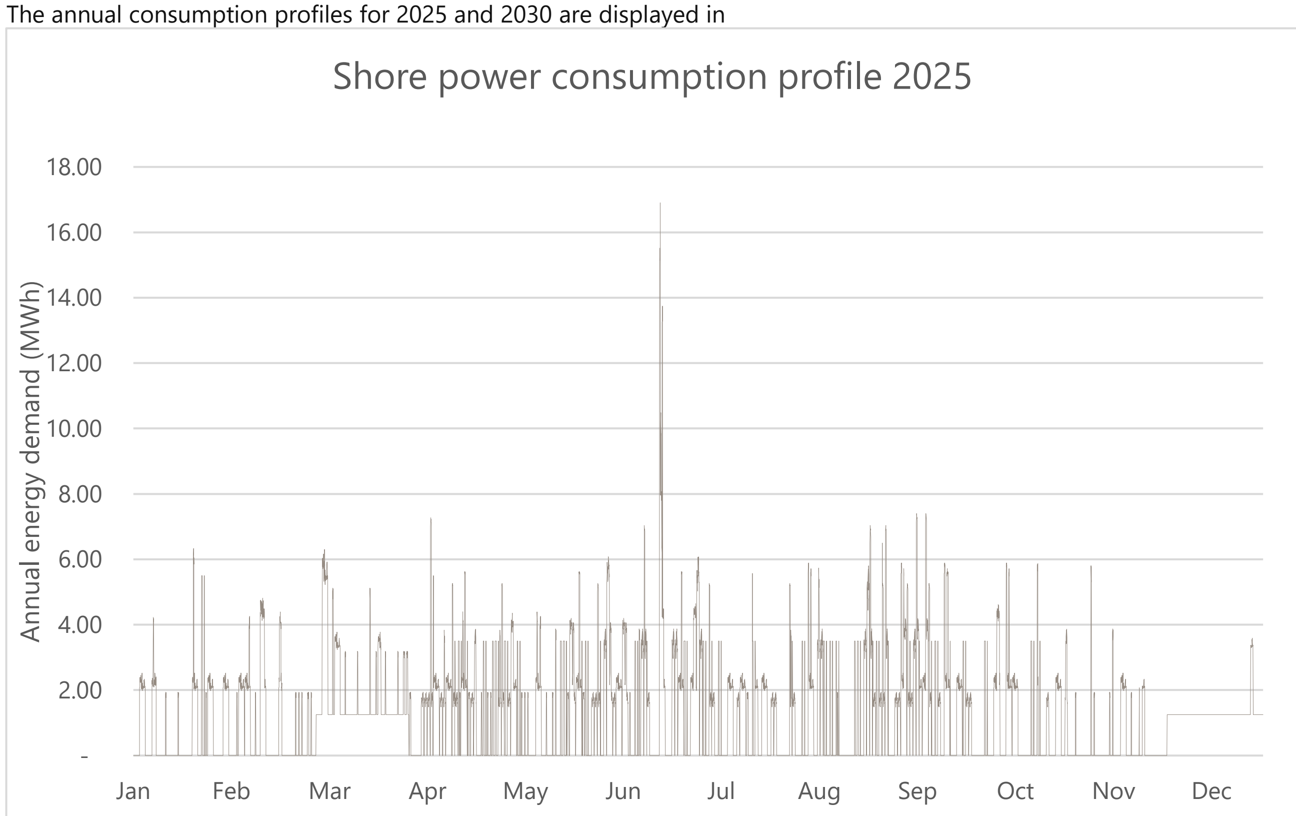


Figure 3—9 and Figure 3—10 respectively. The large 30 days steps within the profiles can be explained by the Rig port calls. Discussions with the client, indicated that the rig vessels will typically berth for a period of 30-90 days at a time resulting in a sustained period of consumption.

The peak power demand is envisaged to be 18.1MW (22.6MV) based on the agreed maximum number of ships berthing and their typology as per discussions with the client (Table 3-8). This is based on the assumption that a maximum of seven vessels/ships could berth simultaneously at the south harbour.

The profile demands provide a conservative estimate of the peak power demand due to the difference in the power demands used for the profile methodology. 18.1MW was taken forward for techno-economic analysis.

Table 3-8 Maximum shore power demand at South Harbour

Vessel typology	Power requirement (MW)	Power requirement (MVA)
DSV 1	1.9	2.4
DSV 2	1.3	1.6
DSV 3	1.3	1.6
CSV 1	2.5	3.1
CSV 2	2.0	2.5
Large cruise	5.5	6.9
Medium cruise	3.6	4.5
TOTAL	18.1	22.6

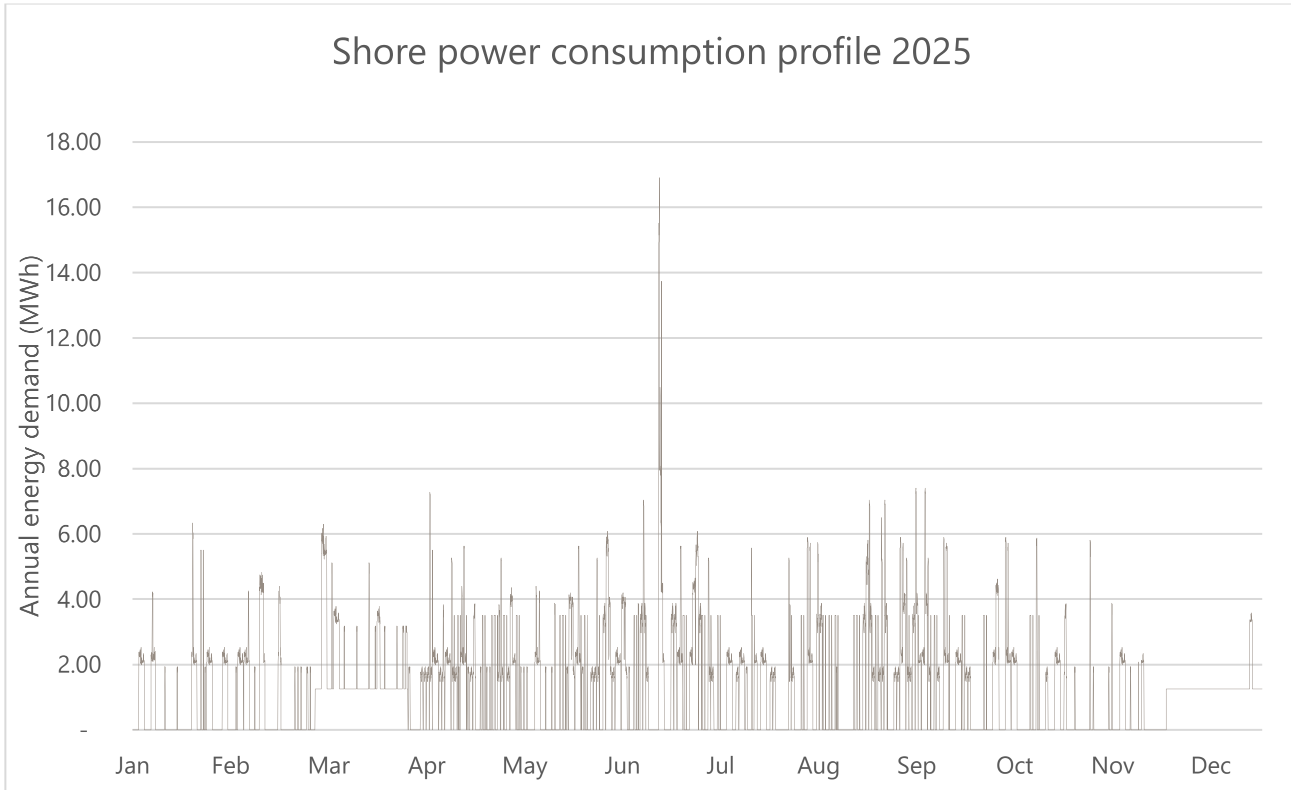


Figure 3—9 Shore power consumption profile 2025

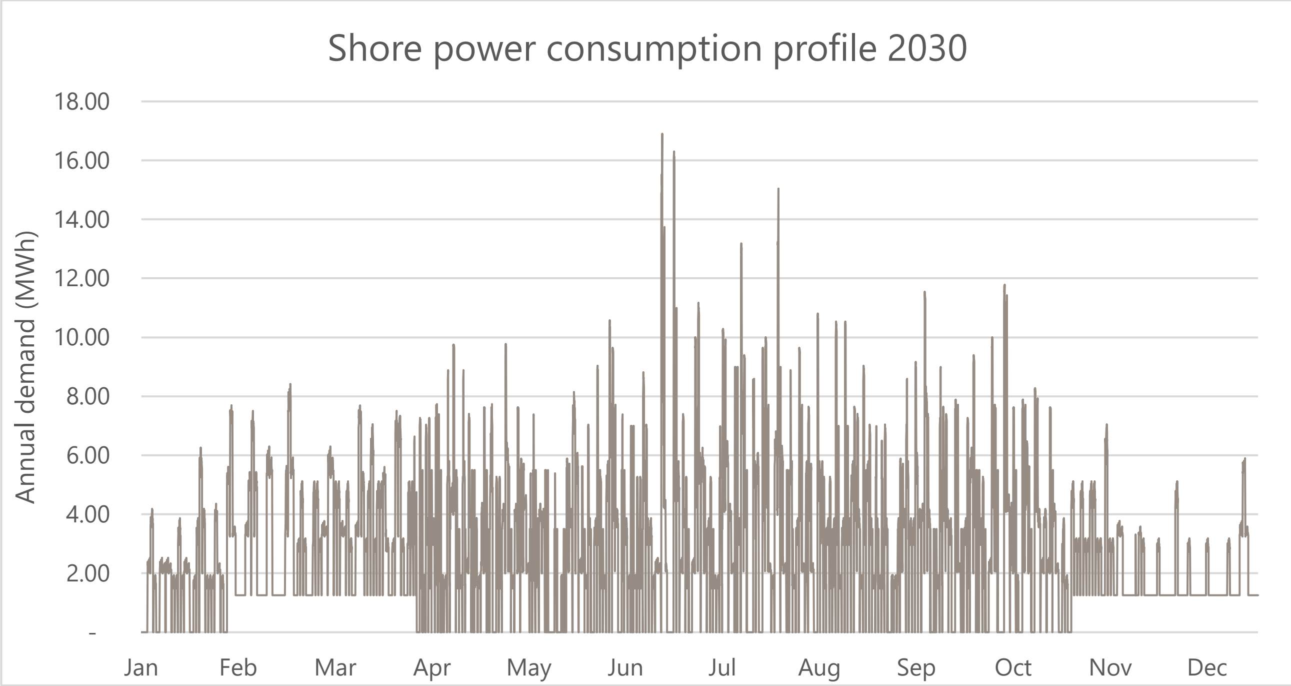


Figure 3—10 Shore power consumption profile 2040

Further details regarding the profile generation is displayed in Appendix B.

3.5 Carbon emissions

3.5.1 Carbon Emissions Projections

The proposed scenarios within this study are compared against a counterfactual option to assess the carbon and social benefits of shore power and renewable technology implementation. A counterfactual option represents an alternative scenario that could have been considered prior to the outcomes of the current undertaken study. For the purpose of the carbon savings, shore power provision was compared against a counterfactual of combustion of MGO within vessels.

Traditionally, when ships are in port, they use their auxiliary engines to provide power for the ship's operations. This is also known as cold ironing. Business as usual (BAU) for port zero would involve the ships leaving their engines running whilst at berth to ensure power is available for the ship systems. The most common fuel used during this process is MGO. BAU for the landside demands would be electrified loads with 100% of the power requirement being imported from the grid.

The carbon emissions associated with shipping can be identified as a combination of those happening during navigation and the ones at berth. The carbon emissions associated with the vessels at berth and during navigation fall directly within tenant scope 3 emission identified by POA, as per PoA scope emission inventory and carbon reduction plan (Appendix G).

For the purpose of this study, it is key to calculate the berthing emissions in order quantify the carbon reduction benefit of implementing a shore power system.

Carbon emissions based on the generated shore power profiles were calculated. Fuel consumption for profile generated scenario has been based on information from previous engagement with vessel operators and high level assumptions on the fuel supply required by the various vessels.

For comparative purposes the carbon emissions associated with the vessels utilising MGO at berth were calculated. This enabled the quantification of the emissions saving through utilisation of shore power.

No detailed information on fuel consumption and related emissions has been provided by vessel operators. However, International Maritime Organisation (IMO) in the fourth GHG study (2020) details the Specific Fuel Consumption (SFC) for each type of ship based on their age.

A representative value of 0.175kg/kWh has been adopted which represents medium speed vessels that utilise marine diesel oil based engines.

It is assumed the majority of vessels have been constructed from 2001 onwards and a 92% generator efficiency was applied to the SFC. The conversion to carbon emissions has been possible through DESNZ 2021 Government Greenhouse Gas Conversion Factors for Company Reporting, identifying an emission rate of 3.250 kgCO2/kg of MGO.

Considering the above carbon intensity of the MGO and SFC factor leads to an overall carbon factor of ~0.61 kgCO2/kWh for all vessels types.

The emissions during navigation are considered as Tenant scope 3 by PoA. However, PoA could enable the vessels and ships to use alternative fuels to reduce emissions.

PoA has provided initial fuel demands for the south harbour and their annual increase. By 2028, the annual carbon emissions related to fuel supplied by PoA have been estimated to be 579,440 tCO2e/year. It is assumed the amount of fuel the port can provide operators stabilises post 2028 due to infrastructure constraints (landside storage capacity). Therefore, for the purpose of this study, vessel emissions related to navigation are assumed to remain constant post 2028.

The annual carbon emissions from the generated profile MGO consumption and vessel navigation is displayed in Table 3-9.

Table 3-9 Vessel carbon emissions

	2025 tCO2e/year	2026 tCO2e/year	2027 tCO2e/year	2028 tCO2e/year	2029 tCO2e/year	2030 tCO2e/year
Emission at berth under PoA Scope (MGO)	6,876	3.5.2 8,629	10,383	12,136	13,890	15,643
Emission in navigation outside PoA scope	365,047	438,056	525,668	579,440	579,440	579,440
Total Ship Emissions	371,923	446,685	536,051	591,576	593,330	595,083

It is assumed for the purpose of this study that the landside demands remain constant year on year. DESNZ projections are used to estimate the carbon emissions for the landside demands between 2025 and 2030. The forecasted DESNZ electricity emissions factor is displayed in Figure 3—11. The landside carbon emissions are displayed in Table 3-10.

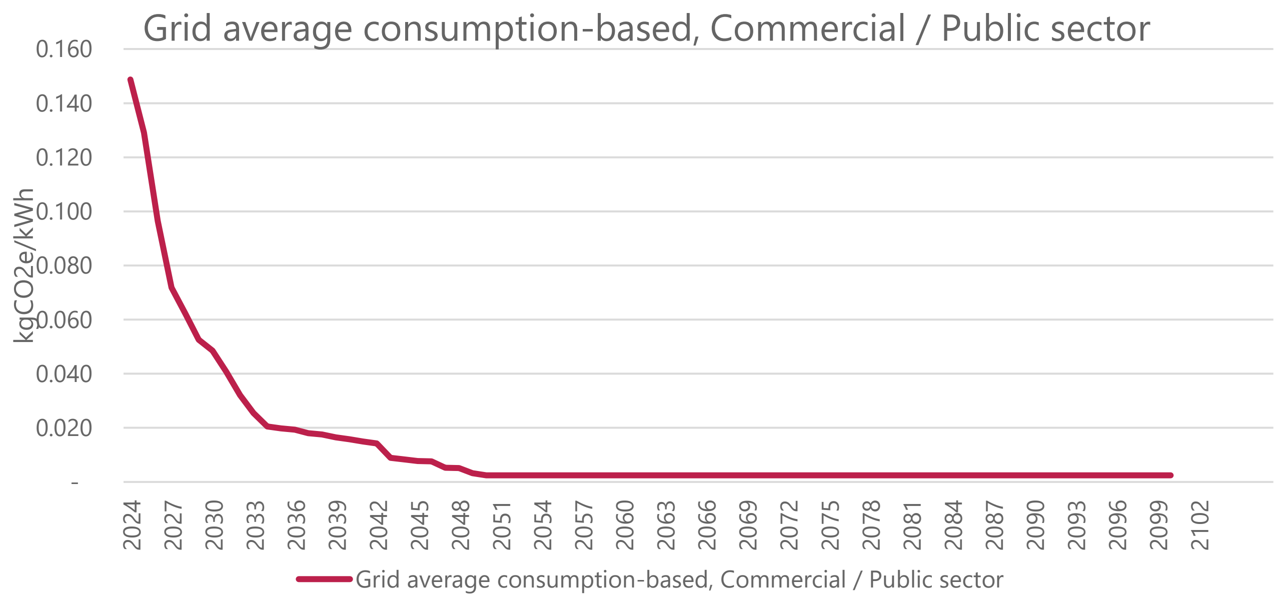


Figure 3—11 DESNZ carbon emissions forecasting

Table 3-10 landside carbon emissions

	2025 tCO2e/year	2026 tCO2e/year	2027 tCO2e/year	2028 tCO2e/year	2029 tCO2e/year	2030 tCO2e/year
Landside emissions	351	262	196	170	143	132

Further details regarding the carbon emissions methodology is displayed in Appendix F.

3.5.3 Remaining emissions

As discussed in section 3.3, the generated profiles for shore power are based on assumptions made regarding the duration of the calls and typology of vessels calling at the South Harbour. Due to the lack of historical berthing data, assumptions were necessary to formulate a representative profile.

Although the generated profile is based on the accurate number of calls per year, it assumes all vessels calling at the port will utilise shore power. It's possible this will not be the case, especially during the early years of shore power implementation (2025 -2030).

Consequently, some vessels may continue to use MGO at berth during the project lifetime. A sensitivity analysis was carried out to estimate the possible residual berthing emissions during the project lifetime if 100% shore power uptake is not achieved. The assumed shore power uptake followed the High uptake scenario outlined in Table 3-5. The remaining vessels were assumed to use MGO. The results for this analysis is graphically displayed in Figure 3—12 and Table 3-11.

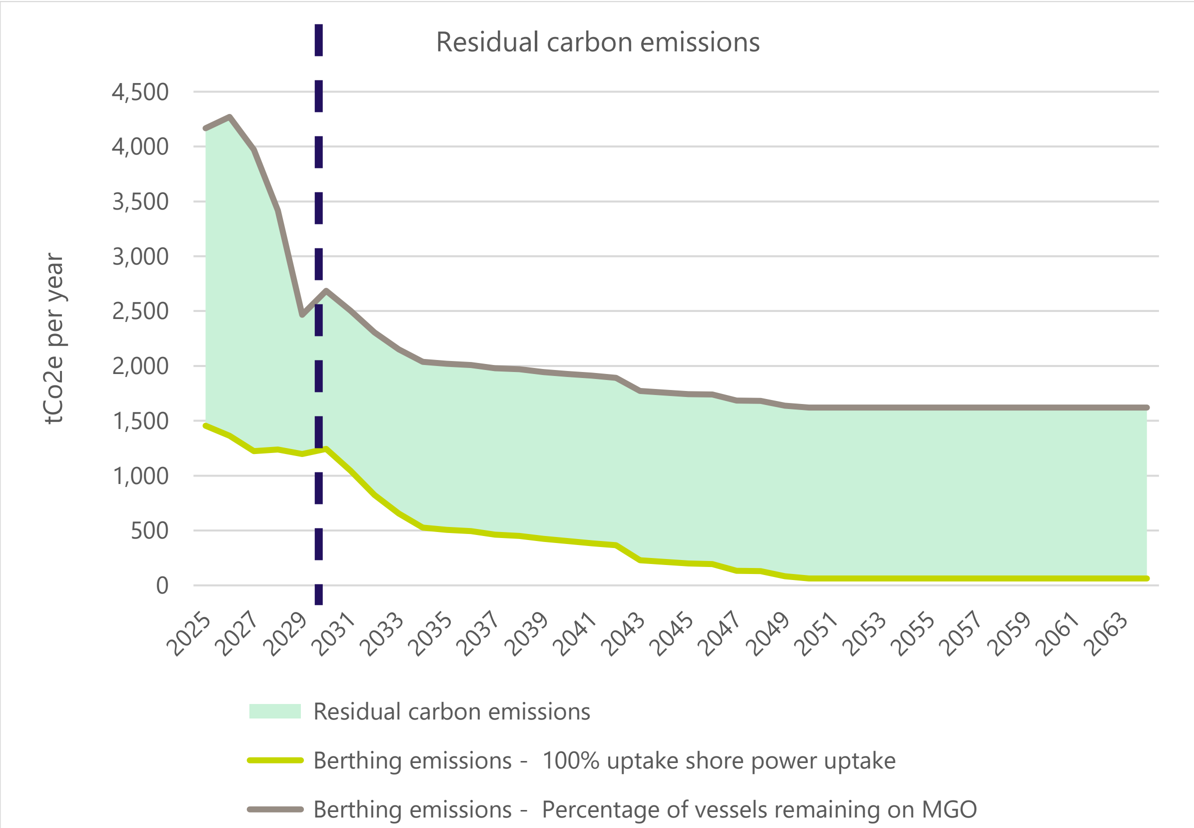


Figure 3—12 Residual carbon emissions from continued MGO usage at berth

Table 3-11 Residual carbon emissions from continued MGO usage at berth

Year	2025	2026	2027	2028	2029	2030
Percentage of shore power demand utilising MGO	50%	40%	30%	20%	10%	10%
Residual carbon emissions (tCO2e/year)	2,710	2,906	2,748	2,179	1,269	1,440

If 100% shore power is not achieved then up to an additional 65,572 tCO2e would be generated between 2025 and 2030. The residual carbon emissions would be greatest in this early period of the scheme. However more and more vessels would transition towards shore power over the project lifetime, gradually reducing the amount of continued MGO usage.

This sensitivity is provided to highlight how the uncertainties over the assumption used in the modelling could have an impact on the carbon emission and, consequently, over the targets of net zero set by PoA.

It shall be noted that the uncertainties do not impact the proposed infrastructure i.e. electrical network but rather the annual demands hence the economics and carbon performances. As already stated, further investigation is required to refine the assumptions.

It is assumed that the profile taken forward to the TEM analysis would still be a realistic one.

3.6 Risks and assumptions

Several datasets have provided by the client to assist with the demand and carbon analysis. However, some key assumptions were still made. There is a correlation between the number of assumptions made and the amount of risk surrounding the results.

Some of the key assumptions are outlined below:

- The seasonal distribution of the port calls
- The maximum power demands of the vessels at berth
- The exact period of the day when the vessels berth

In addition key risks surrounding the demand analysis is as follows:

- Lack of final as built drawing information and metered data for onsite landside consumption
- Future allowance for additional buildings is indicative only
- Detailed profile consumption only available for a limited number of vessels
- Projection of calls and their duration are uncertain and difficult to predict
- Historical data was only available for the north harbour and assumed applicable for the south harbour
- Actual simultaneity of berthing and peak power demands has been based on a conservative scenario
- Uptake of shore power by vessel operator is not formally confirmed

Further details regarding the risk and assumptions associated with the power demands and carbon emissions is outlined in Appendix C and Appendix D.

4 Scenarios Definition

Three different scenarios have been investigated within this report. They provide an understanding of the different solutions for the south harbour in relation to the emission reductions and PoA ambition to enable their clients to decarbonise their operations.

The stretch scenario has been chosen for a detailed techno-economic (TEM) investigation as agreed with PoA. All scenarios are based on initial figures related to vessel traffic/berthing hours and limited information of as built infrastructure (harbour still under construction) which shall be refined and confirmed before progress in the design stages.

Table 4-1 summaries the key differences between the scenarios.

4.1 Baseline Scenario

A baseline scenario has been developed to provide the minimum implementation required at the south harbour to reduce the emissions but is unlikely to reach the goal of zero emission by 2040. This scenario considers the introduction of a shore power system (HV and LV) to cut the vessel emission at berth.

A provision for a BESS is made to manage the peaks of the vessels and limiting required infrastructure i.e. n. of transformer and contracted capacity.

Operational vehicles (HGV, fork lifts) at south harbour, both PoA's and third parties', would remain supplied by fossil fuel and the vessels are still operating with MGO while the normal vehicle fleet is assumed to be fully electric with provision of electric chargers.

All the electricity is provided by the grid, which will likely not fully decarbonise by 2040, presenting a risk to PoA not meeting their targets.

4.2 Stretched Scenario

This scenario expands on the baseline case to meet to the 2040 zero emission target. On site renewable generation (trough PV and Wind turbines) and battery storage is provided to cover the landside and a significant portion of the shipside demands

Solar energy could help satisfy the demands EV chargers while the wind would mostly supply the shore power demands of the vessels. An allowance for a BESS is made to cover any potential fluctuations of demands and power generation.

Port side vehicles including mobile cranes and forklifts as well as tug vessels should be replaced with zero emissions alternatives (electric or with low emission fuels). The fuel supplied to the vessel should shift from MGO and would likely be HVO (or similar) leading to significant reduction of emissions.

PoA would become an enabler for vessel operator to decarbonise their operation trough shore power and alternative fuel provision (HVO or similar).

4.3 Pioneering Scenario

The port aims to become an energy hub with integration of renewable generation, energy storage and green fuel production.

Renewable energy is provided by wind and solar and supported by the grid. The port would develop zero emission fuel generation, specifically e-methanol, under this scenario. The port is likely to be part of a wider joint venture for the fuel production as it involves deployment of electrolysers for hydrogen production, direct air capture system to provide the CO2 feedstock and methanol synthesis process.

The port would go beyond their targets of zero emission by producing the fuel required for 3rd parties ships and it would become part of the regional developments for hydrogen and zero emission fuels production.

Table 4-1 Scenarios high level description

	Baseline	Stretch	Pioneering
Shore power for vessels	HV and LV shore power connections implemented for vessels at berth. These include decommissioning vessels, cruises, rigs etc	HV and LV shore power connections implemented for vessels at berth. These include decommissioning vessels, cruises, rigs etc	HV and LV shore power connections implemented for vessels at berth. These include decommissioning vessels, cruises, rigs etc
Vessel Refuelling/charging	MGO storage provided within the south harbour. Vessel supplied with MGO	selected vessels are battery / electric ready and can recharge through the port system while berthed. Alternative fuel to replace MGO within the storage facility	Battery electric vessels are being recharged at the port (if any). Methanol supply is implemented as fuel for ships
Port vehicles for operations	Fuelled by MGO	Transitions to electric vehicles	Full transitions to electric vehicles
Staff vehicles	EV charged by grid supplied electricity	EV charged by the port's energy supply system	EV charged by the port's energy supply system
Incoming freight vehicles	Fuelled by MGO	Fuelled by a sustainable alternative fuel	Fuelled by a sustainable alternative fuel which could be emethanol since available on site
Port buildings	Supplied by grid electricity	Power mainly supplied by localised energy generation such as rooftop solar	Power mainly supplied by localised energy generation such as rooftop solar
Onsite renewable generation	N/A	Wind Turbines are deployed within the port to supply the shore power demands.	Renewable energy is supplied to the ports energy system to satisfy buildings and shore power demand, as well as being used extensively for sustainable alternative fuel generation
Battery Energy Storage System	Provisional Allowance for a BESS is made	Provisional Allowance for a BESS is made	The BESS system is expected to support the energy supply needed for alternative fuel processes.
Future infrastructure for Alternative Fuels	N/A	Alternative fuels such HVO is stored within the port storage facility	The port becomes a significant player in the hydrogen market. Not only is it produced on-site but it is also being reformed into methanol as alternative fuel

5 Baseline Scenario

5.1 Overview

The scenario represents the immediate actions that PoA can develop and implement to reduce their emissions and move towards the goal of net zero emission by 2040.

The emissions of vessel during the calls at harbour make up for the 99% of total emissions in the control of the port. Therefore, a shore power provision is crucial to cut these emissions.

A significant electrical infrastructure upgrade is required to meet the expected peak demands from shore power (~22.5MVA). This means a new 33kV primary substation is required to connect ten HV and two LV shore power connection points placed along the quaysides.

A provision for BESS helps to balance the peak loads from the vessels and allows to reduce the connection required from the DNO as well as the size of the substation. The latter is also design with additional space for extra transformers to allow nearby development to connect to it.

Discussions with DNO and surrounding developers is required to finalise the size, the location, the capacity, connection strategy etc.

All electrical infrastructure has been designed to minimize the disruption to the port operation as well as the amount of civil works i.e. hard digging.

The scenario does not include provision for any on site renewable generation and all the heavy machinery operating at the harbour are supplied with fossil fuel.

It is envisaged that implementing the shore power system would lead to a reduction of 96% of the total emission within the South Harbour.

Main risks associated with this scenario:

- Capital investment for shore power is significant and not likely feasible without fundings
- Engagement with SSE and adjacent development is crucial and still to happen whit potential impacts the proposed strategy
- Lack of formal commitment for shore power usage form operators
- PoA will not meet their target of net zero by 2040
- Limited availability of HV system operators for shore power operation

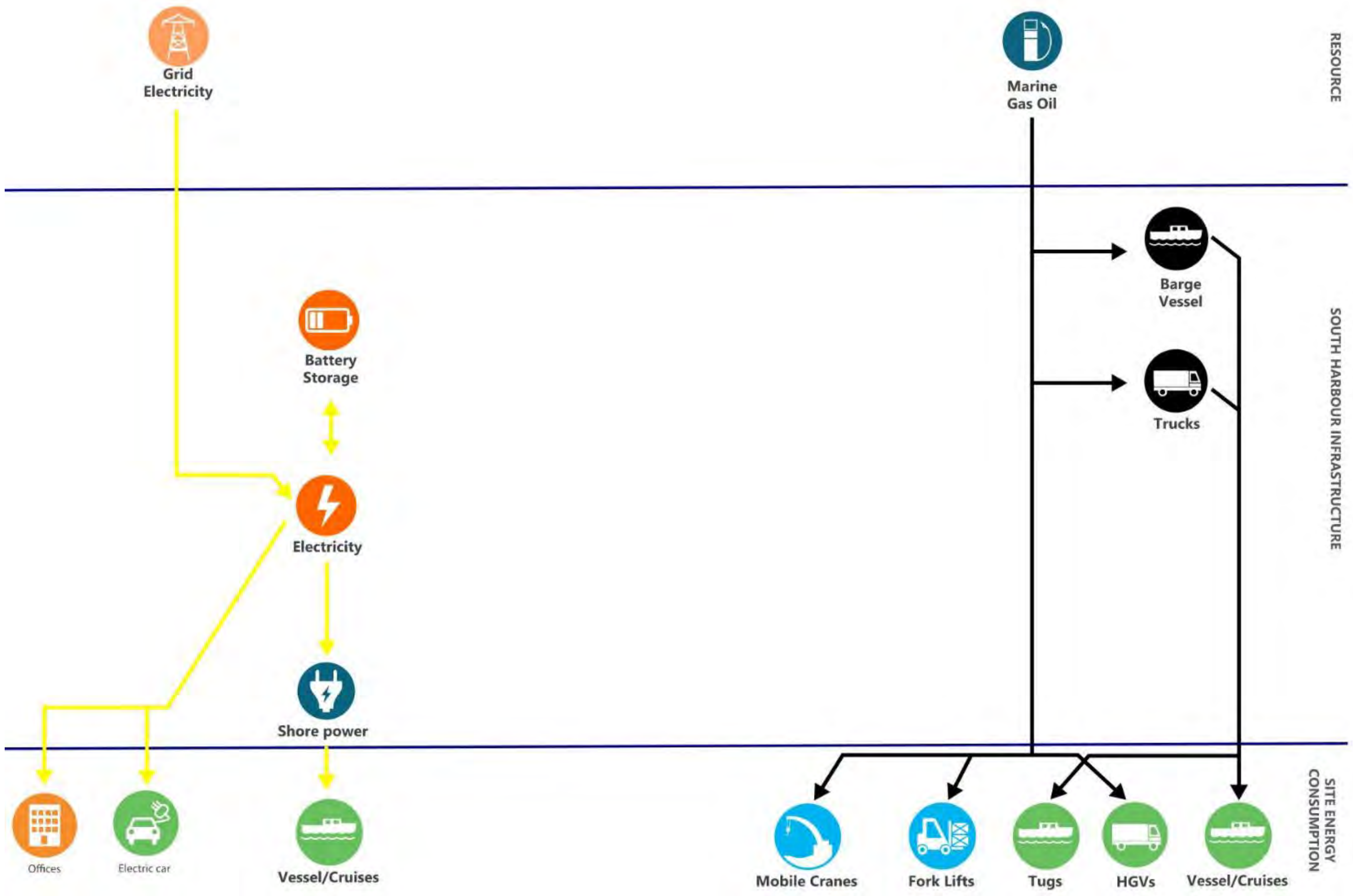


Figure 4—1 Baseline Scenario energy strategy

5.2 Demands

Power demands have been computed based on provided information by PoA, vessel operators and applicable standards and they can be divided in two main categories:

- **Shipside demands**: power supply requirements of different type of vessels while at berth, informing the size of any proposed shore power system.
- **Landside demands**: reflects the buildings demands as well as sitewide infrastructure such as EV chargers, external lighting, ICT etc.

In order to create a representative energy assessment of the ports energy assets both of these demands must be captured.

5.2.1 Landside

The landside demands can be summarised by the categories outlined in Table 5-1. The associated power demands have been derived through a combination of drawings and information provided by PoA:

Table 5-1 Estimate of landside power demands

End use	Power demand (kW)
Gatehouse (called Welfare Building 1 in the schematics)	73kW
Security building (called Welfare Building 2 in the schematics)	40kW
Existing EV charging points	150kW
New terminal building	35kW
New warehouse	75kW
Sitewide infrastructure (pumps, security lighting, CCTV etc)	Various equipment sizes

The provided electrical schematic doesn't represent the actual as built information. Utilising them to estimate the power demands for the landside assets poses a high level of uncertainty and risk. Therefore, an alternative methodology was used to estimate the peak consumption of the port's landside assets.

PoA currently has a 800kVa substation installed onsite. As discussed with the client this substation has capacity to accommodate all the current demands and the new terminal and warehouse building. In the absence of more accurate annual consumption data for each landside asset an assumption was made that the ~90% of the substation capacity is to be utilised (716 kVA).

Based on the above, the annual landside energy demand is estimated at 2.7GWh per year with a peak demand of 680kW.

High level assumptions were used to estimate the landside demand. In order to improve the accuracy of the landside demands metered data should be used, if available in the future, to create a representative profile.

5.2.2 Shipside

The shipside demands captures the energy required by the following vessel typologies while at berth:

- DSV
- CSV
- Cruise ships (large/small)
- Rig

A representative energy profile for the berthing power demands is generated and used to capture variation in call duration and peak demands by the various different vessels.

The call durations in the profile is based on hourly profiles provided by the client and where profiles for some typologies were not available key assumptions were made. As an example, it is assumed that Cruise Ships and Rigs utilise 100% of their engine power for the entire berthing period.

The number of port calls per year was provided by the client. However, an assumption is made regarding the seasonal distribution of the calls. It is assumed the majority of vessels would call during the summer period. The exception to this is for the rigs which only berth during winter.

The generated energy demands from the profile creation is displayed in Table 5-2.

Table 5-2 Shore power annual demands

Year	2025	2026	2027	2028	2029	2030
Shore power profile consumption projection (GWh/year)	11.28	14.15	17.03	19.90	22.78	25.65

The peak demand for the shore power is estimated at 18MW (22.6MV) as per discussions with the client over the maximum amount of vessels berthing at the south harbour at one time. The breakdown of the vessels is included in Table 5-3.

Table 5-3 Maximum power requirements at south harbour

Vessel typology	Power requirement (MW)	Power requirement (MVa)
DSV 1	1.9	2.4
DSV 2	1.3	1.7
DSV 3	1.3	1.7
CSV 1	2.5	3.2
CSV 2	1.8	2.3
Large cruise	5.5	6.9
Medium cruise	3.6	4.5
TOTAL	18	22.6

5.3 Main ship fuel

MGO is still the fuel used by the majority of vessel. PoA storage system guarantees 512,000 m^3/year for their clients. Appendix M includes detail information of MGO properties and related emissions. Refer to Appendix L for indicative routing of fuel pipelines.

5.4 Renewable Generation

The baseline scenario does not consider any onsite renewable power generation. All power demand (including shore power) would be supplied through grid imports and it is therefore subject to the uncertain percentage of renewable contribution feeding the grid.

5.5 Infrastructure requirements

The key infrastructure requirements for the baseline scenario are tabulated in Table 5-4 alongside their correlated footprints (if applicable). This infrastructure would likely be implemented as per Figure 5—2 across the site.

The estimated locations of this required infrastructure is displayed in Figure 5—2. The key aspects to note are the locations of the connection points at the berthing points and that the new substation is located to the left of the site.

The location of the primary substation has been agreed with PoA but it shall be confirmed trough engagement with SSE and the nearby developments.

For more further detail on the infrastructure requirements, refer to section K.1 in Appendix K.

Table 5-4 Key additional infrastructure requirements for baseline scenario

Element	Description	Footprint
Primary substation (includes provisions for optional BESS)	A new substation is required to facilitate shore power	38x43m
LV transformers	Transformers for LV shore connection (required at berth)	~5x5m
Cables and trenches	More cables are required from the new substation to the shore power connection points	~1600m (of new trenches that contain cabling)
Shore power connection point chambers	Underground pits/chambers which house the shore power connection points/sockets	~(2.5x1.5x2)m (LxWxD)

A provision for fuel lines and fuel connection point has been assumed as per Figure 5—2. It is not known at this stage of the project the number, location of fuel points and the extent of associated fuel network, however a conservative assumption has been made and fuel connection points have been considered along Castlegate, Balmoral and part of Dunnottar.

To avoid any potential risk linked to proximity of fuel and electrical lines, the proposed electrical network has been designed to run on separate routes and trenches from the assumed fuel lines. Few crossover between the networks are needed but this are limited and with adequate protection should be feasible.

The coordination with the fuel network shall be refined when a final design for such a network is provided.

5.5.1 Shore power failure modes

There are many risks associated with power systems. For shore power systems, Buro Happold have created an extended analysis with a risk breakdown for each sub-system in Appendix N section N.1. A summary of the reoccurring risks is shown below:

- Circuit breaker failure
- Transformer winding overheating
- Transformer distortion, loosening or displacement of wiring
- Loss of output voltage
- Control failure
- Hardware crash
- Operational failures
- Explosion
- Fire
- Power cable failure
- Bus loss of integrity/continuity
- Passenger intoxication
- Occupational hazard
- Blackout

Most of these risks can be mitigated through adequate design, maintenance, monitoring, operations, and the fact that the vessels can still use their onboard generators should the shore power supply fail.

The list shall serve for PoA to appoint a designer and operator during next stages who can guarantee all the risk are fully investigated and mitigation measures proposed to PoA.

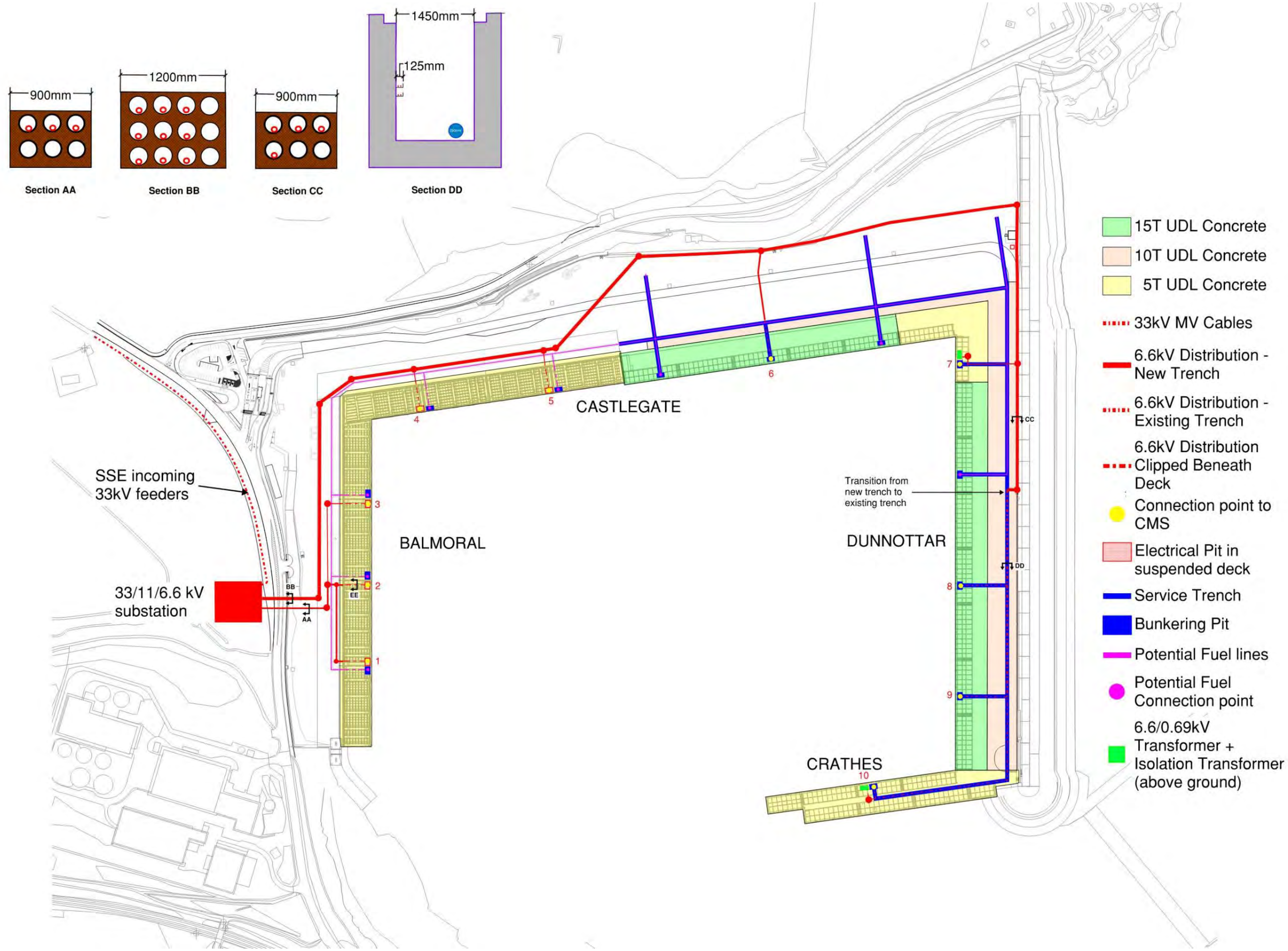


Figure 5—2 Additional infrastructure requirements for baseline scenario (sitewide view)

5.6 Electrical integration of new infrastructure

As the baseline scenario does not propose any new infrastructure at the existing substation, it is to remain the same. A high-level SLD of this is shown in Figure 5—3.

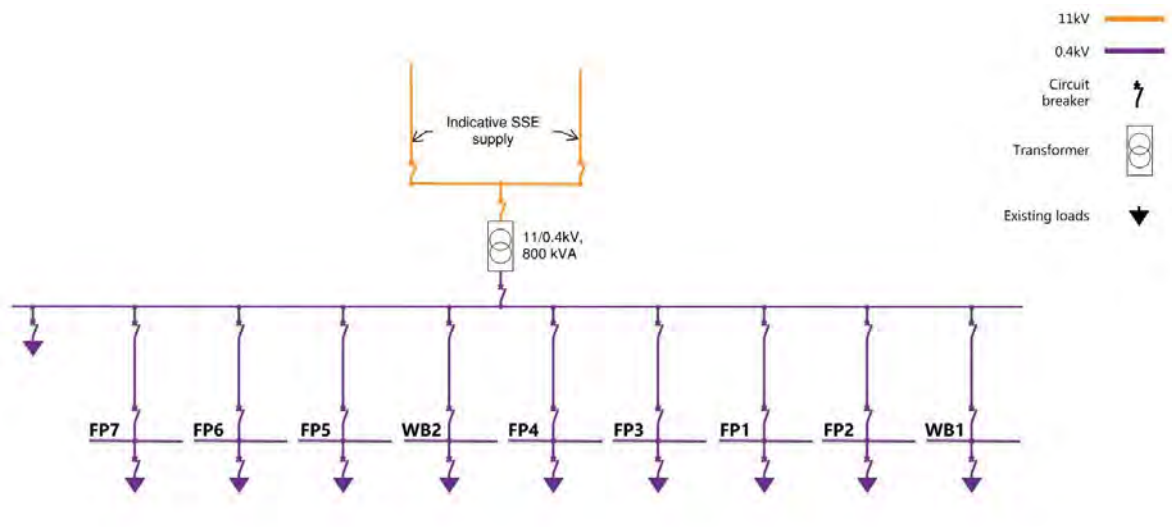
A new substation is required for the shore power infrastructure. The additional shore power system infrastructure proposed is shown in Figure 5—4. It has numbered sections that correlate to the descriptions and explanations below.

1. SSE's 33kV feeders to supply 3 transformers to step down voltage to 3.3kV. 3.3kV is a typical operating voltage level of a frequency converter and having 3 transformers will increase system resilience in case of supply failure.
2. Circuit frequencies to be converted to 60Hz as no vessels at the South harbour operate at 50Hz.
3. 3 transformers to step up voltage to 6.6kV (which are also increasing system resilience). A 3.3/11kV transformer is not provided since all HV vessels calling at the harbour are 6.6kV.
4. A 3.85MWh battery system has been included in the schematic as a provision and would connect to the 3.3kV switchboard for peak shaving and increased resilience. However, this battery is likely not going to be financially recommended and is to be discussed in the techno-economic model section and confirmed in the final submission.
5. Isolation transformers for HV connections will be located adjacent to the substation and feed each connection point separately via a radial network to comply with HVSC standards (BSEN 80005-1).
6. 6.6/0.69kV transformers and isolation transformers will be located at 2 berthing points to reduce cabling costs for the LV vessels which are predicted to have large loads (~2.4MVA).
7. Mobile cable management systems will be used as the interface between shore power and vessels

For information on the reasoning behind this infrastructure required at the new substation, refer to the NZTC Energy Hub 3 – Feasibility of shore power system for PoA's South Harbour report.

Additionally, if the new substation were to serve ETZ or other loads too, an additional transformer (~20MVA 33/11kV) would likely be connected to the 33kV busbar.

Figure 5—3 Baseline existing substation single line diagram



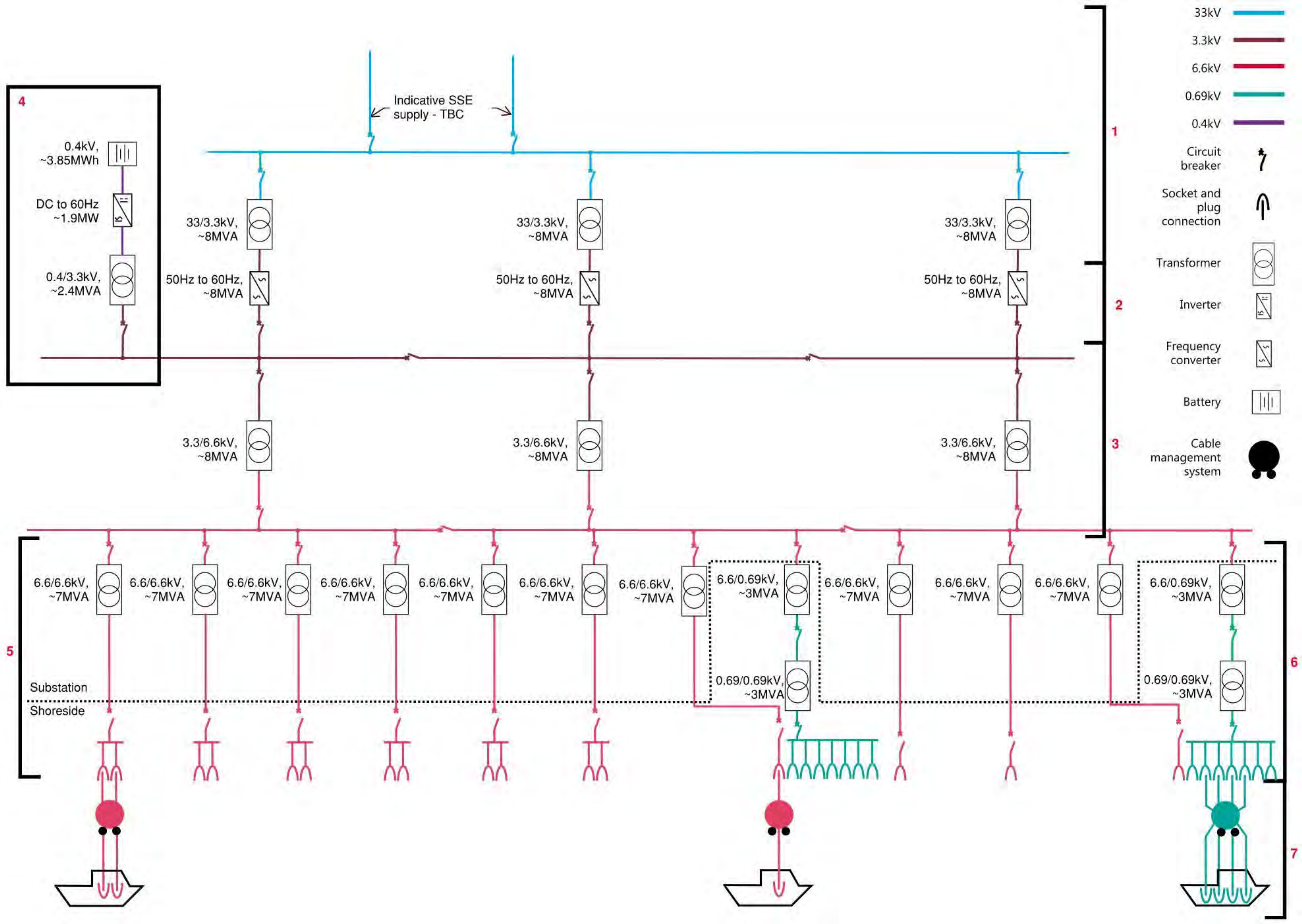


Figure 5—4 High level SLD - baseline scenario

5.7 Carbon emissions reduction

The carbon emissions associated with this scenario are broken down by the landside and shipside carbon emissions. The business as usual emissions is discussed in section 3.5.1. As the landside demands are already electrified, there is no carbon reduction method for those demands implemented as part of this scenario. Therefore the landside demands remain the same as the BAU.

The emissions of vessels during the calls at harbour make up for the almost the total emission within the port boundary. The lower carbon intensity of the national grid compared to MGO results in a significant carbon saving associated with the shore power system.

The lifetime average carbon emissions for the counterfactual is ~15,000 tCO2e/yr. For the base case scenario the lifetime average carbon emissions is 453 tCO2e/yr. This is an average saving of ~14,180 tCO2e/yr which is primarily due to the lower carbon intensity of the grid compared to MGO. This reinforces the importance of implementing a shore power system at south harbour.

The total carbon emissions for the baseline scenario is displayed in Table 5-5. As there is no renewable energy generation implemented, there is no displaced emissions. A 97% reduction in lifetime carbon is achieved through the implementation of a shore power system at the port.

Figure 5—5 graphically displays the carbon emissions saved across the schemes lifetime. There is an increase in emissions saved between 2025 and 2030 that reflects the phased increase in the number of calls per year. This results in an increased power consumption and subsequent emission savings.

In addition the decarbonisation of the national grid between 2024 and 2060 also leads to an increased emissions saving against an MGO counterfactual

Table 5-5 Lifetime carbon emissions base case

Parameter	Lifetime carbon emissions (tCO2e)
PoA emissions (lifetime total)	18,568
Counterfactual emissions (lifetime total)	599,965
Emissions saving (lifetime total)	581,397
Navigation emissions (lifetime total)	23,093,972

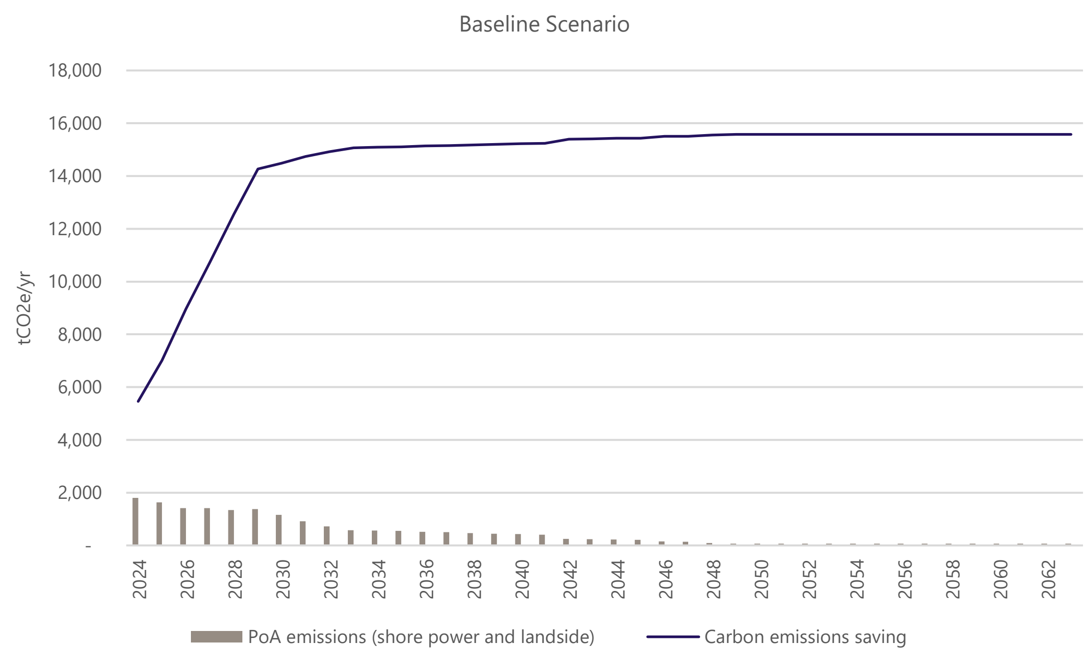


Figure 5—5 Baseline case carbon emissions saved against counterfactual

6 Stretch scenario

6.1 Overview

The scenario represents the immediate and medium-term actions that PoA can develop and implement to reduce their emissions and meet the goal of net zero emission by 2040.

The emission of vessel during the calls at harbour make up for the 99% of total emission in the control of the port. Therefore, a shore power provision is crucial to cut these emissions as well implementation of onsite renewable generation.

A significant electrical infrastructure upgrade is required to meet the expected peak demands from shore power (~22.5MVA). This means a new 33kV primary substation is required to connect ten HV and two LV shore power connection points placed along the quayside.

The port also introduces onsite renewable generation to cover the land side demands such as buildings and EV chargers as well as the shipside demands for shore power.

Solar PV on building rooftop and car pot allows to meet the full annual demand of the landside areas. A single wind turbine is proposed just south close to the main harbour breakwater to meet up to ~93% of the shore power demands.

BESS is crucial to balance the peak loads from the vessels as well as the renewable production to minimise curtailing. The primary substation is design with additional space for extra transformer to allow nearby developments to connect to it.

