

Oil and Gas Authority

NORTH SEA DECARBONISATION

Decarbonisation of the North Sea Study Report Vol 2

REPORT

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Acronyms & Abbreviations

Abbreviation	Description
ABEX	Abandonment and Decommissioning Expenditure
AC	Alternating Current
AGS	Advanced Geothermal Systems
AIS	Air Insulated Switchgear
ALARP	As Low As Reasonably Practicable
AMR	Advanced Modular Reactor
AVR	Automatic Voltage Regulator
BEIS	Department for Business, Energy, and Industrial Strategy

Abbreviation	Description
BESS	Battery Energy Storage System
BMRS	Balancing Mechanism Reporting Service
BTEX	Benzene, Toluene, Ethylbenzene and Xylene
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CFD	Computational Fluid Dynamics
CLV	Cable Lay Vessel
CNS	Central North Sea
COG	Centre of Gravity
CoP	Cessation of Production
CSA	Cross Sectional Area
CSP	Concentrated Solar Power
DAF	Dynamic Amplification Factor
DC	Direct Current
DCS	Distributed Control System
DFIG	Doubly Fed Induction Generator
DG	Diesel Generator
DIFFS	Deck Integrated Fire Fighting System
DoB	Depth of Burial
DOL	Direct Online
DSS	Distributed Strain Stressing
DTS	Distributed Temperature Sensing
ECS	Electrical Control System
EGS	Enhanced Geothermal Systems
EL	Elevation
EMS	Energy Management System
EOR	Enhanced Oil Recovery
EPR	Ethylene Propylene Rubber
ER	Emergency Response
ESD	Emergency Shutdown
ETS	Emissions Trading System
F&G	Fire and Gas
FEED	Front End Engineering Design
FFAS	Fixed Foam Application System
FOWT	Floating Offshore Wind Turbine
FPSO	Floating Production Storage and Offloading
GBP	Great British Pound
GHG	Greenhouse Gas
GIS	Geographic Information System
GIT	Gas Insulated Transmission
GOR	Gas Oil Ratio

Abbreviation	Description
GT	Gas Turbine
HALEU	High Assay Low Enriched Uranium
HMI	Human Machine Interface
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HSE	Health, Safety & Environment
HTGR	High Temperature Gas Reactor
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
Hz	Hertz – The measurement of Frequency
ICOP	Infrastructure Code of Practice
ICSS	Integrated Control and Safety System
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IGBT	Insulated Gate Bipolar Transistor
IM	Induction Machine
IMO	International Maritime Organization
INTOG	The Innovation and Targeted Oil and Gas
ISD	Inherently Safer Design
ISMS	Integrated Security Management System
ISO	International Organization for Standardisation
km	Kilometre
KO	Knock-out
kV	Kilovolts
LCOE	Levelised Cost of Energy
LHV	Lower Heating Value (fuel)
LP	Low Pressure
LPG	Liquified Petroleum Gas
LQ	Living Quarters
LSD	Load Shedding
LV	Low Voltage
LVOC	Liquefied Volatile Organic Compounds
MAH	Major Accident Hazard
MCC	Motor Control Centre
MCFR	Molten Chloride Fast Reactor
MOL	Main Oil Line
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
MV	Medium Voltage
MVDC	Medium Voltage Direct Current
MW	Megawatts