All the vehicles under PoA fleet shall be electric while potential provision for high rating chargers for thirds parties' heavy machinery is investigated.

The main fuel is envisaged to be no more MGO but an alternative one. Initial discussion with vessel operators suggest that in medium term HVO (Hydrotreated vegetable oil) or FAME (Fatty Acid Methyl Ester) would be the primary fuel due to its availability and limited changes required on vessel engines.

Discussion with DNO and surrounding developers is required to finalise sizes, locations, capacities of the system as well as connection strategy etc. All the electrical infrastructure has been designed to minimize the disruption to the port operation as well as the amount of civil works i.e. hard digging.

Main risks associated with this scenario:

- Capital investment is significant and not likely feasible without fundings
- Engagement with SSE and adjacent development is crucial and still to happen with potential impacts the proposed strategy
- Lack of formal commitment for shore power usage form operators
- Deployment of wind turbines is tied to detail feasibility study and related approval of planning applications
- Availability of biofuel HVO/FAME could be limited
- Limited availability of HV system operators for shore power operation

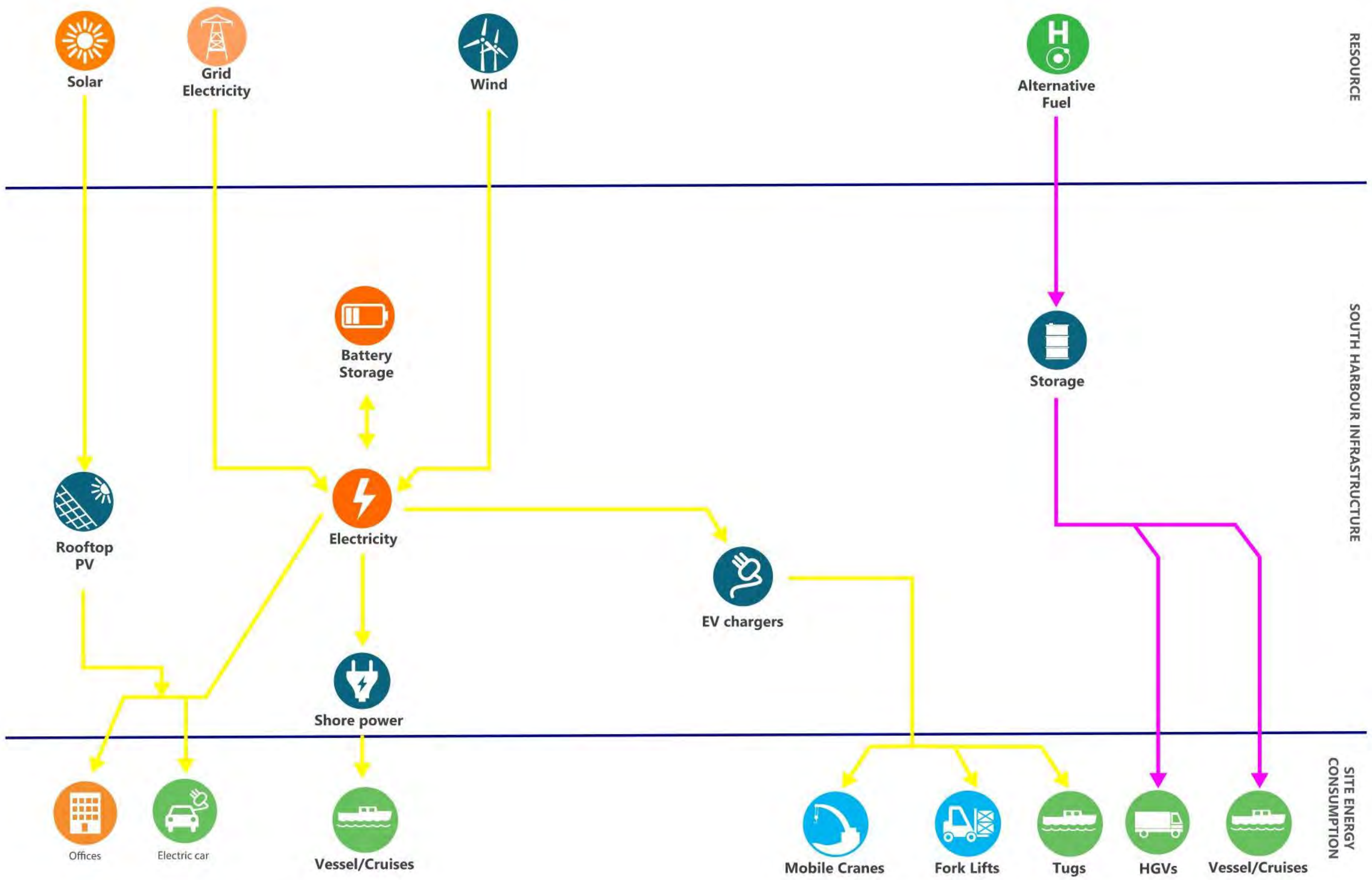


Figure 6—1 Stretch Scenario energy strategy

6.2 Demands

6.2.1 Landside

The landside demands can be summarised by the categories outlined in Table 6-1. The associated power demands have been derived through a combination of drawings and information provided by PoA:

Table 6-1 Estimate of landside power demands

End use	Power demand (kW)
Gatehouse (called Welfare Building 1 in the schematics)	73kW
Security building (called Welfare Building 2 in the schematics)	40kW
EV charging points	150kW
New terminal building	35kW
New warehouse	75kW
Sitewide infrastructure (pumps, security lighting, CCTV etc)	Various equipment sizes

The provided electrical schematic doesn't represent the actual as built information. Utilising them to estimate the power demands for the landside assets poses a high level of uncertainty and risk. Therefore, an alternative methodology was used to estimate the peak consumption of the port's landside assets.

PoA currently has a 800kVa substation installed onsite. As discussed with the client this substation has capacity to accommodate all the current demands and the new terminal and warehouse building. In the absence of more accurate annual consumption data for each landside asset an assumption was made that the ~90% of the substation capacity is to be utilised (716 kVA).

Based on the above, the annual landside energy demand is estimated at 2.7GWh per year with a peak consumption of 680kW.

High level assumptions were used to estimate the landside demand. To improve the accuracy of the landside demands metered data should be used, if available in the future, to create a representative profile.

6.2.2 Potential EV charging

EV charging demands (on top of the existing chargers) have only been provisionally calculated as a precautionary measure to assess the potential impact on infrastructure requirements due to uncertainties surrounding PoA's intentions and commercial viability to implement them.

Uncertainties have arisen due to the lack of information on where/if both PoA and tenants would charge their vehicles (e.g., at home, north harbour or south harbour). As a result, additional EV charging infrastructure and correlated power demands have been omitted from the techno-economic modelling and carbon emissions analysis.

The power demand of additional EV charging was calculated separately to the landside demands. Estimated demands were provisionally calculated for additional 4 no. slow chargers (7kW) and 1 no. ultra-fast (400kW) charger.

The peak capacity of the additional EV charging infrastructure was estimated at 416kW (438kVA). Using this information an annual demand of 1.281GWh was calculated.

Note that the inclusion of these chargers would require another transformer at one of the substations as well as an additional, cabling, switchgear, and feeder pillar, adding approximately ~£500,000 to the capital costs of the project.

For more information on the assumptions used to calculate this demand refer to Appendix E.

6.2.3 Shipside

The shipside demands captures the energy required by the following vessel typologies while at berth:

- DSV
- CSV
- Cruise ships (large/small)
- Rig

A representative energy profile for the power demands at berth is generated and used to capture variation in call duration and peak demands by the various different vessels.

The call durations in the profile is based on hourly profiles and where profiles for some typologies were not available key assumptions were made. As an example, it is assumed that Cruise Ships and Rigs utilise 100% of their engine power for the entire berthing period.

The number of port calls per year was provided by the PoA. However, an assumption is made regarding the seasonal distribution of the calls. It is assumed the majority of vessels would call during the summer period. The exception to this is for the rigs which only berth during winter.

The generated energy demands from the profile creation is displayed Table 6-2.

Table 6-2 Shore power annual demands

Year	2025	2026	2027	2028	2029	2030
Shore power profile consumption projection (GWh/year)	11.28	14.15	17.03	19.90	22.78	25.65

The peak demand for the shore power was estimated at 18.1MW (22.6MV) as per discussions with the client over the maximum amount of vessels berthing at the south harbour at one time. The breakdown of the vessels is included in Table 6-3.

Table 6-3 Maximum power requirements at south harbour

Vessel typology	Power requirement (MW)	Power requirement (MVa)
DSV 1	1.9	2.4
DSV 2	1.3	1.6
DSV 3	1.3	1.6
CSV 1	2.5	3.1
CSV 2	2	2.5
Large cruise	5.5	6.9
Medium cruise	3.6	4.5
TOTAL	18	22.6

6.3 Main ship fuel

Initial engagement with vessel operators indicates that the medium-term fuel for vessel could be FAME or HVO. The main reason for this are as follow:

- FAME or HVO would not require any OEM engine conversion kits and could be use immediately
- FAME cannot be used in the aviation sector making it more easily available, unlikely the other main biofuels (HVO)

Therefore, it is expected that MGO could be replaced by FAME or HVO within the storage facility at the South Harbour enabling the vessel operator to reduce their emission during navigation.

This represents just an option and other biofuels may be chosen at the south harbour. Further discussions and agreements with PoA's clients are required.

Despite the vessel emission at sea are outside the scope of PoA, it is recommended that the port enables their clients to decarbonize their operations in any possible way.

Given the similar density and properties between MGO and FAME, it is not envisaged any required upgrading of the storage facility and related fuel lines.

Refer to Appendix M for additional information on alternative fuel and to Appendix L for indicative routing of fuel pipelines.

6.4 Renewable Generation

The stretch scenario has two forms of renewable generation, and these are from solar PV and wind turbines.

6.4.1 Solar PV

Solar PV has the potential to generate 217 MWh from 268kWp nominal capacity in the form of solar carports and roof mounted panels. Based on PoA requests to limit impact on port operations with ground mounted PV system, this is the maximum capacity at the port.

As per discussion with PoA, Ground mounted PV is not a preferred option due to lack of space and the high land take that would severely impact port operations.

6.4.1.1 Roof mounted

Figure 6—2 shows that there are four existing/planned buildings at the harbour. There are also two buildings that may be built in the future.

From the drawings provided, it appears all existing/planned buildings have pitched rooftops (which is ideal for rooftop PV). These building locations are shown in Figure 6—2 and the related estimated solar PV potential is given in Table 6-4. Note that the two potential buildings are also included.

For more information on the methodology used to quantify the solar PV potential, refer to Appendix H.

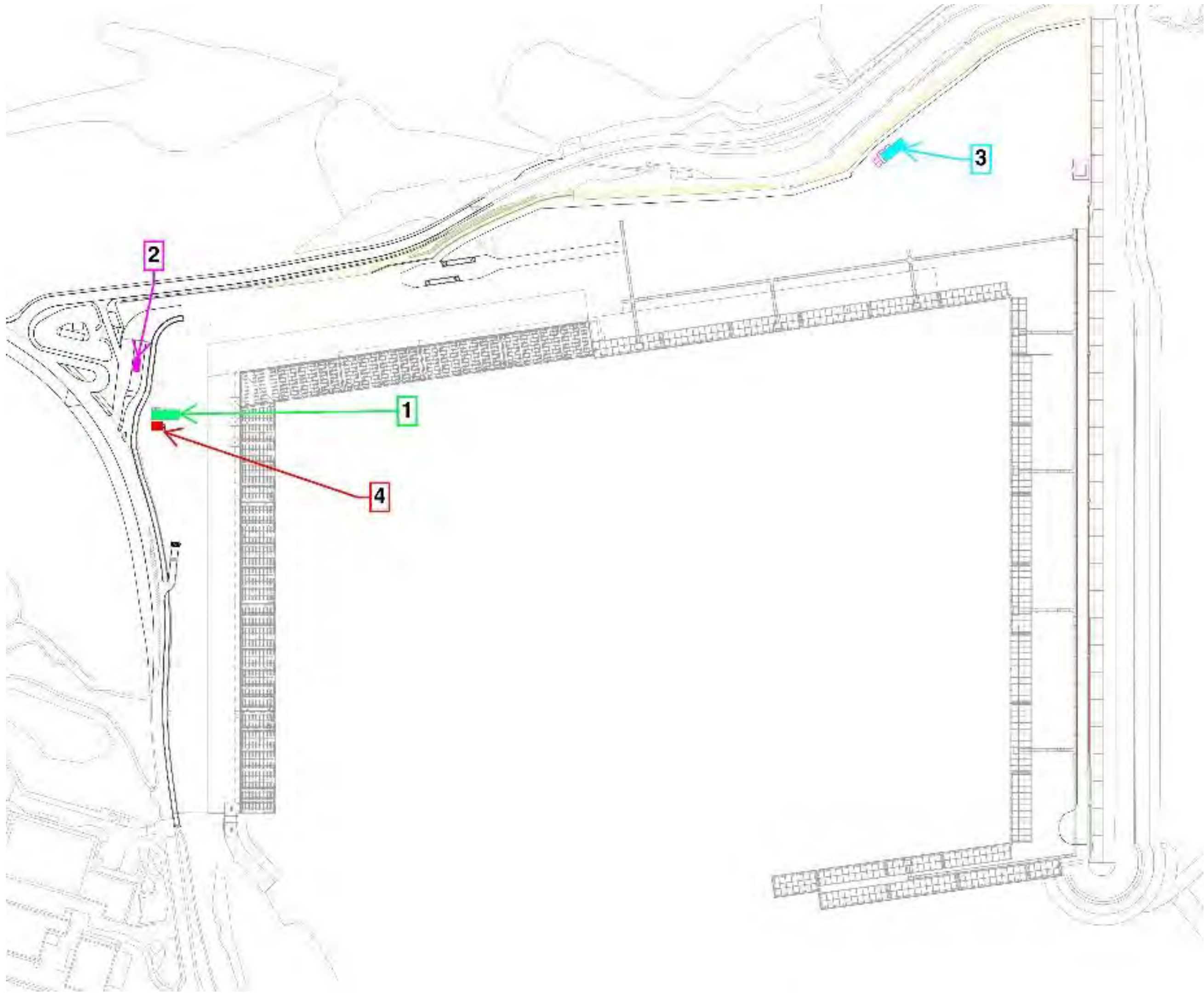


Figure 6—2 Existing PoA buildings (for rooftop solar PV)

Table 6-4 Rooftop solar PV potential (capacity and annual generation)

Location ID	Building name	Nominal capacity (kWp)	Annual Energy Production (MWh)
1	Welfare Building 1	18	14
2	Gatehouse	4	3
3	Welfare Building 2	12	12
4	Building adjacent to Welfare Building 1	6	5
N/A – new building	Warehouse	75	62
N/A – new building	Terminal	35	29

In addition to the buildings mentioned, the additional substation that's required to facilitate shore power could host a 50kWp array and generate ~39MWh annually. Note that this array has not been included in the energy modelling due to uncertainty around the size of the array and the ownership of the substation. To gain clarification, his opportunity should be discussed with the DNO (SSE).

6.4.1.2 Car ports

There is a carpark in the North-West corner of the port and the drawings provided show the individual parking spaces. The spaces deemed suitable are highlighted in Figure 6—3. The curved parking spaces have been omitted due to complexity leading to either high capital costs or being aesthetically poor.

The carpark has the total potential to host 118kWp, generating 92MWh annually. A breakdown of the estimated potential of each carport is shown in Table 6-5. The assumptions and inputs used to calculate them are displayed within Table 9-24 in Appendix H.

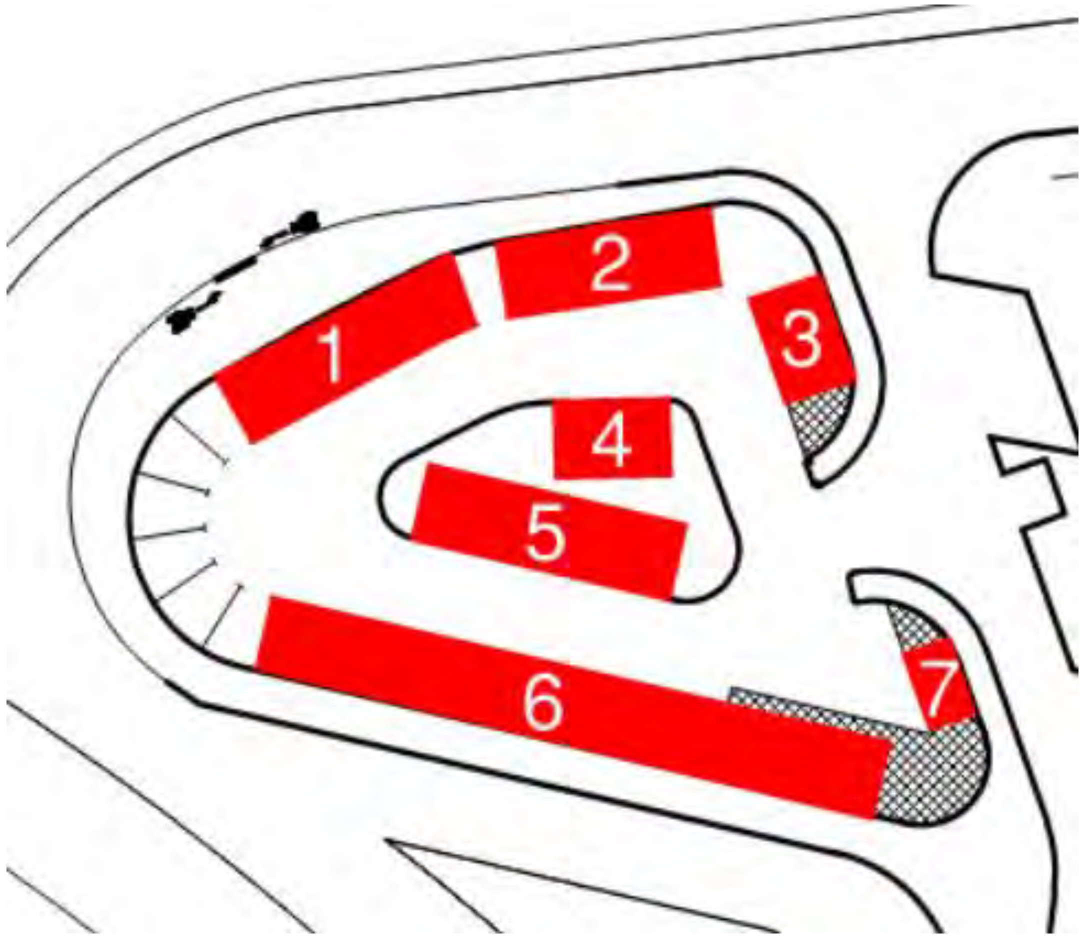


Figure 6—3 Potential locations for solar PV carports

Table 6-5 Solar PV carport potential (capacity and annual generation)

Car Park section	Total PV Area (m2)	Annual Energy Production (kWh/kWp)	Capacity (kWp)	Annual Energy Production (MWh)
1	84	782	18	14
2	71	791	16	12
3	34	742	8	6
4	37	791	8	6
5	87	789	19	15
6	207	789	46	36
7	16	742	3	3

6.4.2 Wind

PoA has potential to facilitate multiple wind turbines in and around the site.

A single 6MW wind turbine could generate 24.51GWh annually.

A 6MW wind turbine is proposed to be located onshore at location shown in Figure 6—4. 6MW was selected due to the energy modelling in section 6.5 and to conserve space at the port (rather than having multiple lower rated turbines).

For more information on alternative locations and the methodology used to quantify the generation potential and determine these locations, refer to Appendix I.

Figure 6—4 Preferred indicative wind turbine location

6.5 Energy modelling

To assess the optimal system configuration, Energy transfers were modelled in energyPRO for multiple scenarios containing up to 3 batteries (1.9MW/3.85MWh each) and 2 wind turbines (WT)s (6MW each), The results from the modelling are shown in Table 6-6 and Figure 6—5. Note that the year labelled along the bottom of the graph relates to the shore power demand in 2025 and 2030 while the different bars along are related to the scenarios in Table 6-6..

The results showed the little impact that a battery has on power imports and exports and gives an initial impression that a battery would not be recommended. Contrary to the results, provision for battery storage is still recommended at this stage due to the uncertainty in demand profiles and should assessed in more detail at a later stage.

Furthermore, the results give a strong impression that an additional wind turbine would lead to an uneconomical amount of exported energy.

As a result of these outputs, it was decided that for the stretch scenario, only the 1 no. wind turbine with and without a battery will be included within the technoeconomic models.

Table 6-6 Stretch energy modelling outputs

Shore power year	Scenari o ID	Description	Peak import (MW)	Peak export (MW)	Total import (MWh)	Total export (MWh)
2025	1	0 battery + 1 WT	14.458	5.677	4052	14844
	2	1 battery + 1 WT			3554	14226
	3	2 battery + 1 WT			3206	13794
	4	3 battery + 1 WT			2862	13369
2030	5	0 battery + 1 WT	15.973	5.672	11919	8334
	6	1 battery + 1 WT			11293	7561
	7	2 battery + 1 WT			10833	6991
	8	3 battery + 1 WT			10368	6417
	9	1 battery + 2 WT	15.489	11.546	6310	27091
	10	2 battery + 2 WT			5974	26650
	11	3 battery + 2 WT			5613	26177

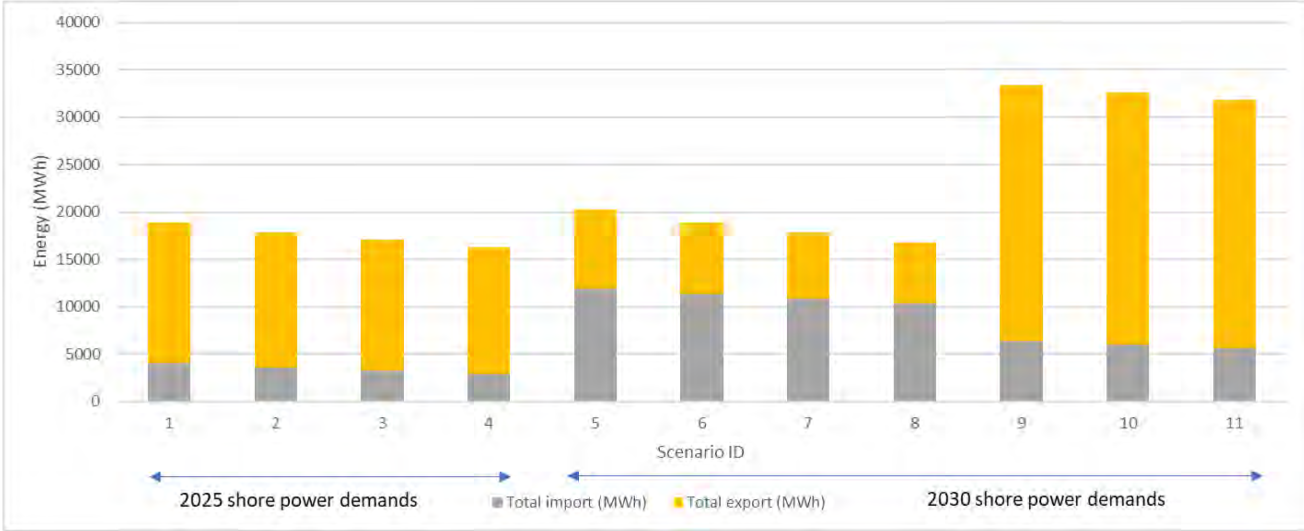


Figure 6—5 Stretch energy modelling - imports vs exports graph

6.6 Infrastructure requirements

The key infrastructure requirements to meet the criteria of the baseline scenario are tabulated in Table 6-7 alongside their correlated footprints (if applicable). This infrastructure would likely be implemented as per Figure 6—6 across the site. Note that the requirements are the same as that of the baseline scenario (section 5.5) with the addition of a wind turbine, solar PV, fuel storage, and EV chargers.

This section will only outline the additional infrastructure required in comparison to the baseline scenario. Refer to Appendix K for more detail.

Table 6-7 Key additional infrastructure requirements for stretch scenario

Element	Description	Footprint
Primary substation (includes provisions for optional BESS)	A new substation is required to facilitate shore power	38 x 43m
Cables and trenches	More cables are required from the new substation to the shore power connection points	~1600m (of new trenches)
LV transformers	Transformers for LV shore connection (required at berth)	~5x5m
Shore power connection points	Underground pits/chambers which house the shore power connection points/sockets	~(2.5x1.5x2)m (LxWxD)
Wind turbine	An onshore wind turbine is recommended	~10m diameter circle (78.54m^2) Height is flexible but >100m is recommended due to greater wind speeds
Solar PV	Solar PV panels, LV cabling, inverter(s), and protection systems	N/A – footprint is on rooftops or above parking and therefore does not impede port operations
EV chargers	EV charging connection points within existing carpark	7kW: negligible (located between parking spaces) 400kW: considerable (preferably located behind parking space if possible or a parking space would need to be sacrificed)

A provision for fuel lines and fuel connection point has been assumed as per Figure 6—6. It is not known at this stage of the project the number, location of fuel points and the extent of associated fuel network, however a conservative assumption has been made and fuel connection points have been considered along Castlegate, Balmoral and part of Dunnottar.

To avoid any potential risk linked to proximity of fuel and electrical lines, the proposed electrical network has been designed to run on separate routes and trenches from the assumed fuel lines. Few crossover between the networks are needed but this are limited and with adequate protection should be feasible.

The coordination with the fuel network shall be refined when a final design for such a network is provided.

6.6.1 Failure modes – renewable generation

This section only discusses the failure modes on top of those in the baseline (section 5.5.1), the renewable generation (solar PV and wind turbines).

6.6.1.1 Solar PV

Solar PV systems can have failures to the PV panels, batteries, charge controllers, inverters, and wires/cabling. For a more in-depth breakdown on the potential failures and their correlated severity and likelihood, refer to N.3 in Appendix N.

A summary of some reoccurring failure types include:

- PV panel electrical failure
- PV panel physical damage
- Battery chemical and physical deterioration/damage
- Equipment overheating/overloading
- Low voltage
- No/low power output

6.6.1.2 Wind Turbines

Wind turbines can have failures to the yaw system, gearbox, electrical system, control system, and hydraulics. For a detailed breakdown on the potential failures and their corresponding severity and likihood for an example wind turbine, refer to N.4 in Appendix N.

A summary of some key failure types include:

- Mechanical subsystem
- Lubrication
- Cabling
- Electronics
- Protection system
- Signalling

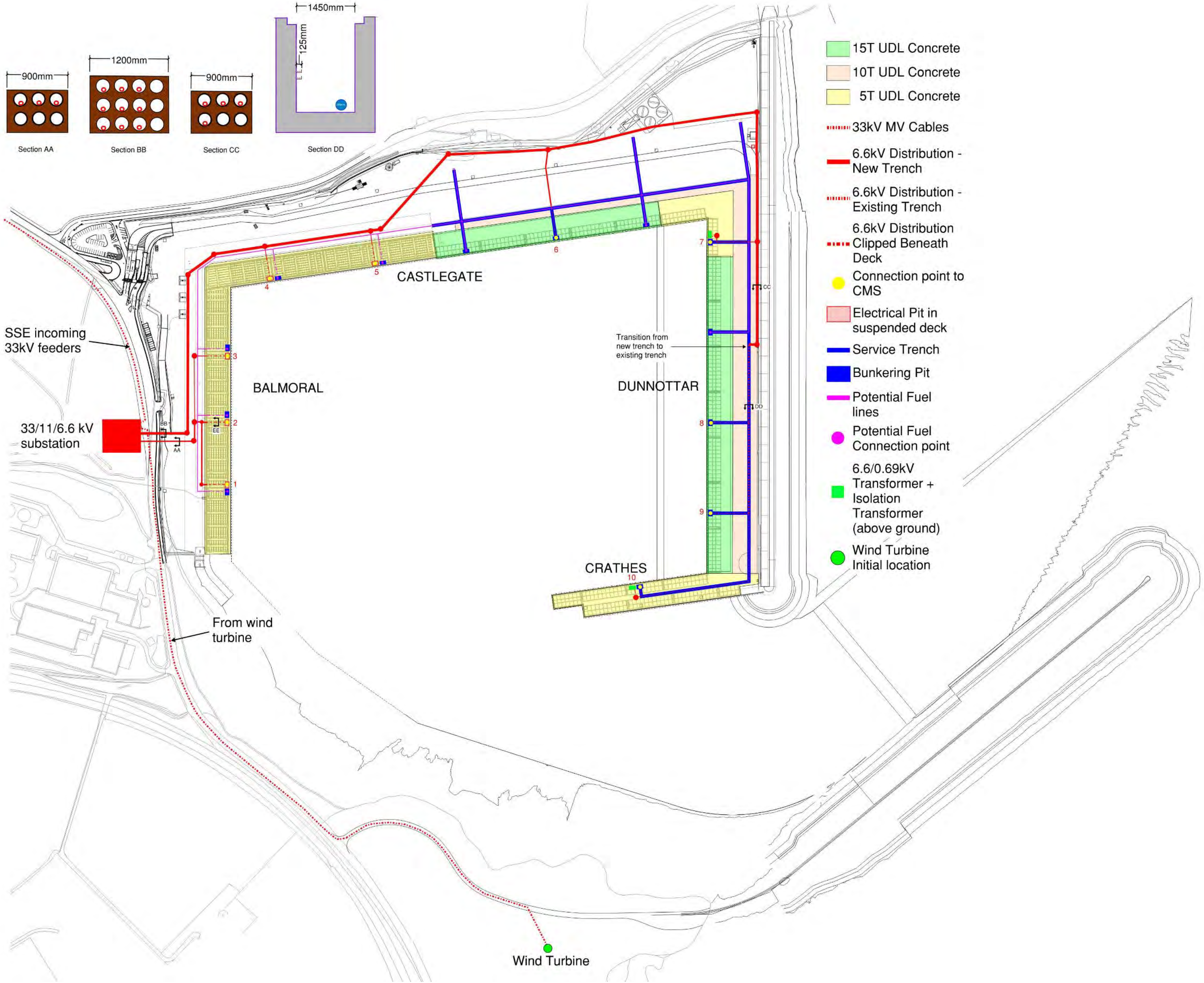


Figure 6—6 Proposed electrical infrastructure (stretch sitewide drawing)

6.7 Electrical integration of new infrastructure

This section details the differences in electrical integration required between the baseline scenario and the stretch scenario.

At the existing substation, the electrical system will be as in Figure 6—7 the difference being the solar PV will connect to the existing/upgraded distribution boards.

The new substation is the same as the baseline scenario but with the additional integration of the wind turbine. This is displayed as section 8 in Figure 6—8. It is seen that the wind turbine could connect directly onto the incoming 33kV busbar, making it ideal if other loads were to connect to the substation (than just PoA's) as the wind turbine generation could easily help supply some of their demands if desired. As mentioned in section 5.6, if the new substation were to serve ETZ or other loads too, an additional transformer (~20MVA 33/11kV) would likely be connected to the 33kV busbar.

Note that the additional EV charging loads have been left out of these schematics due to uncertainty on PoA's desire to install the 400kW charger. Should this be installed, a new transformer or an upgrade would be required at one of the substations. This is only recommended if PoA has agreements in place with the respective operators.

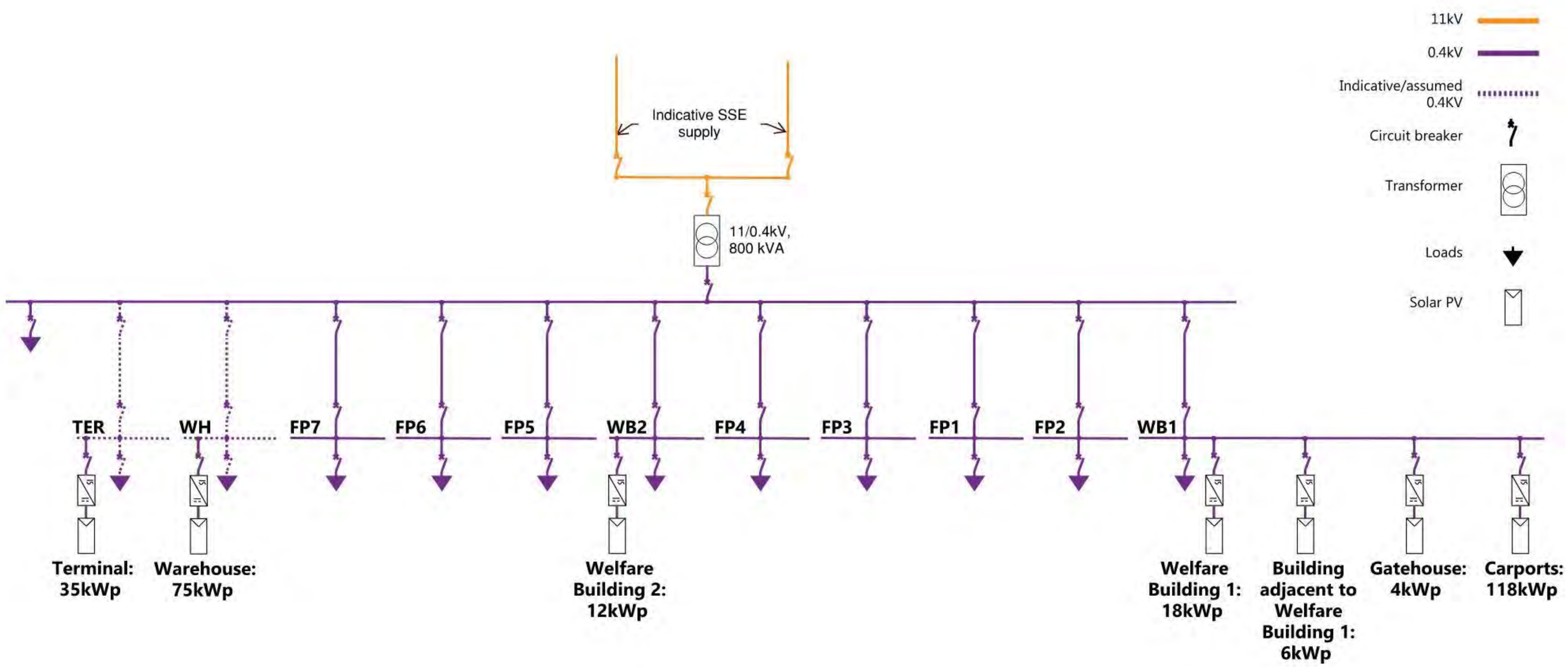


Figure 6—7 Existing substation single line diagram (stretch)

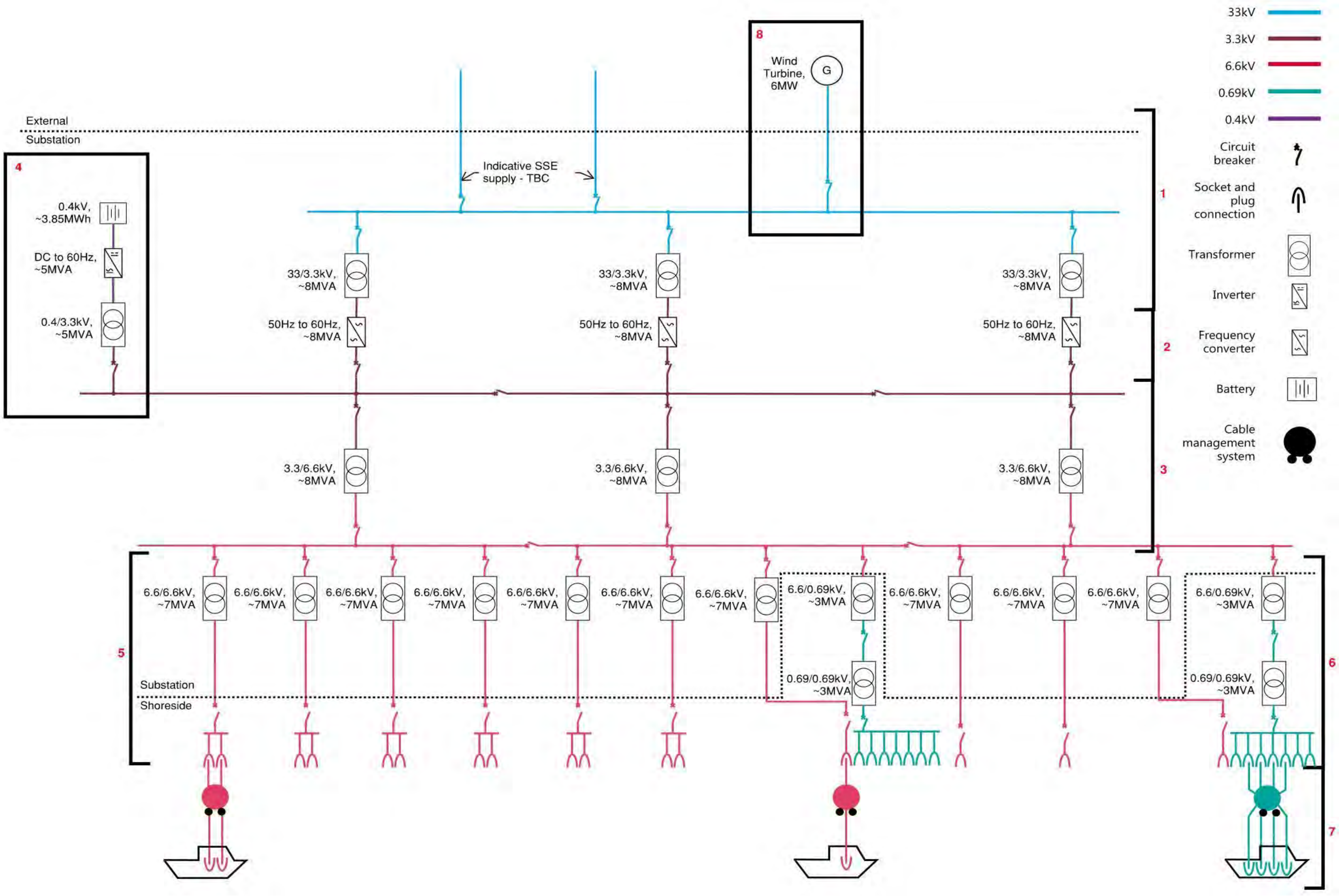


Figure 6—8 New substation single line diagram (stretch)

6.8 Carbon emissions reduction

As per the baseline case, the carbon emissions associated with this scenario are also broken down by the landside and shipside carbon emissions. The business as usual emissions is discussed in section 3.5.1.

The emissions of vessels during the calls at harbour make up for the almost the total emission in the control of the port. The lower carbon intensity of the national grid compared to MGO results in a significant carbon saving associated with the shore power system.

In addition, the implementation of the renewable energy technology such as PV and wind turbines results in zero carbon electricity being provided to both the landside demands and the shore power system. This results in greater carbon savings when compared to both an MGO and the grid electricity counterfactual.

The lifetime average carbon emissions for the counterfactual is ~15,000 tCO2e/yr. For the stretch scenario the lifetime average carbon emissions is 234 tCO2e/yr. This is an average saving of ~14,759 tCO2e/yr. The total carbon emissions for the stretch scenario is displayed in Table 6-8. A 98% reduction in lifetime carbon is achieved through the implementation of a shore power system and the renewable energy technology at the port.

Figure 6—9 graphically displays the carbon emissions saved across the schemes lifetime. There is an increase in emissions saved between 2025 and 2030 that reflects the phased increase in the number of calls per. This results in an increased power consumption and subsequent emission savings. In addition the decarbonisation of the national grid between 2024 and 2060 also leads to an increased emissions saving against an MGO counterfactual

Table 6-8 Lifetime carbon emissions stretch scenario

Parameter	Lifetime carbon emissions (tCO2e)
PoA emissions (lifetime total)	9,608
Counterfactual emissions (lifetime total)	599,965
Emissions saving (lifetime total)	590,357

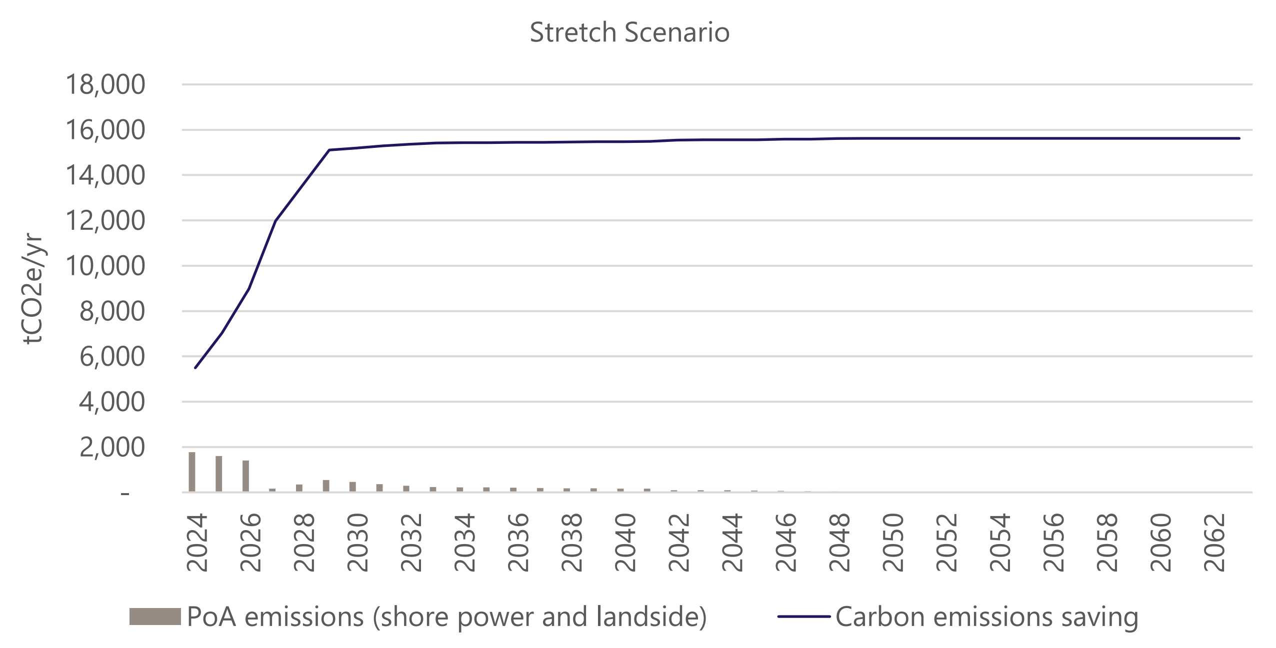


Figure 6—9 Stretch Scenario carbon emissions saved against counterfactual

Carbon reduction in vessel maritime operations

At current, POA supplies vessel operators with MGO for their fuel requirements during operations at sea. The emission associated with navigation is displayed in Table 6-9. It is assumed the amount of fuel the port can provide operators stabilises post 2028 due to infrastructure constraints (landside storage capacity). Therefore for the purpose of this study, the emissions with navigation are assumed to remain constant post 2028.

Table 6-9 Stretch Scenario emissions associated with navigation

	2025 tCO2e/year	**2026 tCO2e/year**	**2027 tCO2e/year**	**2028 tCO2e/year**	**2029 tCO2e/year**	**2030 tCO2e/year**
Emission in navigation by PoA Clients utilising MGO	365,047	438,056	525,668	579,440	579,440	579,440

As discussed, for the stretch scenario HVO could be considered as an alternative fuel source for the POA to supply to vessels with for navigation purposes.The supply of HVO by PoA allows their client to decarbonise their operation with a significant reduction in carbon emissions. The carbon intensity of HVO is 0.036kgCo2e/L which is significantly lower than the carbon intensity of MGO.

Based on PoA estimates of MGO storage requirements, it has been estimated that ~ 22,359,351 tCO2 could be saved throughout the lifetime of the project. This reduction is due to the lower emission factor of HVO compared to the carbon intensity of MGO.

The fuel demands provided by PoA could include also the current need of vessel at berth i.e. running engine for power generation, which would be displaced by the shore power system. If that was the case, the navigation emission would be much lower than the ones showed here. Further investigation is required to clarify this point.

Further information on alternative fuel sources is displayed in Appendix M.

6.9 Integration with regional initiatives

The scenario is focusing on renewable production and alternative fuels for mainly the vehicles in operation at the port. It is known that Energy Transition Zone development, adjacent to the south harbour, is currently investigating the deployment of a 6MW turbine in the Gregness area.

Engagement with ETZ is highly recommended not only for potential sharing of the wind turbine but also for a shared approach to the DNO in relation to the primary substation which would likely also serve ETZ areas.

Moreover, one of the main service companies of heavy vehicles within the port (~100HGVs) has suggested that to cut their emission they are planning to shift to HVO rather the conventional fuel in the short-term transition. While in the longer period they would consider electric or hydrogen, with a preference to the latter.

Due to the plans between BP and Aberdeen City Council to provide Hydrogen fuelling station, there might be an interesting opportunity for PoA enforce third party operation towards a zero-emission type of vehicles at the south harbour. The aforementioned Aberdeen Hydrogen Hub is a concept design for a joint venture between BP and Aberdeen City Council.

The proposed facility, Aberdeen Hydrogen Hub, would involve building a green hydrogen production and vehicle refuelling facility, powered by a purpose-built solar farm, linked by an underground solar grid connection. It's likely the scheme would produce excess renewable energy which could be purchased by the POA. This could be a more cost effective way of implementing net zero electricity into the Port's operations, however further investigation into this would be needed.

7 Pioneering scenario

7.1 Overview

The scenario represents a long term plan that PoA may develop (or be part of a wider initiative) to cut not only their emissions but enabling their clients to fully decarbonize their operations.

Starting form the proposal made within the stretch scenario, this scenario investigates how PoA may develop a parallel infrastructure to produce alternative fuel i.e. methanol.

Methanol has been chosen due to initial discussion with vessel operators and its production investigated to provide PoA a clear understanding of the different steps required, increased power demands and space take.

It is unlikely that PoA will develop this scenario without other partners (Joint Venture) due to the complexity and requirements This investigation allows PoA to negotiate/engage with third parties knowing the full process and potentially being the enabler of it.

It is expected that the peak demands from Methanol production would require to be at grid level since they might be around 300-500MVA, impossible to host within the south harbour.

Additional Renewable generation trough Solar PV or Wind is required to supply the methanol production plant.

All PoA fleet vehicles shall be electric while potential provision for high rating chargers for third parties is investigated. HGV's could be supplied trough methanol or hydrogen pending future technology choices.

Fuel production involves significant amounts of waste heat which could be a source of revenue for PoA, should any adjacent development requires an heat source.

This scenario is informative only and a detail feasibility study including a commercial strategy shall follow if PoA decides to implement such as strategy.

Main risks associated with this scenario:

- Capital investment is major and not feasible for PoA without fundings or partners
- Engagement with SSE and adjacent development as well as local authorities is crucial prior any further investigation
- Size and complexity of the required systems is significant with the related operation and maintenance constraints
- Lack of clear policies and guidelines for the future fuel for the shipping sector. Methanol could be an option rather than the only option making
- E-methanol production is yet to be deployed at scale
- The technology development and innovation in the next years may lead to a complete different direction and results presented here within

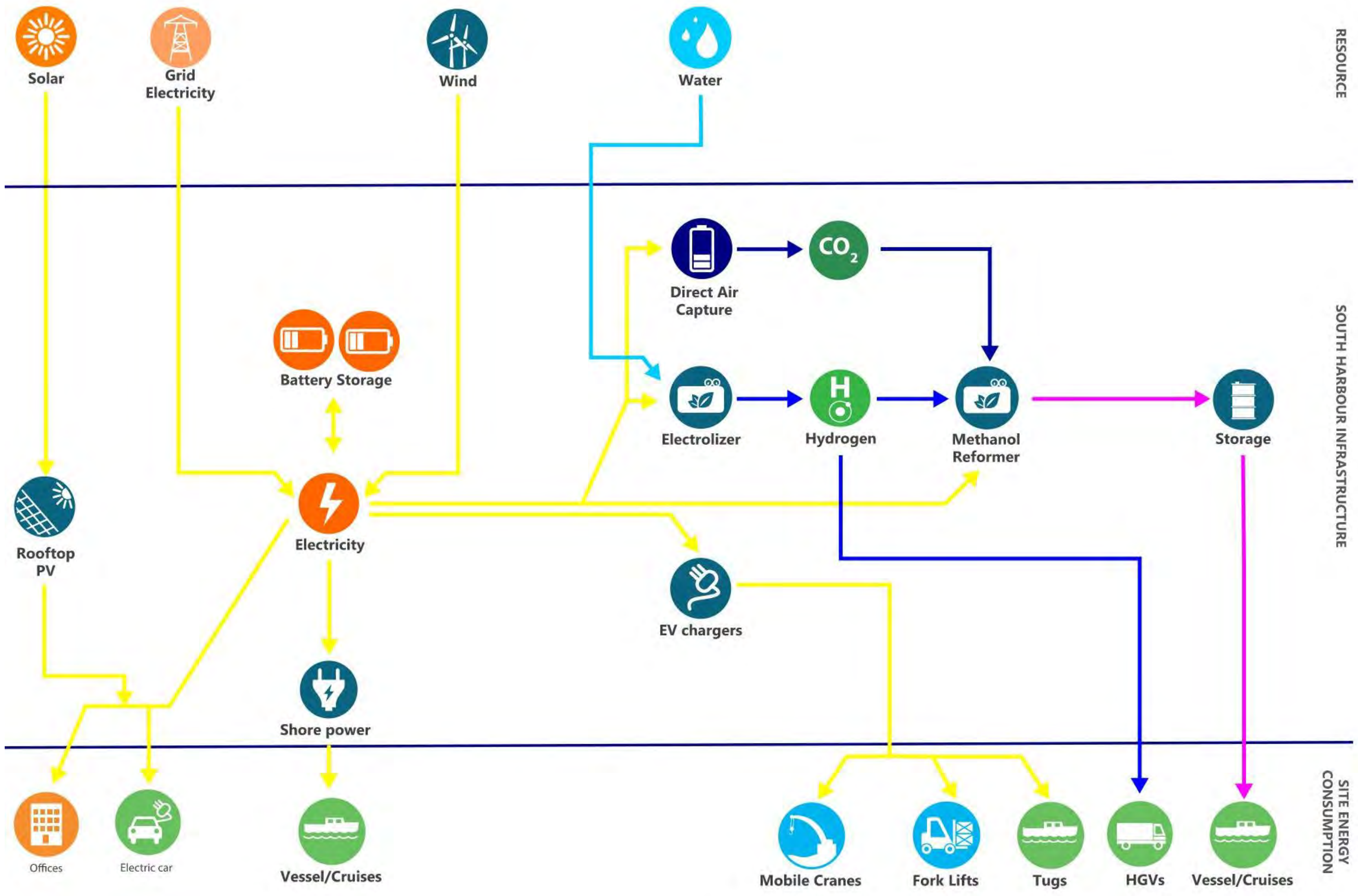


Figure 7—1 Pioneering Scenario energy strategy

7.2 Demands

7.2.1 Landside

The landside demands can be summarised by the categories outlined in Table 7-2. The associated power demands have been derived through a combination of drawings and information provided by PoA:

Table 7-1 Estimate of landside power demands

End use	Power demand (kW)
Gatehouse (called Welfare Building 1 in the schematics)	73kW
Security building (called Welfare Building 2 in the schematics)	40kW
EV charging points	150kW
New terminal building	35kW
New warehouse	75kW
Sitewide infrastructure (pumps, security lighting, CCTV etc)	Various equipment sizes

The provided electrical schematic doesn't represent the actual as built information. Utilising them to estimate the power demands for the landside assets poses a high level of uncertainty and risk. Therefore, an alternative methodology was used to estimate the peak consumption of the port's landside assets.

PoA currently has a 800kVa substation installed onsite. As discussed with the client this substation has capacity to accommodate all the current demands and the new terminal and warehouse building. In the absence of more accurate annual consumption data for each landside asset an assumption was made that the ~90% of the substation capacity is to be utilised (716 kVA).

Based on the above, the annual landside energy demand is estimated at 2.7GWh per year with a peak consumption of 680kW.

High level assumptions were used to estimate the landside demand. In order to improve the accuracy of the landside demands metered data should be used, if available in the future, to create a representative profile.

The E-methanol production is a significant additional demand to be considered in this scenario. Based on expected MGO fuel storage at the south harbour (~580 m³), an indicative daily and annual demand of methanol has been estimated, ~1,065 tMeOH/day and ~388,720 tMeOH/year respectively.

At this stage of design, it is not known if the required volumes of MGO provided by PoA include also the fuel that is currently use at berth by the vessels. If that was the case, a significant reduction in the e-methanol demands and related power demands and infrastructure is expected.

As detailed in Appendix M, the production process includes different steps such as hydrogen production, carbon capture and methanol synthesis and the related indicative demands are listed in Table 7-2.

Table 7-2 E-methanol power demand breakdown

Process	**Capacity t/day**	**Power Demand – MWh**
MeOH production	1,065	8
DAC	1,555	23
H_2 production	213	422
Heat production		33
Total		486

Figure 7—2 shows the overall e-methanol process and the related demands for each step. Given the annual requirements of fuels for the vessel, it is estimated that the annual power demand would be ~4,256 GWh/year.

Assessing the peak demands for such a system is a complex exercise as it depends on the capacity of each equipment (electrolyser, DAC etc) and related storage capacity (if any). However, assuming a peak production of 44 tMeOH/hr would require the electrical infrastructure to provide ~486 MW only for the methanol production.

The scale of electrical infrastructure required is significant and it would require extra high voltage connections and bulk supply points rather than primary substations.

As clear from the demand breakdown, hydrogen production takes up ~87% of the total demands. If the green hydrogen supply came from other sources i.e not produced on site, it would significantly reduce the impact of additional equipment/infrastructure.

These estimates are high level indications of the scale of the required supporting infrastructure and shall be considered as informative only.

Refer to Appendix M for detail information, assumptions and calculations.

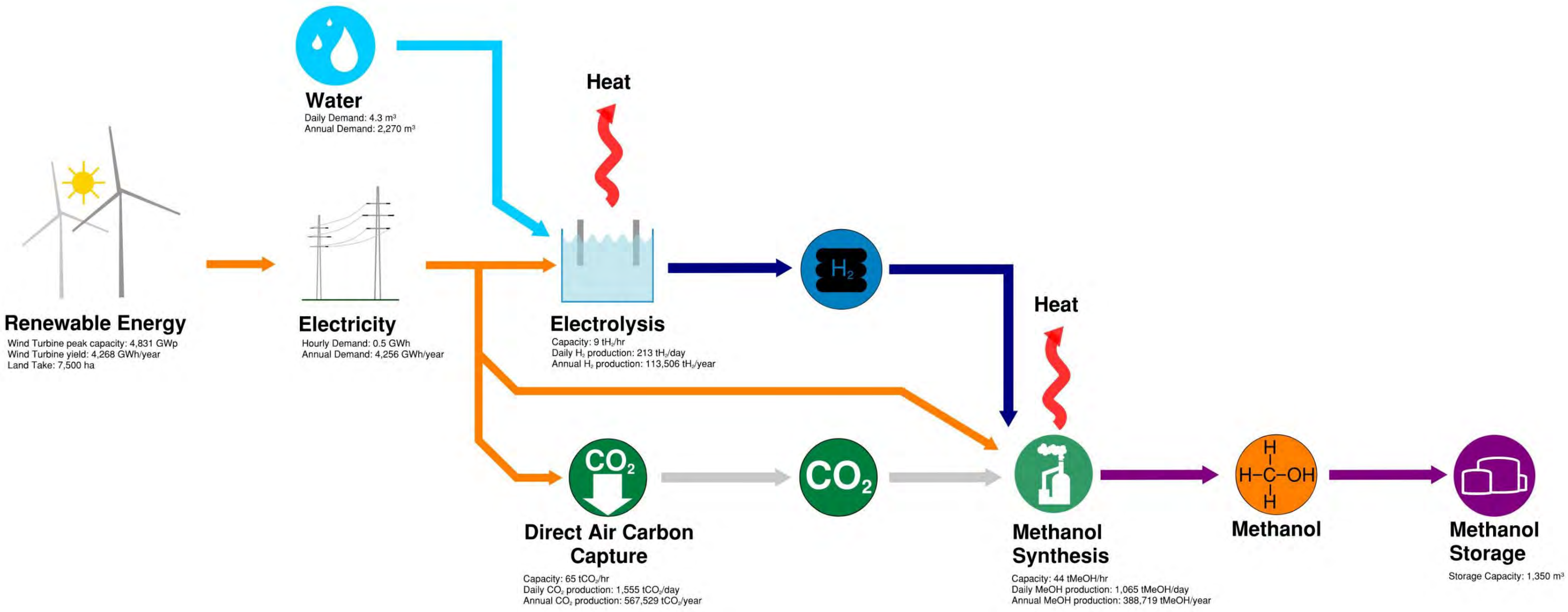


Figure 7—2 E-methanol production process and related indicative demands

7.2.2 Shipside

The shipside demands captures the energy required by the following vessel typologies while at berth:

- DSV
- CSV
- Cruise ships (large/small)
- Rig

A representative energy profile for the berthing power demands is generated and used to capture variation in call duration and peak demands by the various different vessels.

The call durations in the profile is based on hourly profiles provided by the client and where profiles for some typologies were not available key assumptions were made. As an example, it is assumed that Cruise Ships and Rigs utilise 100% of their engine power for the entire berthing period.

The number of port calls per year was provided by the client. However, an assumption is made regarding the seasonal distribution of the calls. It is assumed the majority of vessels would call during the summer period. The exception to this is for the rigs which only berth during winter.

The generated energy demands from the profile creation is displayed Table 7-3.

Table 7-3 Shore power annual demands

Year	2025	2026	2027	2028	2029	2030
Shore power profile consumption projection (GWh/year)	11.28	14.15	17.03	19.90	22.78	25.65

The peak demand for the shore power was estimated at 18MW (22.6MV) as per discussions with the client over the maximum amount of vessels berthing at the south harbour at one time. The breakdown of the vessels is included in Table 7-4.

Table 7-4 Maximum power requirements at south harbour

Vessel typology	Power requirement (MW)	Power requirement (MVa)
DSV 1	1.9	2.4
DSV 2	1.3	1.7
DSV 3	1.3	1.7
CSV 1	2.5	3.2
CSV 2	1.8	2.3
Large cruise	5.5	6.9
Medium cruise	3.6	4.5
TOTAL	18	22.6

7.3 Main ship fuel

Initial engagement with vessel operators indicates that the long term fuel for vessel could be Methanol which should be produced in a renewable way to ensure a zero emission round scheme i.e. emission from combustion to be used for methanol production.

The shift to methanol would still require significant modification on storage and transfer systems as well as OEM engine conversion kits. However, the latter is understood to be already available as W32 Wartsila engines for examples.

Therefore, it is expected that MGO would be replaced by E-methanol within the storage facility at the South Harbour enabling the vessel operator to reduce their emission during navigation.

Despite the vessel emission at sea are outside the scope of PoA, it is recommend that the port enables their clients to decarbonize their operations in any possible way.

Given that the density of methanol is roughly half of MGO, it is envisaged that an upgrade of the storage facility and supplying system is required. Indicatively, the storage facility would need to be double in volume to maintain the same amount of energy supplied to the vessel.

Modifications of fuel lines running through the harbour have not been investigated within this report.

Refer to Appendix M for additional information.

7.4 Renewable Generation

The onsite generation has been assumed the same as the stretch scenario and indicative energy balance investigated. As per section 6.4, a typical 6MW turbine is considered with an annual yield of 24.11 GWh/year.

To provide a worse case estimation for land take, it has been assumed that the methanol production would have a dedicated renewable energy production facility. 177 turbine of 6MWp would be need to cover the annual power demands or alternatively a 4,831 GWp solar farm.

These cannot be installed on site due to their space requirements and their size/capacity is for a grid scale infrastructure (Wind farm) and not something that an organisation as PoA could implement.

7.5 Infrastructure requirements

The key infrastructure requirements to meet the criteria of the pioneering scenario are tabulated in Table 7-5 alongside their correlated footprints (if applicable).

The e-methanol production is considered as additional from what detailed for the stretch scenario. The land take for this process is very significant due to the area required of the wind turbine. These estimates are high level indications of the scale of the required supporting infrastructure and shall be considered as informative only.

Table 7-5 Key additional infrastructure requirements for stretch scenario

Element	Description	Footprint
Primary substation (includes provisions for optional BESS)	A new substation is required to facilitate shore power	35 x 40m
Cables and trenches	More cables are required from the new substation to the shore power connection points	~1600m (of new trenches)
Shore power connection points		
Wind turbine for shore power	An onshore wind turbine is recommended	~10m diameter circle (78.54m^2) Height is flexible but >100m is recommended due to greater wind speeds
Solar PV	Solar PV panels, LV cabling, inverter(s), and protection systems	N/A – footprint is on rooftops or above parking and therefore does not impede port operations
Fuel storage	Fuel storage capacity is not available at this stage but shifting to methanol would roughly require a double of the MGO storage size	
EV chargers	EV charging connection points within existing carpark	7kW: negligible (located between parking spaces) 400kW: considerable (preferably located behind parking space if possible or a parking space would need to be sacrificed)
Wind Turbines for E-methanol	Wind farm of ~ 1.1 GWp is required to cover the e-methanol production.	~7150 ha
Electrolyser for E-methanol	Green hydrogen production up to 213 t/day	~7.2 ha
DAC for E-methanol	CO2 captured from the air with production up to 1,555 t/day	~96.4 ha
E-methanol plant	MeOH plant to combine H2 and CO2 with a production up to 1,065 t/day	~13.5 ha
E-methanol access / ancillary spacing	Allowance for electrical equipment, any building, access roads etc	~23.4 ha

7.6 Carbon emissions reduction

As per the base case, the carbon emissions associated with this scenario are also broken down by the landside and shipside carbon emissions. The business as usual emissions is discussed in section 3.5.1.

The emissions of vessels during the calls at harbour make up for the almost the total emission in the control of the port. The lower carbon intensity of the national grid compared to MGO results in a significant carbon saving associated with the shore power system.

In addition, the implementation of the renewable energy technology such as PV and wind turbines results in zero carbon electricity being provided to both the landside demands and the shore power system. This results in greater carbon savings when compared to both an MGO and the grid electricity counterfactual.

The lifetime average carbon emissions for the counterfactual is ~15,000 tCO2e/yr. For the stretch scenario the lifetime average carbon emissions is 234 tCO2e/yr. This is an average saving of ~14,759 tCO2e/yr. This saving is primarily due to the lower carbon intensity of the grid compared to MGO. This reinforces the importance of implementing a shore power system and renewable technology at south harbour.

The total carbon emissions for the Pioneering scenario is displayed in Table 7-6. A 98% reduction in lifetime carbon is achieved through the implementation of a shore power system and renewable energy technology at the port.

Figure 7—3 graphically displays the carbon emissions saved across the schemes lifetime. There is an increase in emissions saved between 2025 and 2030 that reflects the phased increase in the number of calls per year. This results in an increased power consumption and subsequent emission savings. In addition the decarbonisation of the national grid between 2024 and 2060 also leads to an increased emissions saving against an MGO counterfactual

Table 7-6 Lifetime carbon emissions pioneering scenario

Parameter	Lifetime carbon emissions (tCO2e)
PoA emissions (lifetime total)	9,608
Displaced emissions (lifetime total)	599,965
Counterfactual emissions (lifetime total)	590,357
Emissions saving (lifetime total)	9,608

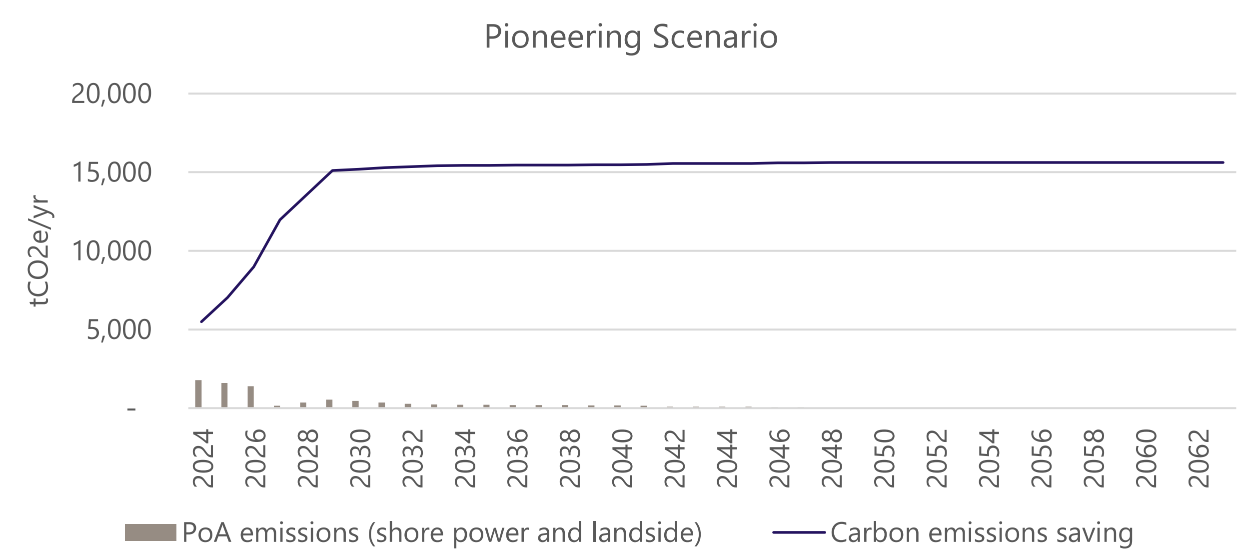


Figure 7—3 Pioneering Scenario carbon emissions saved against counterfactual

Carbon reduction in vessel maritime operations

At current the POA supplies vessel operators with MGO for their fuel requirements during operations. The emission associated with navigation is displayed in Table 7-7. It is assumed the amount of fuel the port can provide operators stabilises post 2028 due to infrastructure constraints (landside storage capacity). Therefore for the purpose of this study, the emissions with navigation are assumed to remain constant post 2028.

Table 7-7 POA emissions associated with navigation

	2025 tCO2e/year	2026 tCO2e/year	2027 tCO2e/year	2028 tCO2e/year	2029 tCO2e/year	2030 tCO2e/year
Emission in navigation by PoA Clients utilising MGO	365,047	438,056	525,668	579,440	579,440	579,440

As discussed, e-methanol is considered a zero emission and produced via renewable energy which do not have any carbon intensity – or very minimal.

The supply of e-methanol by PoA allows their client to decarbonise their operation with a significant reduction in carbon emissions. Based on PoA estimates of MGO storage requirements, it has been estimated that ~ 23,093,972 tCO2 could be saved throughout the lifetime of the project. This reduction is due to the zero emission factor of e-methanol compared to the carbon intensity of MGO.

The fuel demands provided by PoA could include also the current needs of vessel at berth i.e. running engine for power generation which would be displaced by the shore power system. If that was the case, the navigation emission would be much lower than the ones showed here. Further investigation is required to clarify this point.

7.7 Integration with regional initiatives

This scenario shall be considered within a wider area and ownership than PoA given that the production of e-methanol would only help the vessel operator in the decarbonisation of their operation and not PoA. The required infrastructure and land take is likely not manageable by PoA organization and their owned/leased areas.

Therefore, if PoA wishes to place themselves as enabler of third party decarbonisation plan, different partners shall be found to deploy such a scenario.

For example, the Dolphine project has just received funding form the UK government for the deployment of a 10MW green hydrogen production site in front of Aberdeen coast. This could supply cheap hydrogen to the e-methanol facility without the need for onsite green hydrogen production.

DAC systems have a significant investment cost as well as a land take difficult to accommodate. Renewable CO_2 sources could be explored in the vicinity of the South Harbour, such as from biogas.

A potential source of biogas could be the Nigg Waste Water Treatment Plant (Scottish Water) which is serving around 250 000 people in the area with a treatment capacity up to 1.6m^3/s and it is located almost on the boundary of the South Harbour.

It is known that the biogas produced on site supplies a Combined Heat & Power (CHP) unit to meet the WWTP demands and exporting the excess. Quantities of produced biogas, hence of potential CO_2, are not known and it is therefore impossible to assess an indicative contribution to the methanol production.

Engagement with Scottish Water should be held to understand their future plans to reduce emissions. CHP engines are still emitting significant quantities of GHG that will need to be tackled in the next future. Nigg WWTP could provide a CO_2

point source at lower cost than DAC or/and directly produce methanol or hydrogen, increasing the resilience of the supply chain for the fuel production.

Waste heat from the e-methanol production steps could be considered as a heat supply for wider development within a district heating system. Amount of available heat should be estimated trough a detail study based on final e-methanol system configuration and production rates.

8 Techno Economic Model

8.1 Overview

This section examines the techno-economic model (TEM) process that evaluates the best economic solution to decarbonisation the south harbour of the PoA. A TEM has been set-up to assess the possible return on investment for the chosen scenario that can be achieved over a 40-year time period. For this study the Baseline and Stretch Scenarios are carried forward for techno-economic analysis (Section 6).

The TEM assesses scenarios in terms of costs of capital, operational and replacement expenditure (CAPEX, OPEX, REPEX), electricity import costs and revenues from electricity/shore power sales. From this calculated data, an assessment is made on the possible return on investment that can be achieved over a 40 year time period.

The TEM is a pre-tax model used to give an initial indication of costs, revenues and potential cash flows over time.

The key assumptions included:

- The shore power provider would own, operate and maintain the shore power network
- Shore power is sold to consumers at a variable rate. There are no standing charges incurred by the shore power customers. This is because of the variety in frequency of equipment for each user. The fixed costs on the project are absorbed into the variable rate charged.
- Uptake of shore power is modelled across five phases (operational years). It is assumed that the shore power demand increases linearly every year, in correlation with the increase in calls at the port. Post 2030 shore power uptake plateaus, as explained in section 3.3
- The peak capacity of the vessels utilising shore power at berth is assumed at maximum in year one and stays consistent throughout the project lifetime
- There would be a standing charge recoverable by the DNO for the electrification of the shore power. This would be an added operational cost to the scheme.
- Renewable energy generation would be used by the shore power as a priority. This is due the to the shore power demand being a magnitude higher than the landside demands. Prioritising the shore power therefore results in a greater carbon saving when compared to a MGO counterfactual.

8.2 Scenarios and boundary diagrams

The Baseline and Stretch Scenarios have been considered for techno-economic modelling. The modelling considers the impact on implementing a shore power system and renewable energy technology as described in sections 5 and 6.

The use of alternative fuels such as HVO (Hydrotreated vegetable oil) or FAME (Fatty Acid Methyl Ester) as main vessels' fuel for navigation (outlined as part of the Stretch Scenario) is not captured as part of the TEM process. It has been assumed the alternative fuels would be used for the vessel's navigation purposes only.

A more detailed breakdown of the strategy within each scenario to achieve net zero is provided within Table 8-1.

Table 8-1 Scenario options and net zero strategy for demand

	Baseline	Stretch	Pioneering
Shore power for vessels	HV and LV shore power connections implemented for vessel types including decommissioning cruise, rig etc	HV and LV shore power connections implemented for vessel types including decommissioning cruise, rig etc	HV and LV shore power connections implemented for vessel types including decommissioning cruise, rig etc
Vessel Refuelling/charging	MGO storage provided within the south harbour. Vessels supplied with MGO	Vessels that have battery electric charging provision can recharge through port shore power system while berthed. Alternative fuel to replace MGO within the storage facility	Battery electric vessels are being recharged at the port. Methanol supply is implemented as fuel for ships
Port vehicles for operations	Fuelled by MGO	Transitions to electric vehicles	Full transitions to electric vehicles
Staff vehicles	EV charged via grid supplied electricity	EV charged via the port's energy supply system	EV charged via the port's energy supply system
Incoming freight vehicles	Fuelled by MGO	Fuelled by a sustainable alternative fuel	Fuelled by a sustainable alternative fuel which could be methanol since available on site
Port buildings	Supplied by grid electricity	Power mainly supplied by localised energy generation such as rooftop solar	N/A
Onsite renewable generation	N/A	Wind turbines are deployed at the port to supply shore power demands.	Renewable energy is supplied to the ports energy system to satisfy buildings and shore power demand, as well as being used extensively for sustainable, alternative fuel generation.
Battery Energy Storage System	N/A	Larger storage system installed to maximise renewable generation and balance the different additional loads.	The BESS supports the energy supply needed for alternative fuel processes.
Future infrastructure for Alternative Fuels	N/A	Alternative fuels such HVO are stored within the port storage facility	The port becomes a significant player in the hydrogen market. Not only is it produced on-site but it is also being reformed into methanol as alternative fuel

TEM boundary diagrams for the Baseline and stretched scenario is provided in Figure 8—1 and Figure 8—2 respectively.

These diagrams represent the cash flow between the various stakeholders within the PoA operational scope and therefore they represent the cash flow within the techno-economic model. However, different potential commercial structures are not taken into account for the scheme going forward.

For the purpose of this study, it is assumed the PoA would be the operator of the shore power system and would directly own the outlined renewable technology. Alternative commercial structure shall be investigated as part as a detail study such as an Outline Business Case (OBC).

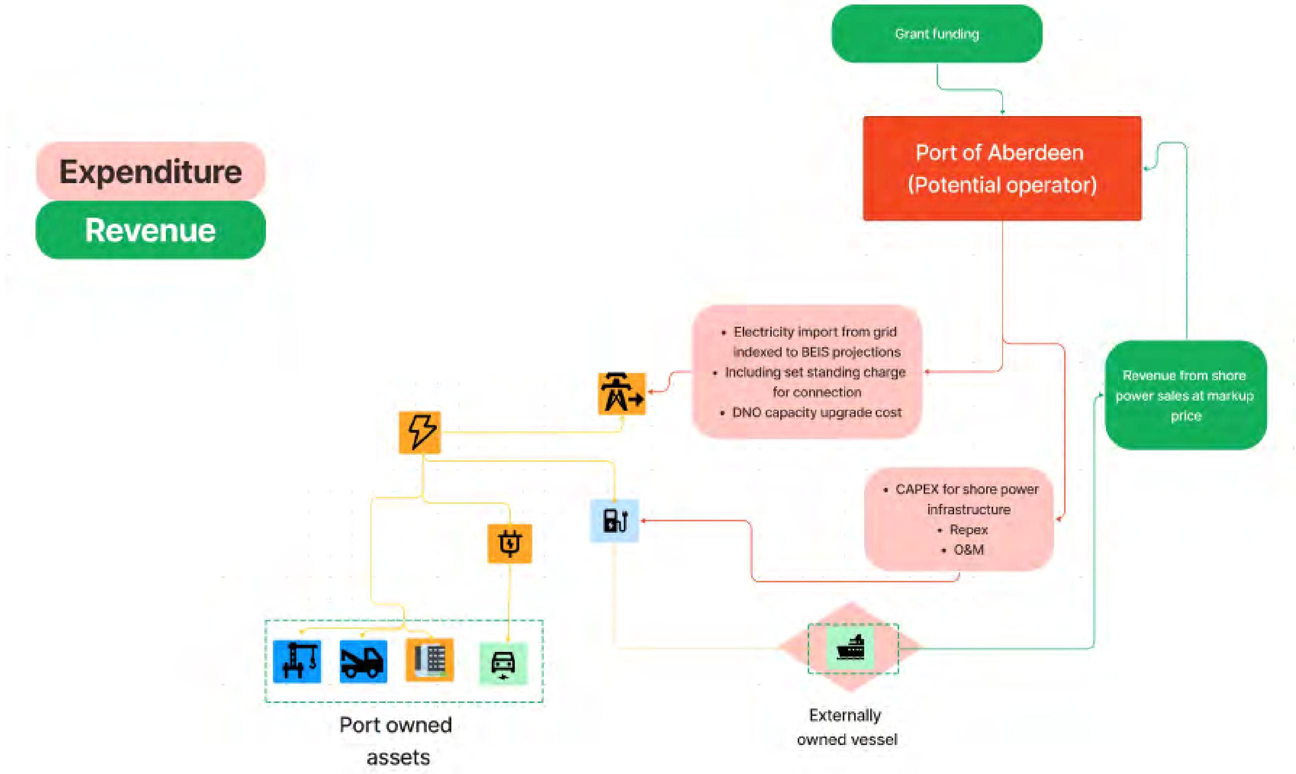


Figure 8—1 Baseline Scenario techno-economic modelling boundary diagram

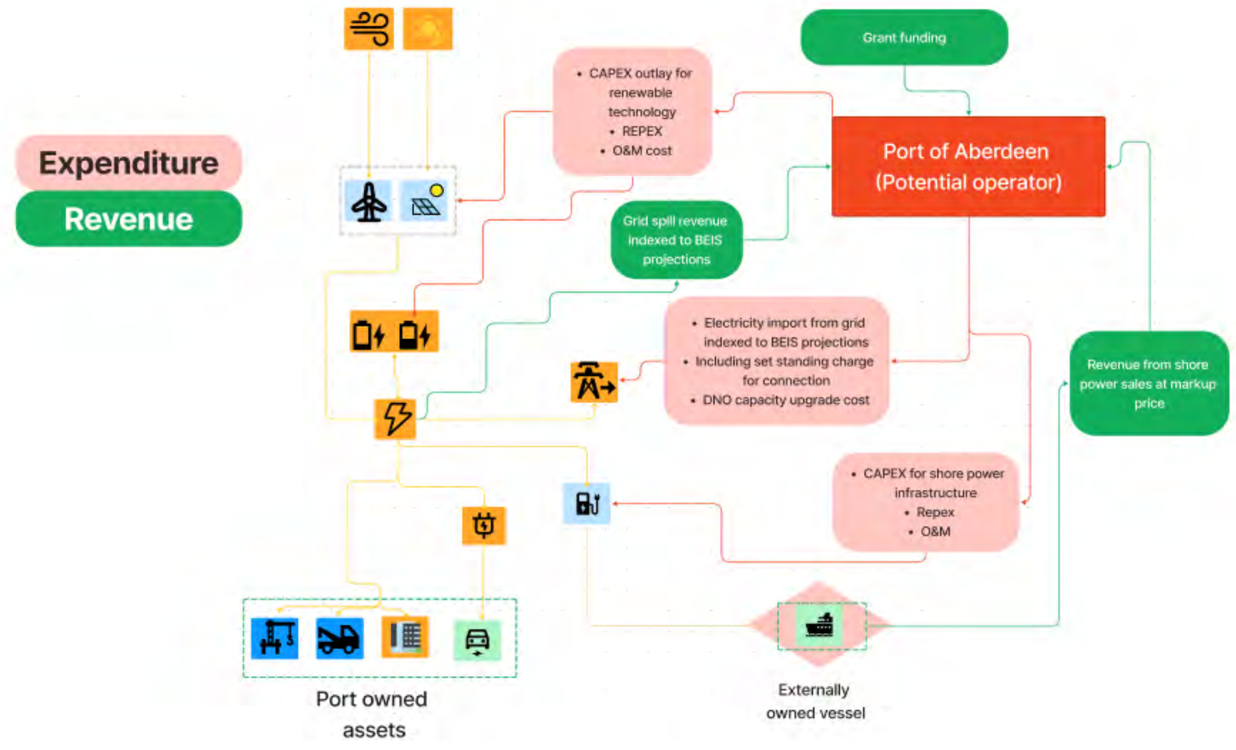


Figure 8—2 Stretch Scenario techno-economic modelling boundary diagram

8.2.1 Modelling assumptions

Table 8-2 shows the various modelling assumptions within the techno-economic model.

Table 8-2 Modelling assumption for the TEM

Assumption	Value	Source	Comment
Electricity import price	22.35 p/kWh	4	Non-domestic large consumer band inc. climate change levy (CCL) Q4 2022
Electricity carbon factor	0.129 kgCO2e/kWh (2025) 0.002kgCO2e/kWh (2064)	5	Electricity emissions factor decreasing over time due to the decarbonisation of the electricity grid in-line with BEIS projections
Marine fuel price	7.7 p/kWh	6,7	Rotterdam marine gas oil (MGO) price in June 2023 $536/t; conversion to GBP 0.75 £/$; Fuel efficiency 0.1902 t/MWh
Marine fuel carbon factor	0.610 kgCO2e/kWh	7	Specific fuel consumption 0.1902 kg/kWh; mass of CO2 produced whilst burning 3.206 kgCO2/kg
Parasitic losses	10%		Calculated electrical losses through cabling and within unit conversion from 11kV/50Hz to 690V/60Hz
Commercial appraisal lifetime	40 years		
Scheme start year	2024		
Discount rate	3.5%	8	HM Treasury, The Green Book
Grant funding	50%		Assumed 50% grant funding would be available from applicable sources

[4] Department for Business, Energy & Industrial Strategy, Gas and electricity prices non-domestic sector, 2021.
[5] Department for Business, Energy & Industrial Strategy, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, 2021.
[6] https://shipandbunker.com/prices#MGO [Accessed 30th March 2022]
[7] International Maritime Organization, Forth Greenhouse Gas Study 2020, 2020.
[8] HM Treasury, The Green Book Central Government Guidance on Appraisal and Evaluation, 2020

8.2.2 Counterfactual

The proposed scenarios within the TEM are compared against a counterfactual option to assess the carbon and social benefits of Shore Power and renewable technology implementation. A counterfactual option represents an alternative scenario that could have been considered prior to the outcomes of the current undertaken study. The counterfactual for this study was a business as usual approach (BAU).

Traditionally, when ships are in port, they use their auxiliary engines to provide power for the ship's operations. This is also known as cold ironing. Business as usual (BAU) for South Harbour would involve the ships leaving their engines running whilst in berth to ensure power is available for the ship systems. The most common fuel used during this process is marine gas oil (MGO). Therefore, for the purpose of the techno-economic modelling shore power was compared against a MGO fuel counterfactual.

The landside demands at south harbour are already electrified. Therefore, the counterfactual for the land demands was also a BAU approach, where the buildings would continue to utilise grid imported electricity for their power demands. This will capture the carbon savings from renewable energy implementation

8.2.3 Mark-up sales price (Shore Power)

The TEM utilised the "goal seek" function to determine the mark-up price needed (difference between the electricity import price and shore power sales price) to deliver a set IRR of 8%. The mark-up price was deemed to be a more useful metric for PoA compared with the shore power sales price, due to the fluctuations seen in current energy prices[9]. It is recommended that PoA should arrange to maintain a consistent shore power mark-up price (pre inflation) across the schemes lifetime. This will allow for security in generating a return on investment.

8.2.4 Capital cost

A capital cost subconsultant has been engaged to initially evaluate the capital costs for the project which is provided in Table 8-3. The cost plan is grouped and split across two phases.

The two phases represent the build out of the infrastructure in line with the structure of the port (suspended deck vs concrete deck) and the required civil works. For the Stretch Scenario, it is assumed that the PV and the BESS infrastructure would be in operation by 2025 and therefore the CAPEX for it incurred in 2024. The wind turbine and associated infrastructure will be operation in 2028 with the CAPEX for the equipment being incurred in 2027.

- Phase 1 – assumed implemented in 2025 – includes all the major civil works (digging, ducting etc), equipment (substation), 7 HV Shore power connections and 1 LV connection (covering all Balmoral and Castlegate quays). Primary substation and associated costs. PV and associated works would be operational in 2025.
- Phase 2 – assumed to be implemented in 2028 – 3 HV shore power connections and 1 LV connection covering Dunnotar and Crathes quays. Wind Turbine and associated works would be in operation in 2028.

This phasing strategy should be refined prior to a full financial modelling methodology at future project stages.

Table 8-3 shows the capital costs breakdown associated with the project where all costs include allowances considered by the cost consultant (Table 8-4) but do not capture VAT. Inflation on all costs was applied to 4th Quarter 2025 to capture any uncertainty regarding the build out date of the project. This value shall be refined at future work stages when a more definite timeline of build out is provided.

The overall capital cost of the Baseline Scenario was estimated at ~£26.5M while for the Stretch Scenario increase to approximately £43.4M. The variation between the two scenarios if the additional costs of the renewable technology infrastructure as part of the Stretch Scenario. The largest cost across both scenarios Is the primary sub-station work.

Table 8-3 Capital Cost breakdown for Stretch Scenario

Sub heading	Equipment	Full build out	Phase 1	Phase 2
Low carbon technology				
	BESS system	3,377,000	3,377,000	-
Renewable power generation 1 (PV)				
	Renewable power 1 (PV)	1,834,100	1,834,100	-
Renewable power generation 2 (WT)				
	Renewable power 2 (WT)	8,145,000	-	8,145,000
Substations				
	Primary Sub-station electrical equipment	8,473,000	8,473,000	-
	Primary Sub-station building and fencing	5,262,000	5,262,000	-
Cable management				
	Cable management solution LV	948,000	474,000	474,000
	Cable management solution HV	1,864,000	1,165,000	699,000
Port Side Connections				
	Port side connection for cable management HV	1,012,000	632,500	379,500
	Port side connection for cable management LV	298,000	149,000	149,000
Meters				
	Metering LV	8,000	4,000	4,000
	Metering HV	50,000	31,250	18,750
Port electrical cabling and civils				-
	Digging/ducting/trench/clipping etc	1,629,000	1,629,000	-
	Electrical cabling costs port side LV	-	-	-
	Electrical cabling costs port side HV	1,698,000	1,698,000	-
	LV isolation transformers	3,086,000	3,086,000	-
Network Ancillaries				
	Manholes	290,000	290,000	-
	Civil Works	190,000	190,000	-
	Additional electrical infrastructure (PV)	79,000	79,000	-
	Additional electrical infrastructure (Wind Turbine)	2,278,000	-	2,278,000

[9] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators [Accessed 19/05/2023]

Total		40,521,100	28,373,850	12,147,250
	Inflation Baseline Scenario	2,030,000	1,906,000	125,000
	Inflation Stretch Scenario	2,918,000	2,043,000	875,000
Overall cost Baseline Scenario		**30,215,000**	**28,366,750**	**1,849,250**
Overall cost Stretch Scenario		**43,439,100**	**30,416,850**	**13,022,250**

Table 8-4 Capital cost allowances

Allowances	% Rate
1. Contractor D&B Fees	3%
2. Preliminaries	12.5%
3. Overheads and Profit	7.5%
4. Contingencies	10%

If the local ETZ project were to go ahead and connect to the same main substation, they would require ~£328k for a transformer at the same site (not to be paid for by PoA). The addition of this transformer though will mean that they should cover some of the substation building/housing costs and consequently slightly reduce the overall project payback period for PoA.

This has not been accounted for in the model in order to provide a worst-case scenario.

8.2.5 Operating cost

The ongoing operational costs within the model are categorised as follows:

- Operation and maintenance costs
- Fuels costs and electricity sales price
- Replacement costs

8.2.5.1 Operation and maintenance cost

Table 8-5 shows the key operation and maintenance cost assumptions modelled. Operational expenditure (OPEX) for equipment is modelled as £/kW or as a % of CAPEX. Metering and billing costs are charged to the port owned connections, and the shore power customers.

Table 8-5 Operation and maintenance assumptions

Technology/Item	Unit	Cost	Source
Solar PV 268kW	£/kW	15	IRENA Renewable power generation costs[10]
Wind turbine 6MW	£/kW	35	As above
Battery	% of CAPEX	2%	Previous BH project experience
Substations	% of CAPEX	2%	Previous BH project experience
Cabling management	% of CAPEX	2%	Previous BH project experience
Port side connections	% of CAPEX	3%	Previous BH project experience
Metering and billing	£/year	500	Previous BH project experience
Staff costs	£/year	20,000	Previous BH project experience

8.2.6 Fuel cost

Fuel costs for the landside and shore power demands are used to calculate the operational expenditure of the project. The impact of renewable energy on the project's operating costs are also taken into account within the TEM.

8.2.6.1 Electricity

Figure 8—3 shows the pre-inflation electricity import price over the course of the scheme lifetime. A 2023 cost of electricity was inputted into the model at 22.35p/kWh based on BEIS Non-domestic large consumer band inc. climate change levy (CCL) Q4 2022.

This cost was indexed within the model in line with BEIS Green Book Commercial/Public sector projections for future fuel costs, which provides a price forecast up to 2035. After this point, it is assumed that the electricity cost stays the same, in the absence of reliable forecasts.

The electricity import price at the start of the modelling period (2024) was indexed at 17.8p/kWh falling to 10p/kWh in 2035 onwards. Due to the volatility of electricity prices, the fuel costs should be revisited at each design stage.

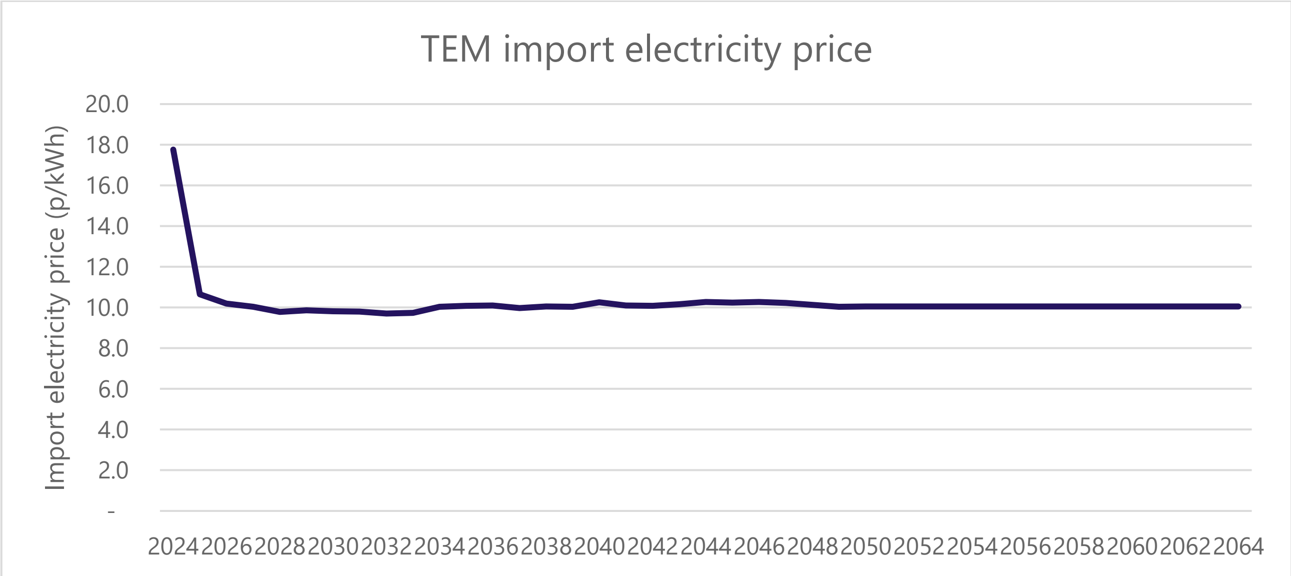


Figure 8—3 TEM import electricity price

The most recent BEIS data on electricity prices was used in the TEM to account for the recent increases in wholesale gas and electricity prices within the modelling approach.

[10] Renewable Power Generation Costs in 2021, International Renewable Energy Agency, 2021 , https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Power_Generation_Costs_2021.pdf?rev=34c22a4b244d434da0accde7de7c73d8

However, with the absence of further short-term price forecasts and the fact this study considers a shore power opportunity across the 40 years, long-term price projections published annually by BEIS have been used for future price forecasting.

The recent increase in electricity prices demonstrates the current dependence on gas for electricity production, particularly when renewable electricity output is lower than expected. However, these prices will begin to decouple as the UK transitions away from combined cycle gas turbine (CCGT) electricity generation and towards renewables.

This transition is captured within the future BEIS projections, whereby gas and electricity prices begin to show more independence by the mid-2020s.

8.2.6.2 Renewable energy generation

The renewable energy generation balance for the Stretch Scenario is displayed in Table 8-6. This data was inputted into the TEM to enable accurate OPEX and Carbon emissions to be calculated. Years 2025 and 2030 are modelled based on the shore power and land profiles discussed in section 3.4. The remaining years are based upon the modelled data and high level assumptions such as:

- total generation from the technologies would remain constant year on year.
- the amount of renewable contribution to the shore power, landside demands and grid spill is adjusted to reflect the change in shore power demand year on year.

Table 8-6 Renewable technology generation energy balance stretch scenario

			Demand (MWh/year)				
			Shore power		Landside demands		
Technology	Year	Total generation (MWh/yr)	Renewable contribution to shore power	Import from grid for shore power demand	Renewables contribution to landside demands	Import from grid for landside demand	Grid Spill (MWh/yr)
PV + Battery	2025	271	161	11,113	114	2,609	-4
	2026	271	149	14,001	94	2,629	28
	2027	271	141	16,885	75	2,648	55
Wind Turbine + PV + Battery	2028	24,706	17,788	2,112	2,223	499	4,694
	2029	24,706	16,800.	5,975	1,976	746	5,929
	2030	24,706	15,653	9,996	1,556	1,166	7,496

8.2.6.3 Marine Gas Oil (MGO)

Within this TEM shore power has been assumed at 100% uptake and therefore vessels would not utilise MGO while at berth. This is the current modelling assumption made throughout the project as discussed in section 3.5.3.

Although this scenario is possible, it may transpire that not all vessels will connect to the shore power system. This may mean that some residual MGO usage will be required, in particular during the early years (2025-2028) where vessels will be transitioning to shore power refuelling infrastructure.

If 100% shore power uptake is not achieved the Stretch Scenario modelled outlined that HVO or an alternative low carbon fuel could be used. For this reason a MGO price was not modelled as part of this economic modelling.

8.2.7 Replacement cost

Table 8-7 shows the life expectancy assumed for the major project equipment. Within the model, 80% of the CAPEX for the equipment is modelled as a REPEX at the end of the equipment lifetime. This cost is modelled as a sinking fund, where a proportion of the REPEX is modelled as a cost each year.

Table 8-7 Equipment life expectancy

Equipment	Replacement period (years)
Wind turbine	25
Rooftop/Ground mounted PV	25
Battery	10
Substations	40
Cable management	15
Port side connection	40

8.3 Revenue

The predicted revenue streams for the POA consist of electricity sold to the following customers

- Ships via shore power
- Electricity grid spill (Stretch Scenario only)

There is no standing charge/fixed tariff charged to shore power consumers. The shore power sale price was calculated by adding a mark up to the cost of importing electricity from the grid (section 8.2.3). The price of Shore power was indexed to the Green Book projections with a weighted percentage difference between the initial shore power price and import electricity cost maintained.

Grid spill sales from excess renewable generation was only captured in the Stretch Scenario. The grid spill electricity was sold back to the DNO at 8p/kWh in year one. This costs was also indexed to BEIS projects to maintain an appropriate grid spill costs throughout the project lifetime.

Electricity generated by renewable technology is provided to the landside demands at no cost as both the renewable technology and landside demands are under the PoA ownership. Although not captured in this model the addition of EV charging for non PoA owned vehicles could represent an additional revenue stream for the project.

If to be modelled, a set price for EV charging (p/kWh) would be established and it would likely be a markup on the gird electricity price, similar to the shore power sales strategy.

Renewable electricity that is used by the ships will be charged at the same shore power price as imported electricity.

8.4 Cash Flow Results

The cash flow results displayed as part of this Techno-economic analysis is as follows:

- Baseline and Stretch Scenario – no grant funding applied
- Baseline and Stretch Scenario – with grant funding applied
- Stretch Scenario – with grant funding applied and DNO costs removed
- Stretch Scenario – with grant funding applied, DNO costs removed and Solar PV removed.

The removal of the DNO costs and PV costs were treated as sensitivities within the TEM.

8.4.1 Cash flow – No grant funding applied

Table 8-8 displays the key economic results from the TEM for both scenarios with no grant funding applied.

Table 8-8 Economic results no grant funding

	Baseline	Stretch Scenario
Total CAPEX	£26,596,000	£43,439,100
Average OPEX per year	£3,500,072	£2,414,645
Average REPEX per year	£345,939	£901,981
Average revenue per year	£6,658,235	£ 7,258,704
Shore power sales price (year one)	62.87/kWh	66.32p/kWh
Mark-up price (average across project lifetime)	52.83p/kWh	56.27p/kWh
NPV at 25 years	£10,729,007	£16,753,822
NPV at 30 years	£15,905,757	£25,276,351
NPV at 40 years	£23,934,337	£38,493,874
IRR at 25 years	6.6%	6.5%
Discounted payback	17 years	18 years

A cash flow curve for the modelled scenarios is displayed in Figure 8—4 and Figure 8—5. As the shore power price is set to provide an 8% IRR, a positive cash flow is achieved over a 40 year period for both scenarios.

A markup of 52.83p/kWh must be maintained between the electricity import price and shore power sales price in order to achieve the desired IRR for the Baseline Scenario while this increases to 56.27p/kWh for the Stretch Scenario. The similarities in markup price between both scenarios suggests that the cost savings and grid spill revenue from the renewable technology do offset the additional capex of the equipment. However the added renewable technology doesn't appear to generate enough Revenue or OPEX savings to significantly reduce the required shore power markup.

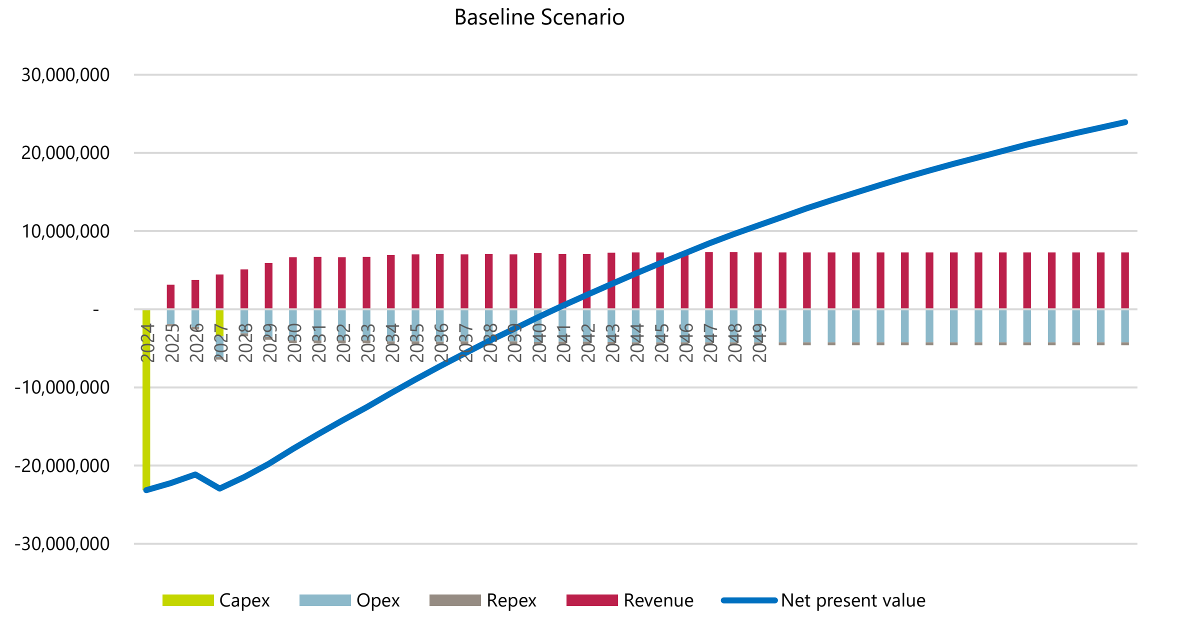


Figure 8—4 Cash flow curve for Baseline Scenario - no grant funding

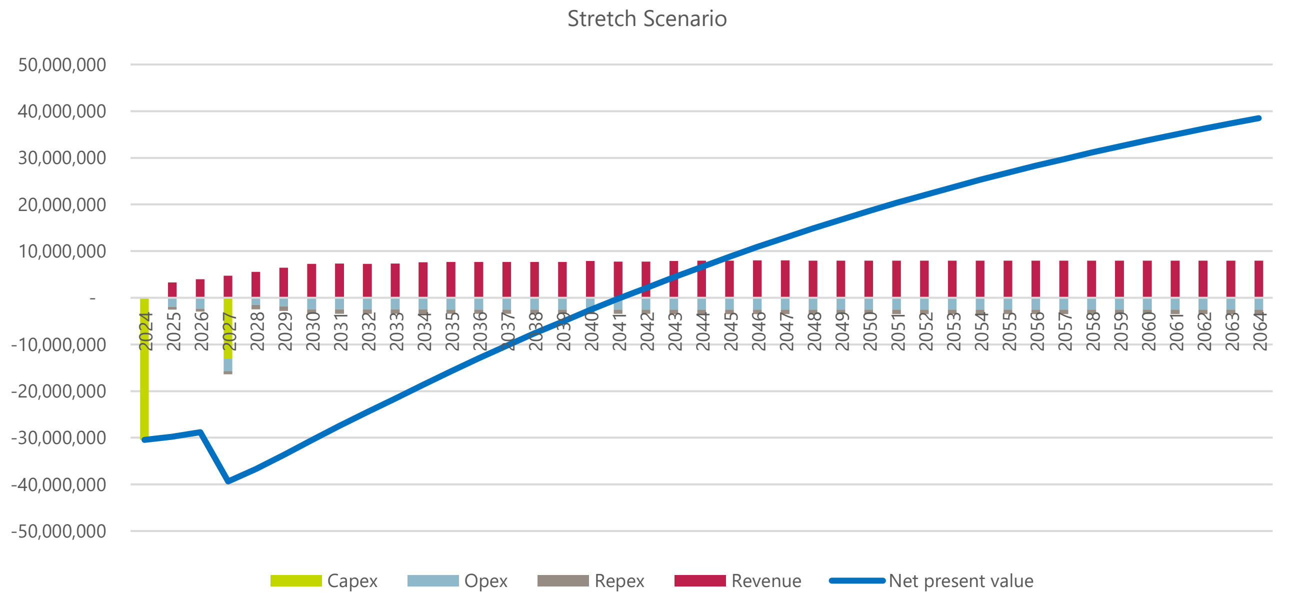


Figure 8—5 Cash flow curve for stretch scenario - no grant funding

8.4.2 Cash flow – grant funding applied

Although there is no clear funding streams for port decarbonisation schemes at this moment of time, it is likely that a scheme such as this would be able to achieve 50% grant funding (from either public or private sources). For the purpose of the TEM 50% grant funding split evenly in year one and year four of the project was assumed.

The key economic results with grant funding is displayed in Table 8-9.

Table 8-9 Economic results with 50% grant funding applied.

	Baseline	Stretch Scenario
Total CAPEX	£13,298,000	£21,719,550
Average OPEX per year	£3,500,072	£2,414,645
Average REPEX per year	£345,939	£901,981
Average revenue per year	£ 5,572,235	£5,499,110
Shore power sales price (year one)	52.62 p/kWh	49.70 p/kWh
Mark-up price (average across project lifetime)	42.62 p/kWh	39.66p/kWh
NPV at 25 years	£6,475,345	£9,912,871
NPV at 30 years	£9,390,403	£14,755,648
NPV at 40 years	£13,911,344	£22,266,273
IRR at 25 years	6.7%	6.6%
Discounted payback	17 years	17 years

Cash flow curves for both scenarios are displayed in Figure 8—6 and Figure 8—7. Again the shore power price was set to provide an IRR of 8%. However due to the reduced CAPEX, through grant funding, the shore power sales price can be lowered compared to a no funding scenario.

A markup of 42.58p/kWh must be maintained between the electricity import price and shore power sales price in order to achieve the desired IRR for the Baseline Scenario while this decreases to 39.66p/kWh for the Stretch Scenario. The addition of renewable technology means a marginal shore power price reduction can be made when compared to the baseline scenario.

Because of the reduced revenue, the NPV is lower compared to the base case for both scenarios. However, the grant funding would enable the Port of Aberdeen to sell shore power at a more competitive price because of this.

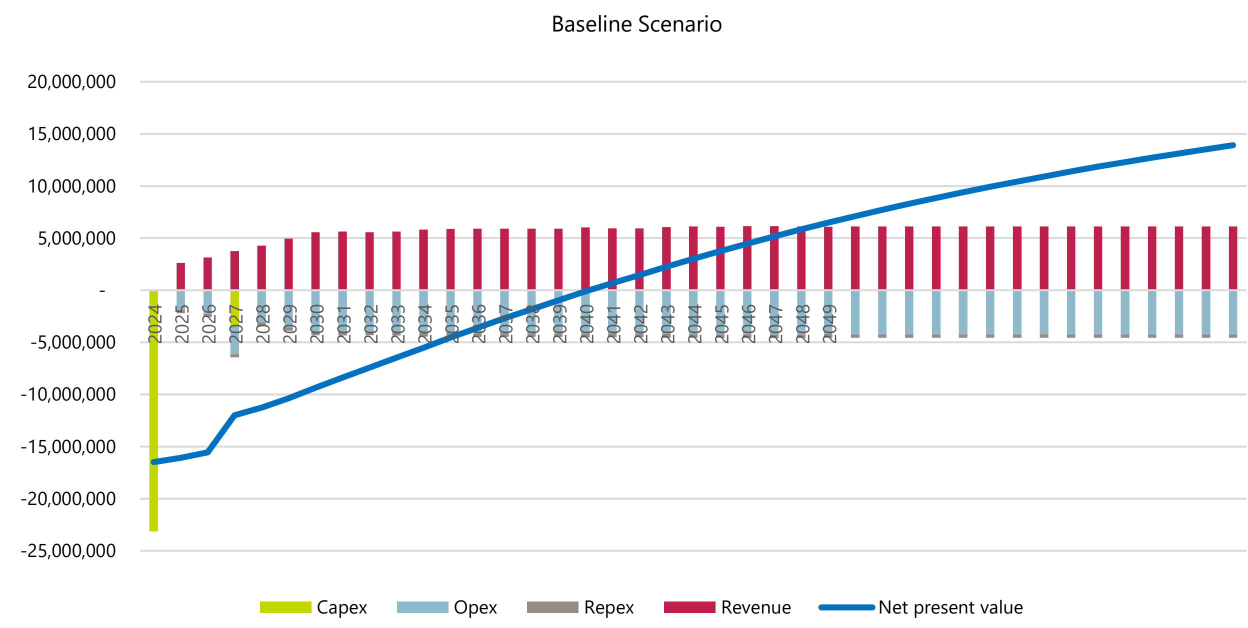


Figure 8—6 Cash flow curve for Baseline Scenario - With grant funding

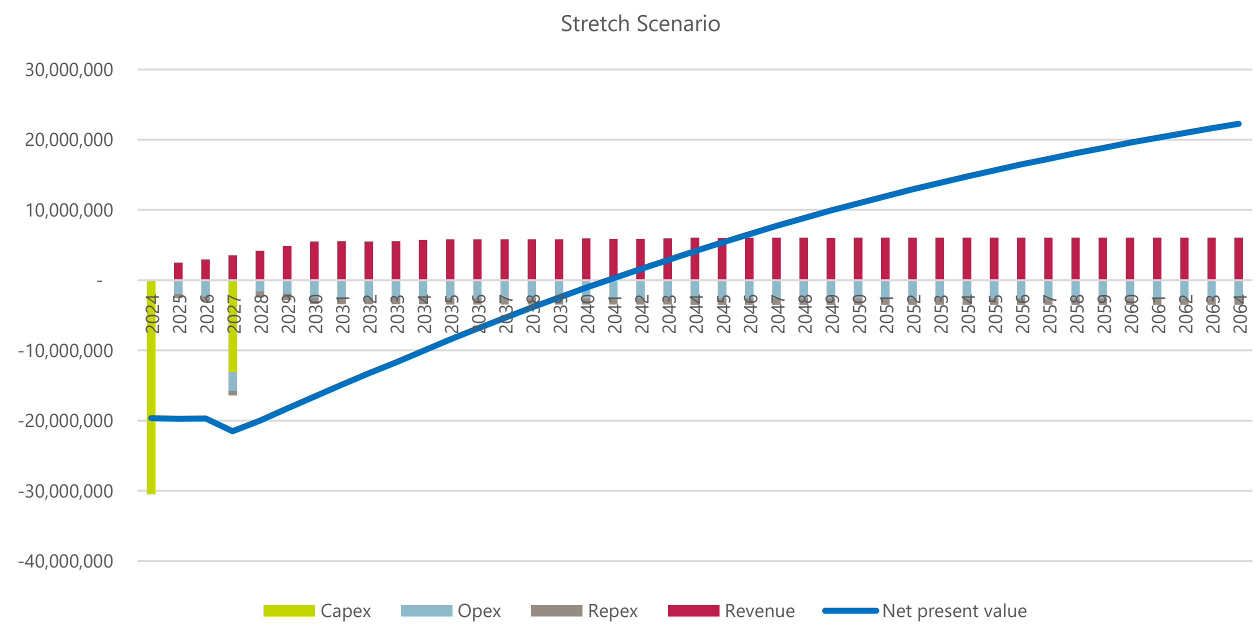


Figure 8—7 Cash flow curve for stretch scenario - With grant funding

8.5 Sensitivity analysis

A sensitivity analysis has been carried out as part of the techno-economic exercise to illustrate the key modelling inputs of the scheme and how these impact the overall project NPV and IRR. Various modelling inputs were varied by ±30% on the base case scenarios:

- Capital cost
- Variable power sales rate (Shore Power sales and grid spill revenue)
- Annual demand

The Stretch Scenario was carried forward for sensitivity analysis.