Abbreviation	Description
MWh	Megawatt Hours
MWS	Marine Warranty Surveyor
NGL	Natural Gas Liquids
NIRO	The Nuclear Innovation and Research Office
NUI	Normally Unmanned Installation
OEM	Original Equipment Manufacturer
OGA	Oil and Gas Authority
OLTC	On Load Tap Changer
OMF	Outer Moray Firth
OPEX	Operational Expenditure
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
ORC	Organic Rankine Cycle
OREDA	Offshore Reliability Data
OWA	Offshore Wind Array
PAU	Pre-Assembled Unit
PBT	Payback Time
PCV	Pressure Control Valve
PD	Partial Discharge
PF	Power Factor
PFD	Process Flow Diagram
PFEER	Prevention of Fire and Explosion and Emergency Response
PFP	Passive Fire Protection
PLB	Post Lay Burial
PLGR	Pre-Lay Grapple Run
PMS	Power Management System
POB	People On Board
PSV	Pressure Safety Valve
PUWER	Provision and Use of Working Equipment
PV	Photovoltaic
PWR	Pressurised Water Reactor
QRA	Quantified Risk Assessment
RAM	Reliability, Availability and Maintenance
RO	Reverse Osmosis
ROV	Remote Operated Vehicle
SCADA	Supervisory Control and Data Acquisition
SCC	Social Cost of Carbon
SCGT	Simple Cycle Gas Turbine
SFC	Static Frequency Converter
SLB	Simultaneous Lay and Burial
SMR	Small Modular Reactors
SNS	Southern North Sea
SOW	Scope of Work

Abbreviation	Description
SVC	Static VAr Compensator
SWACH	Small Waterplane Area Circular Hull
TBM	Time Based Maintenance
TCTU	Topsides Cable Termination Unit
TDR	Time Domain Reflectometry
TEG	Tri-Ethylene Glycol
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
TFSW	Trans Frontier Shipment of Waste
therm	100 Standard Cubic Feet
TOS	Top of Steel
TR	Temporary Refuge
TRL	Technology Readiness Level
TUTU	Topsides Umbilical Termination Unit
UKCS	United Kingdom Continental Shelf
ULS	Ultimate Limit State
UPS	Uninterruptable Power Supply
VCB	Vacuum Circuit Breaker
VFD	Variable Frequency Drive
VLCC	Very Large Crude Carrier
VRU	Vapour Recovery Unit
VSD	Variable Speed Drive
WHR	Waste Heat Recovery
WHRU	Waste Heat Recovery Units
WL	Water Level
WTG	Wind Turbine Generator
XLPE	Cross-Linked Polyethylene

1. Executive Summary

Katoni has undertaken a study on “An Optimised Method for Interfacing Distributed Sources of Renewable Generation with Existing Offshore Oil and Gas Installations Requiring Secure Sources of Low Emissions Power” (from here on referred to as the Decarbonisation Project).

The project's aim was to study and develop a design for an offshore electrical power network that would act as an interface between distributed sources of renewable power and Oil & Gas assets, with the intention to minimise equipment, modifications and infrastructure required on the platforms themselves. Instead, control and safety equipment, as well as power transformation and distribution equipment, would be located on new, dedicated infrastructure.

The driver for the development of the Decarbonisation Project concept came from Katoni's experience in brownfield modifications and study work, including electrification and power generation projects.

Platform electrification and power generation in the UKCS has typically been approached on a platform-by-platform basis. This approach often renders these types of projects unfeasible due to the scale of modifications required to the platforms, which are often aging assets with short remaining life, and with limited available capacity to support the required modifications.

This led Katoni to develop a concept that would allow platforms to electrify their topsides power and reduce emissions in the most economically feasible manner with minimal on-platform modifications.

The study objective was to attempt to define a methodology to promote standardisation and industrialisation of large-scale electrification of the United Kingdom's North Sea region. Promoting concepts such as repeatability, scalability and knowledge sharing, the study aimed to determine the feasibility of such a concept.

The key area of focus was evaluating a consumer driven technology solution, i.e., minimising modifications on existing assets, with the burden on external equipment selected to provide as close to platform required power supplies (in terms of voltage, frequency etc) as possible.

The study focused primarily on the design and specification of the infrastructure required to provide this solution.

The project intention was to develop a modular design that could be scaled up or down to suit regional infrastructure clusters and the distribution of potential renewable sources of energy such that the same design principles could cover a high percentage of existing UKCS infrastructure, which will be quantified utilising an envelope-based approach.