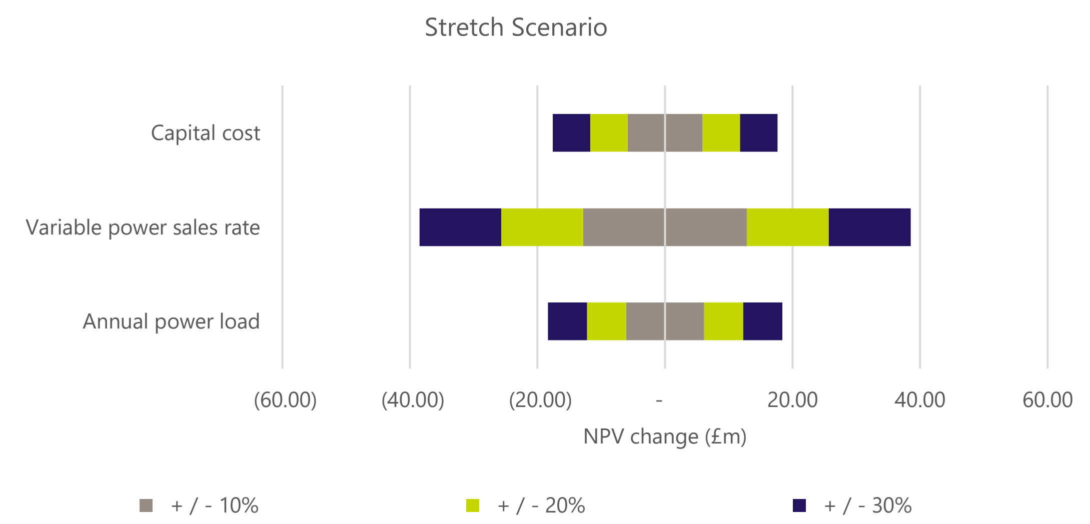


Figure 8—8 Sensitivity graph for Stretch Scenario

A sensitivity graph for the stretch scenario is displayed in Figure 8—8. The Stretch Scenario is sensitive to an increase in the sales rate of the electricity (±£12.84M). This includes shore power sales and the grid spill revenue.

The scheme is also sensitive to annual power load (±£6.12M). This represents the annual demand of the shore power which impacts both the OPEX and Revenue for the scheme. This highlights the importance of reducing the uncertainty surrounding shore power uptake by vessels and subsequent shore power demands.

Increase in these values would increase the performance of the scheme, indicating that further analysis of the shore power sales rate should be carried out in a full financial work package as part of a future OBC.

The scenario is also sensitive to capital costs (±£5.87M). This is to be expected due to the additional costs of the renewable technology compared to the base case scenario.

8.5.1 Distribution Network Operator connection

The power connection for new infrastructure at the south harbour requires cooperation with the Distribution Network Operator (DNO), Scottish and Southern Energy (SSE). The power connection can be broken down into two separate components, the contestable and non-contestable works.

In the context of a shore power system, contestable works typically refer to the parts of the installation that can be carried out by multiple contractors or suppliers, and which are subject to competition. These may include the supply and installation of equipment such as transformers, switchgear, cabling, and connectors.

The non-contestable works refer to the parts of the shore power and renewable energy systems that are typically the responsibility of the port or the power utility. These may include the design of the electrical grid, the connection to the local power source, and the commissioning and testing of the entire system. These works are typically not subject to competition, as they are usually carried out by the entity that owns or operates the power grid or the port infrastructure.

Non contestable works can only be carried out by the local Distribution Network Operator. The Access SCR policy change coming into effect from April 2023, includes provisions for cost sharing between the DNO and customer for non-contestable works that require carrying out for large scale grid reinforcements.

The DNO would be responsible for paying the full non-contestable costs associated with maintaining and upgrading their network infrastructure. However, the DNO may be able to recover some of these costs from customers through their electricity bills, subject to regulatory approval.

A graphical representation of the Access SCR scheme is displayed in Figure 8—9.

Figure 8—9 Access SCR scheme explanation

Because of this change in policy, it's possible that SSE will pay for the full substation upgrade cost required by the scheme (~£13.7M) (Table 8-3). Therefore, a sensitivity analysis was carried out by removing the substation costs from the Stretch Scenario and assuming the 50% grant funding still applied by to the scheme.

A cash flow curve for the chosen both scenarios with the substation costs removed and grant funding is displayed in Figure 8—11. The key economic results are displayed in Table 8-10.

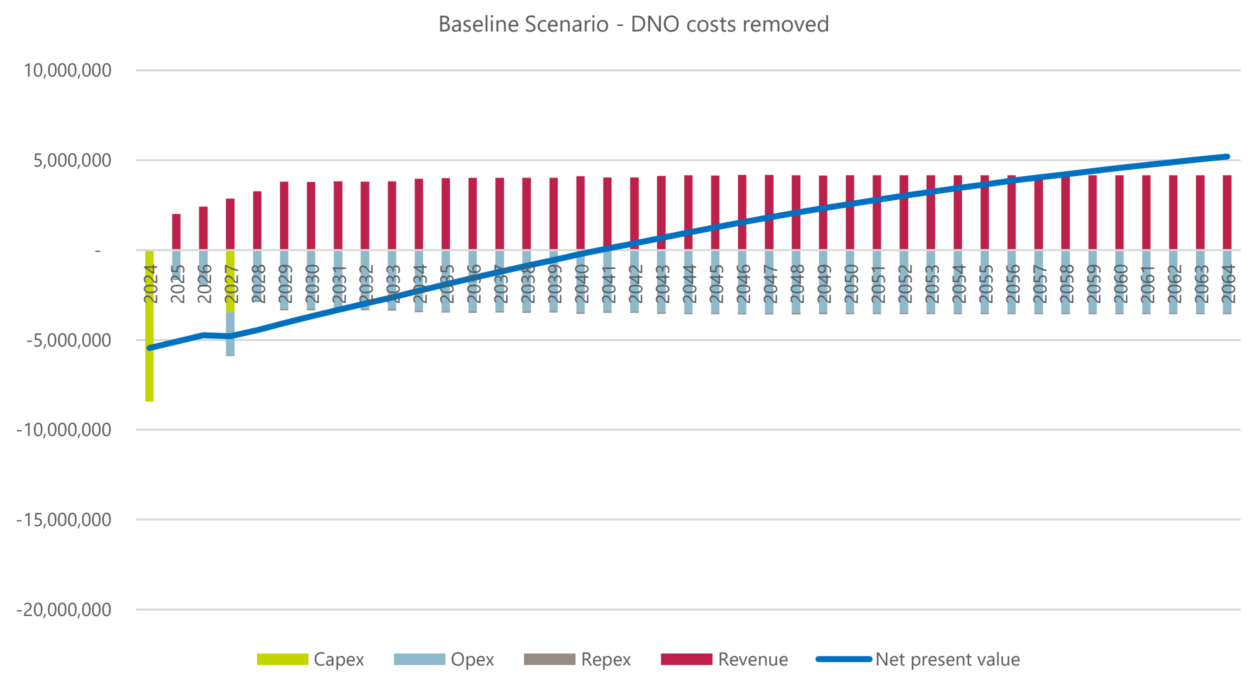


Figure 8—10 Cash flow curve for Baseline Scenario (with grant fundding) - substation cost removed)

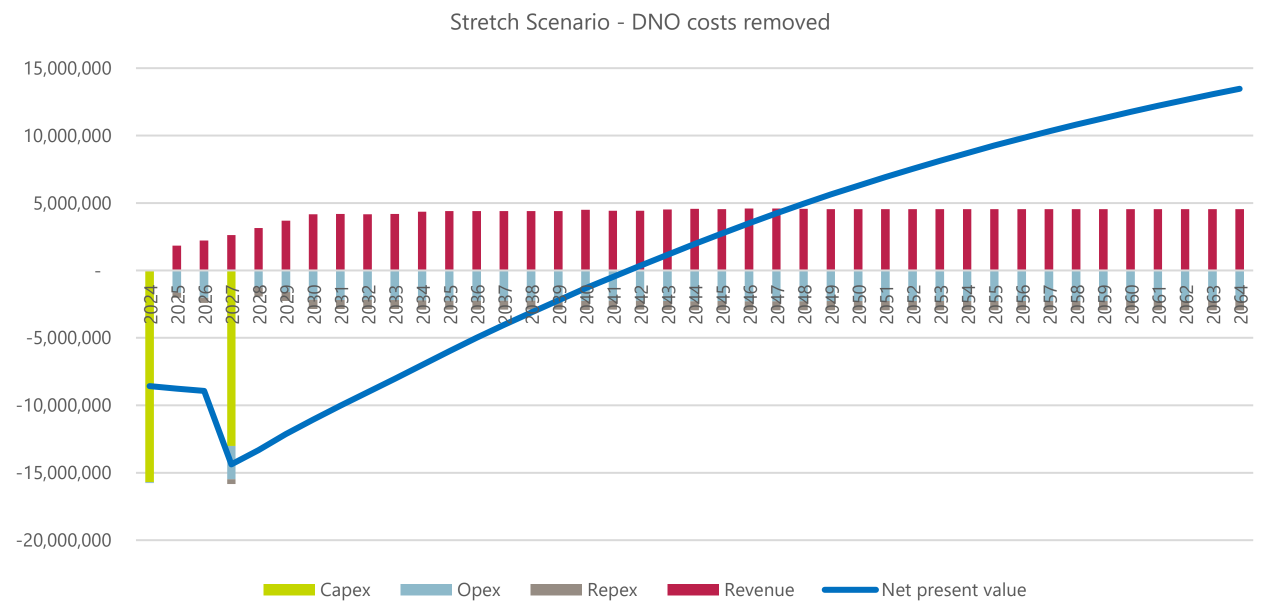


Figure 8—11 Cash flow curve for Stretch Scenario (with grant funding) - Substation cost removed

Table 8-10 - Comparisons between base case and DNO substation (with funding)

	Baseline Scenario – with grant funding and DNO costs removed	Stretch Scenario – with grant funding and DNO costs removed
Total CAPEX	£5,936,000	£14,357,550
Average OPEX per year	£3,232,072	£2,146,645
Average REPEX per year	£77,939	£633,981
Average revenue per year	£3,840,524	£4,151,237
Shore power sales price (year one)	40.42p/kWh	36.97p/kWh
Mark-up price (average across project lifetime)	30.38p/kWh	26.93p/kWh
NPV at 25 years	£2,324,115	£ 5,628,733
NPV at 30 years	£3,453,905	£8,702,415
NPV at 40 years	£5,206,086	£13,469,364
IRR at 25 years	6.6%	6.4%
Discounted payback	17	18

Removing the DNO costs from the scheme decreases the Capex by ~£13.7M, reducing the overall costs of the Baseline Scenario to ~£11.8M and the Stretch Scenario to ~£28.71M. With grant funding also applied the overall capital costs falls to ~£5.9M and ~£14.3M respectively.

This reduction in Capex means the price that the shore power is sold at would be more competitive for the customer. An average markup price of 30.38p/kWh would be required for the Baseline Scenario, compared to 42.62 p/kWh if DNO costs were to be included. A markup price of 26.93p/kWh would be required for the Stretch Scenario, compared to 39.66p/kWh if DNO costs were to be included.

This analysis indicates that implementing renewable technology within the Stretch Scenario does reduce the required markup price of the shore power, despite the initial CAPEX investment being higher. However the reduction in shore power is only ~4p/kWh.

Further investigation is recommended to reduce the uncertainties outlines throughout the report and test again the TEM to verify if the current results are still applicable and whether a wind turbine can provide a significant benefit to the scheme or not.

The lower markup price still meets the 8% IRR required for the project. The lower shore power sales price results in less revenue for the scheme over 40 years, consequently the NPV after 40 years is decreased compared to the base case.

However, this lower shore power price could entice more vessels to berth at the Port and utilise shore power. This would subsequently increase the quantity of shore power sales compared to the modelled scenarios in this study. This could further improve the economics of the shore power schemes.

8.5.2 Solar photovoltaics

From the initial results the majority of the grid spill revenue is generated by the wind turbine, installed in 2028. This indicates that the PV has limited impact on the economic performance of the scheme while still requiring ~£2M of upfront investment. An additional sensitivity was tested where the solar PV was removed from the Stretch Scenario, in addition to the removal of the DNO costs and grant funding applied. The battery was retained to help reduce the peak demand required by the remaining electrical infrastructure.

The energy balance from the renewable technology was updated to account for the removal of the PV. The updated inputs is displayed in Table 8-11.

Table 8-11 Key economic results for Stretch Scenario – No DNO substation costs (with funding)

			Demand (MWh/year)				
			Shore power		Landside demands		
Technology	Year	Total generation	Renewable contribution to shore power	Import from grid for shore power demand	Renewables contribution to landside demands	Import from grid for landside demand	Grid Spill
No renewable technology	2025			11,275		2,723	
	2026			14,150		2,723	
	2027			17,025		2,723	
Wind Turbine + Battery	2028	24,435	17,593	2,307	2,199	524	4,643
	2029	24,435	16,616	6,160	1,955	768	5,864
	2030	24,435	15,512	10,137	1,540	1,183	7,383

The cash flow graph for the stretch scenario with grant funding applied, no DNO costs and no solar PV is displayed Figure 8—12. The key economic results are displayed in Table 8-12.

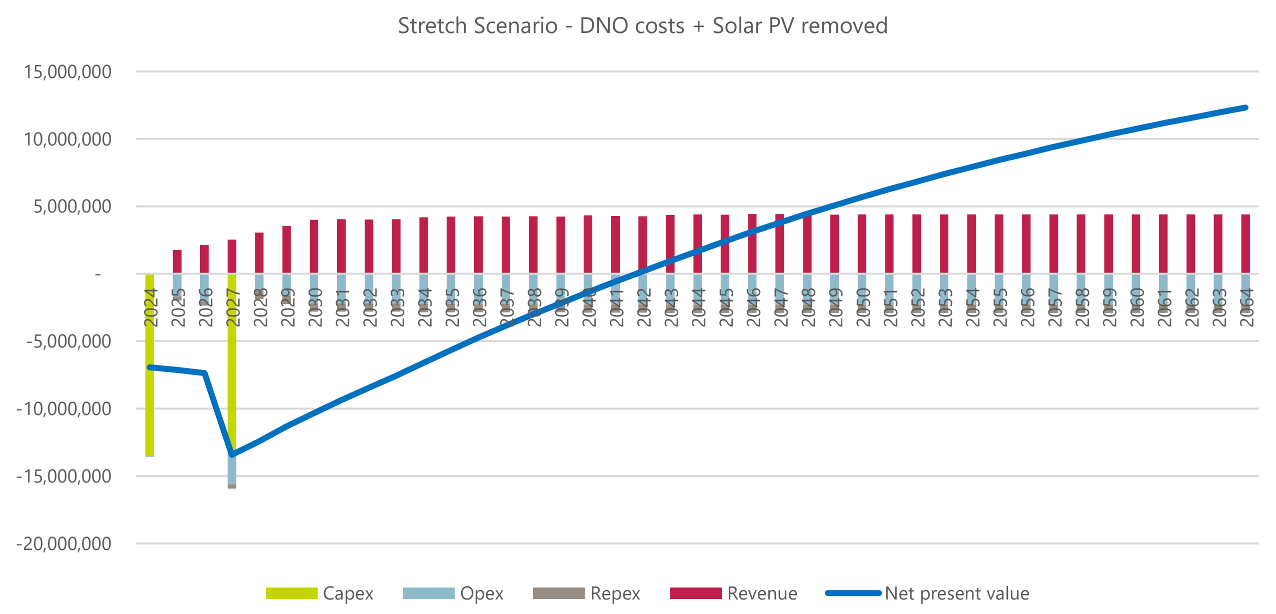


Figure 8—12 Cash flow curve for Stretch Scenario (with grant funding) - Substation costs and Solar PV removed

Table 8-12 – Key economic results for Stretch Scenario – No DNO substation costs , solar PV removed (with funding)

	Stretch Scenario (NO DNO costs + PV removed)
Total CAPEX	13,332,500
Average OPEX per year	2,162,508
Average REPEX per year	576,722
Average revenue per year	4,001,679
Shore power sales price (year one)	35.59p/kWh
Mark-up price (average over scheme lifetime)	25.55p/kWh
NPV at 25 years	£5,070,749
NPV at 30 years	£7,913,200
NPV at 40 years	£12,321,535
IRR at 25 years	6.4%
Discounted payback	18 years

The removal of the PV results in a £2.05M decrease in CAPEX for the stretch scenario and with the removal of the DNO costs and grant funding also applied the overall capital costs falls to ~£13.3M, compared to ~£21.7M in the base case.

Again this reduction in CAPEX means the shore power price can be lowered. An average markup price of 25.55p/kWh would be required. Although this is lower than when the PV is retained the difference is marginal (1.38p/kWh of difference when the DNO costs are removed).

The decrease in the required shore power markup price indicates that the PV does not add economic benefit to the scheme. This is because the majority of the grid spill revenue comes from the installation of the wind turbine. The grid spill generated by the PV does not payback on the system itself.

However, it should be noted that in this modelling process the generation from the PV has been prioritized to the shore power. The decision to retain the PV for the landside demands only should be explored further. In addition, all the PV does not add economic benefit to the scheme the carbon savings should also be considered when assessing it's value to the project.

Furthermore, the solar PV CAPEX used within the model appears very conservative and could be much lower in reality, significantly improving its economic value within the scheme.

By comparing the base case with DNO costs removed (Table 8-10) and the Stretch Scenario with DNO and Solar PV costs removed Table 8-12. We can identify the economic benefit of the wind turbine in isolation. The avoided OPEX and grid spill revenue from the turbine reduces the shore power sales price by 4.83p/kWh.

8.6 Social impact

As well as looking at the economics of the scheme it is also important to consider the social benefit linked to the shore power system. The social benefits have been measured through the following parameters:

- Carbon abatement value
- Air quality impact value

Using the monetary value associated with preventing the release of one tonne of carbon equivalent into the atmosphere[11], the social value of carbon abatement by utilising shore power and renewables has been calculated for the project and compared with the counterfactual.

The social value of the project does not take into account grant funding as the reduction in project CAPEX can lead to an increase in social value. Therefore, a social IRR was calculated prior to applying possible grant funding. The social value of baseline scenario (No DNO costs), the Stretch Scenario (No DNO costs), and the Stretch Scenario (No DNO cost + PV removed) are assessed.

Implementing prosed technology at the south harbour is expected to save approximately the following when compared to the respective BAU cases.:

- 581,397 tCO2e for the Baseline Scenario (No DNO cost)
- 590,357 tCO2e for the Stretch Scenario (No DNO costs)
- 590,197 tCO2e under the Stretch Scenario (No DNO costs + No PV)

This equates to an average annual emission saving of 14,399 tCO2e/yr and 14, 395tCO2e/yr for each scenario respectively.

Using the carbon values published by DESNEZ to achieve net zero by 2050, carbon abatement values are calculated. These results are displayed in Table 8-13.

Table 8-13 Carbon abatement social benefit

	Baseline Scenario No DNO costs)	Stretch Scenario (No DNO costs)	Stretch Scenario (NO DNO costs + PV removed)
Lifetime carbon abatement vs counterfactual	£198.08M	£201M	£201M
Annual average carbon abatement vs counterfactual	£4.85M	£4.92M	£4.92M

Air quality also impacts the social value of a project. Therefore, it is important to account for the air quality impact of pollutants e.g. NOx, SOx and particulate matter through the burning of marine fuel, whilst at berth in Aberdeen South Harbour.

Air quality is of great relevance in the south harbour since it is envisaged that major developments are under design in the proximity of the harbour.

The IMO has previously published typical pollutant emissions per tonne of marine fuel burned within their greenhouse gas study. This information was combined with the Department for Environment Food & Rural Affairs publication on the air quality damage cost of certain pollutants[12] to generate an air quality damage cost associated with marine fuel, which was compared with electricity (Appendix F).

[11] https://www.gov.uk/government/publications/assess-the-impact-of-air-quality/air-quality-appraisal-damage-cost-guidance#annex-a-updated-2020-damage-costs [Accessed14th June 2023]

Marine fuel has approximately 50 times more air quality damage impact cost compared to electricity (9.85 p/kWh vs 0.21-0.31 p/kWh).

A breakdown of the value of the air quality impact is displayed in Table 8-14.

Table 8-14 Air quality abatement social benefit

	Baseline scenario (No DNO costs)	Stretch Scenario (No DNO costs)	Stretch Scenario (NO DNO costs + PV removed)
Discounted project air quality impact value vs. counterfactual (over scheme lifetime)	£49M	£50M	£50M

The overall social values for both sensitivities is captured in Table 8-15. Both scenarios achieve a high social IRR due to the carbon and air quality damage associated with MGO that is reduced/avoided via electrification.

Table 8-15 Overall social value of Shore power system

	Baseline Scenario (No DNO costs)	Stretch Scenario (No DNO costs)	Stretch Scenario (NO DNO costs + PV removed)
Carbon abatement vs counterfactual	£198.98M	£201.70M	£201.66M
Air quality impact vs counterfactual	£93.68M	£95.78M	£95.76M
Overall social value vs counterfactual	**£292.66M**	**£297.49M**	**£297.42M**
Social IRR (%)	45.8%	27.9%	29.9%

From an air quality and carbon abatement benefit the PV does not appear to add value to the project. The base case scenario has the highest social IRR due to it having the highest cashflow across the project.

8.7 Techno-economic modelling conclusions.

The study confirms that there is an economic case to implement a shore power system and renewable technology at the South Harbour within the Port of Aberdeen. Based on the generated annual shore power and landside demands a significant carbon reduction would be achieved compared to a BAU approach.

For both the Baseline Case and Stretch Scenario a markup on shore power sales is required to meet an 8% IRR over the 40 year lifetime. Without grant funding a marginally higher markup price is required for the Stretch Scenario in order to achieve payback on the additional renewable technology CAPEX.

In addition, the renewable technology results in a high annual REPEX cost for the stretch scenario, again contributing to the higher shore power price.

If 50% grant funding can be identified for the project the shore power markup price can be decreased for both scenarios. This means a more competitive shore power price can be offered to vessels. With this reduction in CAPEX, the Stretch Scenario can offer a lower markup price compared to the Baseline scenario.

[12] https://www.gov.uk/government/publications/assess-the-impact-of-air-quality/air-quality-appraisal-damage-cost-guidance#annex-a-updated-2020-damage-costs [Accessed11th April 2023]

However the difference between the average shore power markup price over the scheme lifetime is marginal (2.92p/kWh). From an economic perspective, this suggests that the wind turbine and solar PV do not justify the levels of investment required.

It's possible that the DNO would pay for the required primary substation costs associated with the scheme through the Access SCR policy change as of April 2023. If this is the case, the CAPEX of the scheme could be reduced by ~£13.7M. This reduction in CAPEX would enable the price of shore power to be sold at a lower rate.

Based on the results of this study PV does not seem to offer an economic benefit to the scheme. When comparing the shore power prices including the PV systems results in a reduction of 1.38p/kWh (considering DNO costs removed). In addition, the PV offers an further carbon saving of 160 tCO2e over the project lifetime compared to without.

The Wind turbine offers a saving of 8,800 tCO2e when compared to the base case. Therefore the PV offers a return of > 0.00001 tCO2/£ spent. The wind turbine offers a return of 0.0006 tCO2/£ spent. Neither of renewable technologies indicate a payback on the investment from an economic or carbon perspective. The base case however offers a viable method to implement shore power at the South Harbour.

The current model is based on the green book forecast over carbon intensity of the grid (Figure 3—11), showing a rapid decrease in the short term future. In case this forecasts are proven too optimistic, implementation of renewable generation on site could represent a viable option.

An appropriate solution for the POA could be to investigate a Power Purchase Agreement. A power purchase agreement (PPA) is a contract between two parties where the buyer agrees to purchase a certain amount of electricity from the power producer over a specified period of time, at a predetermined price.

The buyer can secure a long-term supply of renewable energy at a fixed price, which can help to hedge against volatile energy prices and provide a reliable source of power. Overall, PPAs can help to promote the growth of renewable energy projects and support the transition to a low-carbon economy.

A PPA agreement could secure the Port of Aberdeen with a fixed low cost electricity import price for its proposed shore power scheme going forward. Other local renewable energy schemes in the area may be available to enter a PPA agreement with the POA.

For example, the Aberdeen Hydrogen Hub is a concept design for a joint venture between BP and Aberdeen City Council to develop a green hydrogen production and vehicle refuelling facility, powered by a purpose-built 8MW solar farm, linked by an underground solar grid connection. The solar farm is also currently planned to adjacent to the south harbour making the case for a private wire connection potentially attractive.

It's likely the scheme would produce excess renewable energy which could be purchased by the POA. This could represent a more cost effective way of implementing net zero electricity into the Port's operations, however further investigation into this would be needed.

9 Summary and recommendations

9.1 Project Overview

The report has investigated three different scenarios that PoA could implement in short-medium-long term to reduce or eliminate their carbon emissions in alignment with PoA targets for net zero.

The stretched scenario has been further detailed as the short-medium term solution. This includes the potential for a shore power network deployment together with onsite renewable generation at the South Harbour as well as introduction of alternative fuels (HVO/FAME) within the bunkering storage facility of the harbour.

A pioneering scenario where PoA produce e-methanol as alternative fuel has been investigated to show the required infrastructure (hydrogen and CO2 production, methanol synthesis and associated renewable generation). This scenario should be consider as informative only to support PoA in any future discussion with authorities and stakeholders regarding e-methanol production.

9.2 Key findings and recommendations

Given the high anticipated electrical demands should a shore power system be implemented, and the level of flexibility required by PoA with regards to berthing points accommodating different vessel types, a dedicated electrical network to support the shore power system has been proposed. The main findings of the report are:

- **Existing infrastructure assessment**
  - An 800kVA substation currently supplies power requirements at the South Harbour and it is not deemed sufficient to meet projected shore power demands and facilitate new renewable infrastructure
  - Existing Low Voltage (LV) networks are to be maintain to ensure power distribution from the 800 kVA substation to the buildings, pumps and external lighting
  - The berthing point service trenches running along the quaysides are used to run a part of the electrical network for shore power while the rest preserved for any implementation of fuel lines
- **Projected Demand analysis**
  - Detailed analysis of number of calls and their duration for different types of vessel has been carried out. Sensitivity analysis over these parameters has provided a range of potential power demands for the shore power system
  - An annual power demand of ~28 GWh/year has been estimated by 2030, assuming a gradual uptake in vessel consumption of shore power starting in 2025 of 11.2 GWh/yr. Consumption profiles for landside and shipside demands have been estimated based on provided information
  - A coincident peak demand of 22.6 MVA by 2030 has been calculated to supply vessels at berth, based on 7 vessels at berth simultaneously
- **Proposed infrastructure for the stretch scenario**
  - A new primary substation with 24 MVA of capacity alongside HV/LV distribution cabling and shore power infrastructure (including. transformers, frequency conversion and cable reels) is required to meet the projected 2030 demands. Additional space is included within the substation for potential expansion due to future adjacent developments i.e. the Energy Transition Zone (ETZ) development
  - A new shore power system is required within the South harbour:
    - Up to ten HV shore power connection points are proposed along all quaysides areas to allow for greater flexibility with up to seven vessels potentially supplied simultaneously
    - Two LV shore power connection points have been designed to cover the demands of smaller vessels
    - The LV connections require above ground infrastructure on the deck but these have been strategically located at Crathes and Dunnottar quayside to minimize operation disruption
    - HV and LV cable routing have been identified to utilize as much as possible the existing services trenches and mitigate any major civil work i.e. hard digging of the large portion of the decks
    - Existing bunkering pits have been identified to potentially host shore power connection points due to the expected available space
- **On site renewable generation**
  - The total annual demand is ~28 GWh/yr. At full build out 60% of this demand could be met through on site renewable generation and storage. The remaining 40% could be met through direct grid import. The total annual generation from the renewables is ~24 GWh/yr. Of this generation ~17GWh could be consumed on site while ~7GWh would be exported to grid
  - The investigated onsite renewable generation consist of:
    - A 6 MW wind turbine is proposed nearby to the south breakwater to cover the shore power demands
    - A total of 268kWp solar PV system is proposed on top of the existing and future building to meet the landside demands
  - A Battery Energy Storage System (BESS) optimal sizing has been investigated to maximise renewable energy use on site and the modelling shows that a BESS may not be required. However, an allowance for BESS of 3.85 MWh is made to cover the uncertainty over the demand and generation profiles. More detail in section 6.5
- **Alternative fuel deployment**
  - The pioneering scenario shows that an e-methanol production facility would require a footprint significantly in excess of available land areas within the harbour. Furthermore, significant grid reinforcement would be required to meet electrical demands
  - A detailed description of the different steps required to produce e-methanol and related demands and space take is presented in the pioneering scenario (section 7) to allow PoA for any future decision and discussion with other stakeholders
  - Comparison of emissions between Marine Gas Oil (MGO), Hydrotreated Vegetable Oil (HVO) and methanol as stored fuel at port is included to illustrate the difference in carbon benefit.

- **Techno economic modelling and environmental impact**
    - Within the techno-economic modelling, two scenarios are modelled to capture the impact of renewable technology on the price of shore power and PoA's overall carbon emissions. The two scenarios modelled are as follows:
        - Baseline Scenario
        - Stretch Scenario (alternative fuel not included)
            - The total CAPEX investment for the scheme has been estimated at £43M. However, the port is unlikely to incur the full extent of these costs due to provision of grant funding and DNO absorption of elements of the grid upgrade costs (which account for £13m of the overall CAPEX)
            - The markup required on the base shore power sales price, above the electricity import cost, is highly dependent on the Capital costs of the project
            - When considering the CAPEX for the Stretch Scenario the addition of Solar PV and an onshore Wind Turbine does not provide additional economic benefit to when compared to the base case. This is due to the additional ~£15M required on the equipment and supporting infrastructure
    - Techno-economic modelling indicates a shore power markup price of 52.83 p/kWh and 56.27 p/kWh for the Baseline and Stretch scenarios respectively is required to achieve an 8% IRR without grant funding over the 40 year modelled lifetime (Figure 9—1 and Figure 9—2). This markup can be lowered to 42.62 p/kWh and 39.66p/kWh when 50% grant funding is applied.

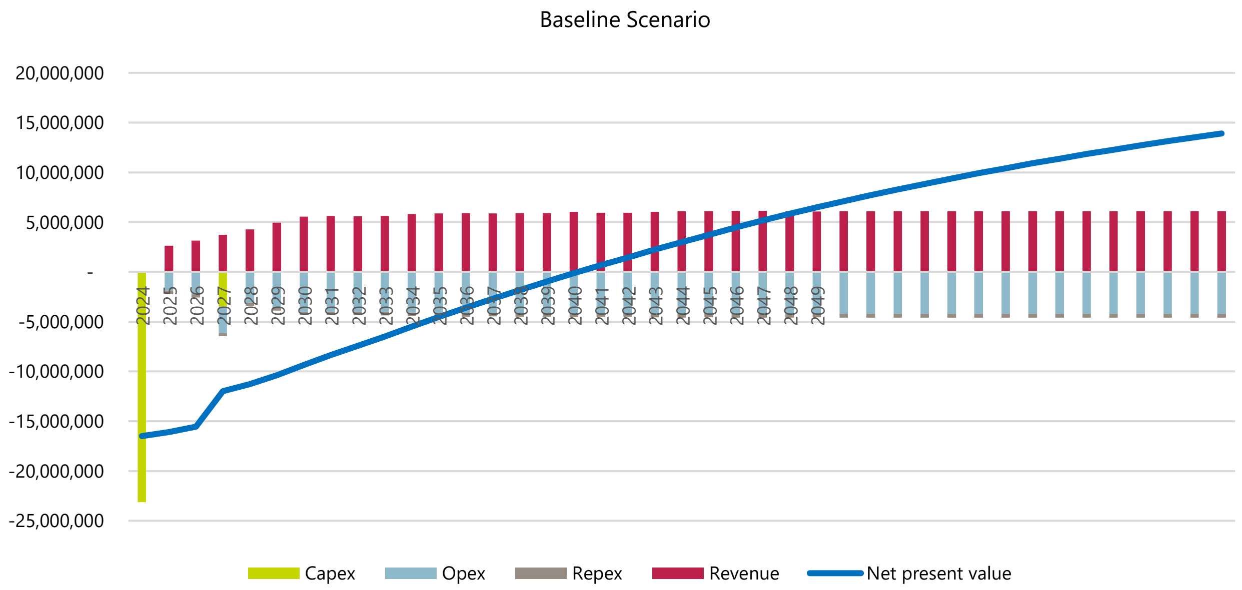


Figure 9—1 Cash flow curve for Baseline Scenario - With grant funding

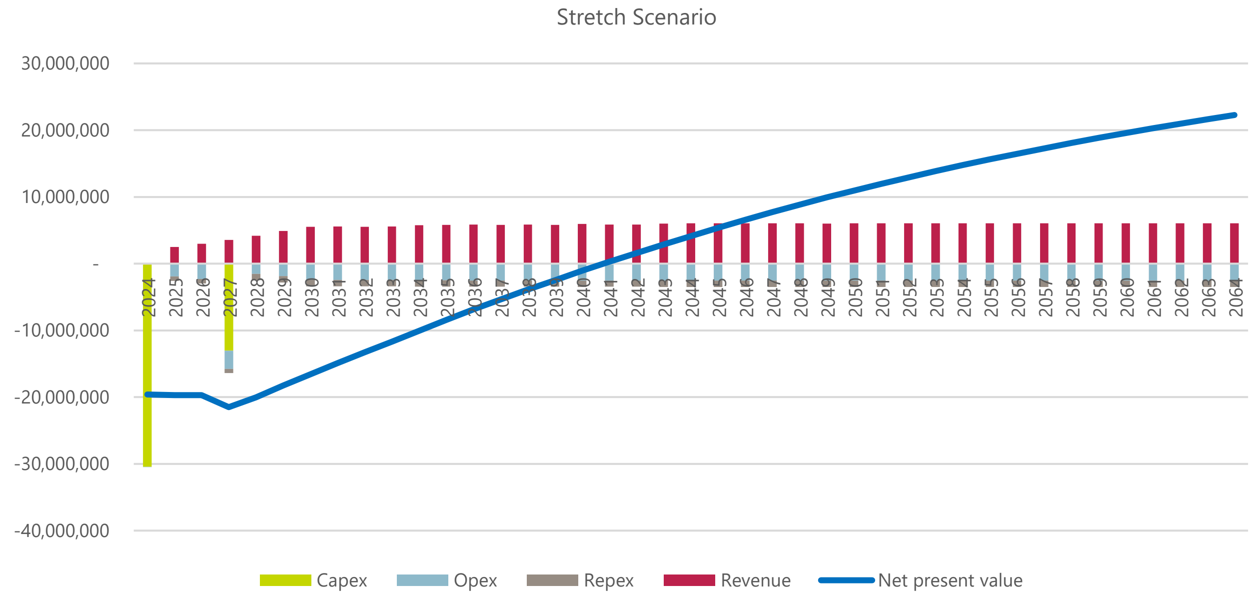


Figure 9—2 Cash flow curve for stretch scenario - With grant funding

- The stretch scenario is highly sensitive to the capex. It is possible that SSE would cover the CAPEX for the required primary substation through the Access SCR policy change. This capex reduction would further cut to the shore power sales price to a markup of 25.55 p/kWh for the Stretch Scenario with grant funding applied. A lower markup could lead to increased berthing traffic hence higher shore power sales with further improvement of the scheme's economics.
- Modelling indicates the solar PV system to not offer an economic benefit to the scheme. When comparing the shore power prices, with DNO costs removed in combination with grant funding, the inclusion of the PV systems results in a reduction of 1.38p/kWh of power sold.
- The PV system offers an additional carbon saving of 160 tCO2e over the project lifetime, offering a return of > 0.00001 tCO2/£ spent while the Wind turbine leads a saving of 8,800 tCO2e when compared to the base case, offering a return of 0.0006 tCO2/£ spent. This is based on the projected the carbon intensity of the grid assumed to drop significantly in the next future. If this projection was to be optimistic then the savings from renewable energy would be much higher.
- Current TEM indicates that on site renewable technologies provide a tiny benefit from an economic or carbon perspective to the scheme. The estimated reduction within the stretch scenario (when DNO costs are excluded and grant funding applied) from on site renewables is ~4p/kWhp compared to the baseline scenario.
- Wind turbine and PV could still guarantee low carbon power supply in the case of the grid not following Green Book forecasted prices and carbon intensity.
- Despite a reduction in shore power prices, further investigation is recommended to reduce the uncertainties outlines throughout the report and test again the TEM to verify if the current results are still applicable and whether a wind turbine can provide a significant benefit to the scheme or not.

9.3 Comparison of the three scenarios to include space take, power consumption and emission reduction

Table 9-1 presents the main results and comparison of results. The key observations are:

- **Baseline**
  - Significant emissions under PoA scope are anticipated when considering the baseline scenario due to grid imported electricity. Land take requirements include for a new primary substation, BESS, LVSC which is slightly less than the stretch scenario due to implementation of renewable generation system such as wind turbine and solar PV. Fuel storage requirements are the same as the stretch scenario due to similar density of MGO and biofuels
- **Stretch**
  - The stretch scenario has the same electrical consumption as the baseline scenario. Spatial requirements are slightly greater (0.01Ha) than the baseline due to due to implementation of renewable generation system such as wind turbine and solar PV. Lifetime emissions for marine operations are reduced vs. the baseline scenario due to introduction of biofuel (HVO/FAME) as alternative fuel to MGO
- **Pioneering**
  - The pioneering scenario is significantly more energy and spatially demanding than the baseline and stretch scenarios due to the scale of e-methanol production requirements for vessels. Methanol would require roughly double the storage volume of MGO and HVO, due to its lower energy density, This is based on MGO, HVO and methanol respectively for baseline, stretch and pioneering scenario

Table 9-1 Three scenarios comparison

Scenario	Annual electrical consumption at 2030 (GWh/year)	Annual Renewable generation GWh/year	Total land take (ha)	Fuel storage req. at the harbour m^3	Lifetime emissions within PoA scope (tCO2e)	Lifetime emissions for marine operations at sea (tCO2e)
Baseline	28	0	0.16	576	18,568	23,093,972
Stretch	28	24	0.17	576	9,608	734,620
Pioneering	4,256	4,268	7,290	1,345	9,608	~0

9.4 Key risks

A risk register has been provided as part of Appendix P. Key risks associated with the proposed design include:

1. **PoA fail to gain wider political support for shore power system**
   a. *PoA to develop design to OBC and DPD level applicable funding body requirements which could potentially support up to 50% of capital costs of infrastructure and consult with government departments to test basis for system procurement and delivery is transparent and according to best practice.*
2. **Failure to attract participating shore power users or delay in implementing shore power infrastructure therefore resulting in reduced revenue leads to revenue gap to repay any borrowing / investment.**
   a. *Investigate alternative revenue grants including sharing of risk until further participating operators (and revenue) are sufficient to cover operating costs including any borrowing costs.*
3. **Failure to identify funding sources adequate to meet the capital costs of the scheme, particularly the grant funding to meet the 50% of CAPEX base case**
   a. *PoA should continue to engage with potential funding bodies such as the DfT and keep track of the development of the Clean Maritime Plan 2023 as well as other potential funding opportunities. Operator / off taker contribution to infrastructure deployment should also be considered. Should <50% of the CAPEX cost be covered through grant funding then shore power sales price would need to increase if the base case IRR is to be met. A series of sensitivities have been undertaken around this in the financial case.*
4. **Costing estimates increase during design development**
   a. *Quantity Surveyors have been engaged to produce the cost plan - this should be revisited at later stages. This engagement process will highlight any cost hotspots which require further design development.*
5. **Shore power consumption estimates vary vs actual consumption**
   a. *Power demand sensitivity has been completed as part of a detailed vessel movement analysis and modelled as a sensitivity, but risks remain due to inherent variability between design and operation. Continued refinement of the model may be required if a significant change in predicted operator use becomes apparent.*
6. **Electrical grid capacity availability following DNO engagement**
   a. *Early engagement should be made with the Distribution Network Operator (DNO) to determine grid reinforcement requirements and associated cost responsibilities with difference stakeholders. Independent Distribution Network Operators (IDNO) could be consulted to once commercial approaches are agreed, potentially offering cost saving over provision of infrastructure from the DNO*
7. **Space provision for the primary substation to be secured**
   a. *Engagement with nearby developers should be undertaken as a priority to agree locations for new primary substations adjacent to PoA land*
8. **Renewable generation:**
   a. *TEM results appear to suggest renewable generation on site don't provide significant economic benefits while they still contribute to reduce the carbon emission offsetting the carbon intensity of the grid*
   b. *Phasing and installation of shore power system and wind turbine on site shall be further investigated and agreed. Earlier introduction of the turbine could lead to higher benefits from economic and carbon perspective*
   c. *Engagement with development in the vicinity of the south harbour is recommend and it could result in a better financial performances i.e. private wire connection to BP solar farm or Power Purchase Agreements*

9.5 Next steps

It is recommended to develop a more detailed study such as an Outline Business case focusing on:

- Refinement of the demands peak and annual distribution as well as of the infrastructure requirements
- Engagement with SSE and developers within the areas for coordination over the primary substation and supply arrangement
- Engagement with CMS manufacturers to confirm shore to vessel interfacing can be satisfied for lvsc at a reasonable cost
- Engagement with shore power system manufacturers and provide for potential improvements of the strategy
- Engagement with the client and DNO around the electricity import price for shore power connection
- Definition of the commercial structure for the landside and shipside systems and related renewable generation
- Further discussions with the client regarding the upper limit to the shore power sales price. Workshops with potential end users to assess competitive pricing structure.

Appendix A Contract Deliverables

A.1 Contract deliverables

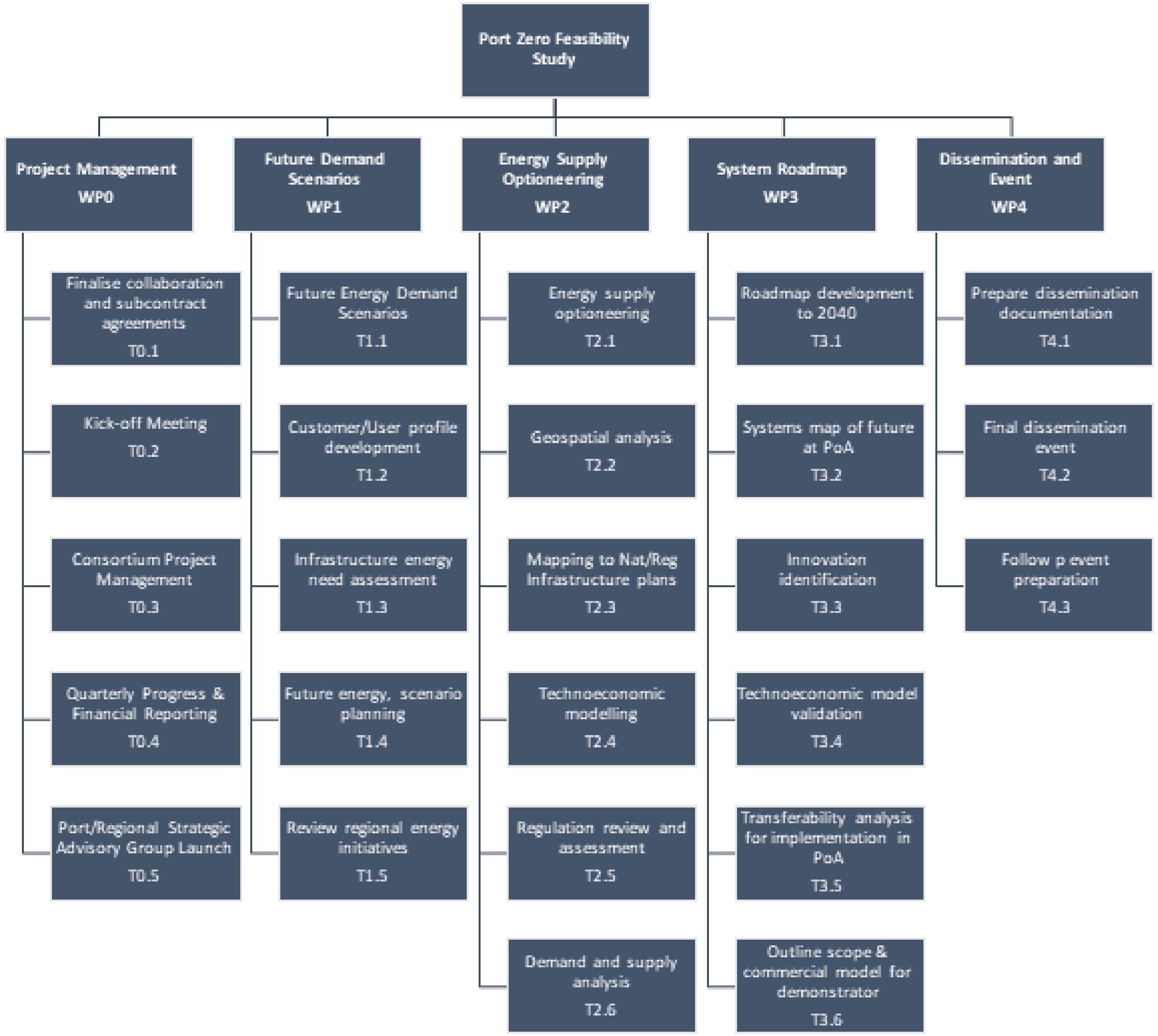


Table 9-2 Deliverables checklist

Contract Deliverable for Buro Happold	Corresponding Section	Comment
T 1.1 Future Energy Demands	Refer to section 3.4, 6.2, 7.2	
T 1.2 Consumer/User profile Development	Refer to section 6.5	
T 1.3 Infrastructure energy need assessment	Refer to section 5.5, 6.6, 7.5	
T 1.4 Future energy, scenario planning	Refer to section 4	Support to ESC
T 2.1 Energy supply optioneering	Refer to section 3.2, 6.5, 6.7	
T 2.2 Geospatial analysis	Refer to section 3.2, 5.5, 6.6, Appendix H, Appendix I	
T 2.4 Technoeconomic modelling	Refer to section 8	
T 2.6 Demand and supply analysis	Refer to section 3.3, 3.4, Appendix B, Appendix C, Appendix D, Appendix E, Appendix M	
T 3.4 Technoeconomic model validation	Refer to section 8	
T 3.6 Outline scope & commercial model for demonstrator	N/A	Support to ESC
T 4.1 Prepare dissemination documentation	N/A	

Appendix B Berthing Analysis

Buro Happold contribute in a parallel project for the South Harbour where the berthing data for the North Harbor as well and the estimated data for the South Harbour have been investigated. This data captured the number and duration of the calls for several different ship typologies during the years

This data was used to form four different shore power scenarios for the South Harbor:

- Low call duration | low uptake
- Low call duration | High uptake
- High call duration | low uptake
- High call duration | high uptake

The low call duration | low uptake and the High call duration | high cases uptake were taken forward for further analysis and they represented the worst and best case scenarios in terms of potential shore power demand from 2025 onwards.

The data from the berthing and power analysis was ultimately used for generating indicative annual power consumption profiles for the shore power system.

B.1 Berthing Analysis

Potential shore power demand for DSVs, CSVs and cruise vessels at South Harbour has been investigated as detailed in this section.

The demand at berth is a function of number of calls, berthing hours per call, and power demand/hour.

PoA has provided the following data which have been further clarified during multiple meetings:

- Historic berthing data (2019-2022) for port calls from large vessels at both harbours, with South Harbour calls starting from July 2022
- Assumptions for call growth at South Harbour to 2027 and 2030
- Data on Cruise vessels and cruise vessels stays
- Data for 2023 port calls

Vessel operators have provided the following:

- Power demand profiles for 5 DSV calls, and 4 DSV calls

B.1.1 Data quality

In agreement with PoA, the historical berthing data have been cleaned to remove any cross-overs for visits which straddle different years and remove any non-berth data (visits labelled “TRIALS” or “ANCHOR”),

Different cruise operators have been directly contacted and a sufficient set of replies gathered. PoA confirmed to assume a 10 hour stay and provided the maximum length of cruise vessels which can use the port.

Vessel operator’s power data for DSVs and CSVs is very detailed, however there is a discrepancy between the length of the representative calls they provided, and actual call length data as supplied trough the historical berthing data.

B.1.2 Calls

As agreed with PoA, their projected data have been used on 2023 South Harbour calls, rather than extrapolating based on actual South Harbour calls in Nov-Dec 2022; this is primarily because the actual South Harbour data only covers 2 months – not sufficiently representative.

Call growth post 2023

PoA have given call growth for cruise and vessels to 2030 and for overall traffic growth to 2027. Further correspondence has agreed the following assumptions:

- the growth rate for non-cruise vessel types is the same
- general cargo vessels unlikely to use shore power
- the “decommissioning” vessel call sub-type is split proportionately between DSV and CSV calls.

Cargo vessels are generally more transient and in the case they require a shore power supply, it is envisaged that the their demands are not greater than the ones described for DSV/CSV. Therefore, the shore power system may allow them to connect.

Further correspondence has also clarified expected growth rates to 2030, and that after 2030 calls can be treated as constant.

The summary of these assumptions leads to the values set out in Table 9-3 below:

Table 9-3 Calls per year by vessel type 2023, 2027, 2030

	Calls/year		
	2023	2027	2030
General Cargo	29	75	94
DSV	59	153	193
CSV	24	61	77
Cruise	15	87	101
Total	127	367	465

B.1.3 Berthing hours

For cruise ships call duration has been confirmed by PoA to be 8am-6pm, i.e. 10 hours per call.

For DSV/CSV calls, it has been indicated that the duration will vary greatly by job, and that historic berthing data provided by PoA should be used.

It has been assumed that the North and South Harbour combined 2019-2022 and 2022 data is more likely to be representative, given the shortage of data points (14 in total) for DSV/CSV Nov-Dec 2022 at South Harbour.

For DSVs and CSVs (unlike for cruise vessels, whose likely call duration is clearly defined) the duration of calls is extremely varied, from a couple of hours to seven weeks as shown in Figure 9—3 and Figure 9—4.

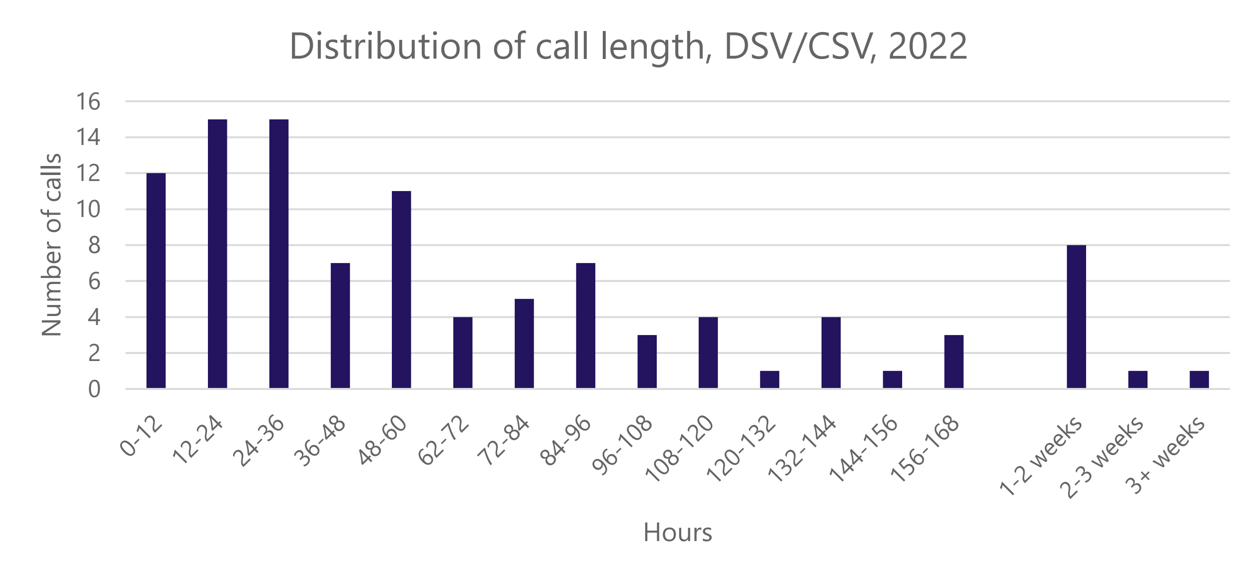


Figure 9—3 DSV/CSV call length in 2022 across North and South Harbour

Despite this wide variation within a year, the average call length per year is comparatively constant between years, as shown in Figure 9—4 and Table 9-4.

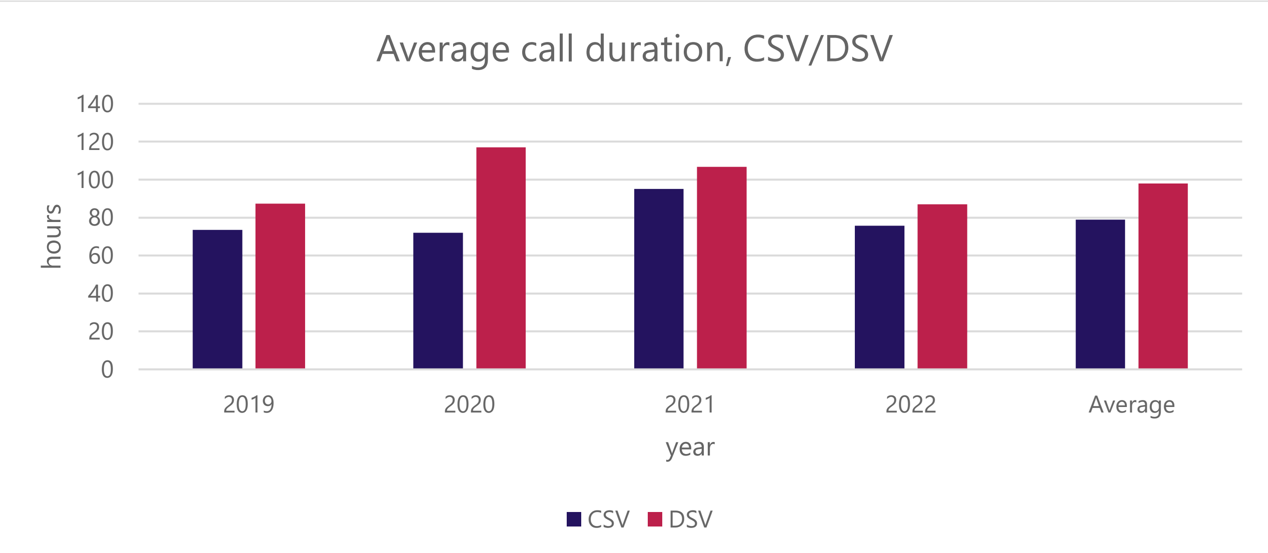


Figure 9—4 CSV/DSV average call duration

Table 9-4 CSV/DSV average call duration

Average call duration (hours)	CSV	DSV
2019	73	87
2020	72	117
2021	95	107
2022	76	87
2019-2022	79	98

These data show slightly higher call duration during COVID years (2020-2021). Data to date at South Harbour shows slightly longer calls than the 2022 average, skewed by 1 of the 14 calls being very long (7 weeks).

PoA have indicated that this call – an “winter layup” call – might be more prevalent in future. To accommodate such uncertainties, a “low” value for CSV/DSV duration as the 2022 average, and “high” value to be the 2019-2022 average have been used for the analysis of this report.

Table 9-5 range of CSV/DSV call duration

	Range of call length (hours)	
	CSV	CSV
Low	76	87
High	79	98

It is highly recommended that these figures are revisited at end October 2023, when a full year’s South Harbour data is available and constantly updated.

The berthing hours may not coincide with the actual shore power consumption period i.e. vessel could berth and not need any power supply. However, for the purpose of this report it is assumed that the two are coincident.