A quantification of platform emissions reduction and basin emissions from implementation of this concept is also considered and detailed in this report.

The study also evaluated alternative low carbon fuel sources such as use of hydrogen, or alternative renewables to replace or supplement wind.

This report outline in detail:

- The issue we are trying to address
- The challenge of finding a solution
- Our technical solution
- Demonstrating what renewables can do for Oil and Gas
- What is the physical solution is
- The economics of the proposed design
- Potential additional opportunities which come from the proposed solution

For the key findings and please see Volume 1 of this report.

2. Introduction

Katoni has undertaken a study on “An Optimised Method For Interfacing Distributed Sources Of Renewable Generation With Existing Offshore Oil And Gas Installations Requiring Secure Sources Of Low Emissions Power” (from here on referred to as the Decarbonisation Project).

The project is to study and develop a design for an offshore electrical power network that would act as an interface between distributed sources of renewable power and Oil & Gas installations with the intention to minimise equipment, modifications and infrastructure required on the platforms themselves. Instead, control and safety equipment, as well as power transformation and distribution equipment, would be located on new, dedicated infrastructure.

It is anticipated that an individual system will comprise primarily of a floating Main Hub Substation (Main Hub) which could incorporate generation, transformation, storage, controls and distribution. From the Main Hub a number of smaller Sub-distribution Hubs (Sub Hubs) could be supplied which would then provide the final transformation and power regulation to provide a suitable input to an individual Oil & Gas installation. The final cable run would be short enough that the power would be supplied at the appropriate voltage and frequency minimising the modifications required at the receiving installation.

The local Sub Hub would be equipped with suitable safety and control equipment to ensure that imported power is safe and reliable with the ability to reduce fault currents and harmonics to minimise upgrades or modifications being made to the Oil & Gas platform itself.