In summary, the total annual hours of potential shore demand, for differing values of call duration, for DSV, CSV and cruise in 2023, 2027 and 2030, are set out in Table 9-6 to Table 9-8 below.

The following values remove 1 hour per call for connecting/disconnecting:

Table 9-6 Call duration for shore power in 2023

2023		Annual call duration (hours) for shore power	
	No. of calls	Low	High
DSV	59	5,074	5,723
CSV	24	1,800	1,872
Cruise	15	135	135
TOTAL	98	7,009	7,730
	hours/year/berth	1,001	1,104
	hours/day/berth	3	3

Table 9-7 Call duration for shore power in 2027

2027		Annual call duration (hours) for shore power	
	No. of calls	Low	High
DSV	153	13,158	14,841
CSV	61	4,575	4,758
Cruise	87	783	783
TOTAL	301	18,516	20,382
	hours/year/berth	2,645	2,912
	hours/day/berth	7	8

Table 9-8 Call duration for shore power in 2030

2030		Annual call duration (hours) for shore power	
	No. of calls	Low	High
DSV	193	16,598	18,721
CSV	77	5,775	6,006
Cruise	101	909	909
TOTAL	371	23,282	25,636
	hours/year/berth	3326	3662
	hours/day/berth	9	10

Appendix C Shore Power Demands

C.1 Average power demands

C.1.1 DSV/CSV power demands

Vessel operators' data show a range of mean power demand across 5 example DSV calls at 1,266-1,440kW. These calls are 5-24 hour duration. This is not fully representative of berth duration, as some calls last many weeks. It has been confirmed that for longer duration calls, the data from example DSV4 could be used with mean power demand of 1,400kW.

DSV data has minimum power demands for the 5 calls in the range 936-1,022 kW, and peak power demands of 2,054-2,315kW.

For CSVs, data shows 4 long calls (32-120 hours), with mean power in the range 1,700-2,000kW.

C.1.2 Cruise power demand

The IMO provides data on vessel at berth power consumption by vessel class, but the cruise data is poor, with an assumption of 3,500kW for all vessels from 10,000-60,000 GT, and 11,500 kW for anything over 60,000 Gt. The list of ships from PoA has size varying from 40,000 to 110,000 Gt.

Different cruise operators have been contacted, asking for details on power consumption at berth and the power requirements have a wide range: 3 to 10 MW. However, the high end of these is not applicable to the south harbour, as these ships are too big - only the power data for vessels which would fit into South Harbour (length <280m) have been used.

The range of average demand for south harbour-compatible cruise vessels is 1.6 to 5.5 MW, with 2.5-3.5 MW the most common. On top of this, there are 3 "R-Class" vessels which have higher demands ~6-8 MW and they would fit into the south harbour.

Rig power demands

POA provided key data for the rig vessels that would potentially berth at the south harbour. It was acknowledged that a rig may not call into port in any given year depending on contract terms etc. However it was likely that a minimum of 2 rig calls per year would occur. On average the berthing period for the rigs would vary between 30 – 90 days per call. On average the rigs would consume approximately 8m3 of fuel per day and a power demand of 1.25MW.

Cargo vessels

As noted in discussion with the client it was assumed that cargo vessels would not utilise shore power on a call to call basis. Therefore demands for cargo vessels were not generated as part of this study.

Peak power demands

The data on CSV/DSV power demands is shown in Table 9-9

Table 9-9 Power demands statistics for CSV/DSV calls

Call	Mean power (MW)	90th percentile (MW)	99th percentile (MW)	Max (MW)
CSV 1	2.0	2.2	2.4	3.7
CSV 2	1.8	2.0	2.3	3.2
CSV 3	1.7	1.8	2.0	5.0
CSV 4	1.8	2.0	2.5	3.1
DSV 1	1.3	1.5	1.8	2.1
DSV 2	1.3	1.5	1.8	2.2
DSV 3	1.4	1.6	1.9	2.3
DSV 4	1.4	1.7	1.9	2.3
DSV 5	1.3	1.4	1.8	2.2

Following discussion with PoA, it has been agreed that for purposes of calculating maximum shore power requirements we would assume:

- 7 vessels at berth simultaneously, all capable of and wanting to use shore power;
- These would comprise one large cruise vessel (peak power 5.5 MW) one medium cruise vessel (peak power 3.6 MW), 2 CSVs and 3 DSVs;
- One of the DSVs and one of the CSVs would be considered at 99% percentile, the rest of the DSVs/CSVs would be considered at mean power.

This combines to give Table 9-10.

Table 9-10 Maximum power requirements at south harbour

	Power requirement (MW)
DSV 1	1.9
DSV 2	1.3
DSV 3	1.3
CSV 1	2.5
CSV 2	1.8
Large cruise	5.5
Medium cruise	3.6
TOTAL	18.1

These values shall however be coordinated and verified with all the operator willing to call at the south harbour and connect to shore power.

C.1.3 Annual power demands

The preceding values in previous sections combine to give the following summary for potential shore power annual demands at South Harbour, Table 9-11.

Table 9-11 Average annual south harbour shore power demand for DSV, CSV and Cruises

		Annual GWh					
		2023		2027		2030	
Average kW		Low	High	Low	High	Low	Mid
1400	DSV	7,104	8,012	18,421	20,777	23,237	26,209
1800	CSV	3,240	3,370	8,235	8,564	10,395	10,811
3500	Cruise	473	473	2,741	2,741	3,182	3,182
	Total	10,816	11,854	29,397	32,082	36,814	40,202

C.2 Profile generation methodology

For the renewable energy technology sizing and the techno-economic analysis, consumption profiles were generated for the shore power demand. In order to generate the shore power profile, detailed profiles for DSV/CSV calls were used.

Profiles for the other vessel types were not available. In the absence of profiles for cruise ships it was assumed they would utilise 100% of their power demand for 9 hours of the day, between 8am – 6pm. In addition assumption were made that the rigs would require 100% of their power demand for 24 hours of the day while at Berth.

The generation of a cumulative annual profile provides additional value to the work carried out previously as part of the berthing analysis. This is because the generated profile captures variation in call duration between vessels and therefore enabled a greater understanding of the base/peak loads for each call.

As outlined, in section 3.3 the duration of the call is dependent on multiple factor which are difficult to predict with confidence. The average call duration for the various vessels types were estimated based on POA data. As these were the average berthing periods they did not capture demand variations during the calls that would realistically occur.

As explained the detailed DSV/CSV call profiles provided do not align with the average berthing periods estimated trough the historical data. However, this was to be expected due the multiple factors and their uncertainties involved.

The intention of the generated energy profile is to provide a realistic shore power usage case. Therefore, the profiles were considered more realistic than the average call duration figures. Despite this, it is still important that the annual demand for the generated profile fits in the range of the four established uptake scenarios.

In order to establish the required annual power demand from the profiles, an average power demand (derived from the 99th percentile data) was used for the CSV and DSV vessels (Table 9-9). The higher percentile used as power demand is to cover for multiple uncertainties such as the different type of operators and different engine capacities of various vessels.

Both large and smaller cruise ships were captured in the generated profile. The power demand and distribution for these vessels were based off the POA's historical data and the IMO max power demand data. The rigs power demands utilised the data provided by the POA. A summary of the power demands used in the profile generation process is displayed in Table 9-12.

Table 9-12 Shore power profile power demands

large cruise Ships power consumption (kW)	Small cruise Ships power consumption (kW)	DSV power consumption (kW)	CSV power consumption (kW)	Rigs power consumption (kW)
5,500	3,500	1,936	2,525	1,250

The number of port calls per year per vessel type used in the generated profiles is displayed in Table 9-13. The number of port calls per profile matched the estimated port calls provided by the client, refer to section 3.3.

However, assumptions were made regarding distribution of the calls between winter and summer based on initial coordination with PoA. It was assumed that approximately two thirds of the DSV/CSV port calls would occur in summer. Primarily cruise ships berth during the summer and rigs only berthing during the winter. The seasonal port call breakdown is displayed in Table 9-14 and Table 9-15.

Table 9-13 Port caller per vessel type (2025 - 2030)

Years	Cruise Ships	DSV	CSV	Rigs
2023	15	59	24	2
2024	33	83	33	2
2025	51	106	43	2
2026	69	130	52	2
2027	87	153	61	2
2028	92	166	66	2
2029	96	180	72	2
2030	101	193	77	2

Table 9-14 Seasonal port call breakdown 2025

2025			
Port calls	Winter	Summer	Total (as per berthing analysis)
DSV	36	70	106
CSV	15	28	43
Cruise	1	50	51
Rig	2	0	2

Table 9-15 Seasonal port call breakdown 2030

2030			
Port calls	Winter	Summer	Total (as per berthing analysis)
DSV	49	144	193
CSV	26	51	77
Cruise	1	100	101
Rig	2	0	2

Two consumption profiles were generated using the port calls from 2025 and 2030 Figure 9—5 and Figure 9—6. The annual demand for both of these profiles falls between the low uptake and high uptake scenarios for the respective years as discussed, Figure 9—7.

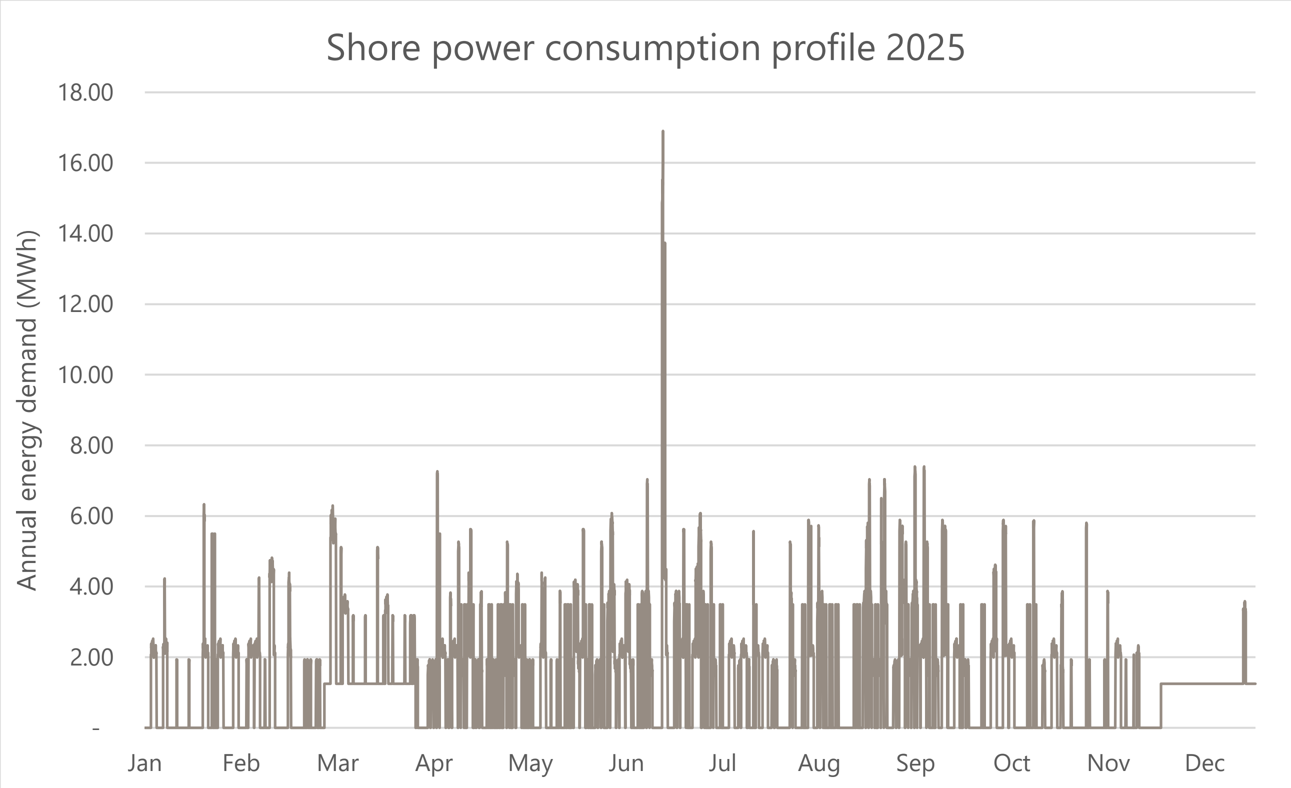


Figure 9—5 2025 Shore power profile

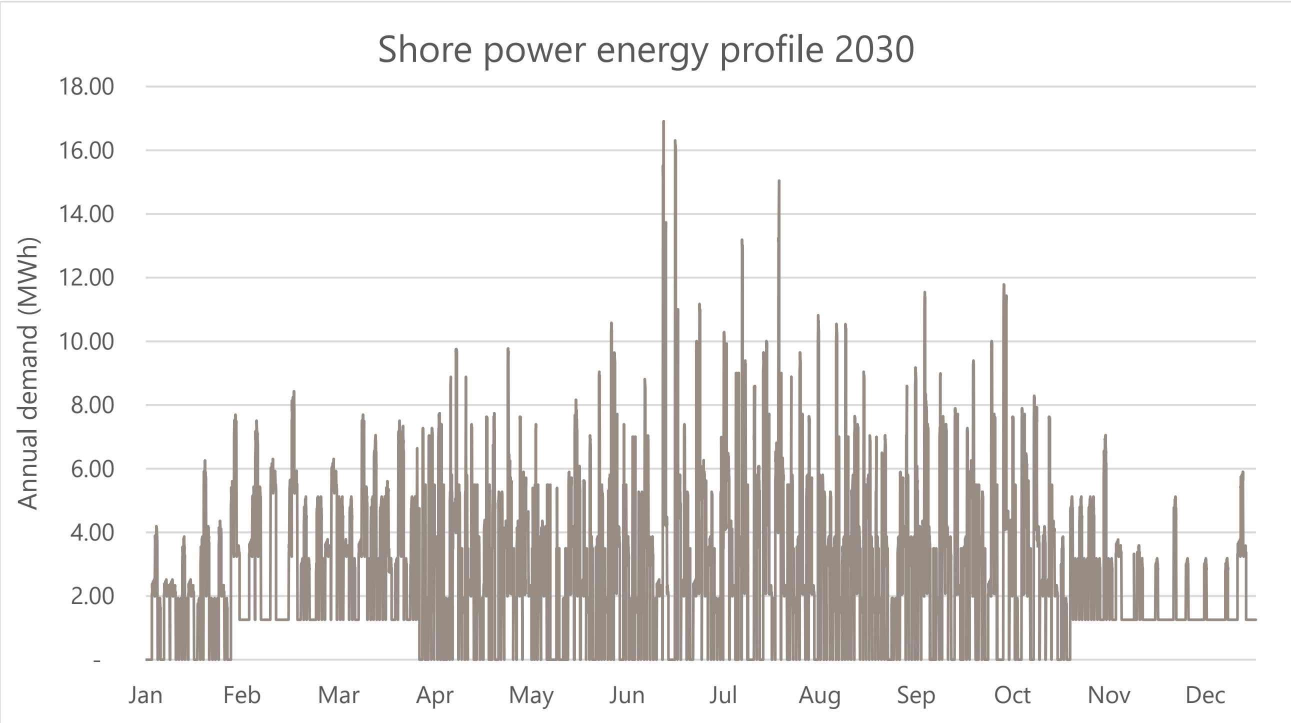


Figure 9—6 2030 shore power profile

Based on the two profiles in 2025 and 2030 a demand trajectory between those two points was generated. This is displayed in Table 9-16.

Table 9-16 Shore power profiles projected demand trajectory

Year	2025	2026	2027	2028	2029	2030
Shore power profile consumption projection (GWh/year)	11.28	14.15	17.03	19.90	22.78	25.65

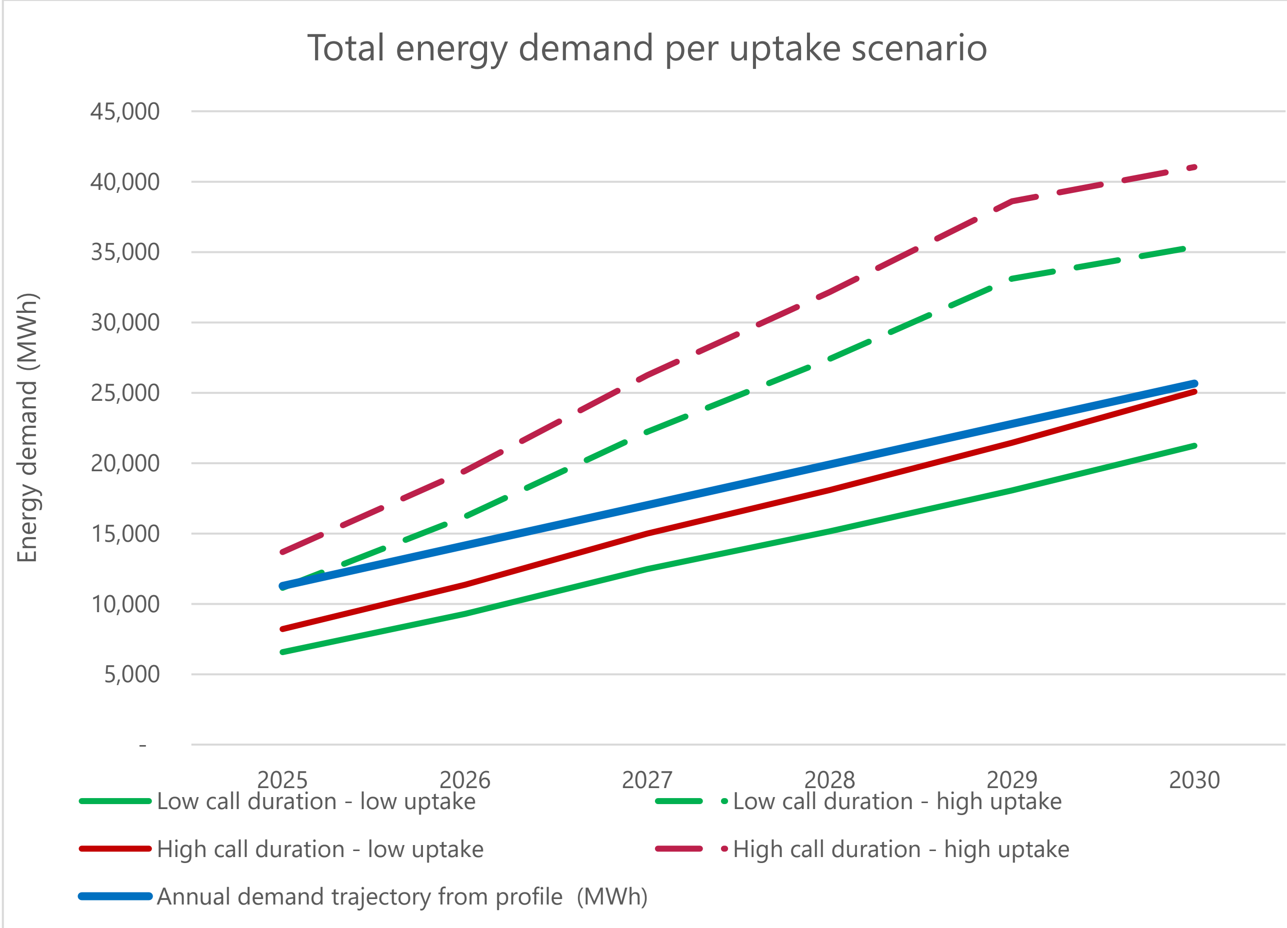


Figure 9—7 Shore power comparison between profile and average scenarios

Creation of the demand profiles is difficult task for vessel calls and their duration since these are unpredictable. However, it has been demonstrate that a profile created from detailed data for limited number of vessels fall within the previously estimated average scenarios.

Therefore, the renewable generation sizing will be based on these consumption profiles which are assumed reasonable. However, it is recommend to verify all these data trough detail metering of vessel consumption at berth as well as historical data of calls and duration at the south harbour (with at least 1 year or records).

For the shipside emissions the power demands were based on historical data for the different vessel types. The use of historical data does reduce risk surrounding the power consumption figures used for each vessel typology. However it is realistic that some vessels will be anomalies and have a demand not captured in the historical data.

Despite this, the creation of four uptake scenarios captures variation in the predicted berthing energy demands and therefore reduces risk. When the shore power system has been implemented a wider range of historical usage data will be available. This would improve the berthing, demand and profile analysis. In particular access to a wider range of hourly consumption data would improve the reliability of the profiling generation.

Detailed information regarding the ships engines and generators were not available at the time of this study. Therefore there is a risk associated with the SFC factor chosen for the carbon analysis. All vessels were assumed to have a MDO engines and have been constructed after 2001. A more detailed breakdown of the ships age and engine type would improve the reliability of the chosen SFC factor and reduce risk regarding the carbon emissions calculations.

Appendix D Landside demands

For the landside assets an assumption based on the size of the onsite substation was used to estimate the annual and peak demands. The below schematic (Figure 9—8) provided by the client was used to identify the key end use landside demands

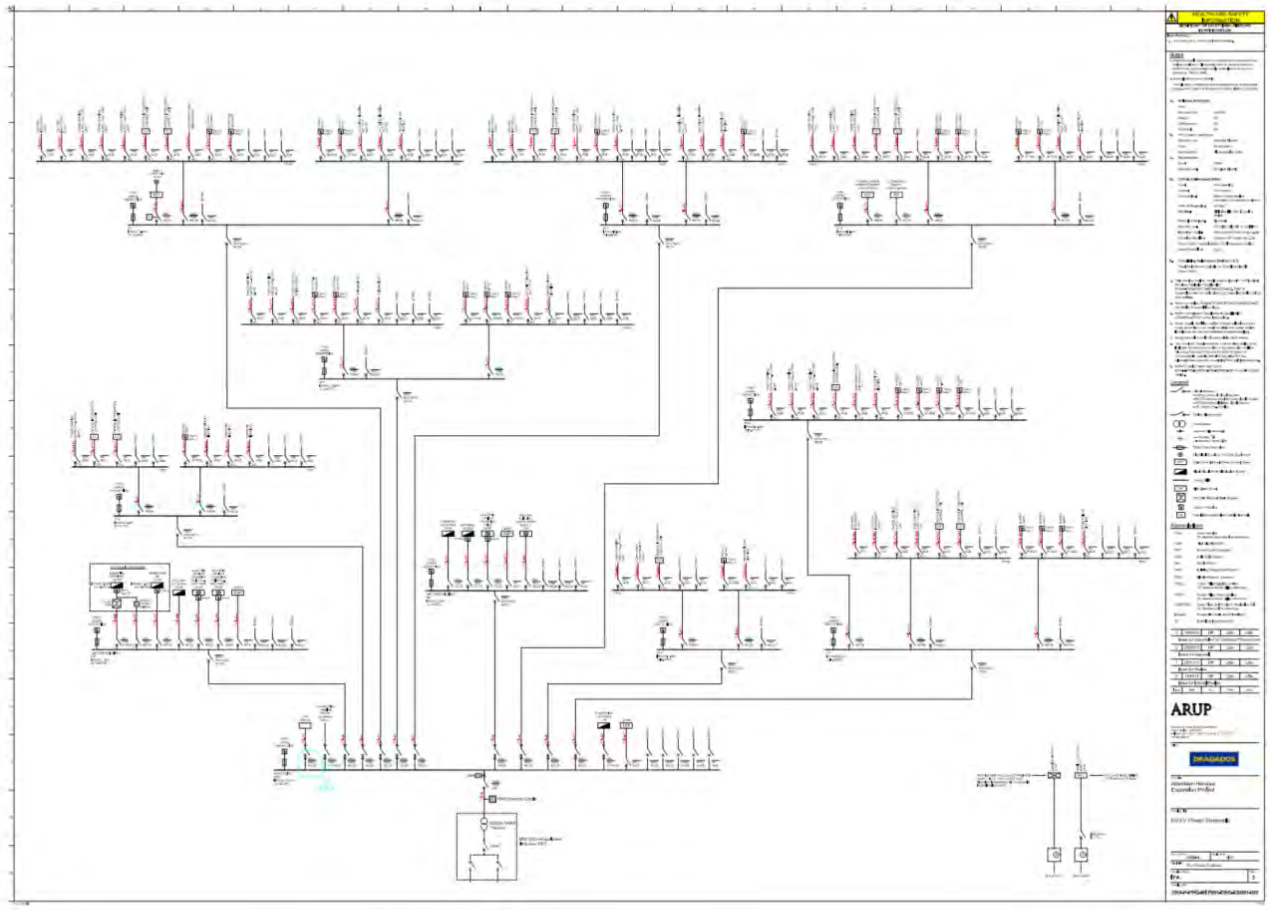


Figure 9—8 Electric infrastructure schematic for landside power use

It should be noted that the calculated landside demand was based upon the information available at the time of this study. Due to the assumptions made, the accuracy of the landside demands poses a risk to the study although fractional compared to the shipside demands

As the port is currently under construction the amount of data regarding the landside assets was limited. Additionally design statements/ building schematics for the new warehouse and new terminal building were not available at the time of this study. The reliability of the calculated landside demands would be improved through metered consumption data once the landside assets have been constructed and have been operational for a minimum of one year.

If metered data is not available industry standard benchmarks could be used, in conjunction with design plans and building layouts, to create a representative landside energy demand. Both of these methodologies would improve the reliability of the results and reduce risk associated with the data outputs.

Appendix E Potential EV charging demands

Additional EV charging infrastructure has been investigated only as a potential feature. The south harbour has already a provision EV charging (n. 3 of 50kW chargers) and these could be sufficient to serve the PoA's vehicles at the south harbour. At the time of writing this report, no additional information (number of vehicles expected, typology, millage etc) are available to assess any additional requirement for EV infrastructure to serve the PoA's fleet.

There is a possibility the chargers could be desired due to employee EV uptake, PoA EV uptake and tenants use of electric HGVs. Therefore, a provision for a ultra-fast charger (400kW) has been investigated. This could serve HGV, machinery such as mobile cranes etc which are under third party operations, hence not within PoA fleet.

Inclusion of such a charger would lead a upstream impact on the electrical infrastructure with the need for another transformer at one of the substations as well as an additional, cabling, switchgear, and feeder pillar, adding ~£500,000 to the capital costs of the project.

This option could be considered if/when PoA reaches an agreement with the operation agents to charge their vehicles at the south harbour.

Given the uncertainties and likely financial unfeasibility, the additional EV charging infrastructure and correlated power demands have been omitted from the techno-economic modelling and carbon emissions analysis.

The power demand of additional EV charging was calculated separately to the landside demands. Estimated demands were provisionally calculated for additional 4 no. slow chargers (7kW) to serve PoA fleet and 1 no. ultra-fast (400kW) charger for third parties' vehicles.

The peak capacity of the additional EV charging infrastructure was estimated at 416kW (438kVA). Using this information an annual demand of 1.281GWh was calculated.

A.1 Methodology

To calculate these provisional EV charging demands the following assumptions/steps below were used/preformed:

1. Assumed charger requirements: 4 no. slow chargers (7kW) for employee personal vehicles and 1 no. ultra-fast (400kW) mainly for PoA vehicles or personal employee vehicles but could also be used for tenant HGVs if desired
2. Estimated peak demand (kW): diversity factors were given from a DNO and were applied based on the quantity of each charger type
3. An hourly profile was produced based on the assumed daily consumption profile shown in Figure 9—9 for weekdays and weekends
4. Summed hourly profile for annual demand (GWh)

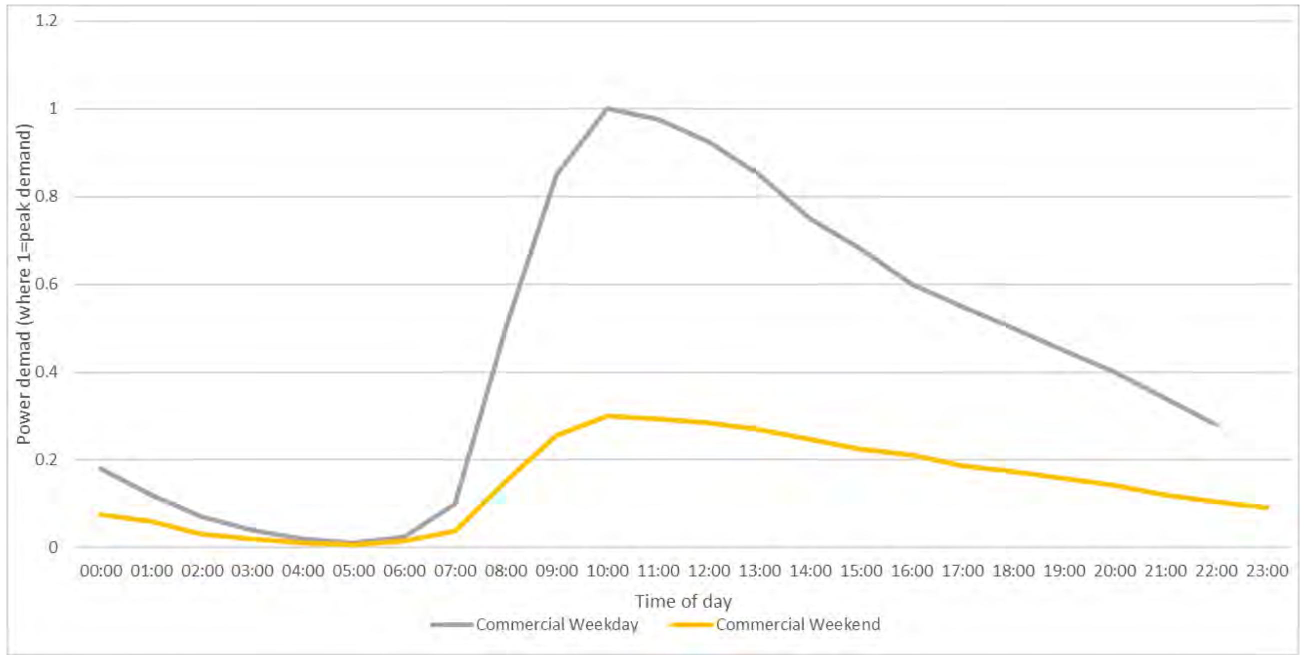


Figure 9—9 Estimated EV charging demand profile

A.2 Infrastructure requirements

If the additional EV chargers are desired, the following is required for each charger type:

- 7kW EV chargers will require a charge point sock and this could be like the one shown in Figure 9—9. As seen, the footprint of these is negligible and they can be located between the parking spaces within the existing carpark.
- 400kW chargers will require more land than the 7kW chargers and may require the use of a small part of land behind the parking space or the sacrifice of an entire parking space for it to be accommodated.

EV chargers for HGVs have been omitted from the infrastructure requirements due to the expected use of alternative fuels being used for most vehicles. However, if the 400kW charger were to be used and were positioned away from any height constraints (e.g., not directly beneath the solar carports etc.), there may be potential for dual purpose for HGV charging provided they have compatible connector types.

Figure 9—10 An Example 7kW EV charger

Figure 9—11 An example 400kW EV charger

Appendix F Carbon emissions

Utilising the data collected as part of the berthing analysis, carbon emissions for the POA could be established. It is key to capture the vessel emissions at berth as well as the carbon emission for landside power consumption. For the vessels at berth, two sets of carbon calculations are undertaken:

- A counterfactual scenario where the vessels would continue to utilise MGO for their berthing power requirements.
- A shore power scenario for the vessels at berth. This scenario is analysed as part of the techno-economic model

Carbon emission are calculated for three shore power scenarios:

- Low call duration | low uptake
- High call duration | high uptake
- Generated shore power profile demands.

The carbon emission for the low and high call uptake scenarios, based off the berthing analysis, is carried out to provide a worst and best case in terms of carbon dioxide reduction from shore power. The generated profile demands are captured to provide a realistic scenario (refer Appendix B further details). A MGO counterfactual is used for the initial carbon analysis. The impact of shore power on the carbon emission is investigated as part of the techno-economic modelling.

F.1 Methodology

The methodology for calculating carbon emissions of the vessels followed the methodology outlined in the International Maritime Organisation (IMO) fourth GHG study (2020). In order to calculate the carbon emissions associated with MGO consumption, the amount of fuel consumed by each vessel while at berth is required.

A Specific Fuel Consumption factor (SFC) estimates how much fuel vessels require to produce a kWh of energy. The SFC value is based on the vessel's age and engine type (Table 9-17). For the purpose of this study it is assumed all vessels would be Medium speed (MSD) and utilise a Marine diesel oil engine (MDO) resulting in a chosen SFC value of 0.175 kg/kWh of energy used.

Table 9-17 The SFC_{base} given in g/kWh for different engine and fuel types, and year of built

Engine type	Fuel type	Before 1983	1984 - 2000	2001 +
SSD	HFO	205	185	175
	MDO	190	175	165
	MeOH	N/A	N/A	350
MSD	HFO	215	195	185
	MDO	200	185	175
	MeOH	N/A	N/A	370
HSD	HFO	225	205	195
	MDO	210	190	185
LNG Otto (dual – fuel, medium-speed)	LNG	N/A	173	156
LNG Otto (dual – fuel, slow-speed)	LNG	N/A	N/A	148 LNG + 0.8 MDO (pilot)
LNG diesel (Dual fuel)	LNG	N/A	N/A	135 LNG + 6.0 MDO (pilot)
LBSI	LNG	N/A	156	156
Gas turbines	HFO	305	305	305
	MDO	300	300	300
	MeOH	N/A	N/A	203
Steam turbine (and boilers)	HFO	340	340	340
	MDO	320	320	320
	LNG	285	285	285
Auxiliary engines	HFO	225	205	195
	MDO	210	190	185
	LNG	N/A	173	156

[13] The CO2 reduction potential of shore-side electricity in Europe, B. Stolz, M. Held, G. Georges, K. Boulouchos, Appl. Energy, 285 (2021), Article 116425

Equation 1 denotes the conversion from power demand to fuel consumption utilising a SFC.

Equation 1

$$\mathrm{FC} = SFC \times W$$

FC = Fuel consumption

SFC = Specific fuel consumption factor

W = power in Ws

SFC values refer to mechanical power output of the engines. Academic research[13] into shipping fuel consumption notes that the efficiency of the onboards generators producing electricity from this mechanical power are estimated to be ~92%. Therefore, only 92% of the respective auxiliary engine power demand on board ships has to be supplied from the shore power system. To account for this the SFC factor used is adjusted based of a 0.92 efficiency factor, thus producing a SFC of 0.190 kg/kWh.

The IMO 4th GHG report gives emissions factors for a variety of pollutants, in kg per tonne fuel. In order to assess carbon emissions produced per kilogram of MGO consumed a carbon factor of 3.206 is used (Table 9-18). This process is outlined in Equation 2.

Table 9-18 Different fuels' fuel-based emission factors (EFf) and their carbon content.

Fuel type	EFf (g CO2/g fuel)
HFO	3.114
MDO	3.206
LNG	2.750
LSHFO 1.0%	3.114

Equation 2

$$\text{Carbon emisisons} = FC \times CF$$

CF = carbon factor

An overall carbon factor that accounts for the SFC conversion is calculated that would calculate the carbon emissions from the kWh power demand (as opposed to grams of fuel consumed). The overall factor was calculated as 0.610 kgCO2e/kWh and is outlined in Equation 3. This overall factor was taken forward for use within the techno economic model.

Equation 3

$$\text{Overall carbon factor} = \frac{SFC}{0.92} \times CF$$

$$\text{Carbon emisisons} = \mathit{Overall\ carbon\ factor} \times \mathit{Power\ demand}\ (kWh)$$

It should be noted that the International Maritime Organisation (IMO) fourth GHG study (2020) notes the possible inclusion of a load factor included as part of Equation 1. This addition is displayed in Equation 4.

Equation 4

$$\text{SFCme} = \text{SFCbase} * (0.455 * \text{load}^2 - 0.710 * load + 1.280)$$

The parenthetic component of Equation 4 is known as the main engine load correction factor (CFL). This correction factor accounts for variation in engine efficiency at varying movement speeds. This is not required when accounting for the fuel consumed at berth.

The outlined methodology is used to calculate the carbon emissions associated with the vessels using MGO while at berth. The calculated carbon factor of as 0.610 kgCO2e/kWh is applied to the demand throughout the project lifetime. Generally, there are no significant changes to the carbon factor associated with MGO, as its chemical composition remains constant year on year. he current UK grid energy mix consists of a wide range of technologies, e.g. nuclear power stations, gas power plants, wind farms, coal power stations etc. Additionally it's anticipated the UK grid will decarbonise as the UK transitions away from gas electricity generation. For these reasons the future power grid emissions factor published by DESNZ was used to simulate future changes in the electricity carbon emissions.

The DESNZ Grid average consumption based, commercial/ public sector carbon projections was chosen for the electricity carbon factor indexation. Figure 9—13 indicates the decrease in the carbon intensity of the UK national grid as discussed previously.

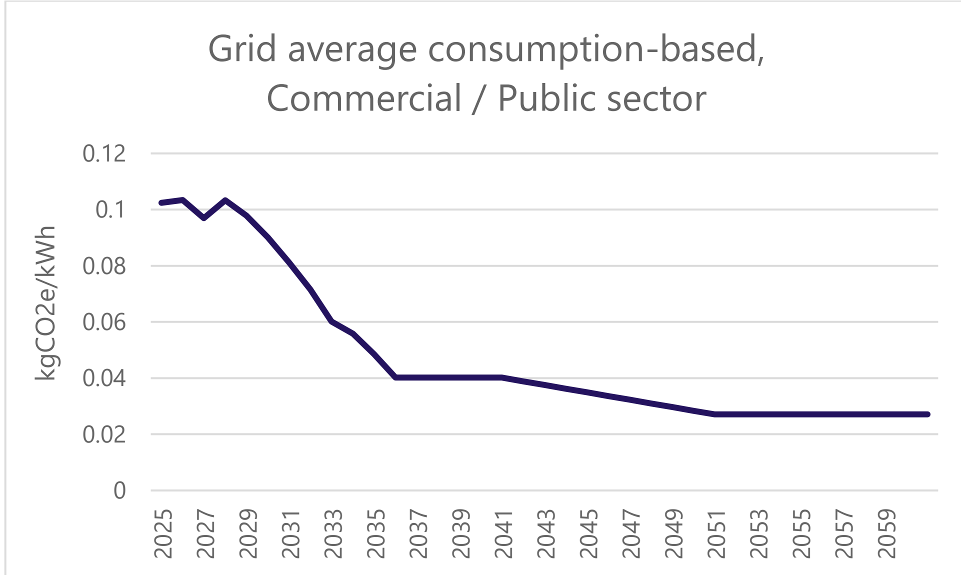


Figure 9—12 BEIS grid electricity carbon emissions projections

F.2 Analysis emissions at berth

Using the energy demands from the low and high uptake scenarios, carbon emissions associated with the vessels at berth utilising MGO is displayed in Figure 9—13 and Figure 9—14 respectively. The highest carbon emissions are associated with the DSV vessels, due to the large number of expected port calls per year. The carbon emissions remain constant from 2030 onwards in line with the POA build out plan, Table 9-19

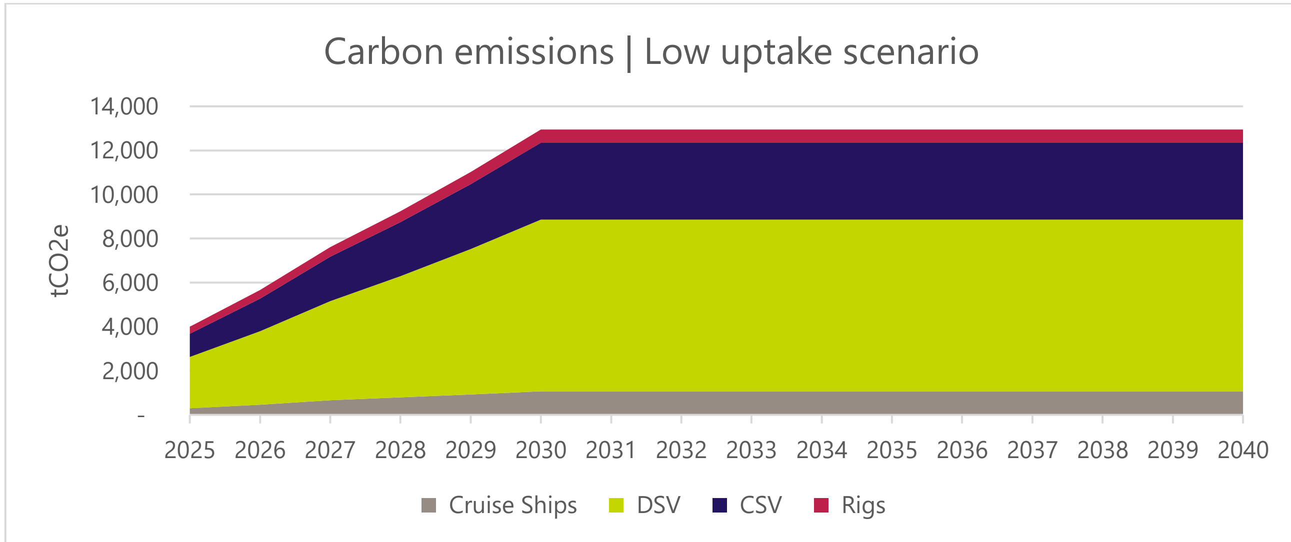


Figure 9—13 Low uptake berthing emissions

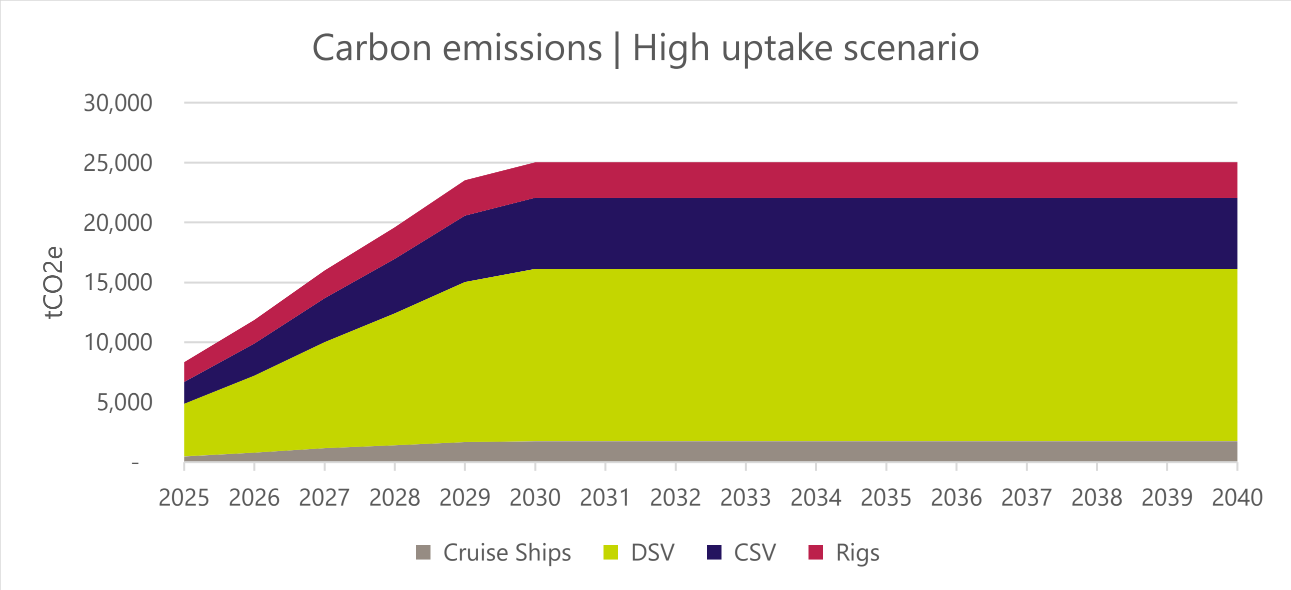


Figure 9—14 High uptake berthing emissions

Table 9-19 Annual carbon emissions per year at build out

Year	2025	2026	2027	2028	2029	2030
Low uptake scenario carbon emissions (tCO2e/yr)	4,006	5,666	7,608	9,238	11,018	12,949
High uptake scenario carbon emissions (tCO2e/yr)	8,342	11,861	15,997	19,603	23,539	25,024

F.3 Modelled shipside emissions

The shore power energy profile is used to generate annual demands that are taken forward as part of the techno economic analysis. Two sets of carbon emissions are derived from these demands:

- A counterfactual assessment with the vessels still using MGO
- A shore power scenario where the vessels utilise electricity to meet their power demand.

These two sets of data enable the carbon savings of the shore power system to be quantified.

The carbon emissions associated with MGO consumption is displayed in Table 9-20. Again the carbon emission remains constant from 2030 onwards. A detailed breakdown of the carbon emissions per vessel type was not possible due to the methodology used for the profile creation. However for the purpose of assessing the entire ports annual carbon emissions this level of granularity is not required.

Table 9-20 Carbon emissions from generated scenario

Year	2025	2026	2027	2028	2029	2030
Realistic profile scenario carbon emissions tCO2e/yr	6,876	8,629	10,383	12,136	13,890	15,643

A comparison between the MGO emissions at berth is displayed in Figure 9—15. This figure indicates that the profile generated emissions falls between the the low and high uptake scenarios. This reinforces the impression that the profile generated emissions provides realistic case.

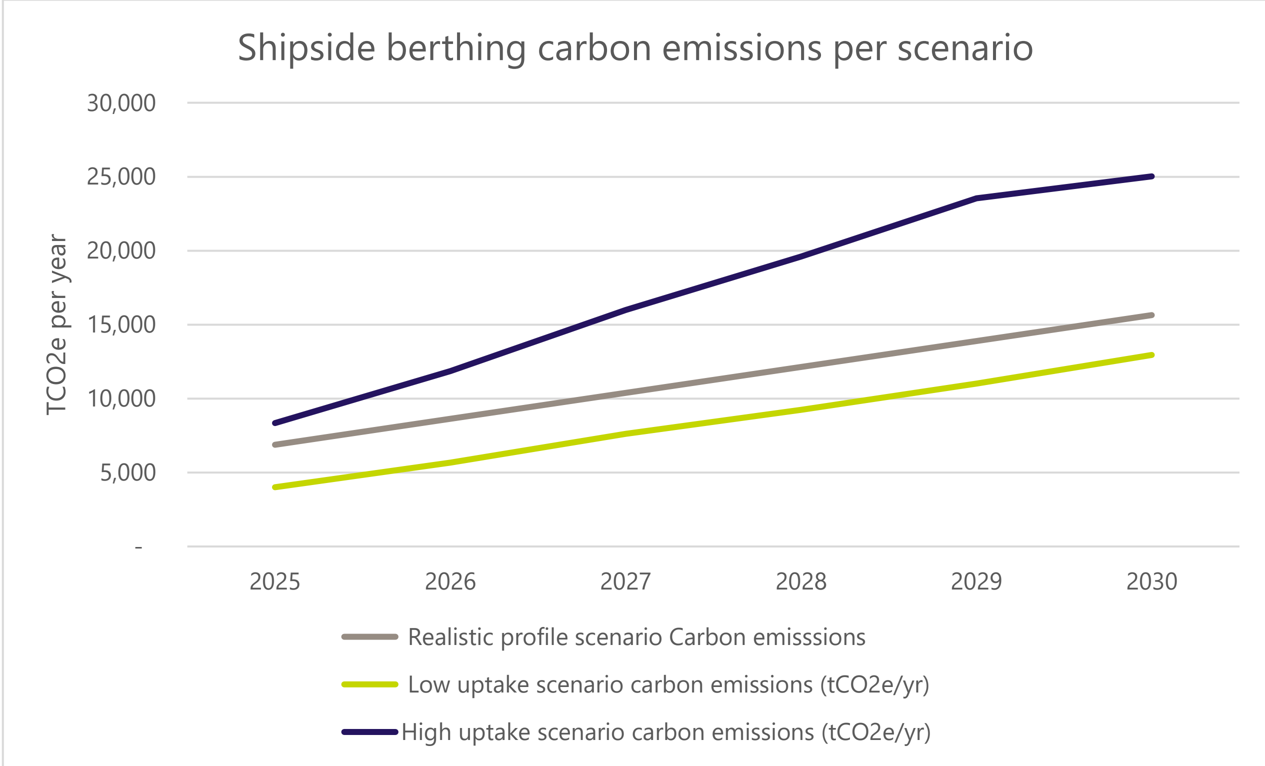


Figure 9—15 Shipside berthing emissions per scenario

A breakdown of the carbon emissions associated with the shore power systems is discussed in sections 5.7 , 6.8 and 7.6. These section contains further details regarding the electricity carbon factor used and the methodology behind indexing the grid carbon factor. In addition the carbon savings are outlined.

F.4 Landside emissions

Based on information provided by the client the landside demands are fully electrified i.e. there is no existing gas infrastructure. For these reasons the future power grid emissions factor published by BEIS is used to simulate future changes in the electricity carbon emissions.

The carbon factors used and associated carbon emissions is displayed in table (Table 9-21). There is no change in the landside energy demands year on year, therefore the reduction in carbon emissions is driven by the decarbonisation of the grid as discussed previously.

When assessing the entire port's carbon emissions it's clear that the landside emissions have a marginal impact compared to the emissions at berth. This places emphasis on the need for a shore power system to deliver POA's net zero goals.

Table 9-21 Landside carbon factors and emissions

Year	2025	2026	2027	2028	2029	2030
Grid average consumption-based, Commercial / Public sector carbon factor kgCO2e/kWh	0.123	0.091	0.075	0.069	0.065	0.052
Landside and EV charging emissions factor tCO2e	335	248	204	188	177	208

Appendix G PoA carbon reduction plan

PoA has recently finalised a carbon reduction plan for the north harbour which includes a detail emission catalogue as well as a number of option to cut the emission in next 5, 10 and 15 years.

Reduction measures are outlined within the Plan, and it is projected PoA can achieve:

- Net Zero within scope 1 and 2 emission sources by 2035 achieving reduction of 82.93%
- A reduction of scope 3 sources by 57% by 2040

The scope emission breakdown is provided below with comments regarding the applicability at the south harbours.

G.1 Scope 1

In order to achieve 53% reduction target within scope 1, the following reduction measures are planned for 2025, 2030 and 2035.

Table 9-22 Scope 1 North Harbour carbon reduction plan, reproduced from [14]

Targeted emission source	**Reduction initiative**	**Reduction Target %**			**Comments** (Burohapoold)
		2025	**2030**	**2035**	
company facilities, fugitive emissions (F- gas)	Annual Maintenance checks to prevent leaks	5%	-	-	
Company fleet, vehicles, and vans	Replacement of diesel/petrol company cars with electric. PoA has a total of 19 vehicles, 2 out of 19 are currently electric. Two to be replaced in 2023. Aiming to replace 13 vehicles from 2023 to 2035, with the intention of having a fully electric fleet by 2040.	Replace 2 more cars to electric	Replace four more cars to electric	Replace 5 more cars to electric (only 4 cars left diesel to offset)	It is envisaged that the South Harbour would not need any car replacement as electric cars should be chosen in first place.
Company fleet, pilot boats	PoA currently has three pilot boats. HVO implementation in short term. Electrification set to be complete by 2030..	HVO trialling planned for 2023-25. Emission saving based on a 25% rollout.	Electrification of all pilot boats.	-	South Harbour is not currently hosting pilot boasts. However, the shower power provision would support the 2030 target is required.
Equipment and machinery	HVO testing and implementation in short-term. Electrification of all equipment set to be complete by 2030.	HVO trialling planned for 2023-25. Emission saving based on a 25% rollout.	Electrification of all port equipment and machinery.	-	No fixed equipment is envisaged within the South Harbour
Gas	Conduct an energy efficiency audit to explore insulation and energy efficiency options for the Port buildings.	Reduce 5% by implementing recommendation from 2023 Energy audits.	-	-	No gas network exist or is planned at the south harbour

[14] Port Of Aberdeen – Carbon Reduction Plan, Sealand projects (2023)

The overall targets set at the north harbour appear achievable and they could potentially be exceeded at the south harbour. Being a brand new harbour, PoA could ensure the following for the south harbour:

- Deploy directly electric cars
- New infrastructure shall guarantee minimum/zero fugitive emissions
- The pilot boats to compatible with the shore power system proposed

It is noted that the machinery and port equipment under PoA ownership is envisaged to be very limited at the south harbour with only fork lift and small vans. These could be electrified in line with the above targets or before.

G.2 Scope 2

Table 9-23 Scope 2 North Harbour carbon reduction plan, reproduced from

Targeted emission source	**Reduction initiative**	**Reduction Target %**			**Comments** (Burohapoold)
		2025	**2030**	**2035**	
Electricity	Perform energy efficiency audit. Investigate the best RE purchase option. Onsite clean energy production feasibility testing and potential implementation. Or direct line- Purchase Power Agreement with renewable energy supplier.	Energy audits to be planned for 2023-2024 and measures to be implemented by 2025 which is anticipated to bring a 5% reduction & Procurement of a renewable energy tariff.	Renewable tariff procured.	Onsite clean energy Production OR Direct line/ Purchase Power Agreement with Renewable Supplier.	In line with proposed strategy within the South Harbour

Scope 2 emission carbon plan can be implemented at the south harbour and on site renewable generation will be investigated. These shall also include any demands coming the shore power system.

G.3 Scope 3

Scope 3 reduction measures have been split into non-tenant and tenant activities, the combined reduction for the following tables achieves a 57% emission saving across all scope 3 sources.

G.3.1 Non-tenant

In order to achieve the 28.88% reduction target in scope 3 non-tenant activities the following measures:

Table 9-24 Scope 3 Non-Tenant North Harbour carbon reduction plan, reproduced from [15]

Targeted emission source	**Reduction initiative**	**Reduction Target %**			**Comments** (Burohapoold)
		2025	**2030**	**2035**	
Business Travel	Start a carbon budget and cap travel- aim to reduce travel by utilising MS Teams.	Reduce travel by 25%	Reduce travel by 50%	Reduce travel by 75% Offset the rest	Applicable to South Harbour
Waste	Reduce, reuse, recycle. Assign the Environmental Coordinator to find opportunities to reduce and reuse.	25%	50%	Maintain 50%	Applicable to South Harbour
Employee commute	Cycle to work scheme. Increase of electric car charging points Salary sacrifice scheme for electric cars	12.5% reduction	25%	Maintain 25%	Applicable to South Harbour
Water	Water audit to detect leaks. Implementation of water saving technology	5% reduction	12.5%	12.5%	Applicable to South Harbour
WFH	-	-	-	-	

G.3.2 Tenant

In order to achieve the 57% reduction target in scope 3 tenant activities the following measures are planned for 2025-2040:

Table 9-25 Tenant Scope 3 North Harbour carbon reduction plan, reproduced from 15

Targeted emission source	**Reduction initiative**	**Reduction Target %**			**Comments** (Burohapoold)
		2025	**2030**	**2035**	
Client Vessels	Shore Power: Albert	Planned implementation for 2023.	-	-	Shore power is already included in the south harbour energy strategy
	Shore Power Mearns	Planned implementation for 2023.	-	-	
	Shore power: RORO	Planned implementation for 2023.	-	-	
	Shore power: Torry	-	implementation		
	Shore power: Eurolink	-		implementation	
	Shore power: Jamieson	-		implementation	
	Shore power: Trinity	-		implementation	
	Shore power: Waterloo	-	implementation		
	Shore power: Clipper	-	implementation		
	On-site carbon capture	-	-	Feasibility testing	Potentially considered for the south harbour
	Invest in port infrastructure to provide clean fuel for vessels (LNG/biodiesel/H2 / NH3)	-	-	-	Potentially considered for the south harbour
	Operational measures: Reduce speed at harbour jurisdiction	Reduce 5%	-	-	To be considered for the south harbour
	Operational measures: Decrease waiting time at the anchor	Reduce 4%	-	-	To be considered for the south harbour
	Incentivise clean fuel vessels	-	-	-	Potentially considered for the south harbour
Electricity and Gas use in tenant facilities	Energy efficiency audits and implementation of recommended measures. Award schemes with tenants to reduce emissions. Potential for onsite clean energy production use for tenants.	5%	25% Influencing tenants to use clean energy	50% Potential for clean energy provided onsite	South harbour currently has no tenants.