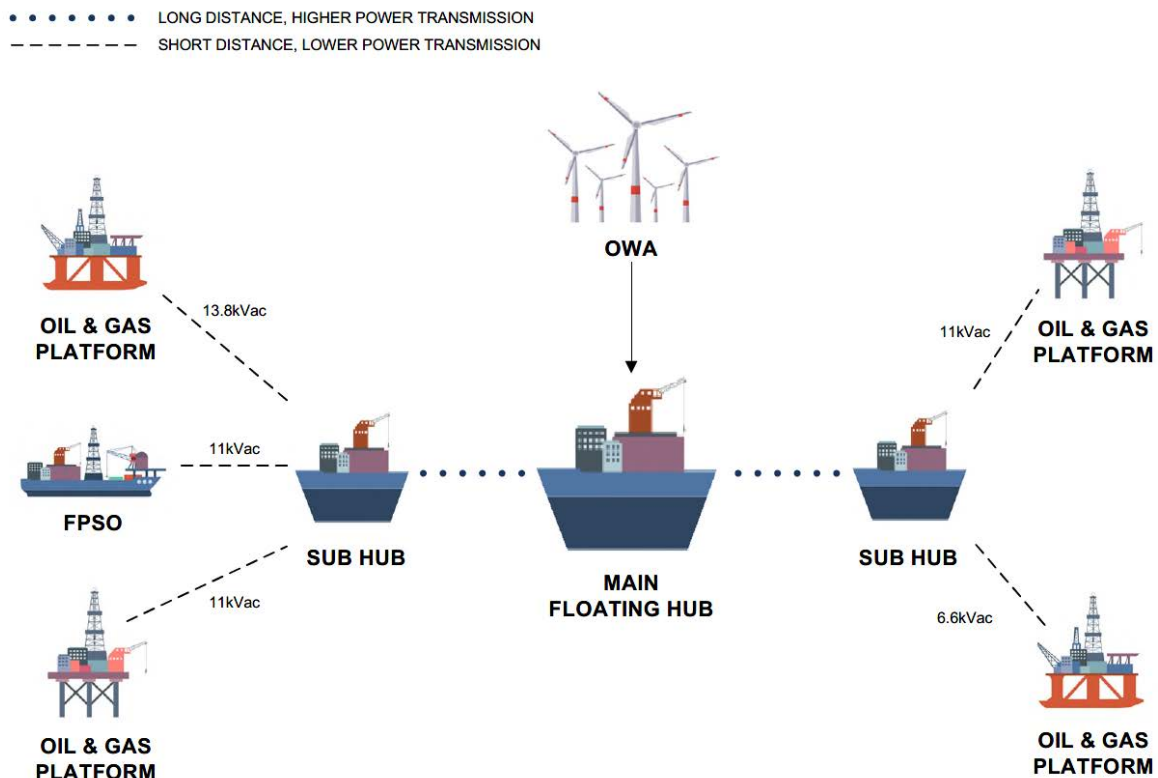


Figure 2-1 - Simplified Topology of Power Network

As shown in Figure 2-1 the system would comprise of:

- Offshore Wind Array
- Floating Main Hub Substation (Main Hub)
 - o OWA Receipt
 - o Local Power Generation
 - o HVDC Power Transmission
- Local Sub-Distribution Hubs (Sub Hubs)
 - o HVDC Receipt
 - o MVAC Distribution

To further the study Katoni Engineering have received input from the following contributors to this study:

- Sevan SSP
- GE Power Systems
- TechnipFMC
- Core Power
- SPC Network

3. Report Objectives

The study objective is to attempt to define a methodology to promote standardisation and industrialisation of large scale electrification of the United Kingdom's North Sea region. Promoting concepts such as repeatability, scalability and knowledge sharing, the study will look to determine the feasibility of such a concept.

The key area of focus is evaluating a consumer driven technology solution, i.e. minimising modifications on existing assets, with the burden on external equipment selected to provide as close to platform required power supplies (in terms of voltage, frequency etc) as possible.

The study has focused primarily on the design and specification of the infrastructure required to provide this solution, and to define the requirements of the Main and Sub-distribution Hubs, along with the interconnecting power cables.

The project intention was to come up with a modular design that could be scaled up or down to suit regional infrastructure clusters and the distribution of potential renewable sources of energy such that the same design principles could cover a high percentage of existing UKCS infrastructure, which will be quantified utilising an envelope based approach.

A quantification of platform emissions reduction and basin emissions from implementation of this concept is also considered and detailed in this report.

4. Project Overview

Assets will be evaluated based on certain criteria to determine their applicability for full or partial electrification based on the following:

- Power Requirements
- Geographical Location
- Existing Asset Infrastructure

Cessation of Production date has been excluded from the basis of the study based on electrification of the North Sea potentially changing the strategy of assets life time.

4.1.1 Utilisation of Data

Katoni have worked with Operators of assets in three different areas of the UKCS North Sea to understand the demands of the assets, evaluate clustering of assets together and evaluate platform topology.

The key areas to be evaluated are:

- Central North Sea (CNS)
- Outer Moray Firth (OMF)
- Southern North Sea (SNS)

4.1.2 International Boundaries

The study has focused on UK sector assets only for electrification. No technical analysis will be considered at this stage for Dutch, Danish or Norwegian assets which geographically are in salient locations.

No reference to regulation across international boundaries will be considered as part of this study.

Cross border assets will not be considered in the Clustering Assessment.

5. Study Boundaries

The study will consider wind power from either a dedicated offshore wind array (OWA) for the Oil & Gas industry or from an offshore wind farm (OWF) with a commercial export connection to shore. Consideration will be made of the inputs into the Main Hub from the OWA/OWF.

It is considered the input will be provided in the form of multiple 33 kV incoming connections, depending on the size of the Main Hub and the amount of power which is required to be distributed to Sub Hubs.

Input to the system will be considered based on either:

1. Dedicated OWA to be balanced by local generation either on the Main Hub, or power sharing arrangement from asset(s).
2. Connection to OWF with large overprovision. Priority of supply will be to the Main Hub in the event of low wind speeds to the detriment of export to onshore, and in extreme cases import from shore would be facilitated.

Scenario 1 is considered as the core concept for this study. For the concept proposed, the main provision of input power is supplied based on wind generation, or local Main Hub generation, operating in an island mode.

Future connection to the National Grid is considered as an opportunity, not a core concept for this design.

6. Platform Clustering Study

6.1 Objective

This study aims to detail the methodology used to determine the proposed location of the Main Hub & Sub Hubs whilst minimising the total number of Hubs & Subsea Cables required to facilitate electrification of asset Clusters.

The purpose of completing the Platform Clustering study is to understand the technical feasibility of powering offshore Oil & Gas assets via the Main & Sub Hub arrangement. The outcome of this study will enable the equipment requirements & layout of the Main & Sub Hubs to be determined.

6.2 Methodology

6.2.1 Software

AutoCAD2022, in conjunction with the AutoDesk Geolocation software, was used to complete the Clustering assessment. Information relating to North Sea Infrastructure was obtained from OGA's open-source data centre /1/.

6.2.2 Clustering Map Set-up

The following modifications to AutoCAD's standard set-up were implemented to allow data input based on asset coordinates:

- Units changed to kilometres.
- AutoCAD file set-up revised to include Longitude & Latitude input.
- Geographical location plugin Map uploaded into AutoCAD toolbar.
- GIS coordinate system set to 'British National Grid'.

Information gathered from the OGA Data centre was filtered to remove assets that fall outwith the geographical parameters of the study; additionally, assets marked as 'Decommissioned' or 'Removed' were deleted. Examples of the downloaded data is shown below in Table 6-1 below.

X - Long	Y - Latitude	Asset Name	Reporting Group
-1.7430611	58.3055371	Captain	Ithaca Energy
2.337002021	56.69870349	Judy	Harbour
1.33620749	54.2906178	Kilmar	Alpha Petroleum
1.955434107	57.03220523	Shearwater	Shell
1.6623554	57.2942648	ETAP	BP

Table 6-1: Example of Download Information

To aid identification of assets 'Layers' were created in AutoCAD with corresponding titles to the reporting group & asset name information. Additionally, reporting groups were designated a specific colour, i.e. Shell Assets = Yellow, Chrysaor Assets = Red.

Name	On	Color	Freeze	Lock
SHELL_SHEARWATER A		yellow		
ITHACA ENERGY_CAPTAIN		green		
CHRYSAOR_JUDY		red		
BP EXPLORATION_ETAP PDR		white		
ALPHA_KILMAR		200		

Figure 6-1: Example of AutoCAD Layer Tab

North Sea assets were plotted according to their Longitude & Latitude utilising the 'Geolocation' function within AutoCAD. and then assigned to their respective Layer.

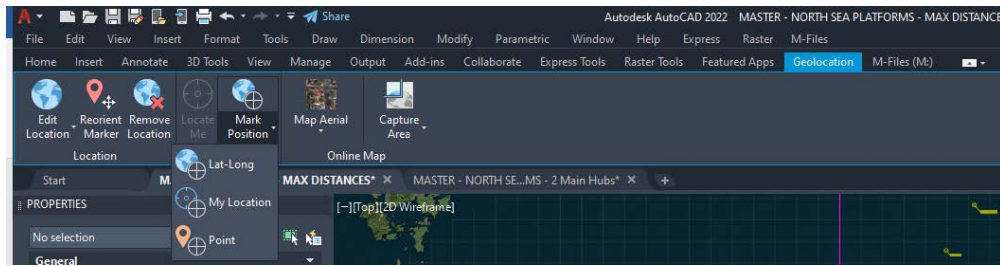


Figure 6-2: AutoCAD Geolocation Plugin

To further aid the identification of potential asset clusters & relative distances, a 10km Grid structure & Quadrant system were incorporated into the Map. The initial mapping of the Outer Moray Firth & Central North Sea assets are illustrated in Figure 2-3 with Quadrants C-E shown.