[15] Port Of Aberdeen – Carbon Reduction Plan, Sealand projects (2023)

Appendix H Solar PV

Solar photovoltaic (PV) is a mature technology and converts sunlight into electricity without emitting any operational greenhouse gases or other pollutants, making it key to decarbonising the power sector.

To validate the suitability of the South Harbour for solar PV, Buro Happold initially produced the annual generation map in Figure 9—16. Data was taken from Global Solar Atlas and symbology was later applied in QGIS to create a better visualisation at the harbour.

From the image, it's observed that a maximum annual generation of ~916kWh/kWp is possible which warranted a study of the solar PV potential on site.

The suitability of roof mounted, ground mounted, and carports is investigated further within this section.

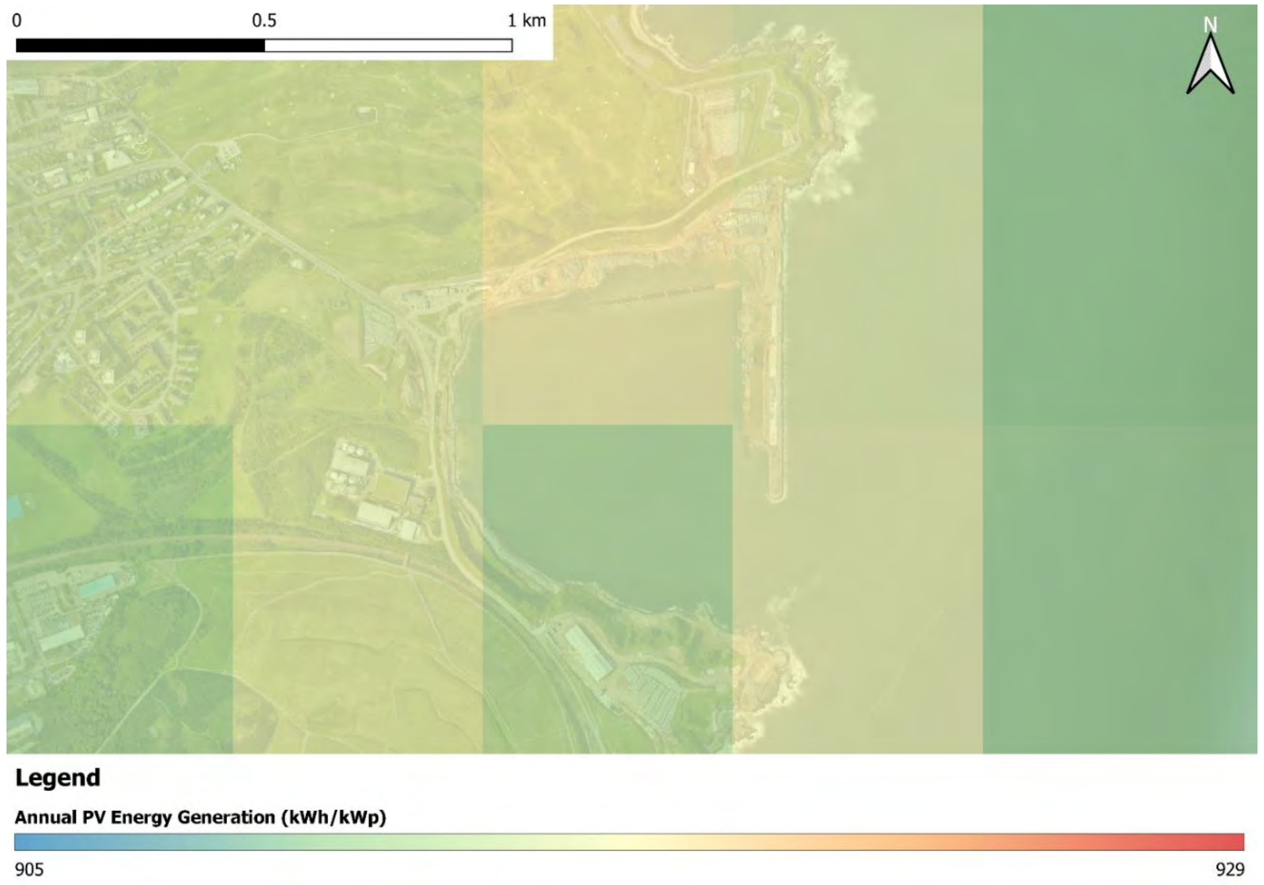


Figure 9—16 PoA south harbour solar irradiance map

H.1 Roof mounted

The assumptions/inputs used to quantify the rooftop PV potential are outlined in Table 9-26. For the new buildings, the conservative assumptions of their nominal capacity potential being equal to their peak power demand, and the PV orientations being southeast facing were also made.

The methodology used was as follows:

1. Gather inputs in Table 9-26
2. Estimate available capacity:
   a. $\frac{220Wp}{m^2} \times measured\ rooftop\ area\ (m^2) \times rooftop\ area\ reduction\ (\%)$
3. Obtain annual generation potential for south, east, west, southeast, and southwest orientations in PVGIS for a 1kWp system (kWh/kWp)
4. Apply the annual generation potential to each measured rooftop's nominal capacity for their respective orientation
5. Summarise the potential of each building

Table 9-26 Rooftop solar PV assumptions and inputs

Description	Value(s)	Input Source
Nominal array capacity per area (Wp/m^2)	220	SunPower
Pitched roof slope (°)	30	Buro Happold assumption
Generation per capacity at each orientation (kWh/kWp)	South: 881.34 West: 696.21 East: 693.57 Southwest: 828.33 Southeast: 825.76	PVGIS
Available area reduction (for maintenance walkways etc.)	Pitched roof: 20% Flat roof: 40%	Buro Happold assumption
Measure rooftop area (planes that are suitable for PV)	Building: 1: 103 m^2 2: 25 m^2 3: 67 m^2 4: 36 m^2	Measured from incoming drawings

H.1.1 Carports

The methodology/assumptions used to calculate the solar PV carport potential was as follows:

1. Gather inputs in Table 9-27
2. Estimate available capacity:
   a. $\frac{220Wp}{m^2} \times measured\ suitable\ parking\ space\ area\ (m^2)$
3. Obtain annual generation potential for different orientations/azimuths in PVGIS for a 1kWp system (kWh/kWp)
4. Apply the annual generation potential to each carport's nominal capacity for their respective orientation

5. Summarise the potential of the entire carpark

Table 9-27 Solar PV carport assumptions and inputs

Description	Value(s)	Input Source
Nominal array capacity per area (Wp/m^2)	220	SunPower
Carport slope (°)	10	Buro Happold assumption
Generation per capacity at each orientation/azimuth (kWh/kWp)	0° (south): 790.96 13.7°: 789.01 -28.3°: 781.62 70.7°: 741.63	PVGIS
Potential PV area	Shown in	Measured from incoming drawings

Appendix I Wind turbines

Wind turbines are a mature technology which convert kinetic energy in the wind into mechanical energy (as the blades turn), which is in turn converted into electricity via a generator. This is done without emitting any operational greenhouse gases or other pollutants, making it key to decarbonising the power sector.

To validate the suitability of the South Harbour for wind turbines, Buro Happold initially produced the average wind speed maps at 50m and 100m heights in Figure 9—17 and Figure 9—18respectively. Data was taken from Global Wind Atlas and symbology was later applied in QGIS to create a better visualisation at the harbour. It was observed that average wind speeds are ~7.5m/s and ~8.6Xm/s at 50m and 100m heights respectively. These results warranted a further study of wind turbines at the harbour.

The suitable locations and generation potential are discussed within this section.

Figure 9—17 PoA south harbour wind speeds at 50m

Figure 9—18 PoA south harbour wind speeds at 100m

I.1 Suitable locations

Wind turbines are subject to many locational constraints. Using the geographical constraints in Table 9-28 and case studies on existing wind turbine locations, the potential locations in Figure 9—19 were derived. The only geographical constraint (at a desktop study stage) was the small site of special scientific interest (SSSI) (shown in the figure). Also, the locations are or have potential to be in line with the buffer zones outlined in Table 9-29.

The proposed locations and some of the potential alternatives have a numeric ID in Figure 9—19 and are described in more detail below:

- 1: This is located onshore and within PoA's land ownership. It is the preferred location because it would require the least amount of infrastructure upon installation.
- 2+3: These could be installed along the breakwater like the setup shown in Figure 9—20 (left) or alternatively, installed slightly offshore as per Figure 9—20 (right). Onshore installation is deemed unfeasible due to the restricted access along the breakwater and the related impact on the breakwater structure itself.
- 4: Turbine(s) could be positioned onshore and parallel to the port as in Figure 9—21 or slightly offshore as in Figure 9—20 (right). This location has been ruled out due to the topographic constraint of this area.

Quantities of wind turbines at each location are dependent on the size of the installed turbine and their spacing requirements.

Overall, one wind turbine at location 1 was proposed due to PoA's preference, predicted lower capital costs, and the energy modelling results of a 6MW wind turbine in section 6.5.

Figure 9—19 Potential wind turbine locations

Table 9-28 Wind turbine geographical constraints

Turbine/Geographical Constraint	Source
Ramsar	Scottish Government
Special protection areas	Scottish Government
National scenic areas	Scottish Government
NNR	Scottish Government
Sites of special scientific interest	Scottish Government
Planned renewable energy projects	DESNZ

Table 9-29 Wind turbine buffer zones

Type	Buffer distance (m)	Reference
Residential buildings	500	[16]
Road	1.1 x turbine height	[17]
Railway tracks	1.5 x turbine height	[18]

[16] RegenSW. (2012), *Residential buffer zones for wind turbines*, RegenSW, pp. 5.
[17] Sunderland City Council. (2020), *Wind Energy Development Study*, pp. 17.

Figure 9—20 Example of wind turbines on a breakwater – Port of Antwerp-Bruges, Belgium (left) Example of (slightly) offshore wind turbine - IJsselmeerdijk, Netherlands (right)

Figure 9—21 Example of wind turbines along a portside – Mersey Wind Farms, Port of Liverpool

[18] Sunderland City Council. (2020), *Wind Energy Development Study*, pp. 17.

I.2 Generation potential

To understand the generation potential at the port, the hourly generation output of an example 6MW wind turbine was calculated (at 100m hub height) using Renewables.ninja, an online research tool that takes wind speed data and uses the virtual wind farm model to produce hourly power outputs for wind turbines from leading manufacturers. These hourly outputs were summed to give the 24.51GWh annual production mentioned in section 6.4.2.

Appendix J Battery Energy Storage System - BESS

Buro Happold have tabulated a list of battery energy storage technologies in Table 9-30 to compare mainly costs and performances.

Table 9-30 includes batteries which are widely available up to those which are emerging and could be considered an option for the future. In summary, the Lithium-ion outperforms all other options significantly within the current market and is suggested as the near-term solution if a battery is desired.

On the other hand, solid state batteries could be explored in the longer-term if a battery is desired due to the expected high energy densities. It must be noted that this industry is rapidly developing and changing and therefore if a battery were to be installed in the longer-term, the market should be re-evaluated.

Table 9-30 Battery energy storage systems comparison

Battery Energy Storage System	Readiness	Approx. Cost per kWh (£/kWh) 2018	Approx. Cost per kWh (£/kWh) 2025	Energy Density (Wh/l)	Cycle life (equivalent full cycles)	Advantages	Disadvantages
Lithium-ion	Widely available	271	189	200-735	500-20,000 cycles	Very high energy density, low maintenance, long cycle life, scalable, cost efficient	Risk of thermal runaway, limited thermal tolerance
Lead-acid	Widely available	260	220	50-100	250-2,500 cycles	Low cost, simple technology, reliable	Low energy density, short cycle life, poor performance in low temperatures
Sodium-sulfur	Commercially available	661	465	140-300	1,000-10,000 cycles	High energy density, long cycle life	High cost, high operating temperature, sodium polysulfides are corrosive
Redox flow	Emerging technology	555	393	15-70	12,000-14,000 cycles	Low cost, long cycle life, low toxicity	Low energy density, complex technology, limited thermal tolerance, high cost, limited scalability
Nickel-cadmium	Widely available	400	N/A	70-170	2,000-2,500 cycles	Reliable	High cost, low energy density, toxicity concerns
Nickel-metal hydride	Widely available	250-1500 (year 2008)	N/A	100-280	1,000-5,000 cycles	High energy density	Short cycle life
Solid-state	Emerging technology	N/A	400-800 (2026)	>1000	5,000-10,000 cycles	Very high energy density	High cost, still in development

Appendix K Infrastructure Requirements

K.1 Baseline

All proposed Infrastructure design has the aim of reducing the civil works required to deploy the shore power system, especially near the berth while allowing flexibility for the future deployment of alternative fuel pipelines.

This is achieved maximising the utilization of the existing infrastructure (utility trenches) and routing the cable to avoid the areas with significant concrete which would require hard digging.

The main components that were investigated in more detail and have been deemed crucial in the space planning exercise are listed below:

- Main substation location
- LV transformer locations
- New trenches
- Use of the existing trenching
- Clipped cabling beneath the suspended deck
- Connection point locations

Based on indicative selection of equipment and cables, arrangements discussed in this section should be able to provide the required power to each connection point, also considering the derating losses in the power distribution.

However, cable derating shall be carefully investigated during the next stage of design since it could prevent the system operation. In particular, selection of cables, trench configuration and typology (number of cables and their spacing) shall be further studied.

K.1.1 Primary Substation location

The proposed main substation location is shown on the West of Figure 5—2 (in section 5.5). This location was selected due to PoA's desire to keep the North-East of the port clear for quayside operations. Note that the identified area also includes indicative provisions for BESS and the isolation transformers. The total estimated land take comes to ~38 x 43m.

Also, it is very likely that SSE would add their own primary substation nearby due to several upcoming projects within the vicinity of PoA. If this were the case, it could lead to reductions in network reinforcement costs for PoA.

It is also known that this area is under further investigation from a PoA ownership perspective and it is included in a regional discussion with close developments.

K.1.2 LV transformer locations

LVSC requires a shoreside step-down transformer and an isolation transformer at the shoreside due to the expected high loads of the vessels. This has been allocated an indicative space allocation of ~5x5m.

There are two locations proposed (one in Dunnottar and one in Crathes). These locations were selected as they are believed to be where LV vessels would most likely berth and would have the least impact on quayside operations.

It should be noted that any vessels that require a 690V LV supply must call at one of these berthing points should they wish to connect to shore power.

K.1.3 Connection point locations

Connection points contain the junction boxes and would be located at the berthing area. One side of a CMS will connect to these junction boxes (and the other side will connect to the vessel).

There are ten connection points proposed and their locations are shown in Figure 5—2 (in section 5.5). The locations of these aim to limit any significant impact to quayside operations by being as close to the berthing points as possible, reducing the impact from cabling lying on the quayside floor. Furthermore, the area that each CMS can serve will be greater.

K.1.4 New trenches

The solid lines shown in Figure 5—2 (in section 5.5) are showing cabling areas which would require new trenches and it is likely that these areas will be direct buried and ducted.

Figure 9—22 shows an indicative cross section of the trench and Figure 9—23 shows an example of what the ducting could look like.

Adequate protection shall be carefully investigated during the design stages to ensure any potential interaction between utilities is fully controlled and the risk accounted for.

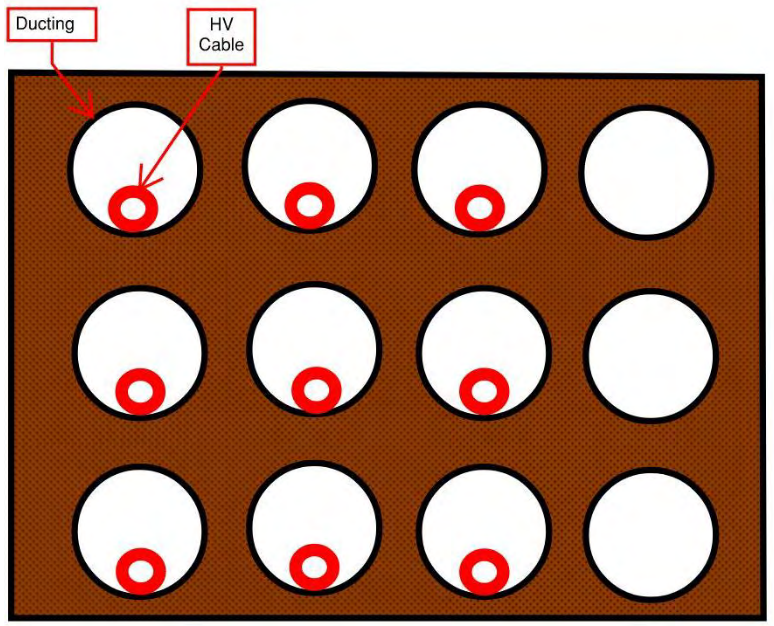


Figure 9—22 Indicative direct buried trenching arrangement

Figure 9—23 Example of direct buried ducted cables (from etech components)[19]

K.1.5 Existing trenches

The dashed red lines within the blue lines shown in Figure 5—2 (in section 5.5) (at Dunnottar and Crathes) represent the proposed use of existing trenches for cabling.

The existing trenches are utilised only after where it is believed future fuel supplies stop. This is to account for to the uncertainty on regulations regarding the use of HV cabling alongside future fuel lines.

By doing this, the risk of the potential significant disruption due to failure of one of the two networks (HV or Fuel) within the same trench is significantly reduced.

Figure 9—24 shows the existing trench cross section in which the existing potable water piping has been shown alongside the proposed HV cables (clipped to the wall of the trench). Size and location of the existing trench as well as the potable network has been taken from the detailed drawings provided by PoA.

It is envisaged that the size of the trench will easily allow the installation of the HV lines. However, discussion with the DNO shall confirm this assumption and any particular installation requirement during the next stages of design.

Adequate protection shall be carefully investigated during the design stages to ensure any potential interaction between utilities is fully controlled and the risk accounted for. If the risk cannot be adequately controlled, a new trench may need to run alongside the existing trench instead.

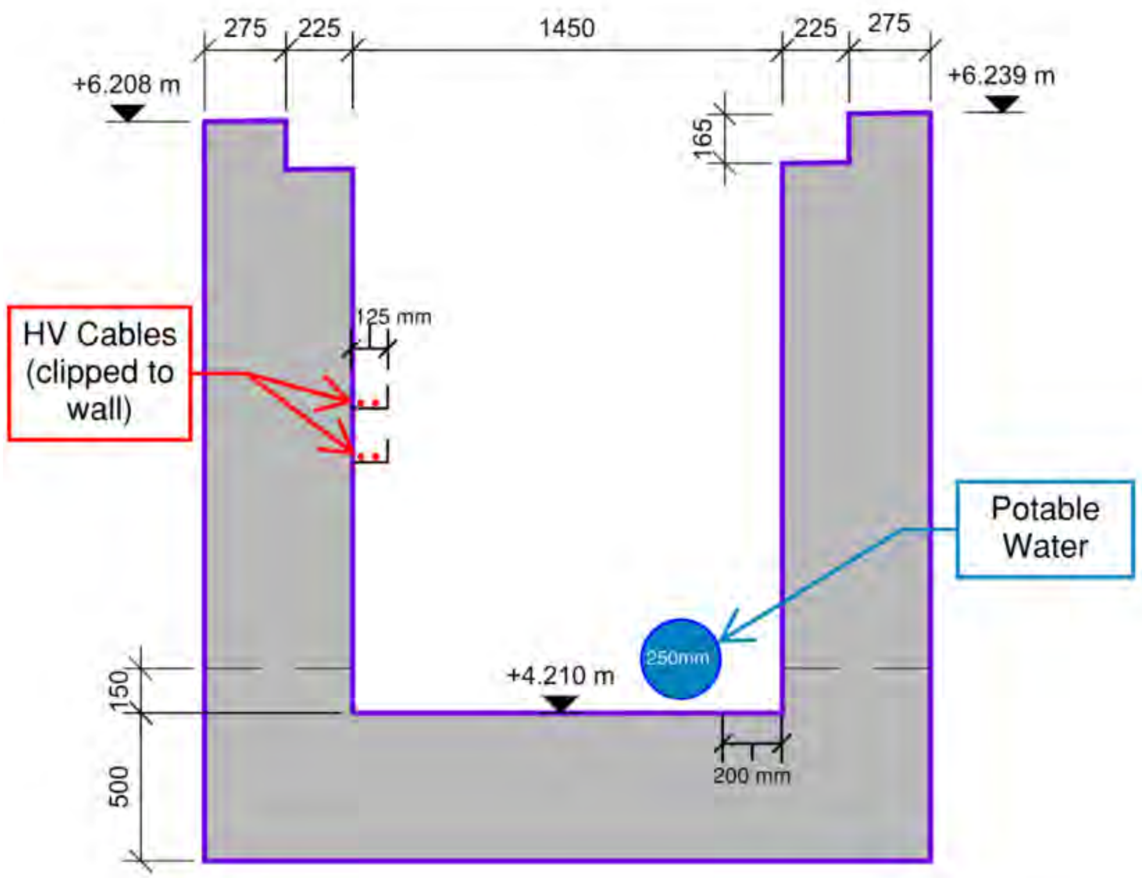


Figure 9—24 Indicative cable arrangement within existing trenches based on typical details shared by PoA

K.1.6 Suspended deck

Balmoral and Castlegate East have been designed with a suspended deck structure (Figure 9—26 and Figure 9—27) to attenuate the impact that incoming waves might have within the harbour structure.

Such a configuration allows for minimal civil infrastructure work to distribute the electrical network which could be hung on the bottom of the suspended deck section – similar to the potable water distribution network.

Figure 9—27 shows the indicative distribution along the suspended decks. Cable protection from the harsh environment (sea water) shall be carefully investigated during the detail phases of the project. However, it is envisaged that a ducted cable would present a potential option and is shown in the example arrangement, Figure 9—25.

The HV cabling route has been chosen to reduce any crossing with the existing and potential utilities (fuel lines), which are or will be direct buried. HV cables section would not need to cross any service trench since the it has been descoped and all the services along the Balmoral Quay and Castlegate West Quay are or would be running as direct buried.

However, adequate protection shall be carefully investigated during the design stages to ensure any potential interaction between the different services is fully controlled and the risk accounted for.

[19] https://etechcomponents.com/the-definitive-guide-to-underground-cable-ducting/

Figure 9—25 Ducted power cables beneath the Port of Long Beach (from EMSA[20])

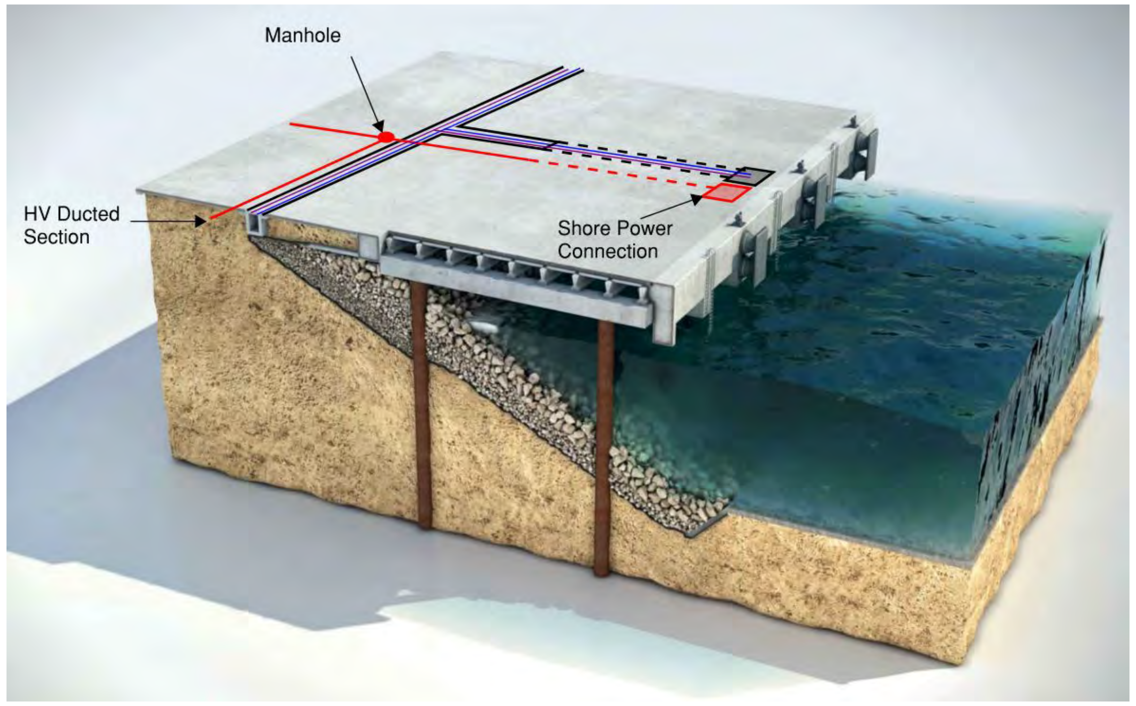


Figure 9—26 Proposed power cables beneath suspended deck (aerial view)

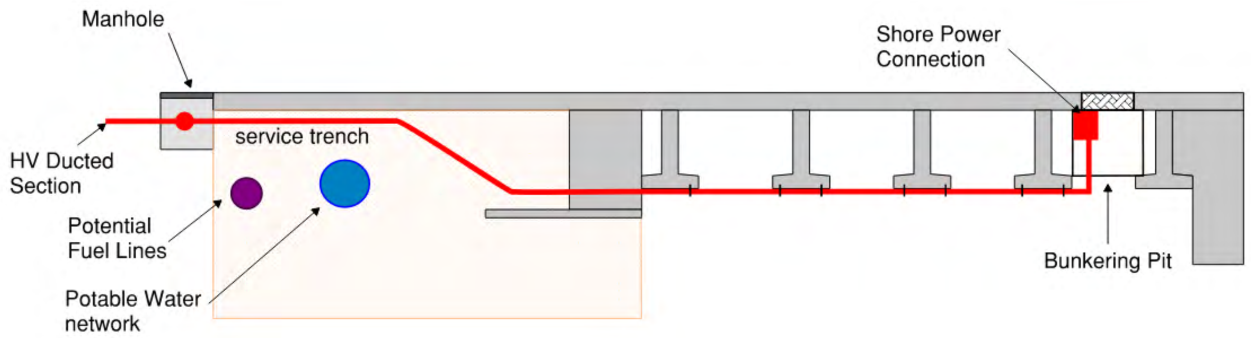


Figure 9—27 Proposed power cables beneath suspended deck (cross section)

K.2 Additional infrastructure for stretch scenario

This section outlines and describes the additional infrastructure required in the stretch scenario. Note that all infrastructure from the baseline scenario is also required.

K.2.1 Wind Turbine

An onshore wind turbine will require approximately a 10m diameter circle land take (78.54m^2) for just the tower/wind turbine structure itself. For reference, an example onshore wind turbine is shown in Figure 9—28.

The height of wind turbine is flexible but is recommended to be greater than 100m to maximise generation due to the greater wind speeds.

A buffer zone is required between wind turbines and certain properties, but these buffer zones are property and location specific. A 500m buffer is considered a typical separation distance between a wind turbine and residential property to avoid unacceptable noise impacts[21].

A buffer zone of 1.5 x turbine height could be required at railway tracks[22].

A buffer zone of the turbine height + 10% could be required at roads[23].

[20] https://emsa.europa.eu/electrification/sse.html
[21] RegenSW. (2012), *Residential buffer zones for wind turbines*, RegenSW, pp. 5.
[22] Sunderland City Council. (2020), *Wind Energy Development Study*, pp. 17.

[23] Sunderland City Council. (2020), *Wind Energy Development Study*, pp. 17.

Figure 9—28 Example onshore wind turbine

K.2.2 Solar PV system

The solar PV systems will require solar panels, inverters, and LV cabling. Footprints of these items varies depending on the size of the array.

For pitched rooftops, the infrastructure intrusion of the solar PV panels is considered negligible as they lye parallel to the rooftop as shown in Figure 9—29. If the terminal or warehouse buildings are to have a flat rooftop, then the infrastructure could be more intrusive if there were other plans for the rooftop. An example flat rooftop system is shown in Figure 9—29.

Figure 9—29 Example pitched rooftop solar PV (left) **Example flat rooftop solar PV (right)**

The required inverters will again vary in size depending on the array size but are best to be installed within the building where it's cooler (for greater yields and reduced aging). Inverters are often mounted onto a wall within the building as shown in Figure 9—30.

Figure 9—30 also shows the cabling, note that it is clipped to the walls within the building. Most cables outside the building will be located behind the panels to minimise visual impact.

Figure 9—30 An example commercial/ industrial PV inverter

A.3

Appendix L Alternative Fuel pipelines deployment

As per PoA ambitions, fuel lines to host MGO are currently under design (although no detail available) and potential alternative fuels lines may be included further to this (i.e. Hydrogen).

The proposed electrical infrastructure for shore power has been designed to allow flexibility while maintaining minimum segregation and separation between electrical cables and potential fuel lines. Enforceable standards or design guidelines to define the required spacing of alternative fuel lines and electrical cabling are not known. Guidelines in relations to direct buried installation are available, although the services that these relate to do not include fuel lines, as explained within this section.

During the subsequent stages of design, engagement with DNOs and operators of the different system are required to confirm each constraint and verify if additional protection/intervention is needed.

It is recommended that in the case of two types of fuels line provision within the site, the supply pipelines follows distinct and separated routes to minimize any disruption and limit the fire/explosion hazard.

A.4 NJUG guidelines

The National Joint Utilities Group (NJUG) provides guidelines for the positioning and colour coding of underground utilities when direct buried. Hydrogen isn't specifically mentioned in NJUG guidance and would therefore be treated more generally as a gas.

According to NJUG, all gas pipes should be colour coded yellow with marking on the pipe depending on the material construction i.e. polyethylene, steel etc. Careful consideration of the material choices for hydrogen pipes is required as hydrogen can cause embrittlement in typical natural gas pipe materials (i.e. steel).

The depth of gas pipes varies depending on the pressure of the pipe and the location of the pipe routing i.e. open fields/agriculture, paved footways, private roads and uncultivated land. A summary is provided in Table 9-31, covering guidance is for natural gas where different pressures and velocities may be required.

Table 9-31 Gas pipe depths in different locations

Location / Pressure		2 bar or below	>2 bar to 7 bar	> 7 bar to 16 bar	> 16 bar
Open fields and agricultural land	Min	1100mm	1100mm	1100mm	1100mm
	Deep ploughing	By agreement	By agreement	By agreement	By agreement
Rural & urban locations	Paved footways	600mm	600mm	1100mm	1100mm
	Verges & private roads	750mm	750mm	1100mm	1100mm
	Uncultivated land, pasture agreed to be permanent and land not open to vehicular traffic	1100mm	1100mm	1100mm	1100mm

NJUG also suggest minimum depths for electrical installation as shown in Table 9-32.

Table 9-32 Electrical cables depths in different locations

Location / Pressure		132kV	66kV	33kV	20kV	11kV	LV & services
Good agricultural land	All situations	910mm	910mm	910mm	910mm	910mm	910mm
Footpaths, verges, uncultivated land, pasture agreed to be permanent and land not open to vehicular traffic	Rural	900mm	750mm	750mm	600mm	450mm	450mm
	Urban	900mm	750mm	750mm	600mm	450mm	450mm

For Oil and fuel pipelines, NJUG recommend a minimum of 900mm depth coverage with the note that "all works within 3 metres of oil fuel pipelines must receive prior approval". It is therefore suggested that in the portion of oil fuel lines (MGO/HVO) that will be direct buried, these are located at least 3m away from the HV cables for this initial infrastructure assessment.

Coordination between the different operators is required and crucial to define the optimal setting out of the different networks. It is also expected that given the structural design of the quayside i.e. loadings of the decks, lower depth may be acceptable for the DNO since protection from vehicles loadings shall be already achieved.

Figure 9—31 shows the NJUG proposed horizontal distances between utilities for direct buried installations. As per NJUG, It is recommended to keep a minimum of 600mm between gas/hydrogen networks and electrical cables.

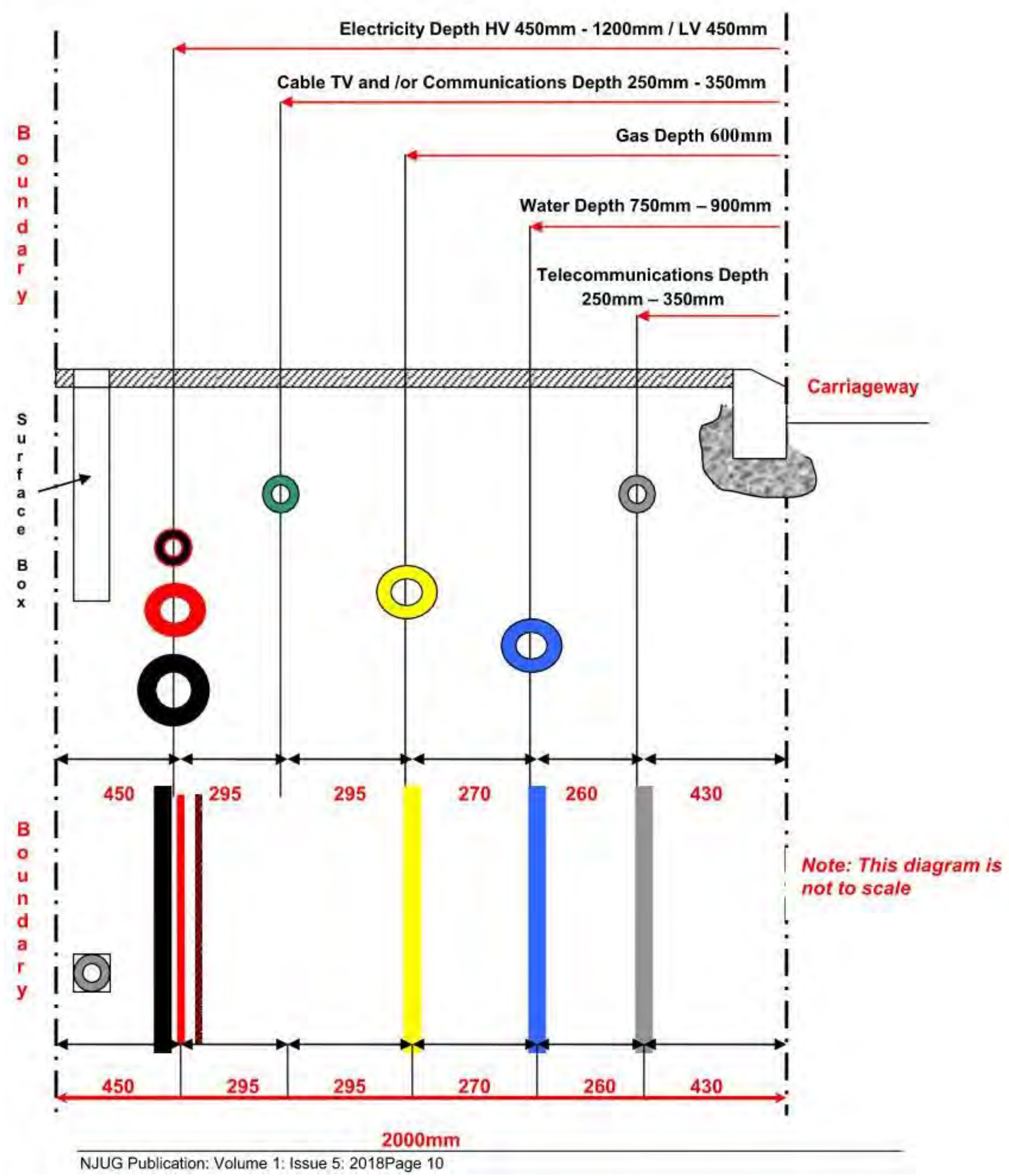


Figure 9—31 Recommended positioning of utility apparatus in a 2 metre footway.

A.5 Hydrogen standards

The International Organization for Standardization (ISO) includes guidance relating to hydrogen generation, liquid and gaseous hydrogen storage, distribution, refuelling and general considerations. The currently available standards are summarised in Table 9-33.

Table 9-33 List of current hydrogen ISO standards

ISO Standard	Name
ISO 13984:1999	Liquid hydrogen - Land vehicle fuelling system interface
ISO 13985:2006	Liquid hydrogen - Land vehicle fuel tanks
ISO 14687:2019	Hydrogen fuel quality - Product specification
ISO/TR 15916:2015	Basic considerations for the safety of hydrogen systems
ISO 16110-1:2007	Hydrogen generators using fuel processing technologies - Part 1: Safety
ISO 16110-2:2010	Hydrogen generators using fuel processing technologies - Part 2: Test methods
ISO 16111:2018	Transportable gas storage devices - Hydrogen absorbed in reversible metal hydride
ISO 17268:2020	Gaseous hydrogen land vehicle refuelling connection devices
ISO 19880-1:2020	Gaseous hydrogen - Fuelling stations - Part 1: General requirements
ISO 19880-3:2018	Gaseous hydrogen - Fuelling stations - Part 3: Valves
ISO 19880-5:2019	Gaseous hydrogen - Fuelling stations - Part 5: Dispenser hoses and hose assemblies
ISO 19880-8:2019	Gaseous hydrogen - Fuelling stations - Part 8: Fuel quality control
ISO 19880-8:2019/AMD 1:2021	Gaseous hydrogen - Fuelling stations - Part 8: Fuel quality control - Amendment 1: Alignment with Grade D of ISO 14687
ISO 19881:2018	Gaseous hydrogen - Land vehicle fuel containers
ISO 19882:2018	Gaseous hydrogen - Thermally activated pressure relief devices for compressed hydrogen vehicle fuel containers
ISO/TS 19883:2017	Safety of pressure swing adsorption systems for hydrogen separation and purification
ISO 22734:2019	Hydrogen generators using water electrolysis - Industrial, commercial, and residential applications
ISO 26142:2010	Hydrogen detection apparatus - Stationary applications

ISO/TR 15916:2015 provides some general guidelines for hydrogen safety issues and relevant mitigation. The document details the considerations needed for hydrogen facilities including location, exclusion zones and protecting barriers. The guidelines provided by ISO are generic and specific separation distances, exclusion zones and protective barrier requirements would be decided during the design process of the facility.

Requirement for hydrogen installation shall be agreed with operator of the hydrogen infrastructure or specialist designer before progressing in the design.

A.6 Indicative strategy for fuel pipelines within the south harbour

Assuming two different fuel might be implemented, an indicative routing for a MGO pipeline and an H2 pipeline is shown in Figure 9—32.

The key principles adopted for this initial routing are:

- Segregation of the difference service as far as feasible
- Limit proximity of hazardous lines such as MGO/H2 and HV cables to limit any knock on effect in case of failure of one network to others
- Segregation between MGO and H2/gas lines due to uncertainties over H2 installation requirement and to mitigate risk of knock on failures
- Maintain higher flexibility for shore power connection as well as fuel points – currently 10 shore power connection points could be installed and up to 8 fuel connection points
- Limit the civil work required maximising the run of the HV cables as direct buried along the soft scape areas adjacent to Dunnottar's crown wall walkway.

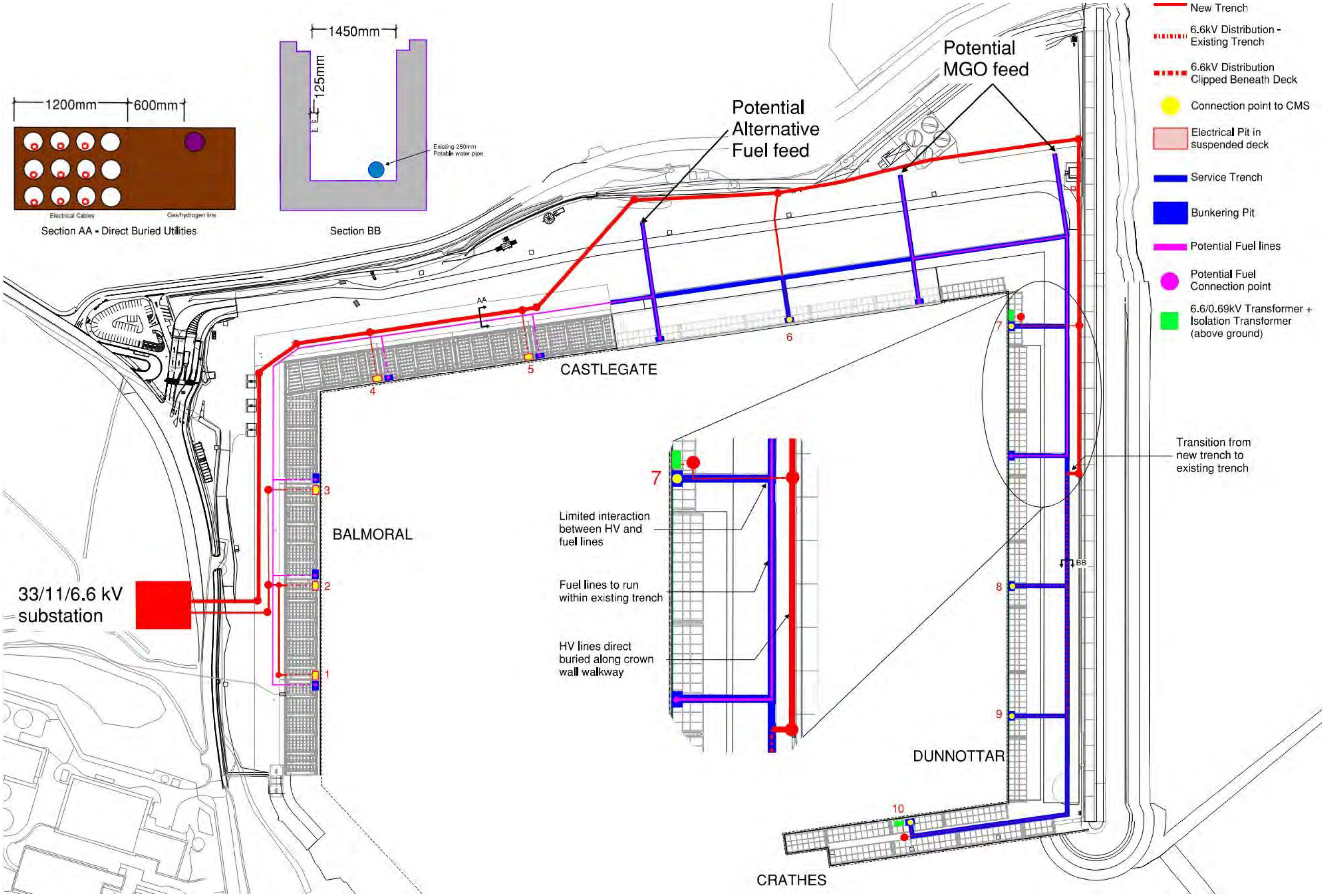


Figure 9—32 Potential routing of fuel and alternative fuel pipelines

Although Figure 9—32 shows two different type of fuel but same approach could be use if only one fuel is deployed.

The proposed fuel line routing shall be updated and potential improvements can be achieved such as reductions of pipelines runs, when the detailed requirements are provided such as the number of required fuel points along the different quaysides.

Currently, only one fuel connection point is proposed along Dunnottar and Crathes. However, if more connection points are deemed necessary, the HV transition to the existing trench could be shifted south allowing additional fuel connection although this will reduce the number of connection for shore power.

Fuel pipelines are proposed along Castlegate west and Balmoral quays. Along these quays, services are direct buried and potentially both MGO and H2 could be deployed here pending the requirements from operators are met.

The fuel lines will also depend on the location of the storage facilities, it is expected that these facilities would have stricter requirements in terms of distances from buildings, infrastructure elements or quayside operation areas due to likely higher damage from a failure.

It is recommended to revisit the proposed pipelines network when the key information (fuel type, number and location of connection points) becomes available. Potential switch between fuel lines and HV lines along Dunnottar (HV lines to fully run within the trenches) might be then an option to be further investigated.

A.7 Potential option of trench sharing

A service trench is currently running along Catlegate west, Dunnottar and Crathes quayside (Figure 9—32) hosting only potable water mains. Potential sharing of this trench for HV cables and fuel lines has been considered to avoid or reduce the required soft/hard digging.

Colocation of electrical HV cables and fuel lines (MGO, HVO, Ammonia, H2 etc) presents a risk in terms health and safety due to the high flammability of the fuel.

Hydrogen fuel lines are investigated in more detail as per discussion with PoA. Information on other fuels are included at the end of this section.

The use of hydrogen at industrial sites or transportation hubs is still an innovative concept. Transporting hydrogen, a highly flammable substance, in congested areas poses several risks:

- **Spillage and leaks:** Hydrogen can cause embrittlement in certain materials, leading to corrosion and weakening of metal structures. This could lead to leaks, spills or failure within the area
- **Explosions:** Hydrogen is highly combustible, and if not handled properly, leaks or accidents could lead to fires or explosions. Adequate safety measures, training for personnel, and strict protocols are essential to mitigate these risks
- **Toxicity:** While hydrogen itself is not toxic, certain hydrogen production methods (e.g., steam methane reforming) may produce trace amounts of harmful by-products such as carbon monoxide

The current project design suggests locating hydrogen pipes within the existing trench while the HV cables would be directly buried separately, therefore minimising the interaction of fuel and HV lines. However, at the time of this study there are no standards nor guidelines available to define the required mitigation measures within a trench for hydrogen piping.

Therefore trench sharing could be investigated as an option to be verified with operators. Trench sharing of utilities has several benefits including reducing civil work costs and minimising disturbance to the surrounding environment.

As stated the primary risk associated with hydrogen and HV utilities trench sharing is the possibility of fire or explosions from possible combination of an electrical ignition source and a flammable gaseous substance as hydrogen.

For this to occur, fault or damage would likely have to occur to both the HV supply and hydrogen transport pipe within the shared trench. Unplanned electrical arcing can occur in the system when HV cables become damaged or defective.

Such defects may arise from various factors, including deterioration of cable insulation, physical harm to the cable structure, excessive cable heating, abrupt power surges, or simply the natural aging of the electrical infrastructure. Mechanical failure could also be caused by abrupt failure of highly pressurized fuel lines (hydrogen) which would then likely trigger ignition.

Electrical faults are more likely to occur at joints, therefore it is crucial to limit these when deploy the network.

The occurrence of hydrogen leaks/failures in a transport pipe can result from: metal piping corrosion, human errors causing physical damage to the pipe, or the gradual wear and tear of the infrastructure over time. Significant leaks in confined spaces would also increase the risk of explosions.

The coexistence of hydrogen leaks and electrical arcs significantly amplifies the potential for explosions. Trench sharing increases the risk of hydrogen leaks and electrical arcs occurring simultaneously and within a concentrated area.

For the purpose of this analysis encasing of the electrical cables is not being considered. Although encasing the electrical cables in a fine fill material and/or ducting would further reduce the chance of any hydrogen leaks coming into contact with the cables, it would also result in their derating.

Derating of the proposed electrical HV cable would lead to use of larger cables to compensate for the reduced carrying capacity caused by the insulation or surrounding materials. In the event that the PoA, opts to use encasement of the electrical infrastructure as a mitigation method, a thorough review of the current proposed electrical infrastructure would be necessary.

Due to the risk of explosions, the relevant fire/life safety codes should be adhered to24. These provide requirements and suggestions for determining the level of hazard (classification) and for mitigating the risks involved. The relevant codes include but are not limited to:

- National Fire Protection Association (NFPA) 70
- NFPA 496, 497
- American Petroleum Institute RP 500 A,B,C
- European directive ATEX 94/9
- BS EN IEC 60079

Specific standards may be followed by different operators and H&S teams.

It should be noted that when placing HV electrical cables within the vicinity of the hydrogen pipes the electrical cables should be carefully bonded and grounded to drain static electricity and to carry electrical fault currents to the ground. Grounding the electrical infrastructure would reduce the potential for electrical arcing which could ignite potential hydrogen leaks in the area.

In order to further minimize the risk of interaction between failures on HV and fuel lines, a partition wall within the existing trench could be considered. This is similar to city scale utility tunnel approach where dry and wet utilities are separated by walls. However, such tunnels have sizes not applicable to the south harbour. The principle of wall separation could still be applicable to the existing utility trench along the quaysides.

[24] Hydrogen Pipeline Systems AIGA 033/14 , Asia Industrial Gases Association, 2014

A visual representation of this concept is displayed in Figure 9—33. It should be noted that this sketch is for representation purposes only and a full design should be carried out if this option is to be progressed.

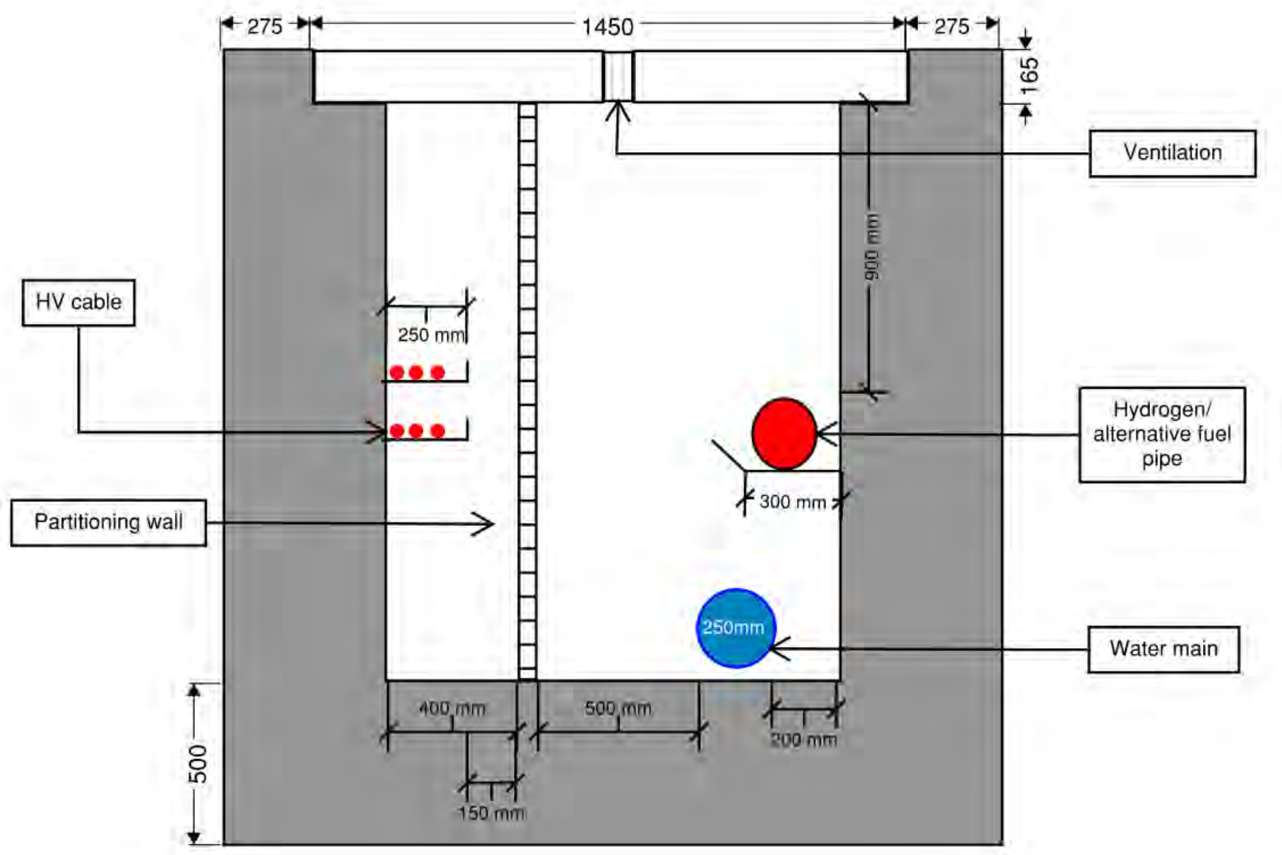


Figure 9—33 Representation of possible shared trench configuration

The purpose of the partition wall is to reduce the risk of hydrogen leaks or spills coming into contact with a potentially damaged HV supply. It should also protect the HV cables from any potential mechanical damage caused by abrupt failure of hydrogen line, hence it should be designed to resist any potential blast coming from the high pressurised pipeline. Specialist designer shall be consulted when requirements from operator and H&S team are available.

No published guidance has been identified that states the required thickness or properties (air tightness, sealing etc) for partitioning wall. This should be discussed with contractors if this approach is carried forward to future design stages.

At the South Harbor, the existing trenches are equipped with built-in vents positioned within the top section of the trenches (Figure 9—34). It is proposed that these vents would be retained above the hydrogen pipelines.

Ventilation would be key to preventing a buildup of hydrogen gas within the trench and therefore reduce the risk of explosions. Required amount of ventilation would also be dictated by the operational pressure within the pipeline i.e. higher pressure, higher ventilation likely required.

Detailed calculations and assessments should be carried out to assess if existing openings in the trench are sufficient to guarantee effective ventilation.

While the partition wall could be incorporated into the design to mitigate trench sharing risks, it may present potential challenges for accessing the utilities during maintenance. However, It is assumed that the vented slabs could be removed to allow access to the utilities.