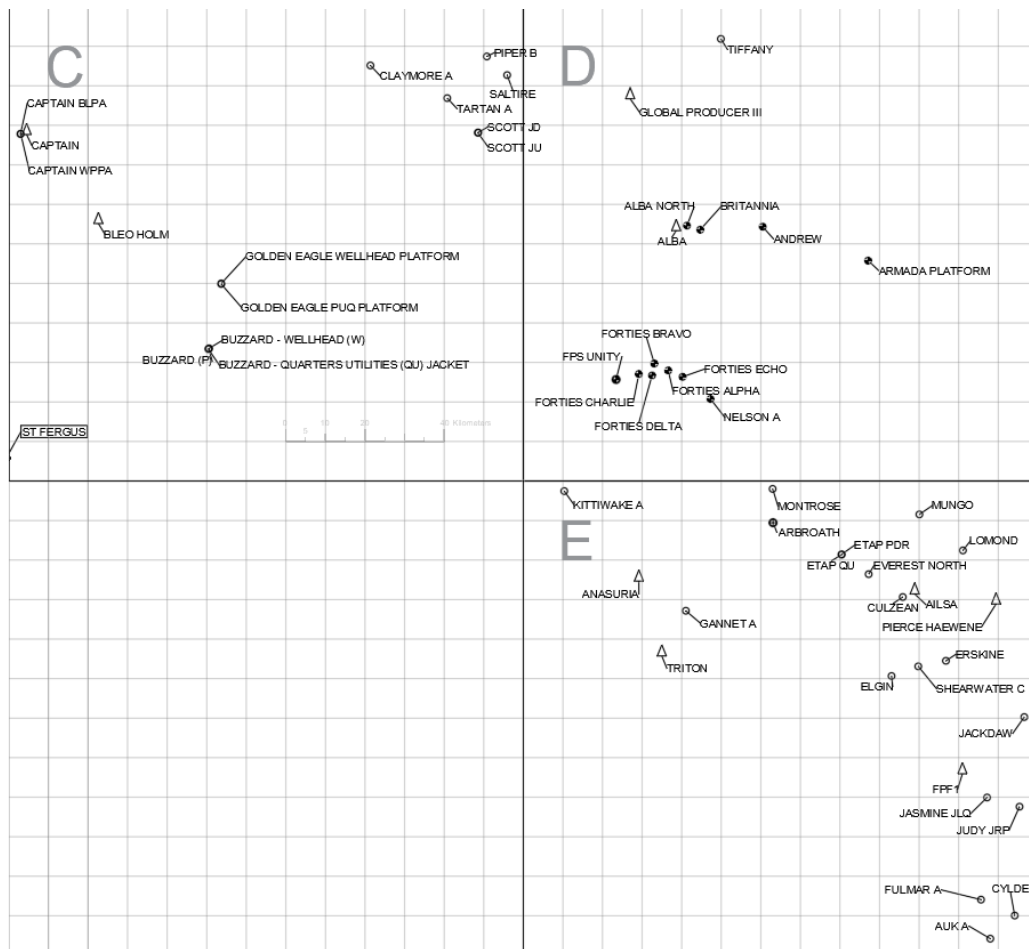


Figure 6-3: OMF & CNS – Infrastructure

6.2.3 Platform Clustering Methodology

The clustering assessment used a scaled method of transmission voltage, platform demand & assets' geographical location to determine efficient clustering of assets & subsequent location for the Main Hub & Sub Hubs.

A method for determining the maximum transmission distance based on maximum permitted voltage drop was utilised to determine a radius around the asset based on the required asset power demand.