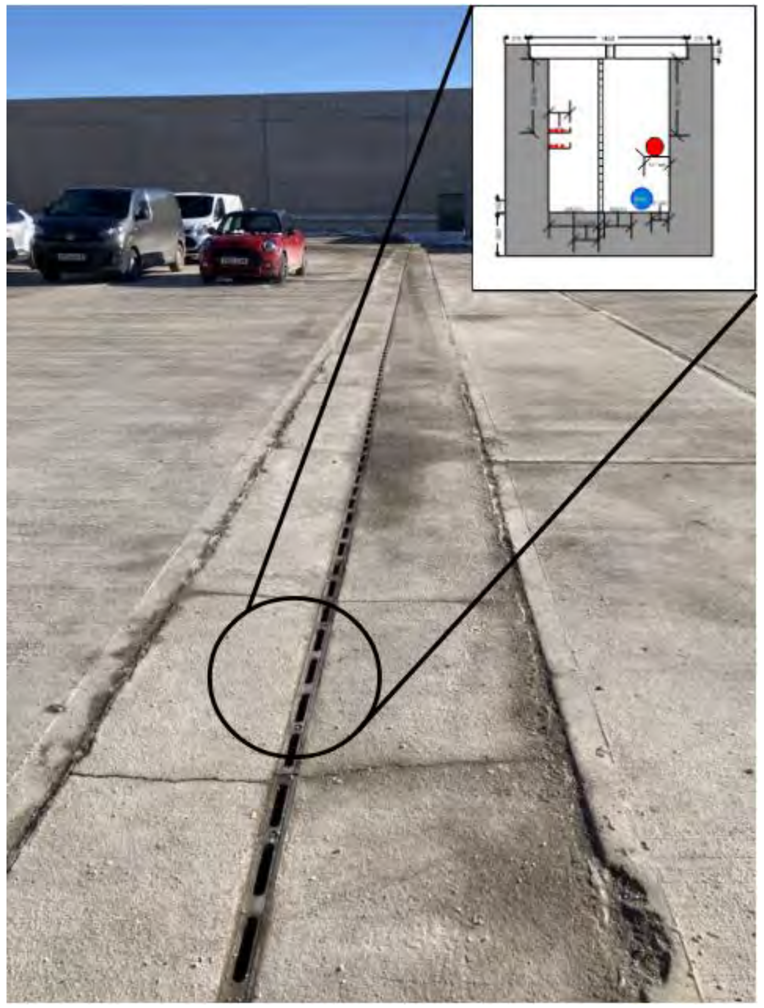


Figure 9—34 Existing trenches at south harbour

According to published industry guidance [25], a minimum width of approximately 550mm is necessary within the trench to allow a human to enter for maintenance tasks. However, due to the existing space allocated for utility trenches and the inclusion of a partition wall, meeting this requirement would not be feasible.

Figure 9—33 doesn't include the space take for any valve or equipment installed along the pipelines which would further reduce the available space in particular sections.

However, the Hydrogen and HV cables are positioned within 1m of the trench's top access point, potentially allowing maintenance work to be carried out by reaching down. This approach would not be suitable for the water mains or any other utilities located at a lower depth. The utility layout outlined in Figure 9—33 is for representation purposes only.

Based on operators and H&S teams input, the trench configuration could change if this approach is taken forward.

The primary space limitation arises from the placement of the partition wall. There is a possibility that this wall could be demolished or removed during maintenance periods and then rebuilt or replaced afterward. This would enhance accessibility in the area but increasing the complexity and cost of the maintenance operations.

[25] Ministry Of Defence, 1996, *Design and Maintenance Guide 8 Space requirements for plant access, operation and maintenance.*

For the purpose of this analysis into trench sharing hydrogen has been selected as the alternative fuel to MGO however alternative fuel choices are discussed further in Appendix M. Various fuels exhibit distinct spill characteristics.

While hydrogen poses a high explosive risk, alternative fuels like Ammonia or HVO (Hydrotreated Vegetable Oil) are comparatively less flammable (Table 9-38). Consequently, if these alternative fuels are chosen for further examination, additional/different mitigation measures for trench sharing shall be considered.

Despite the reduced explosion risk of alternative fuels like Ammonia or HVO compared to hydrogen, they come with their own set of challenges as describe in relevant literature[26,27].

- **Ammonia**
  While it presents a lower fire risk, Ammonia has is toxic and volatile. In the event of an ammonia spill, the gas rises and displaces the normal air in the area, potentially leading to a higher concentration of ammonia nearby. This poses a health risk to individuals in the vicinity. In order to prevent a concentration build-up of ammonia in a confined spaces, such as within a trench, a greater emphasis should be placed on adequate ventilation and leak detection rather than the partitioning wall and reducing the explosion risk.
  For example the ventilation displayed in Figure 9—34 may need to be increased. Therefore the proposed design choice shall be assessed and investigated further pending on the type of fuel, operator requirement and necessary safety measures required
- **HVO**
  HVO is significantly less flammable than hydrogen due to its higher flash point and it is also less toxic than Ammonia. Therefore HVO could be considered a safer alternative for a trench sharing strategy. However, it is advisable to implement mitigation measures when any concentrated fuel is present.
  While HVO is less toxic than Ammonia, inhaling a large concentration of HVO can still cause health issues in individuals, though to a lesser extent. Therefore, the outlined ventilation strategy is still recommended.
  In addition, although not as flammable as Hydrogen, incomplete combustion of HVO leads to a complex mixture of airborne solid and liquid particulates and gases, including carbon monoxide which again has a negative impact on human health. Therefore, considering a partitioning wall between the HV cables and HVO supply pipe remains a viable mitigation method to reduce the risk of HVO ignition.
- **MGO**
  Since MGO (Marine Gas Oil) shares comparable chemical properties with HVO, it is advisable to apply similar mitigation methods for MGO as those recommended for HVO.
- **Methanol**
  Methanol is highly flammable due to its low flash point indicating its easily ignited at lower temperatures. Therefore, methanol has a higher risk of being ignited via electrical arcing. A partitioning wall to separate methanol spills/leaks from electrical infrastructure should be considered if this alternative fuel is carried forward. Methanol is also toxic for individuals hence ventilation should be prioritised as mitigation methods to preventing illness from spills or leaks. However, the vapours from methanol are denser than air and therefore would collect at the bottom of the trench. This would make vapor dissipation difficult.

The trench sharing solution shall be further investigated when more information are available such as:

- final number and location of fuel proposed fuel points within the site
- chosen fuel for the supply infrastructure
- adequate leak detection systems for any fuel lines integrated with supply shout off procedures
- requirements of contractors and onsite Health and safety teams who should define the risks from the selected fuel, and discuss subsequent mitigation methods
- investigation into appropriate ventilation and partitioning methods to reduce the risk of toxic substances build up and explosions
- alternative health and safety methods to encasing the electrical infrastructure as to avoid derating the HV supply cables

As described throughout the section, health and safety requirements shall be given priority when designing a share trench in dependence of the fuel and operator requirements.

A.8 Conclusions

The primary advantage of utilities trench sharing is the minimising civil costs related to excavating multiple utility trenches. In addition, trench sharing would also reduce the risk of congested utility trenches gathering in one area, commonly referred to as a “pinch point”.

The outline benefits should be weighed up against the risks associated with placing HV cables and concentrated fuel supplies in close vicinity. These risks are primarily caused by the possibility of electrical arcing from a damaged HV cable and a fuel leak/spill caused by a damaged fuel supply pipe.

Possible mitigation methods for trench sharing have been considered, such as a partition wall and additional ventilation within the open trench. These proposals need to be investigated and validated further at subsequent design stages. In particular, further investigation into access and maintenance requirements would be necessary.

Situating utilities in separate trenches is considered safer due to the reduced risk of explosions. Aside from safety considerations, placing utilities in separate trenches will also have other benefits including access and maintenance of services due to the greater spatial allowances to be made within the individual trenches. However this is subject to the space available on site.

Although this report acknowledges that trench sharing is a possible strategy for the South Harbour, further consideration is needed. The economic benefit of reducing the number of utility trenches being excavated on site should be weighed up against the embedded risks, cost of additional mitigation methods and logistical considerations required for trench sharing.

The higher constraints from health & safety perspective would apply to the fuel storage facility where higher risk of accidents would occur. This should be assessed as part of a standalone study.

When considering both the benefits and risks of trench sharing, this report recommends the following approach be taken:

- Limit any sharing of the trench as far as possible in line with the currently designed infrastructure;
- A cost – risk - benefit analysis for trench sharing should be conducted.
- if trench sharing is necessary for certain sections then the appropriate risk mitigation methods should be explored and implemented. These include a partitioning wall to reduce the risk of explosions and ventilation to reduce the build-up of volatile gases from any fuel spills
- PoA shall define the number of required fuel connection points
- PoA should confirm the chosen alternative fuel for subsequent design stages, as it will directly influence the mitigation strategy implemented for trench sharing.
- PoA should engage with relevant contractors to further outline plans for trench sharing and required mitigation methods. These should include specific leak detection systems along the fuel pipelines.

[26] SEA\LNG Ltd, 2019, Comparisons of Alternative Marine Fuels

[27] Spill Behavior, Detection, and Mitigation for Emerging Nontraditional Marine Fuels, Oak Ridge National Laboratory for US Department of Energy

Appendix M Alternative fuels and e-methanol production

A.9 Overview of alternative fuels

The section aims to provide a technical comparison between the main alternative fuels – Hydrogen, Ammonia, E-Methanol, HVO - and conventional fuels (MGO) and it includes considerations to their future availability and cost.

E-Methanol has been investigated in more detail since it has been recognised as a likely long term solution trough initial discussion with vessel operator and in line with international guidelines (IRENA, IMO etc). E-methanol is produced combining green hydrogen (through electrolysis) and captured CO2 while all the energy needs shall be met via renewable generation sources.

A high-level land use analysis has been carried out to assess the requirement for a E-methanol plant and associated renewable energy generation.

A full transition to low/zero carbon fuels is not envisaged to be deployed at scale in the short-term future. During the transition period fuels such as biofuels (Fatty Acid Methyl Esters) and paraffinic fuel (HVO) may be used since they could be more easily available and they wouldn't require significant changes to the ship's vessel.

A.9.1 Emission analysis

The UK Government projects that to achieve net zero by 2050, approximately 13% of emissions reduction in shipping would be delivered through efficiency and electrification, with the remaining emissions saving (87%) delivered through the development of zero-carbon fuels (Climate Change Committee, 2020, Sixth Carbon Budget), Figure 9—35.

Different low and zero carbon fuel are currently under consideration within the industry and each of them present advantages and disadvantages.

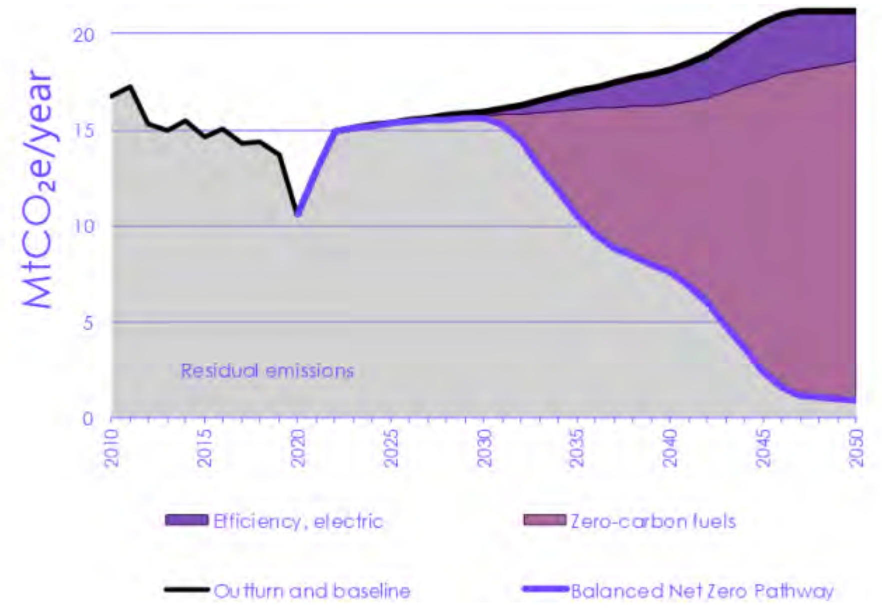


Figure 9—35 The Sixth Carbon Budget projections for Net Zero Pathway for the shipping sector. reproduced from [28]

[28] BEIS, 2020 UK Greenhouse Gas Emissions, Final Figures

Any fuel (alternative or not) would result in emission from their combustion. Many of these would still emit no negligible amount of CO2eq and particulates not aligning with the targets by Scottish government and PoA.

However, some of the fuels, such as e-methanol or green hydrogen. are considered zero emission when considering the overall carbon emission i.e. from production to combustion.

With regards of the emission from combustion only, IMO provides a breakdown of the combustion emission from methanol and conventional fuels and considers the CH_4 and N_2O negligible for all fuels within a marine engine combustion process.

Table 9-34 shows that combustion of methanol releases an amount of CO_2 similar to MGO while it releases much lower quantities of NOx and no sulphur SOx.

The proliferation of emission control areas (ECAs) around the world, where emission limits are even more stringent, requires the use of very low sulphur fuel oil or marine gas oil, making methanol a better candidate.

Table 9-34 Emission from combustion only comparison between Methanol and conventional fuels, reproduced from [29]

Compound	MGO g/MJ	HFO g/MJ	MeOH g/MJ
CO_2	75	77	69
CH_4	0	0	0
N_2O	0	0	0
NOx	1	1	0.4
SOx	0.04	0.5	0

While considering the whole fuel production process, e-methanol is considered net zero as its production productions includes carbon removal from the atmosphere or from other renewable sources to compensate for the emissions produced during combustion. The CO_2 is then used to synthesize the fuel.

The life cycle emission of different fuel are listed by BEIS carbon factors Table 9-35 BEIS currently includes only bio-methanol and not e-methanol which however is expected to have a lower CO_2 equivalent rate than bio-methanol due to its production process (explained in next sections).

For Biofuel (Methanol and Hydrotreated Vegetable Oil (HVO) emissions), BEIS does not include the CO_2 emissions which are assumed absorbed "by fast-growing bioenergy sources during their growth" while the rates refer to the N_2O and CH_4 emissions only.

This implies that both Bio Methanol and HVO are produced from renewable sources and all the CO_2 produced during combustion is offset trough carbon capture techniques.

Table 9-35 Equivalent Emission comparison as per BEIS carbon factors [30]

	MGO kg/l	HFO kg/l	Bio MeOH kg/l	HVO kg/l
CO_2 equivalent	2.78	3.11	0.00676	0.036

The international Council on Clean Transportation has produced a comprehensive life cycle emission comparison between the main bio-fuels ,Figure 9—36 taking into account also the Indirect Land Use change (ILUC). E-methanol is not listed but the figure still provides a useful comparison between Bio-methanol (produced from biomass) and conventional fuels.

[29] Methanol as marine fuel: Environmental benefits, technology readiness, and economic feasibility (International Maritime Organization, 2016)
[30] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2022

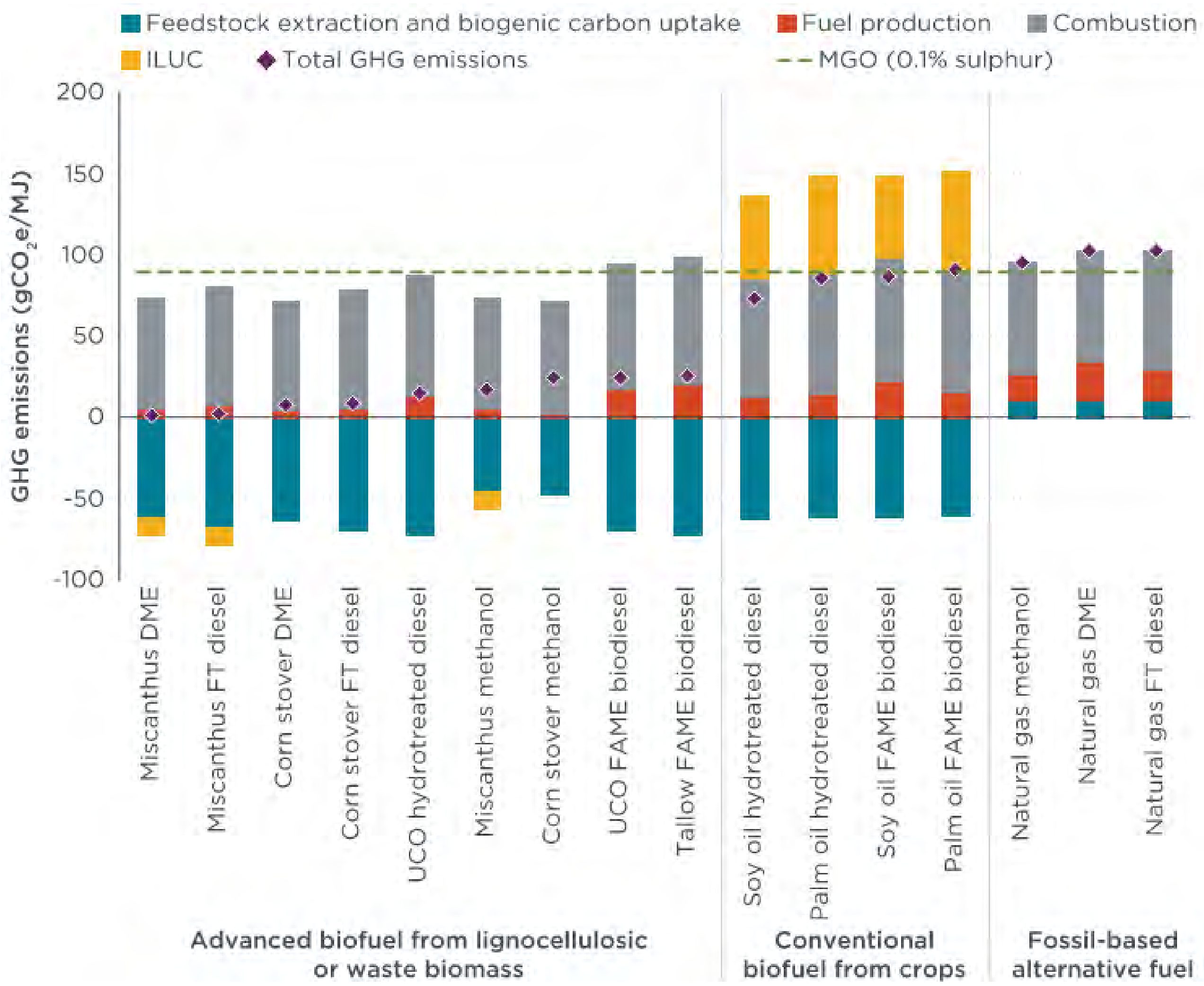


Figure 9—36 Life-Cycle GHG emissions (100-year GWP) of the alternative liquid marine fuels and feedstock, reproduced from [31]

Emissions from ammonia fired engines are still difficult to be found in literature due to the novelty of this solution. Generally, ammonia combustion would lead to significant life-cycle GHG emission reduction between 83.71% and 92.1% compared to fossil fuel (A pathway to decarbonise the shipping sector by 2050, IRENA 2021).

A recent study by Nadimi et al [32] analyses the performance of an ammonia/diesel dual fuel internal combustion engine (ICE). As the blend of ammonia increases there is a drastic reduction in CO_2 emissions while a significant increase of N_2O and NO_X is noted.

Despite having 298 times greater GHG effect than CO_2, the quantities of emitted N_2O still lead to significant overall CO_2 equivalent reduction. More data/studies are required to assess the GHG impact of ammonia burned engine considering that significant amount of unburned ammonia was measured [32] with the related impact on GHG emissions.

[31] The potential of liquid biofuels in reducing ship emissions (International Council on Clean Transportation, 2020) https://theicct.org/publication/the-potential-of-liquid-biofuels-in-reducing-ship-emissions/

A.9.2 Fuels properties

A comparison between the fuel's energy density as well as physical properties is needed to understand the potential of any fuel as substitute to fossil fuel. Hydrogen, ammonia and methanol are discussed in more detail since more attractive within the maritime sector.

Based on the energy density, an overall comparison between the main current and future fuels is shown in Table 9-36 and graphically in Figure 9—37. Hydrogen at standard conditions has been used as a basis for comparison and a lithium-ion battery has also been included for a comprehensive analysis.

Table 9-36 Mass and volume related energy density of different fuels

Fuel	Density / kg/m³	Mass-related energy density (LHV) / MJ/kg	Mass-related energy density ratio / fuel: hydrogen (gas, 1 bar)	Volume-related energy density (LHV) / GJ/m³	Volume-related energy density ratio / fuel: hydrogen (gas, 1 bar)
Hydrogen (Gaseous, 1 bar)	0.089 (25 °C, 1 bar)	120.1	1:1	0.01	1:1
Marine gas oil (MGO)	860 (15 °C, 1 bar)	42.8	0.36:1	36.60	3,421:1
Diesel	846 (15 °C, 1 bar)	42.6	0.35:1	36.00	3,364:1
Kerosene	830 (15 °C, 1 bar)	46.2	0.38:1	35.30	3,299:1
Petrol	740 (15 °C, 1 bar)	46.5	0.39:1	34.40	3215:1
Liquefied natural gas (LNG)	430 (15 °C, 1 bar)	48.6	0.40:1	20.80	1,944:1
FAME	880 (20 °C, 1 bar)	37.0	0.31:1	33	3084:1
Methanol	792 (15 °C, 1 bar)	19.9	0.17:1	15.76	1,473:1
Ammonia (Liquid)	600 (−34 °C, 1 bar)	18.9	0.16:1	11.34	1,060:1
Hydrogen (Liquid)	71 (-253 °C, 1 bar)	120.1	1:1	8.50	795:1
Hydrogen (Gaseous, 700 bar)	42 (25 °C, 700 bar)	120.1	1:1	5.04	471:1
Lithium-Ion Battery*		0.7	N/A	2.20	N/A
Methane	0.706 (25 °C, 1 bar)	47.1	0.39:1	0.03	3.1:1
Ammonia (Gaseous)	0.749 (25 °C, 1 bar)	18.9	0.16:1	0.01	1.3:1

**Average values used for Batteries. Energy density varies greatly between manufacturers and size.*

[32] Effects of ammonia on combustion, emissions, and performance of the ammonia/diesel dual-fuel compression ignition engine. E.Nadimi, G. Przybyla et al, Journal of Energy Institute 2023

Hydrogen has a very high mass-related energy density compared with other fuels (approximately 3× higher than methane) and doesn't generate any CO2 emissions under combustion. Hydrogen can also be utilised within a fuel cell to generate electricity.

However, hydrogen needs to be compressed or liquified to have comparable volume-related energy density with other fuels.

Ammonia can be produced using green hydrogen and nitrogen in the Haber-Bosch process. Ammonia is a gas under standard conditions but is easily liquified at −34°C.

The liquefaction of ammonia requires significantly less energy compared to hydrogen due to the difference in temperature needed (−253°C vs −34°C).

E-methanol is produced by combining green hydrogen and captured CO2 from industrial processes or from Direct Air Capture (DAC). The combustion of methanol produces CO2 emissions, although the fuel can be seen as net zero due to the roundtrip carbon emissions.

Methanol has a higher volumetric energy density compared to hydrogen and ammonia i.e. it produces more energy considering the same volume and can be easily stored at ambient condition in liquid form.

Although the mass related energy density for hydrogen is one of the highest, its volumetric density is one of the lowest even when at liquid state meaning that to store the same amount of energy bigger tanks would be required.

Therefore, a difficulty with using hydrogen as a fuel in the transportation sector, in addition to storage considerations as a high-pressure gas or a cryogenic liquid, is designing vessels with sufficient storage space for hydrogen fuel.

Ammonia appears to be attractive if at liquid state with a requirement for ~-34°C temperature which could pose a technical challenge for the vessel i.e. maintaining low temperatures would require additional equipment and related power supply.

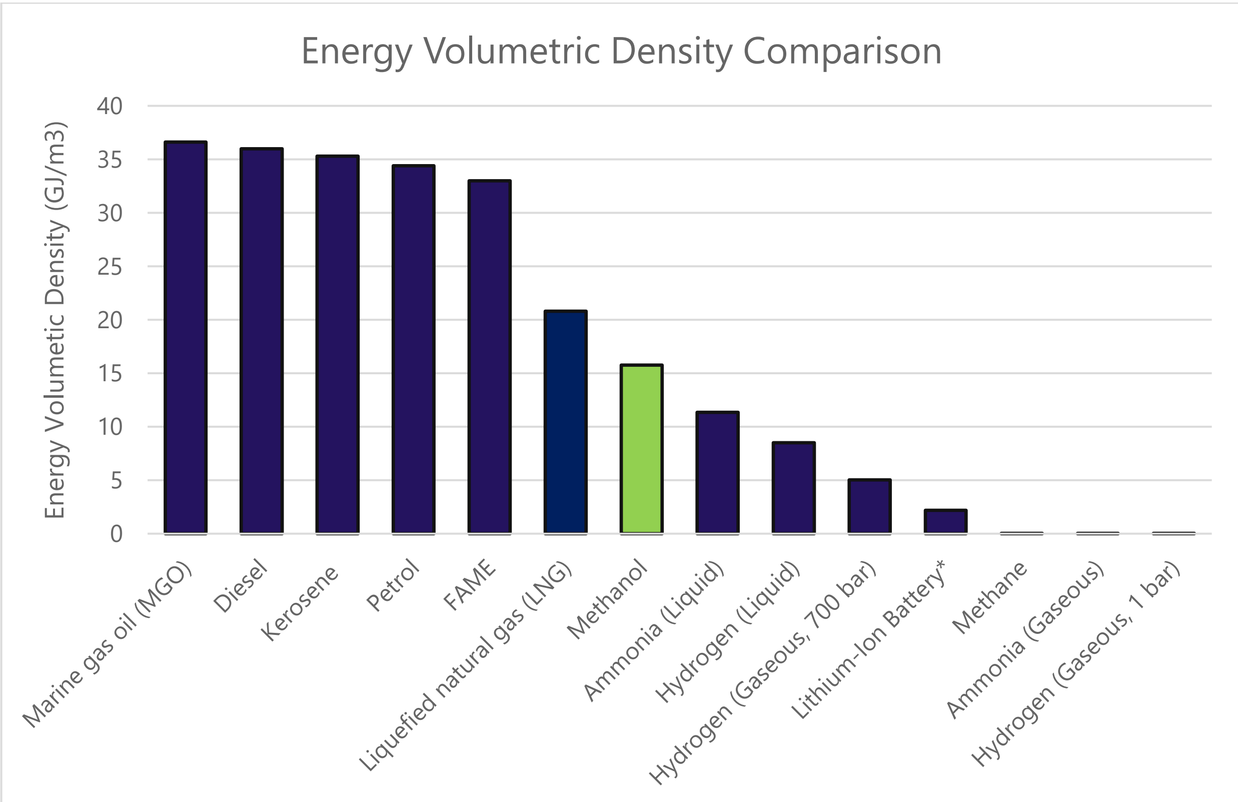


Figure 9—37 Energy Volumetric density comparison between main fuels

Methanol shows a good energy density at standard conditions and it would require roughly double the volume of MGO to store the same amount of energy compared to conventional fuels. It will require significant upgrades/changes on the vessel but OEM conversion kit are already available (Wartsila W32).

A.9.3 Fuel spill risks and impacts

Alternative fuels shall also be investigated and assessed based on their potential spill in water and impact on marine environment and ecosystem.

Generally, the spill profile depends on density of the fuel, water solubility and kinematic viscosity which determine the dissipation rate and the extent of area impacted.

Liquid Hydrogen has a very low density leading to a fast rise above the water level and the associated vapour cloud has a restricted sea surface footprint with limited flammability zone. Although no toxic, hydrogen main risk is related to its explosiveness and flammability since it can be ignited by hot surfaces or sparks.

The effect of wind speed over the hydrogen spill profile can be significant and modify the cloud shape and sea surface footprint.

Ammonia is highly toxic to humans and marine life and it needs to be handled by trained professionals also within the port areas. In a spill, 70% of ammonia will quickly dissolve in water under ammonium hydroxide while the rest will rise in the air to combine with water vapour and form hot ammonia hydroxide due to heat release during the reaction[27] .The hot and toxic zone will threat marine life.

Ammonia and ammonium hydroxide are difficult to ignite hence a low fire hazard when spilled.

Methanol is very volatile and in case of a spill will evaporate and its vapours rise and disperse rapidly. While the majority of the spill will quickly dissolve in water, the area adjacent to the spill will be highly flammable.

It is expected methanol to have a rapid degradation in the environment and a large spill may have impacts only near the release point[27].

Table 9-37 shows an overall comparison of the spill behaviour of the three alternative fuels and HVO for a comprehensive evaluation.

Table 9-37 Comparison of spill characteristic of alternative fuels, reproduced from [27 above]

	HVO	Methanol	Ammonia	Hydrogen
Behaviour when spilled	Will behave as a diesel spill and rapidly spread out as a clear oily film	Will rapidly spread out and dissolve into water	Will partition into water forming a heated surface layer of ammonium hydroxide	Will form a cold cloud on the water surface
Dissipation or degradation rate	Moderate: expected to take up to a week or more	Fast	Fast	Fast
Ecological impacts	No long term impacts are expected. Aquatic life may become coated	No long term impacts, but aquatic life in contact with spill may be poisoned	No long term impacts, but marine life near the spill zone may be burned and poisoned	No long term impacts, but marine life at the water surface in the spill zone may suffocate or become chilled
Flammable/explosion risk	Low	High	Low	High
Toxicity	Low	Yes, but limited to spill zone	High	Low
Air displacement and suffocation risk to crew	None	Low	High	Possible
Spill clean up	Boom containment is most optimal	Will dissipate before clean-up can begin	Will dissipate before clean-up can begin	Will dissipate before clean-up can begin
Detection probability with current practice	Moderate	Low	Low	Low

The spill behaviour of any alternative fuel considered shall be further investigated in relation to the different location where it may occur and the associated risks i.e. spill in the harbour, open sea etc. However, it appears that hydrogen and ammonia could pose significant risks in an harbour due the difficulty to contain their spread and their high flammability and toxicity, respectively.

Detailed health&safety and risk assessments of spills are not part of the scope of this report and they shall be carefully investigated and any impact on port infrastructure and operation considered.

A.9.4 Power To X processes

In relation to the maritime sector and based on above sections, hydrogen, ammonia and methanol currently appear to be most competitive as potential alternative fuels when produced via renewable energy.

Therefore, the focus has been reserved for the Power to X (PTX) solutions which refer to production of chemical components (X) through use of green power. These could be green hydrogen, green basic chemicals, e-methanol, green ammonia etc. All the PTX require hydrogen as input to deliver the desired end product.

Figure 9—38 shows a general process map on how PTX could be produced trough renewable energy supply with focus on ammonia and methanol.

Most of the alternative fuels considered within this report could be produced with fossil fuel (coal and gas) contribution such as blue/grey hydrogen, blue/grey methanol etc . However, any of the processes relying on fossil fuel are not presented.

For a comprehensive overview of all current and alternative fuels, refer to *A pathway to decarbonise the shipping sector by 2050 (IRENA 2021)* and *Innovation Outlook – Renewable Methanol (IRENA 2021).*

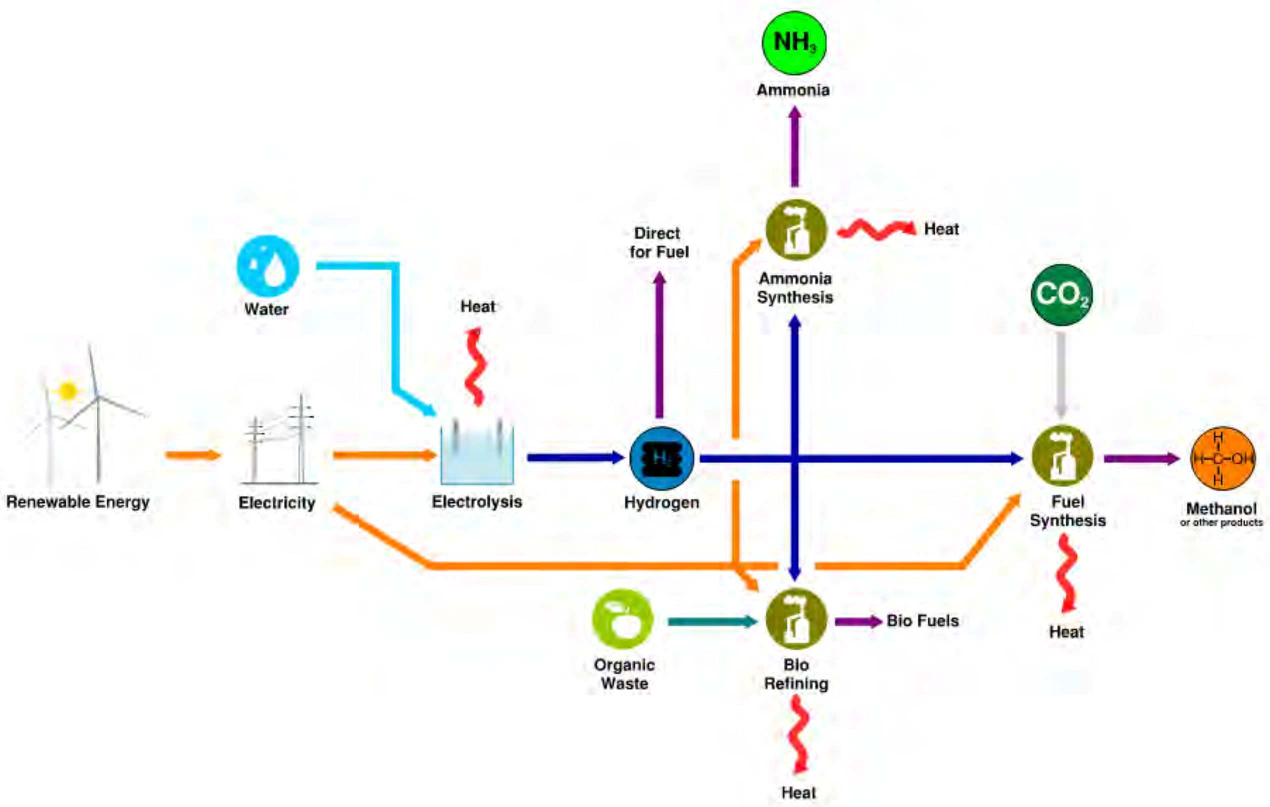


Figure 9—38 Indicative general PTX process map

Most of PTX processes release waste heat whose temperatures and quantity are strictly related to the individual process and to the level of heat recover within the production system. Potential integration of district heating network shall be investigated on case-by-case basis as this could lead to additional community benefit and reduction in emissions.

Based on the above and initial indication from vessel operators, Methanol has been considered in more detail within this report.

The technology and policies progresses within the maritime sector (vessels/ship engines upgrades, common agreement on alternative fuel, carbon taxation etc), within the fuel/energy production (carbon capture, renewable energy etc) as well as within the overall transport sector (competition between sectors for a type of fuel) will have a great influence on the type of fuel to be used within the maritime sector.

A.10 E-Methanol

Methanol is widely used within the chemical industry as a component for other chemicals such as formaldehyde, plastics etc. Around 98 million tonnes (Mt) are produced every year, nearly all from fossil fuel with a life-cycle emission of ~0.3 gigatonnes of CO2 (Innovation Outlook – Renewable Methanol, IRENA 2021).

According to IRENA report[33], methanol has already been deployed within the maritime sector with ships example such as Stena Germanica (50 000 t) and Methanex operating their 50 000 t chemical tankers on dual fuel engine.

This section discussed different aspects of methanol such as the production processes, the energy demands and space requirements.

For a comprehensive description and detail, it is recommended to refer to the following report/papers referenced throughout the report:

1. Innovation Outlook – Renewable Methanol, IRENA 2021
2. A pathway to decarbonise the shipping sector by 2050, IRENA 2021
3. Carbon Footprint of Methanol, Methanol Institute
4. Key issues in LCA methodology for marine fuels, International Council on Clean Transportation 2023
5. Methanol as marine fuel: environmental benefits, technology readiness, and economic feasibility, International maritime organisation 2016
6. The Role of Carbon Capture and Utilization, Carbon Capture and Storage, and Biomass to Enable a Net-Zero CO2 Emissions Chemical Industry, P. Gabrielli, M. Gazzani, M. Mazzotti, Industrial & Engineering Chemistry Research 2020

Due to the fast evolving technology and process, all the findings included here-within shall be verified before PoA takes any key decision.

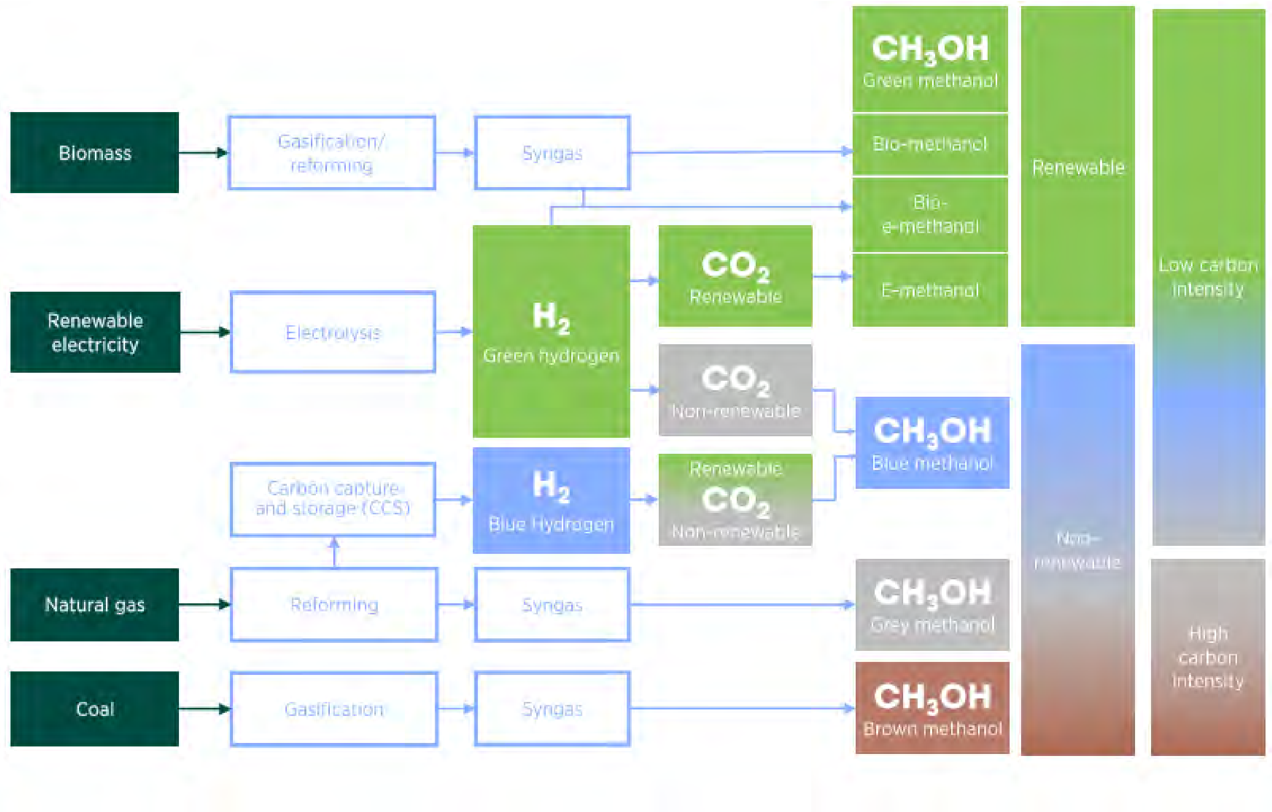
A.10.1 Methanol Production process

To date methanol is mostly produced via fossil fuel but only renewable methanol shall be considered as a potential alternative to the current MGO/HFO.

Renewable methanol can be produced using renewable energy and renewable feedstocks in two ways:

- Bio-methanol. It is produced from biomass (organic waste, biogas from landfill or sewage etc) involving gasification and reforming process with associated heat and power consumption.
- E-methanol. It is produced combining green Hydrogen and CO_2 which shall be captured from renewable sources (DAC, BECCS, point sources etc)

An overall process map for methanol production is shown in Figure 9—39.



Renewable CO_2: *from bio-origin and through direct air capture (DAC)*
Non-renewable CO_2: *from fossil origin, industry*

Figure 9—39 Production routes for methanol, reproduced from [33]

The focus of this report is on renewable methanol and specifically on E-methanol since it is considered the production process potentially implementable at the South Harbour and its surrounding areas.

Bio-methanol produced from biomass grown and processed for specific purposed of making chemicals would require ~37 times more land than the E-methanol route[34]. Refer to section A.10 for more details on potential contribution from biomass sources.

E-methanol is a liquid product that can be obtained from CO2 and hydrogen trough a catalytic process, through a power to X technology, Figure 9—39.

The simplest and more mature method is to make hydrogen through electrolysis and combining it with CO2, producing the E-methanol.

Another approach would be to produce both components of syngas, CO and H2, through electrolysis, followed by conversion of the syngas to e-methanol as practised for conventional methanol production. While this route could achieve a higher conversion efficiency, it is less developed than water electrolysis[33].

Direct electrochemical conversion of CO2 and water to methanol is also being studied, but so far only limited efficiency and yield have been achieved at a laboratory scale[33].

Figure 9—40 shows the indicative process to produce E-methanol with green hydrogen and CO_2 as separate feedstocks.

The production generally requires multiple feedstocks as follow which shall be obtained via renewable energy supply:

- CO_2 from renewable source or DAC
- Green Hydrogen through electrolysis

A.10.2 Carbon Dioxide Feedstock

CO_2 supply for methanol production is generally divided in two groups.

CO_2 point source from industrial process

In this case CO_2 would likely come from industries that rely on fossil fuels, making the CO_2 fossil based and the overall process CO_2 positive. Using such a feedstock could still be considered a low carbon option since otherwise the CO_2 would be released into the atmosphere.

UK hydrogen strategy [35] is currently envisaging large amount of CCUS (Carbon Capture Utilisation and Storage) on industrial sites where blue hydrogen could be produced. As an example, Government aims to establish CCUS in four industrial clusters by 2030 at the latest, supporting the ambition to capture 10Mt/CO2 per annum.

However, this could become an incentive from fossil-based industry to keep the business-as-usual process. Therefore, fossil-based CO2 should not be considered as feedstock.

CO2 captured from the air or trough biomass

Point sources of renewable CO_2 are usually referred as biogenic sources such as from distilleries, fermentation units, Municipal Solid Waste, biogas etc. Normally, the CO2 produced within these processes is emitted to the atmosphere.

When the CO_2 from these units is captured either for storage or utilisation, the process is usually referred to as bio-energy with carbon capture and storage (BECCS) or bio-energy with carbon capture and utilisation (BECCU)[33].

Direct Air Capture is another source for CO_2 which do not rely on point source emission and could rather be deployed everywhere – ideally in location with higher CO_2 concentrations.

Currently there are two approaches being used to capture CO2 from the air: solid and liquid DAC.

[33] Innovation Outlook – Renewable Methanol, IRENA 2021
[34] The role of carbon capture and utilization, carbon capture and storage, and biomass to enable a net-zero CO2 emission chemical industry, P. Gabrielli et al, Industrial & Engineering Chemistry Research, 2020
[35] UK Hydrogen Strategy (publishing.service.gov.uk)

Solid DAC (S-DAC) is based on solid adsorbents operating at ambient to low pressure (i.e. under a vacuum) and medium temperature (80-120°C). S-DAC systems would not require any water input but rather could captured up to 2 tonnes of water from the atmosphere per each ton of CO_2 captured[36].

Liquid DAC (L-DAC) relies on an aqueous basic solution, which releases the captured CO2 through a series of units operating at high temperature (between 300°C and 900°C). Water demands are significant with up to ~50 tonnes of water per ton of CO_2 captured[36].

L-DAC could be deployed at large scale (1MtCO_2/year) while the S-DAC can be a modular solution (50tCO_2/year). Given the overall demands (power, heating, water) and the modularity of the system, a S-DAC is considered more appropriate for the purpose of this report.

For further detail on DAC technology, refer to *Direct Air Capture – A key technology for net zero* (International Energy Agency,2022). It shall be noted that currently that DAC system are still developed at low scale compared to the point source capture which has capturing capacity roughly 3 order of magnitude higher than DAC.

All the above CO2 capture solution shall be supply via renewable energy.

A.10.3 Hydrogen Feedstock

Currently majority of hydrogen production relies on fossil fuels with almost 47% of the global hydrogen production is from natural gas, 27% from coal, 22% from oil (as a by-product) and only around 4% comes from electrolysis.

To produce green hydrogen, there are different type of electrolyser (alkaline, PEM. SOEC) with different heat and power requirements leading to different efficiencies which are in the range of 65% for the more mature technology.

Table 9-38 shows a comparison of the main type of electrolysers including PEM (Polymer Electrolyte Membrane), AEM (Anion Exchange Membrane) and SOEC (Solid Oxide Electrolysers) with the current and expected upgrades in the future.

The detail of each type of electrolyser is not provided within this report but different reports have been referenced throughout this section and they can be used for further investigation.

However, green hydrogen production represents the biggest part within the e-methanol production and any improvement in its efficiency and cost will have a great positive impact in the overall scheme, as described in the next chapters.

Table 9-38 Comparison between current and future electrolyser technical features and cost, reproduced from [38]

	2020				2050			
	Alkaline	PEM	AEM	SOEC	Alkaline	PEM	AEM	SOEC
Cell pressure [bar]	<30	<70	<35	<10	>70	>70	>70	>20
Efficiency [kWh/KgH_2]	50-78	50-83	57-69	45-55	<45	<45	<45	<40
Lifetime [thousand hours]	60	50-80	>5	<20	100	100-120	100	80
Capex for large stack (stack only > 1MW) [USD/kWel]	270	400	-	>2000	<100	<100	<100	<200
Capex range estimate fro the entire system >10MW) [USD/kWel]	500-1000	700-1400	-	-	<200	<200	<200	<300

For more detailed overview of electrolyser technology innovation and progress please refer to *Innovation trends in electrolysers for hydrogen production, IRENA 2022.*

A.10.4 E-methanol production process

To provide a quantitative assessment in terms of energy demand and space required, this report focuses on E-methanol production through green hydrogen and CO_2 supplied through DAC. This guarantees a renewable supply with no reliance on any fossil fuel/burning process and also provides a most onerous scenario in terms of cost and land use.

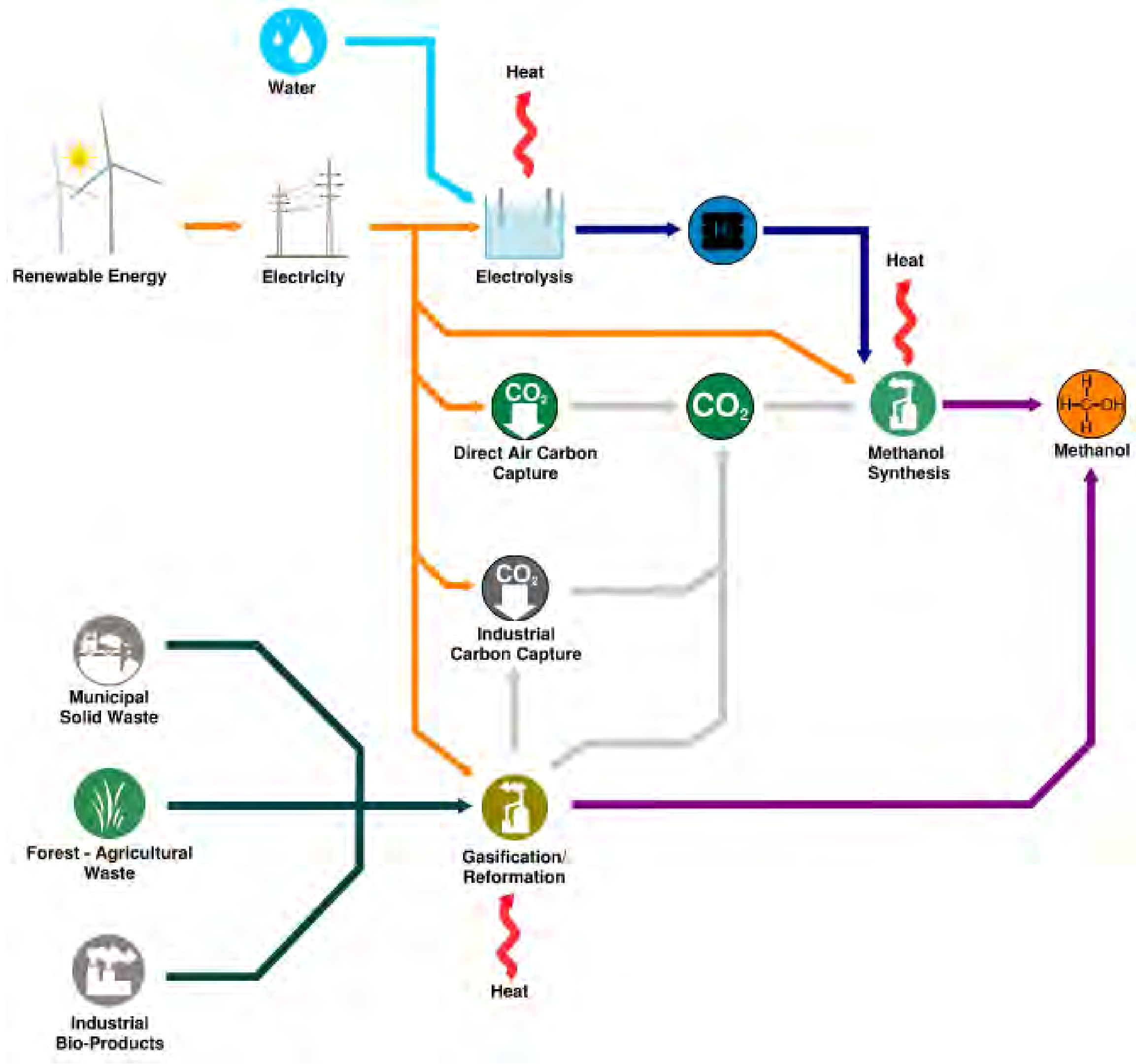


Figure 9—40 General E-methanol process map

As previously described the production of e-methanol follows a precise structure:

1. Hydrogen feedstock shall be provided through electrolysis where water is split in hydrogen and oxygen trough power input and heat is released in the process
2. Carbon Dioxide feedstock shall be obtained from renewable industrial processes such municipal waste, sewage treating plants etc or from direct air capture technology. The quantity of CO2 captured must be equal or greater of the one released through combustion by the end users
3. Both the feedstocks are combined in the methanol reactor to produce the final output and heat is released in the process
4. All the different production steps shall be supplied through renewable energy

[36] Direct Air Capture – A key technology for net zero, IEA 2022

A.10.5 Energy Demand for E-methanol production

Comprehensive studies or reports considering the overall energy demand of the methanol production are difficult to be found in literature.

However, P. Gabrielli, M. Gazzani, M. Mazzotti, in *The Role of Carbon Capture and Utilization, Carbon Capture and Storage, and Biomass to Enable a Net-Zero CO2 Emissions Chemical Industry (Industrial & Engineering Chemistry Research 2020)* provide a detailed breakdown of the energy demands and emissions at each step of the production process for different pathway.

Within their study, two scenarios are relevant for the purpose of this report and are here reported.

- **Carbon Capture and Utilization (CCU) - Point Source Capture (PSC) scenario**
  E-methanol is produced via Direct Air Captured CO_2 and green hydrogen. A post combustion CO_2 system is proposed to capture the emissions at the emitting sources and reducing the size of the DAC unit required upstream.

- **Carbon Capture and Utilization (CCU) - Direct Air Capture (DAC) scenario**
  E-methanol is produced via Direct Air Captured CO_2 and green hydrogen. The DAC unit supplies all the required carbon dioxide with impacts on its size and footprint.

Carbon Capture and Utilization (CCU) - Point Source Capture (PSC) scenario

This scenario and the related energy demands are shown in Figure 9—41 and Table 9-39 based on the production of 1 ton of Methanol (MeOH).

In relation to the maritime sector, this scenario appears unfeasible since it would require post combustion CO_2 capture system to be placed on the ships with clear impact on space but also on energy demand in navigation i.e. more fuel and bigger tanks.

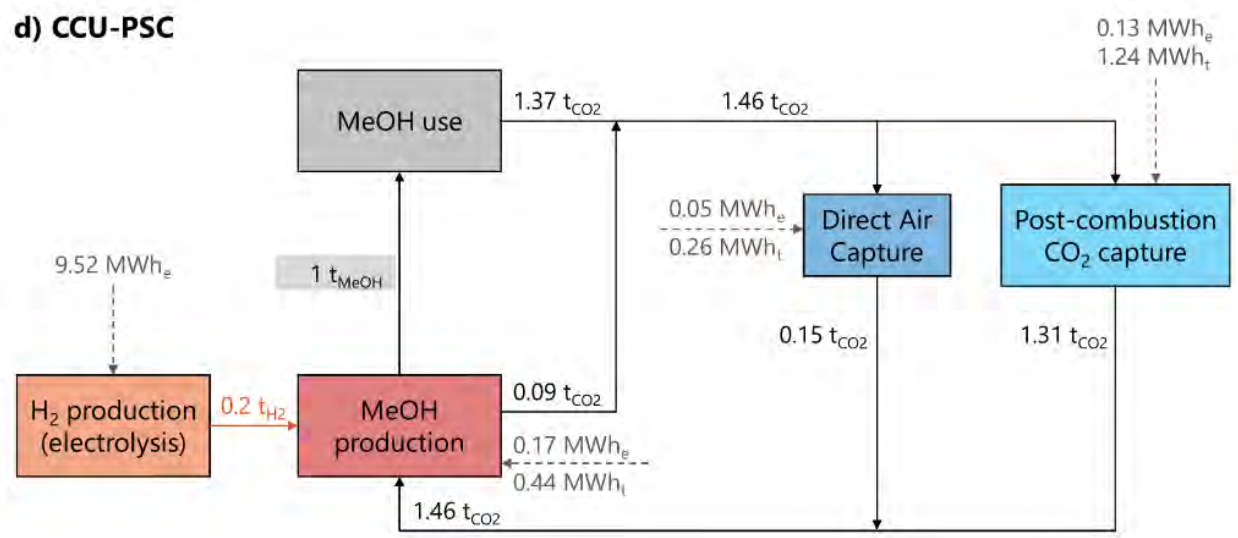


Figure 9—41 Energy demands and emissions for E-methanol production with Post Combustion Capture, reproduced from 34

Table 9-39 Energy demand and emission comparison between CCU-PSC and CCU-DAC scenario, reproduced from 34

		CCU-PSC	CCU-DAC
Input Material [t/t_{MeOH}]	CO_2	1.46	1.46
	H_2	0.2	0.2
Input Electricity [MWh_e/ t_{MeOH}]	MeOH production	0.17	0.17
	DAC	0.05	0.31
	PSC	0.13	0
	H_2 production	9.52	9.52
	Heat production	0.48	0.75
	Total	**10.4**	**10.9**
Input Heat [MWh_t/t_{MeOH}]	MeOH production	0.44	0.44
	DAC	0.26	2.56
	PSC	1.24	0
	Total	**1.93**	**3.00**
CO_2 emissions [tCO2/t_{MeOH}]	MeOH production	0.09	0.09
	MeOH use	1.37	1.37
	DAC	-0.15	-1.46
	PSC	-1.31	0
	Total	**0**	**0**

Carbon Capture and Utilization (CCU) - Direct Air Capture (DAC) scenario

This scenario and the related energy demands are shown in Figure 9—42 and Table 9-39 based on the production of 1 ton of Methanol (MeOH).

In this case no post combustion is proposed making this the most suitable approach for Port Zero where hydrogen, DAC and MeOH synthesis could be collocated in the same area.

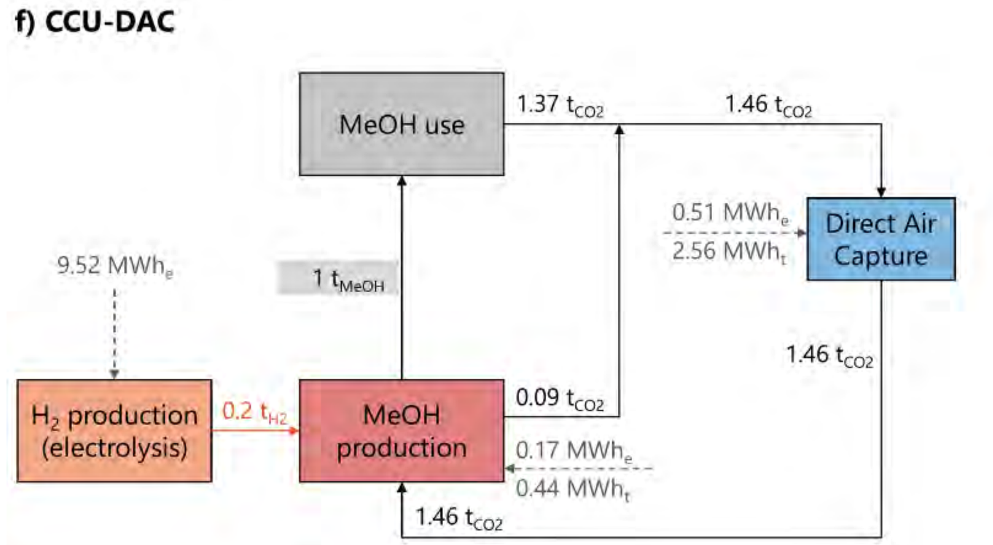


Figure 9—42 Energy demands and emissions for E-methanol production with Direct Air Capture, reproduced from 34

Generally, the findings from source 34 consider specific equipment selection and assumptions. In particular, comparing the DAC heat demand with the values from IEA [37], the DAC process appears to be a L-DAC with related high temperatures required.

A S-DAC approach requires much lower temperatures as well as water which may lead to an increased electrical efficiency.

Nevertheless, it is clear that even a change in the DAC process will not decrease the overall energy demands by a significant amount since the ~90% are associated with the hydrogen production.

The production set up may vary significantly based on the different technologies used and how the recovery of bio/waste products is tackled within the overall process i.e. waste heat. The power and heating demand would vary accordingly but for the purpose of this report the values proposed by Gabrielli et al are used to provide an high level estimate.

A.11 Infrastructure requirements

Assessment of the infrastructure requirements for E-methanol production is crucial to understand the size, the land use and the required renewable energy production.

PoA has provided initial annual estimates for the fuel required at the south harbour with an expected 180,736 tMGO/year or ~512,000 MGOm³/year in 2028, Table 9-40. Average daily demands have been assumed as well as average hourly demands, 495tMGO/day and 21tMGO/hr respectively.

Table 9-40 PoA estimates for MGO storage volumes at the south harbour

	2023	2024	2025	2026	2027	2028
Est Fuel volume p.a. m3	280,000	288,000	322,560	387,072	464,486	512,000
Est Fuel volume p.a. tonne	98,840	101,664	113,864	136,636	163,964	180,736

The fuel demands provided by PoA could include also the current need of vessel at berth i.e. running engine for power generation which would be displaced by the shore power system. If that was the case, the navigation emission would be much lower than the ones showed here. Further investigation is required to clarify this point.

A high level estimate has been based on PoA projections for the storage volume of fuel required at the South Harbour and the DAC considered as source for the CO_2.

As a worst-case scenario, it is assumed that the storage needs to be entirely refilled daily and therefore the methanol production shall cover it. The actual required daily MeOH supply could be estimated trough the measured data of fuel demand at the south harbour which are not available (fuel supply lines still to be deployed).

It is therefore assumed that all the storage volume should be supplied daily i.e. 576 m³ MGO or 495 tMGO.

Given the density of methanol compared to the MGO, the actual daily methanol demand is ~1,065 ton or ~1,345 m³. Therefore, ~213 ton of hydrogen and ~1,555 ton of CO_2 are daily required based on Table 9-41.

Table 9-41 E-methanol power demand breakdown

Process	Output t/day	Power Demand – GWh/year	Source
MeOH production	1,065	66	Power rate for one ton of MeOH from 34
DAC	1,555	198	Power rate for one ton of MeOH from 34
H_2 production	213	3,701	Power rate for one ton of MeOH from 34
Heat production		292	Power rate for one ton of MeOH from 34
Total		4,256	

Hydrogen plant land take

The footprint occupied by the hydrogen production plant is dependent on many factors such as type of electrolyser chosen, storage volume, water quality supply, capacity of the plant and ancillary system (power supply). Even though the sector is moving fast and many new green hydrogen plants of different capacity have been deployed recently or have been planned, there are no many reference for large/medium scale plants.

It is therefore difficult to assess the land take of the plant due the limited data available and only a proper design would clarify the actual space need. However, IRENA[38] provides examples of recent plants with associated footprint for different capacity with the land take vary between 35 to 170 m²/MW.

The highest value has been used for a conservative and initial estimate of the land take.

E-Methanol plant land take

As per the hydrogen plants, very few information is available for e-methanol plants characteristic due to the even more limited number of plants currently deployed/planned (refer to 33 for list of major e-methanol plants).

Conventional methanol plants may require ~293m²/tph of methanol [39] while e-methanol appears to be requiring ~1500m² for a modular plant to produce ~15 000 l/day of methanol as reported by Swiss Liquid Future AG[40].

The latest modular solution has been considered for an initial footprint approximation.

Direct Air Capture land take

The international Energy Agency provides comprehensive detail of the DAC solution and it compares the requirements for the Liquid DAC (L-DAC) and Solid DAC (S-DAC). The land requirement varies between 1.2-1.7 km²/MtCO_2 for the S-DAC and ~0.4 km²/MtCO_2 for the L-DAC[36]. However, as explained in section A.10.2 L-DAC is considered within the report and the highest value is used for a conservative land use estimate.

[37] Direct Air Capture – A key technology for net zero, IEA 2022
[38] Green Hydrogen cost reduction – scaling up electrolyser to meet the 1.5°C climate goal, IRENA 2020
[39] Space-requirements-Power-2-Fuel_def_2020.pdf (smartport.nl)
[40] https://www.swiss-liquid-future.ch/technology/?lang=en

Renewable energy generation land take

The sizing of any renewable generation is strictly depended on the available of the targeted resources i.e. solar and wind and therefore to deliver the same amount of energy the land take changes significantly from one location to another.

For Aberdeen area a detailed solar and wind assessment has been carried out in Appendix H Appendix I and main parameters summarised in Table 9-42.

Table 9-42 Solar PV and Wind Turbines parameters

	Annual Yield GWh/year	Installed capacity MWp	Space take m^2
Solar PV	0.881	1	4550
Wind Turbine	22.11	5	405,000

Wind turbine spacing is based on 6 rotors diameter distance between turbines in the prevailing wind direction and 3 on the other direction, Figure 9—43. This is a conservative estimate and a detail design of the wind farm may lead to a reduction in space.

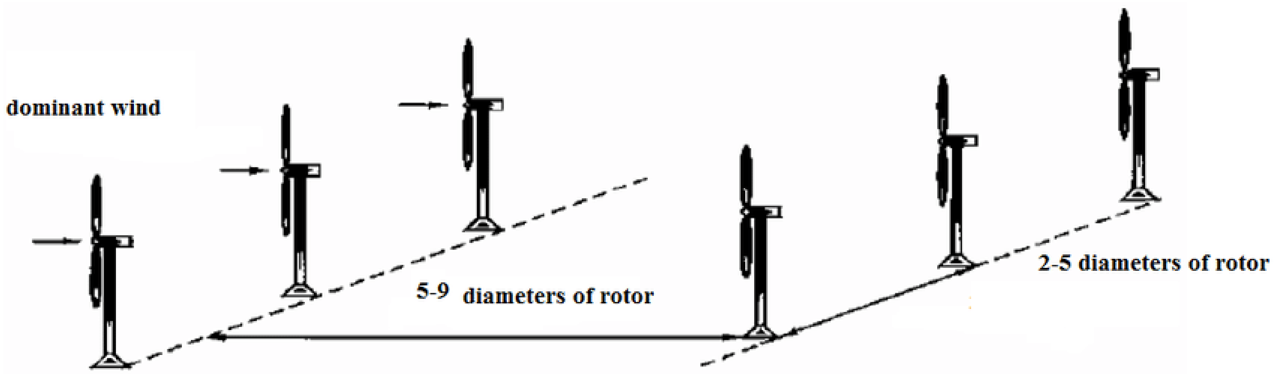


Figure 9—43 indicative spacing between wind turbines

The space between the turbine can be used for other purposes such as farming or cattle while solar PV would occupy most of the space.

The total power demand for the required methanol production is ~4,256 GWh/year which is assumed to be delivered by a ~422MW electrolyser and related methanol plant while the power supply could be supplied by solar or wind sources.

Total E-methanol production land take

Based on above parameters and results, the total area required to produce 1,065 tMeOH/day is 73 km2 or 23.1 km^2 if wind turbines or solar PV are respectively used as power supply. Detail summary of the land take is shown in Table 9-43.

Table 9-43 E-methanol production land take breakdown

	Land take m^2	Capacity	
H_2 production – Electrolyser	71,815	113,506	tH2/year
CO_2 production - Direct Air Capture	964,800	567,529	tCO2/year
MeOH production	135,000	388,719	tMeOH/year
6MW Wind turbines	71,500,206	177	n.
Solar Farm	21,982,899	4,831	GWp
Ancillary infrastructure allowance	234,323		
Total (wind turbines)	72,906,144		

The total land take considers the option with power supply from wind turbines since it is expected to be the potentially viable solution for the demands considered and it could host additional sources of revenue (farming etc) or be located off shore. A solar farm of 22km^2 would be really impossible to be placed close to the harbour or in any and it would require significant investment just to acquire the land.

For comparison, the same amount of methanol but produced from biomass would require ~973km^2 following the finding of Gabrielli et al.

As widely stated within the report, this assessment shall be considered as the high level starting point for a future feasibility study on e-methanol production and how the different development in the area can be integrated.

A.12 E-Methanol cost projections

E-methanol production is currently very low and expensive compared to methanol produced from fossil fuels and it closely related to price of green hydrogen which in turns depended on the price of electricity. With the major deployment of renewable energy plants and hydrogen electrolyser efficiency improvements, it is expected the also the e-methanol cost would reduce significantly.

IRENA estimate that the cost of e-methanol could fall by two to six times as shown in Figure 9—44.

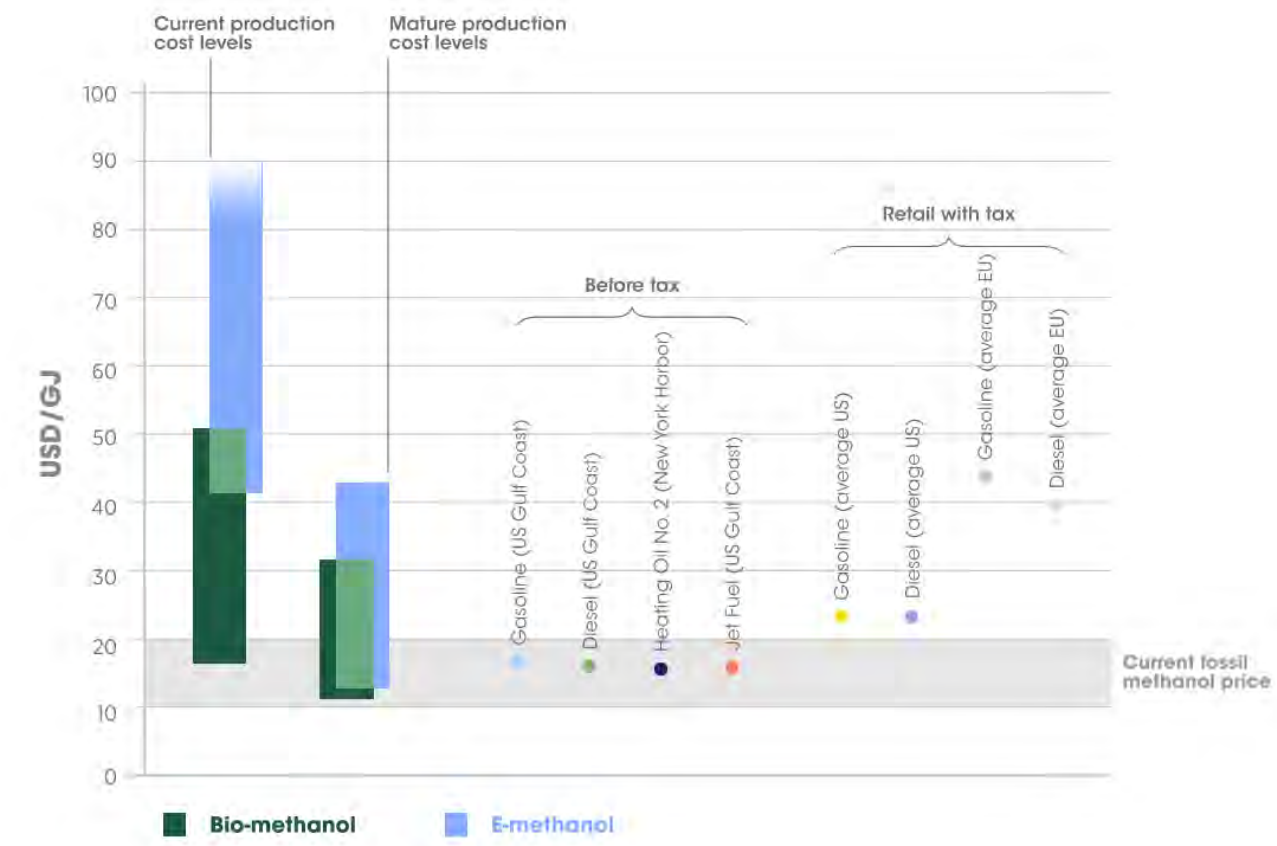


Figure 9—44 Comparison of renewable methanol with other fuels on a price per unit of energy basis, reproduced from 33

Policy support is crucial for any alternative fuel wide deployment since Marine fuel oil is currently untaxed internationally and therefore holds a competitive price advantage over low-carbon fuels. In the medium-term this can be solved at an international level through carbon pricing on marine fuel oil and incentivising low carbon alternatives.

As a comparison measures it here reported the cost projection within the IRENA Decarbonising Shipping report (2021) which suggests ammonia would be cheaper than e-methanol due to the costs associated with carbon capture technology. Ammonia is projected to cost between 67-114 USD/MWh while e-methanol 107-145 USD/MWh.

Ultimately, the actual shipping sector move towards an ammonia, methanol or hydrogen (or other fuel) engine will determine the required fuel(s) and their future demand split. It is for sure recognised that each of them will play a significant role in the decarbonization pathway.

A.13 E-methanol integration with developments near the South Harbour

As described in previous sections, a complex production system would be required to meet the estimated demands for methanol at the South Harbour.

However, the e-methanol production process could be very interesting from an integration perspective with the developments and resources close to the Port.

For example, the Dolphyn project has just received funding form the UK government for the deployment of a 10MW green hydrogen production site in front of Aberdeen coast. This could supply cheap hydrogen to the e-methanol facility without the need for onsite green hydrogen production.

DAC systems have a significant investment cost as well as a land take difficult to accommodate. Renewable CO_2 sources could be explored in the vicinity of the South Harbour. One potential source could be extracting CO_2 from Biogas which, in contrast, requires a biomass feedstock challenging to secure in the region.

However, a potential source of biogas could be the Nigg Waste Water Treatment Plant (Scottish Water) which is serving around 250 000 people in the area with a treatment capacity up to 1.6m^3/s and it is located almost on the boundary of the South Harbour.

It is known that the biogas produced on site supplies a Combined Heat & Power (CHP) unit to meet the WWTP demands and exporting the excess. Quantities of produced biogas, hence of potential CO_2, are not know and it is therefore impossible to assess a indicative contribution to the methanol production.

Engagement with Scottish Water should be held to understand their future plans to reduce emissions. CHP engines are still emitting significant quantities of GHG that will need to be tackled in the next future. Nigg WWTP could provide a CO_2 point source at lower cost than DAC or/and directly produce methanol or hydrogen, increasing the resilience of the supply chain for the fuel production.

Waste heat from the e-methanol production steps could be considered as a heat supply for wider development within a district heating system. Amount of available heat should be estimated trough a detail study based on final e-methanol system configuration and production rates.

Moreover, the UK hydrogen strategy sets out the main hydrogen generation plants and related CO2 storage/CCUS as shown in Figure 9—45. The CCUS site could represent a potential source for CO_2 but the supply chain (storage and transportation) shall be further investigated. It is also expected that these CCUS site will have high competition for their products and it is not sure where and how the CO_2 will be distribute i.e. to which industrial/transportation sector.

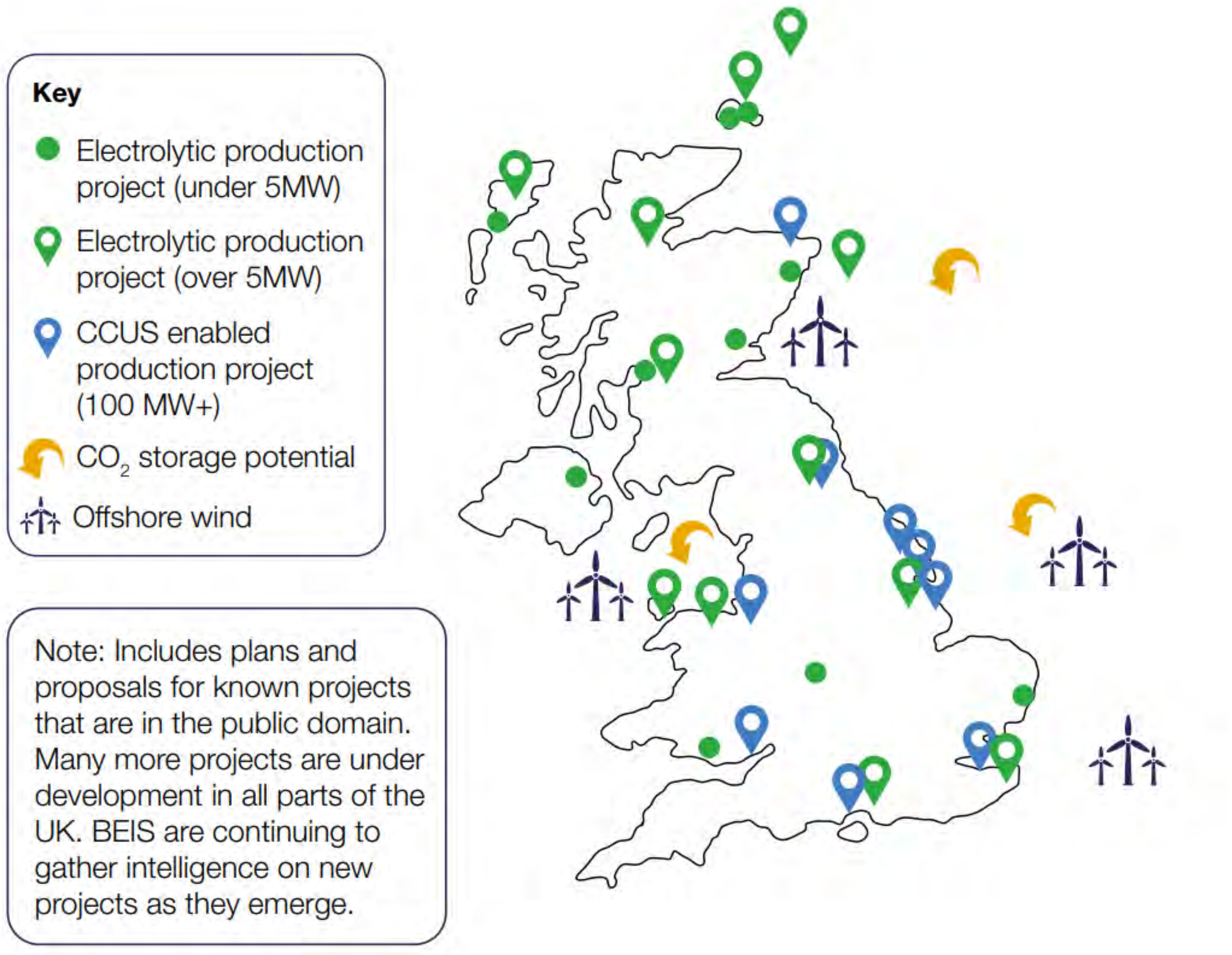


Figure 9—45 Proposed UK electrolytic and CCUS-enabled hydrogen production projects [35]

A.14 Key risks of E-methanol production

- Capital investment is likely to be unbearable if PoA was to fund it
- No space available in the proximity of the south harbour
- Technology progress may lead to different solution than methanol for shipping sector
- Shipping policies and guidelines may introduce stringent requirement for methanol powered ships or specify different preferred fuels
- Overall carbon emission are roughly zero but burning methanol still emits CO2 compared to hydrogen or ammonia
- Providing only methanol on the land side of the harbour could limit the number and type of ships in the future since they may have different type of engine powered by different fuels
- Handling of methanol (storage, supply lines) shall be further investigated in line with main regulations (COMAH, DSEAR etc)
- Cost of methanol may not be attractive for ship operators, especially in the short/medium term
- The ancillary infrastructure required is significant and would require specific design and optimization
- Operators of e-methanol plants (or sub plants) will likely be limited available.

Appendix N Failure modes

N.1 Baseline – shore power

Table 9-44 Detailed shore power failure modes analysis

Risk	Severity	Likelihood	Mitigation
GRID			
Power failure/ Utility Grid blackout	4	2	TSO/DSO reviewing and engagement, considering distributed power supply, backup power supply (e.g battery pack)
Interface Problem - Circuit breaker malfunction	4	1	Signal analysis optimisation, cleaning and terminal verification routines
Control failure	3	1	Ship will use auxiliary engines
BUS - loss of integrity/ continuity	4	2	Adequate design, regular maintenance (including thermographic detection)
Circuit breaker breakdown/ contact degradation	4	3	Signal analysis optimisation, cleaning and terminal verification routines
Loss of feeder HV cable continuity	4	1	Regular inspection, electrical relay coordination, waterproof cables
SHORE SIDE INFRASTRUCTURE			
Transformer Explosion	5	1	Implement hot spot strategies
Transformer Winding Overheating	2	3	Cooling system redundancy and maintenance
Transformer distortion, loosening or displacement of wiring	3	2	Real time signal analysis and hot spot alert strategy implementation
Frequency Converter High Temperature event/ Fire	5	1	Periodic visual inspection and lowering thermal resistance
Loss of output voltage	4	1	Adequate design
Control failure	3	1	Ship will use auxiliary engines
Hardware crash	4	1	Adequate design
Data errors	2	1	Periodic monitoring systems inspections
Operational failure	4	2	Ship will use auxiliary engines
BUS - loss of integrity/ continuity	4	1	Adequate design, regular maintenance (including thermographic detection)
Overload	3	3	Adequate design
CB fail-closed condition	4	1	Signal analysis optimisation, cleaning and terminal verification routines
Power Cable failure/loss of continuity	4	2	Regular inspection, electrical relay coordination, waterproof cables
Occupational hazard	5	1	Adequate design, maintenance, monitoring, perform an arc study and internal arc test
SHIP SIDE			
Synchronisation failure - OPS fails to enter main switchboard	3	1	Ship will use auxiliary engines
Intoxication of passengers onboard	4	1	Safety barriers
Control failure	3	1	implementing fast power restoration procedures, incorporating mechanical tripping of the circuit breaker
Transformer Explosion	5	1	Implement hot spot strategies
Transformer Winding Overheating	2	3	Implement hot spot strategies
Transformer distortion, loosening or displacement of wiring	3	2	Real time signal analysis and hot spot alert strategy implementation
Loss of power cable continuity	3	2	Regular inspection, electrical relay coordination, waterproof cables
Fire in OPS station switchboard	5	1	Adequate design, maintenance, monitoring
Occupational hazard/ Shock/ Arc/ impact/ other	5	2	Adequate design, maintenance, monitoring, perform an arc study and internal arc test
Blackout	4	2	Adequate design, maintenance and monitoring

Risk	Severity	Likelihood	Mitigation
BATTERY BANK (SHORE SIDE)			
Converter (Rectifier/Inverter) High Temperature event/ Fire	5	1	Periodic visual inspection and lowering thermal resistance
Loss of output voltage	4	1	Adequate design
Control failure/ Power management failure	3	1	Ship will use grid electricity or auxiliary engines
BMS failure	3	2	Adequate design
Hardware crash	3	1	Adequate design
Li-ion Fire - Thermal Runaway	5	1	Adequate design, maintenance, monitoring, hot spot strategies implementation
Explosion	5	1	Adequate design and implement hot spot strategies
Mechanical damage	3	3	Periodic visual inspection and safety barriers
Battery Cell deformation	2	3	Battery health monitoring systems
CB fail-closed condition	4	1	Signal analysis optimisation, cleaning and terminal verification routines
Occupational hazard	5	2	Safety barriers
SHIP-SHORE INTERFACE			
Power cables failure/ loss of continuity	4	3	Regular inspection, electrical relay coordination, waterproof cables, adequate storage and handling
Power cable overheating	4	2	Adequate storage and handling
Connectors overheating	3	2	Periodic inspection, consider implementing climate control for switchgear
Socket-plug connection damaged	4	3	Review the traffic design to introduce safety barriers
Communication failure	4	2	Adequate design, ship will use auxiliary engines
Control failure	3	2	Ship will use auxiliary engines, implementing fast power restoration procedures, incorporating mechanical tripping of the circuit breaker
Cable Management System failure - Mechanical failure	4	4	Review the traffic design to introduce safety barriers
Cable over tension	4	4	Adequate design, cable tension alarm
Loss of feeder power cable continuity	4	2	Regular inspection, electrical relay coordination, waterproof cables, adequate storage and handling
Collision/Interference with ship systems	4	3	Review the traffic design to introduce safety barriers
CMS control failure	4	2	Ship will use auxiliary engines, implementing fast power restoration procedures, incorporating mechanical tripping of the circuit breaker
Occupational hazard/ Shock/ Arc/ impact/ other	5	3	Adequate design, maintenance, monitoring, perform an arc study and internal arc test
Overcurrent	4	2	Adequate storage and handling
Fire in CMS unit	5	1	Adequate storage and handling

N.3 Stretch – Solar PV

Table 9-45 Detailed solar PV failure modes analysis (from [41])

Sub-system	Failure modes	Cause(s) of Failure mode	Results / Effects of failure	Severity	Likelihood	Mitigation
Solar PV	Soiling or shading of panel	Improper site selection/Installation	Reduction in energy output	9	5	Proper site selection / Removal of vegetation & obstructions
		Accumulation of dust & soil				Regular maintenance
	Improper Tilt angle	Non availability of geographical location data	Reduction in energy output	7	3	Use weather data (Solar insolation level)
	Improper orientation	Non availability of geographical location data	Reduction in energy output	7	3	
	Fading in the heat	Weak PV modules	Reduced open circuit voltage	7	3	Use weather data (Solar insolation level)
		Charge Controller failure		7	3	
	Bypass diode short out	Lightning / Surge	Reduced open circuit voltage	9	2	Selective shading test
		Improper material selection		9	2	Charge Controller Field test
	Bypass diode reverse connection	Frequent connection and disconnection of the batteries	Damaged PV panel	8	2	Lightning / Surge protection
		Lack of operating/maintenance manual		8	1	Material Selection
	Corroded or burnt terminals	Material failure	Electric arc Shock/injury	10	2	User Instruction
			Hazard	10	2	operating/maintenance manual
			Fire	9	1	Material Selection
		Loose connections		9	1	
		Corrosion		9	1	
	Loose or broken connections	Excessive torque or pressure	Electric arc Shock/ injury Hazard	9	4	Good installation practice/User training
			Fire	9	4	Regular maintenance
	Broken panel glass front	Improper site selection	Electric shock/injury hazard	9	4	Good installation practice / user instruction
		Improper handling	Fire	9	4	
		Hooliganism		10	1	Proper site selection
	Defect in Panel mountings	Material failure	Mechanical Breakage / Damage of panel	10	3	Packaging / Handling
		Improper installation	Injury Hazards	10	1	No Control
		Corrosion		8	1	Material Selection

[41] IJSER. (2014), Failure Modes and Effects Analysis (FMEA) of a Rooftop PV System,

Sub-system	Failure modes	Cause(s) of Failure mode	Results / Effects of failure	Severity	Likelihood	Mitigation
Batteries	Swollen or cracked case	Overcharging	Injury Hazard	9	1	Visual Inspection
	Sulphation	Idle operation/ undercharging	Performance deterioration	8	3	Charge controller field test
	Dirt/corroded connectors	Irregular cleaning of the battery	Discharge of battery	9	4	Regular maintenance / User instruction
		Corrosion	Discharge of battery	9	4	Regular maintenance/User instruction
	Not electrically connected	Loose / Broken connector	Open circuit	9	2	Packaging / Handling
		Material failure	Open circuit	9	1	Material Selection
	Reverse connections are made	Inadequate polarization or indexing	Damage to battery Damage to connection	10	1	Manufacturing Inspection
	Intermittent failure & reduced battery capacity	Ageing	Low energy output	9	4	No control
		End of lifespan	Low energy output	9	5	No control
	Low battery voltage	Faulty controller	Low voltage	9	3	Charge Controller Field test
		Ageing	Low voltage	9	4	No control
		End of lifespan	Low voltage	9	5	No control
	Completely discharge	End of lifespan	No output	10	5	No control
Charge controller / Inverter	Failure of control IC	Inferior design	Improper charging & discharging of the battery Damage to battery	9	3	Manufacturing Inspection/Design
		Use of low quality components	Improper charging & discharging of the battery Damage to battery	9	1	Material Selection
	Short circuiting	Improper connection	Tripped protective gear	10	1	operating/maintenance manual
		Improper connection	Shock/injury	10	1	operating/maintenance manual
		Improper connection`	Hazard	10	1	operating/maintenance manual
		Fault in electrical wiring	Fire	10	2	Continuity testing
	Not electrically connected	Loose / Broken connector	Open circuit	9	2	Packaging / Handling
		Material failure	Open circuit	9	1	Material Selection
	Overloading	Improper selection of PV system	Overheating Damage to the module	8	1	Electrical load calculations & study
		Improper selection of PV system	Overheating Damage to the module			
		Electrical Fault	Overheating Damage to the module	8	3	Using Protective gears
	Low voltage output	Overloading	Low voltage	8	2	Electrical load calculations & study
		Busting of fuse	Low voltage	8	2	Visual inspection
		Abused Battery	Low voltage	8	1	Material Selection
		Failure of PV system	Low voltage	8	1	PV system field test
	Overheating	Failure of heatsink	Damage to PCB	8	1	Material Selection / Manufacturing inspection
		Failure of heatsink	Fire	8	1	Material Selection / Manufacturing inspection
		Failure of heatsink	Injury Hazard	8	1	Material Selection / Manufacturing inspection
	Corroded or burnt terminals	Material failure	Electric arc Shock/injury	9	1	Material Selection
		Material failure	Hazard	9	1	Material Selection
		Material failure	Fire	9	1	Material Selection
		Loose connections		9	4	Good installation practice/User training
		Corrosion		9	4	Regular maintenance

Sub-system	Failure modes	Cause(s) of Failure mode	Results / Effects of failure	Severity	Likelihood	Mitigation
Wires	Overloading	Insufficient conductor ampicity	Overheating	8	3	User Instruction
		Fault in the electrical system	Fire	8	3	Using Protective gears
	Insulation Failure	Pinched wire	Short circuit – no power output, tripped protective gear Shock/ injury Hazard	10	2	Check for current leakage
		Mechanical damage	Fire	10	1	Packaging / Handling
	Conductor failure	Repeated flexing of wire	Open circuit – no output power	8	2	Continuity testing

N.4 Stretch – Wind Turbine

Table 9-46 Detailed wind turbine failure modes analysis (from[42])

Subsystem	Failure type	Severity	Likelihood
Yaw System	Failure of Internal Gear Slewing Bearing System	2	5
	Failure of Yaw Drive Shaft-Pinion System	3	1
	Failure of Yaw Gearbox System	2	1
	Failure of Lubrication System	3	1
	Failure of Yaw Motor System	2	1
Gearbox	Failure of Clamping Unit System	2	1
	Failure of Gearbox Cover System	1	1
	Failure of Gearbox Suspension System	2	1
	Failure of Planet Wheels System	1	2
	Failure of Sun Wheel System	5	2
	Failure of Internal Gear Ring System	2	2
	Failure of Two Stage Fixed Axis Geared System	4	2
	Failure of Lubrication Oil System	5	7
Electrical System	Failure of Power Feeder Cables System	4	1
	Failure of Grounding System	5	1
	Failure of Lightning Protection System	5	1
	Failure of Electrical Protection System	5	4
	Failure of Capacitor Bank System	5	6
	Failure of Thyristor System	2	1
	Failure of Transformer System	0	1
Control System	Failure of Controller System	5	2
	Failure of Uninterruptible Power Supply (UPS)	5	3
	Failure of Signal Networking Hardware System	5	4
	Failure of Meteorological Station	3	2
	Failure of Cable Twist Protection System	5	2
	Failure of High-Speed Centrifugal Release Unit	5	1
Hydraulics	Failure of Electric Motor System	1	1
	Failure of Pump System	5	1
	Failure of Oil Tank System	1	1
	Failure of Filters System	1	2
	Failure of Tubing-Hoses System	1	2
	Failure of (Pipe) Fittings System	1	2
	Failure of Valves System	5	1
	Failure of Rotating Union System	5	2
	Failure of Centrifugal Release Unit	5	1

[42] JESTR. (2020), Preliminary Results for Detection Evaluation in Failure Modes and Effect Analysis Study: 600 kW Wind Turbine Case Study

Appendix O Capital costs

Equipment Location	Description	Item No	Equipment Type	Voltage (kV)	Minimum power rating (MVA)	Length (m)	Size (mm2)	Quantity	Rate	Total	Notes
		1	Fan ventilated transformer	0.4/3.3	2.4			1	£137,000	£137,000	
		2	Battery inverter (7MW discharge)	0.4	2.4			1	£397,000	£397,000	
		3	3.85 MWh Battery Storage (1.9MW discharge)	0.4	1.9			1	£2,843,000	£2,843,000	
Primary Substation	Connection to DNO network at 33kV. To include supply and installation costs as well as concrete foundations, civil works etc.	4	Fan ventilated transformer	33/3.3	8			3	£387,000	£1,161,000	
		5	Frequency converters	3.3	8			3	£459,000	£1,377,000	
		6	Fan ventilated transformer	3.3/6.6	8			3	£430,000	£1,290,000	
		7	Isolation transformer	6.6/6.6	7			10	£354,000	£3,540,000	
		8	Distribution panel	3.3	24			1	£278,000	£278,000	
		9	Distribution panel	33	24			1	£534,000	£534,000	
		10	Distribution panel	6.6	24			1	£293,000	£293,000	
Distribution	To include civil works (concrete hard digging), installation and ancillary works	11	Ducted HV Cabling (3 core)	6.6	7	10,323.25	500	1	£1,698,000	£1,698,000	
		12	HV clips beneath port (for 1 cable)	6.6		112.77	N/A	1	£8,000	£8,000	
		13	New trenches (for 1 cable)	6.6		291.13	300x300 (WxH)	1	£83,000	£83,000	Concrete break out and reinstatement assumed as 300mm
		14	Manholes for trench with 1 ducted cables					4	£5,000	£20,000	
		15	New trenches (for 2 cable)	6.6		17.17	600x300 (WxH)	1	£10,000	£10,000	Concrete break out and reinstatement assumed as 300mm
		16	Manholes for trench with 2 ducted cables					1	£7,000	£7,000	
		17	New trenches (for 3 cable) + 1 spare duct	6.6		81.94	600x600 (WxH)	1	£55,000	£55,000	Concrete break out and reinstatement assumed as 300mm
		18	Manholes for trench with 4 ducted cables					2	£11,000	£22,000	
		19	New trenches (for 4 cable) + 2 spare ducts	6.6		124.03	900x600 (WxH)	1	£126,000	£126,000	Concrete break out and reinstatement assumed as 300mm
		20	Manholes for trench with 6 ducted cables					1	£15,000	£15,000	
		21	New trenches (for 6 cable) + 3 spare duct	6.6		381.87	900x900 (WxH)	1	£426,000	£426,000	Concrete break out and reinstatement assumed as 300mm
		22	Manholes for trench with 9 ducted cables					6	£21,000	£126,000	
		23	New trenches (for 7 cable) + 2 spare ducts	6.6		238.41	900x900 (WxH)	1	£260,000	£260,000	Concrete break out and reinstatement assumed as 300mm
		24	New trenches (for 8 cable) + 1 spare duct	6.6		120.04	900x900 (WxH)	1	£128,000	£128,000	Concrete break out and reinstatement assumed as 300mm
		25	Manholes for trench with 12 ducted cables					4	£25,000	£100,000	

Equipment Location	Description	Item No	Equipment Type	Voltage (kV)	Minimum power rating (MVA)	Length (m)	Size (mm2)	Quantity	Rate	Total	Notes
		26	New trenches (for 9 cable) + 3 spares ducts	6.6		327.42	1200x900 (WxH)	1	£472,000	£472,000	Concrete break out and reinstatement assumed as 300mm
		27	Use of existing trenches (for 1 cable)	6.6		143.31		1	£8,000	£8,000	
		28	Use of existing trenches (for 2 cable)	6.6		235.68		1	£23,000	£23,000	
		29	Use of existing trenches (for 3 cable)	6.6		103.19		1	£14,000	£14,000	
		30	Use of existing trenches (for 4 cable)	6.6		87.91		1	£16,000	£16,000	
		31	LV meters	0.69				2	£4,000	£8,000	
		32	HV Meters	6.6				10	£5,000	£50,000	
Berth	To include civil works, installation and ancillary works	33	Isolation transformer	0.69/0.69	3			2	£1,124,000	£2,248,000	Unable to price on current spec due to tier 2 losses. Price based on 20nr 0.3MVA units to make up total power rating.
		34	Fan ventilated transformer	6.6/0.69	3			2	£419,000	£838,000	Unable to price on current spec due to tier 2 losses. Price based on 4nr 1.5MVA units to make up total power rating.
		35	Mobile HV cable management system with at least 50m of cable length capacity and including 2 (3 core) cables	6.6	7			8	£233,000	£1,864,000	
		36	Mobile LV cable management system with (and including) at least 50m of cable length capacity and including 4 (3 core) cables	0.69	3			6	£158,000	£948,000	
		37	HV shore power connection point	6.6	7			10	£74,000	£740,000	
		38	HV shore power socket	6.6	7			16	£17,000	£272,000	
		39	LV shore power connection point	0.69	3			2	£58,000	£116,000	
		40	LV shore power socket	0.69	0.8			14	£13,000	£182,000	
Civil works	Sub Station buildings and bases for main kit	41	Openings on 5T UDL concrete suspended deck					5	£10,000	£50,000	
		42	Bunkering pits to include HV power connection points					5	£13,000	£65,000	Pits - 2.5m x 1.5m x 2m deep; HV points in item 37
		43	Road crossing for 16 ducts				25000	1	£75,000	£75,000	Assume 150 dia ducts in two stacked rows of 8 ducts
		44	Sub station buildings and fenced enclosures					1	£5,262,000	£5,262,000	38000x43000 (LxW)
Renewable	Solar PV	45	Welfare Building 1 - Rooftop PV and associated cabling + inverter	0.4	18 (kW)			103	£700	£72,100	

Equipment Location	Description	Item No	Equipment Type	Voltage (kV)	Minimum power rating (MVA)	Length (m)	Size (mm2)	Quantity	Rate	Total	Notes
Technology		46	Gatehouse - Rooftop PV and associated cabling + inverter	0.4	4 (kW)			25	£700	£17,500	
		47	Welfare Building 2 - Rooftop PV and associated cabling + inverter	0.4	12 (kW)			67	£700	£46,900	
Renewable	Solar PV	48	Welfare Building 1- Rooftop PV and associated cabling + inverter	0.4	6 (kW)			36	£700	£25,200	
Technology		49	Warehouse - Rooftop PV and associated cabling + inverter	0.4	75 (kW)			unknown		£263,000	
		50	Terminal - Rooftop PV and associated cabling + inverter	0.4	35 (kW)			unknown		£123,000	
		51	Car park section 1 - Carport PV and associated cabling + inverter + canopy frames	0.4	18 (kW)			84	£2,400	£201,600	
		52	Car park section 2 - Carport PV and associated cabling + inverter + canopy frames	0.4	16 (kW)			71	£2,400	£170,400	
		53	Car park section 3 - Carport PV and associated cabling + inverter + canopy frames	0.4	8 (kW)			34	£2,400	£81,600	
		54	Car park section 4 - Carport PV and associated cabling + inverter + canopy frames	0.4	8 (kW)			37	£2,400	£88,800	
		55	Car park section 5 - Carport PV and associated cabling + inverter + canopy frames	0.4	19 (kW)			87	£2,400	£208,800	
		56	Car park section 6 - Carport PV and associated cabling + inverter + canopy frames	0.4	46 (kW)			207	£2,400	£496,800	
		57	Car park section 7 - Carport PV and associated cabling + inverter + canopy frames	0.4	3 (kW)			16	£2,400	£38,400	
	Wind	58	Onshore wind turbine and associated civil work (foundations) at a soft ground site and including 100m of access road	33	6 (MW)	at least 100m hub height		1	£7,927,000	£7,927,000	

Equipment Location	Description	Item No	Equipment Type	Voltage (kV)	Minimum power rating (MVA)	Length (m)	Size (mm2)	Quantity	Rate	Total	Notes
		59	Wind turbine cable	33	6.7	880	50	1	£191,000	£191,000	
		60	Wind turbine cable trench - New trenches (for 1 cable)			880	300x300 (WxH)	1	£27,000	£27,000	
Circuit	Landside substation	61	Welfare building 1 - MCCB 3P 50A	0.4				1	£4,000	£4,000	
breakers /		62	Welfare building 1 - MCCB 3P 200A	0.4				1	£17,000	£17,000	
Distribution		63	Terminal - MCCB 3P 63A	0.4				1	£5,000	£5,000	
Boards: VCB		64	Distribution board - 12 way, 3 phase, 250A	0.4				2	£21,000	£42,000	
vacuum		65	Warehouse - MCCB 3P 125A	0.4				1	£11,000	£11,000	
circuit	Shore power	66	VCB 800A	6.6				25	£42,000	£1,050,000	
breaker,	substation	67	MCCB 3P 3.2kA	0.69				4	£179,000	£716,000	
MCCB -		68	VCB 1600A	3.3				6	£76,000	£456,000	
moulded		69	VCB 200A	33				4	£14,000	£56,000	
case											
circuit											
breaker											
Other infra	ETZ	70	Fan ventilated transformer	33/11	20			1	£328,000	£328,000	Not considered. Only indicative to understand cost related to ETZ integration
	Lanside additional	71	Fan ventilated transformer	11/0.4	0.6			1	£103,000	£103,000	Not considered. Only indicative to understand cost related to ETZ integration
	EVCs	72	MCCB 3P 800A	0.4				1	£62,000	£62,000	Not considered. Only indicative to check impact of super-fast EV charger
		73	MCCB 3P 12A	0.4				4	£28,000	£112,000	Not considered. Only indicative to check impact of additional normal EV charger
		74	MCCB 3P 12A	0.4				4	£28,000	£112,000	Not considered. Only indicative to check impact of additional normal EV charger
		75	EV charger	0.4	7 (kW)			4	£7,000	£28,000	Not considered. Only indicative to check impact of additional normal EV charger
		76	EV charger	0.4	400 (kW)			1	£103,000	£103,000	Not considered. Only indicative to check impact of super-fast EV charger
				CURRENT VALUE						£41,369,100	
		77	Allow for inflation - based on 1Q25 start and 18 month build							£2,979,000	Based on current tender price indices - add 7.20%
				TOTAL ESTIMATED COST PLUS INFLATION - EXCLUDING VAT AND DESIGN TEAM FEES						**£44,348,100**	

Appendix P Risk Register

		Pre-Mitigation					Post -Mitigation			
	CORE SCHEME	**Prob.**	**Impact**	**Risk**	**Action**	**M- MANAGE T - TRANSFER R - REDUCE**		**Prob.**	**Impact**	**Risk**
		1-5	**1-5**	**1-25**	**M/T/R**			**1-5**	**1-5**	**1-25**
Item Ref.	**ITEM**	**P**	**I**	**R = P x I**		**Actions required**	**Lead By**	**P**	**I**	**R = P x I**
1	**1.0 Stakeholders**									
1.1	PoA fail to gain support internally to develop shore power infrastructure	3	5	15	M	PoA to achieve sign off from internal decision makers after having completed a detaitl investigated (OBC) to agree on formal policy approach and procurement route for shore power infrastructure.	PoA / SPV	1	5	5
1.2	PoA fail to gain wider political support	4	5	20	R	PoA to develop and submit OBC and DPD information to applicable funding body for additional funding signoff which could potentially support up to 50% of capital costs of infrastructure and consult with government departments to test basis for system procurement and delivery is transparent and according to best practice.	PoA / SPV	3	5	15
1.3	Vessel operators do not wish to participate, or push back on required planning requirements for implementation of shore power infrastructure.	3	5	15	R	Heads of Terms (HoT's) to be agreed in principal with participating operators including spatial planning. Suggested enhancement of electric take-off contract to include shore power spatial requirements	PoA / SPV	2	5	10
1.4	Vessel owners do not transition their vessels to accommodate shore power, particularly in cases where vessels are rented or leased by harbour users.	3	5	15	R	Harbour areas where operators have decarbonisation targets and good relationships with vessel owners have been selected. Continued engagement between vessel users and owners must take place to promote the retrofitting of vessels to accept shore power, else alternative leasing arrangements should be sought.	PoA / SPV & operators	2	5	10
1.5	Vessel operators may have different requirements for type of alternative fuel to be used in short/long term	3	5	15	M	Port Of Aberdeen to investigate which alternative fuel would be mostly required and consider it for the storage on site while allowing barge/truck supply for other type of fuels	PoA & operators	2	3	6
1.7										
2	**2.0 Business Case**									
2.1	**2.1 Funding and Procurement**									
2.1.1	Failure to identify funding sources adequate to meet the capital costs of the scheme, particularly the grant funding to meet the 50% of CAPEX base case	4	5	20	R	PoA should engage with potential funding bodies such as the DfT and keep track of the development of the Clean Maritime Plan 2023 as well as other potential funding opportunities. Operator / off taker contribution to infrastructure deployment should also be considered Pending on CAPEX cost covered through grant funding, shore power sales price would need to update if the base case IRR is to be met.	PoA / SPV	3	5	15
2.1.2	Unable to develop business case to allow shore power infrastructure to progress. Lack of political will to continue as owner and operator	2	5	10	R	A detiaed OBC shall be developed to inform commitment required from associated parties. This would indicate how to progress implementation of proposed solutions (D&B contracts, O&M etc).	PoA / SPV	3	5	15
2.2	**2.2 Capital costs**									
2.2.1	Costing estimates increase during design development. This includes uncertainty surround renewable energy costs such as PV and Wind Turbines	4	4	16	M	Market testing and bespoke cost consultancy input shall be undertaken to refine the cost plan - this should be revisited at later stages. This engagement process will highlight any cost hotspots which require further design development. Cost sensitivity will be undertaken with the OBC as part of the financial case.	PoA / SPV	3	4	12

2.2.2	Budget underestimated during construction due to unforeseen issues	3	5	15	M	OBC to include cost estimates and contigency to cover any underestimation. These should be considered during contractor awards and funding applications. Key risks identified during design stages and continuing design development to be actively managed and mitigated at appropriate time.	PoA/ Consultant	3	4	12
2.3	**2.3 Revenues/ Operating Costs**									
2.3.1	Failure to attract participating shore power users or delay in implementing shore power infrastructure therefore resulting in reduced revenue leads to revenue gap to repay any borrowing / investment.	5	5	25	R	Investigate alternative revenue grants including sharing of risk until further participating operators (and revenue) are sufficient to cover operating costs including any borrowing costs.	PoA / SPV	4	5	20
2.3.2	Fail to obtain economic value from power sales	3	5	15	R	Within this study a shore power markup price has been calcualted against a variety of electricity prices across a 40 year project lifespan. An average markup price has been estiamted that would provide an economic return on investment made. There will be a need to ensure customer supply contracts reinforce viability of agreed shore power electricity prices and changes in electricity purchase price are backed off to customers	PoA / SPV	2	4	8
2.3.3	Exposure to fluctuations in future energy prices leading to PoA exposed to funding shortfall versus operator power sales	3	4	12	R	Future energy price scenario from DESNEZ tested in financial model to understand sensitivity to future fuel cost fluctuations. To be reviewed and updated during design development. Power sales have been index linked to primary energy prices. Protection from increases in power prices should be considered for PoA power purchase from supplier. Shore power sales prices may need to temporarily increase and this should be considered within operator contracts.	PoA / SPV	2	3	6
2.3.4	Resulting cost of shore power is too high for participating operators	3	5	15	M	PoA could obtain additional capital funding to minimise power cost; tight control of costs for infrastructure rollout is required and index linking of power cost to counterfactual marine fuelling solution which may incur carbon taxes in the future. Power rate to be remodelled on realisation of funding provision before proceeding.	PoA / SPV	2	4	8
2.3.5	Purchase price of power to supply shore power units becomes too high in future in comparison to alternatives (e.g. marine fuel)	3	5	15	R	PoA to consider long term contracts for energy purchase. The implimentation of renewable technology could provide further security against rising energy costs.	PoA / SPV	2	2	4
2.3.6	Information not forthcoming from potential shore power consumers. Estimates have been made for future shore power sales based on best available information.	2	3	6	R	This study used avaialble histroical data to provide estimates of shore power demands. To increase the accuracy of the modelled data early engagement with operators should be completed to update models with anticipated future power demands using best available information. Gradual uptake in power demands for vessels has been factored into early years of shore power operation to reflect vessels being retrofitted to accept shore power and operator buy-in. This should be continually reviewed and may require re-run of model should the be a significant deviation from base case demands.	PoA / SPV	1	3	3

2.3.7	Failure to meet "power on" date requirements for leading to loss of power sales over modelled lifetime	3	5	15	R	Continued consultation has been undertaken with port users throughout the completion of the OBC. During this process mitigation approaches should be agreed including the use of incumbent marine fuel energy supply as a last resort.	PoA / SPV	2	3	6
2.3.8	Some shore power off takers (customers) do not value carbon costs as high as has been assumed in the base case and therefore do not regard utilisation of shore power as economically worthwhile vs. Cost of marine fuel	3	5	15	M	Prevailing sentiment from most operators engaged with is that there is a desire to decarbonise their operations in order to meet self set net zero targets. Continued engagement with operators to promote the use of shore power at Point Law and possible contractual obligations to utilise shore power whilst alongside at selected berths, or based on anticipated duration of stay.	PoA / SPV	2	4	8
2.3.9	Failure to meet project completion deadlines set by project funders.	3	5	15	R	Port of Aberdeen will confirm milestones at the outset of the construction programme with the funding board and manage any delays through regular consultation. There are precedents for delays on previous projects funded through this means so close collaboration will be key.	PoA / SPV	2	3	6
3	**3.0 Planning Consents, Permitting and Environment**									
3.1	Fail to obtain planning / operational permission for shore power infrastructure and associated power connections	2	5	10	R	PoA will need to continue to manage planning / operational concerns for infrastructure through engagement with operators and local stakeholders. Understanding is PoA are the landowners of areas where new infrastructure is being implemented.	PoA / SPV	1	5	5
3.2	High levels of visual impact from infrastructure	1	4	4	R	Thought to be low risk due to industrial nature of the site.	PoA/ consultant	1	4	4
3.3	Fail to obtain planning permission for reneable generation plants such as wind turbines.	3	4	12	M	PoA to liasie with stakeholders and regulating bodies to seek feedback on prposed renebale generation plans (if any) and incorporate any requirement early in the design process	PoA/ consultant	2	4	8
4	**4.0 Technical and design issues**									
4.1	Shore power consumption estimates vary vs actual consumption	4	4	16	M	Power demand sensitivity has been adressed as part of the study but risks remain due to inherent variability between design and operation. Continued refinement of the model shall be done in light of data that will be available for the south harbour.	PoA/ contractor	4	4	16
4.2	In short to medium term (i.e. before the shore power systems are developed) operators install own equipment reducing potential for shore power sales for PoA	1	5	5	M	Dialogue will be maintained with key stakeholders to discuss shore power opportunity and ensure HoTs are agreed. Understanding is that permission would have to be granted from PoA to operators to develop own solutions	POA	1	2	2

4.3	Typology of vessel berthign at south harbour and assocaited power requirements vary between operators and ships	4	4	16	M	Engagement with vessel operators and PoA confimed range of vessel assumed to berth at the south harbour and indicative power demands. Due to the flexible nature of the harbour i.e. any ship could berth, continue refinement is needed.	PoA/ Consultant	3	3	9
5	**5.0 Utilities**									
5.1	Service cabling requires service diversions to accommodate new power cabling	3	5	15	R	Based on initial information provided by PoA, the new infrastructure has been routed and located in such a way to minimise any impact on other utiltiies such as potable water, future fuel lines etc. However, routing shall be verified with the final as built information	PoA/ Consultant	2	3	6
5.2	PoA fails to obtain agreement with the Distribution Network Operator for the provision of power to the shore power system.	3	5	15	R	The DNO is obliged to 'provide a connection upon request' as its statutory duty. Third parties can be used (ICP/IDNO) to reduce the capital cost to connect	PoA/ DNO	2	3	6
5.3	Lack of capacity locally to supply electricity or significant reinforcement required to provide capacity	2	5	10	R	Engagement with the DNO (SSE) shall be undertaken to understand any reinforcement requirements and costs to serve shore power areas. Desktop analysis shows that signifcaitn reinforcement of the upstream network is required to supply the south harbour. A formal quote and timescales should be secured from the DNO at later stages. Intelligent controls to minimise coincident peak demands on shore power systems should be considered if required.	PoA/ Consultant	2	5	10
5.4	Lack of final as built information for the south harbour	5	3	15	R	Multiple information have been received and investigated to assess the as built situation. The proposed electrcial network shall be further verified when also the future planned networks (fuel lines) are installed and remaining part of the port constructed	PoA/ Consultant	4	3	12
6	**6.0 Construction and procurement**									
6.2	Risk of discovering unexpected material in the ground such as contaminated land, archaeology or unexploded ordinances	2	4	8	M	Low risk given the harbour has just been built. Spatial coordination of new infrastructure to avoid impacting existing harbour services and or structural integrity of quays has been considered. Undertake suitable ground investigation prior to commencement of procurement; hold suitable level of contingency within budget.	PoA/ development project engineers	2	2	4
7	**7.0 Future Phases**									
7.1	Future operators of the harbour do not wish to participate	3	5	15	M	Early engagement with historic operators has been undertaken indicating net zero aspirations and good buy in for shore power offtake in future. Enhancement of lease agreements could include shore power use obligations. Future carbon taxes on marine fuels could help justify case for shore power	PoA / SPV	2	4	8

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