For each power distribution voltage a simple iterative voltage drop calculation was developed to determine the maximum amount of power able to be transmitted through a 1000mm² cable, determined to be the maximum standard cable size for submarine power distribution. The following equation was used:

$$P_{Max} = \left(\frac{V_{drop}}{\sqrt{3} * R_C * L_{cable}} \right) * V_{Trans} * PF$$

Where:

P_{Max} = Maximum Transmission Power for specified distance (MW)

V_{drop} = Maximum Voltage Drop (V)

R_C = Resistivity of Cable (Ω /km)

L_{cable} = Length of Cable (km)

V_{Trans} = Voltage of Power being Transmitted (kV)

PF = Power Factor

Using this basis an iterative method was applied utilising multiple distances to produce a power vs distance graph. For each potential transmission voltage this method was then repeated. A 6th order polynomial equation was then generated for each curve for each voltage and utilised as part of a North Sea Electrification Model using asset coordinates to evaluate asset suitability for electrification.

The analysis was completed using two different permissible volt drop figures, one of 2.5% which would conform to the more stringent requirements of BS EN 61892-2 for offshore electrical power, and a slightly less stringent value of 4%.

Volt drop limits could be relaxed further depending on the end user and their requirements, however this would need to be evaluated on an asset-by-asset basis as some may be able to tolerate lower operating voltages better than others.

6.2.4 Best Fit Curves for $V_d=2.5\%$

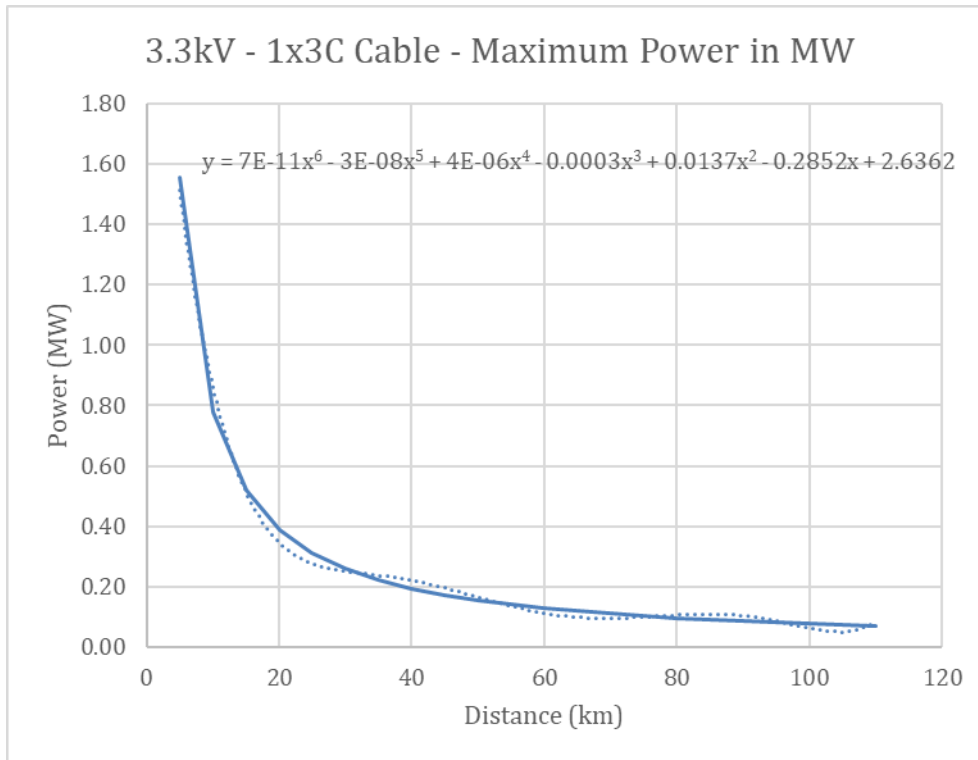


Figure 6-4: 3.3 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=2.5\%$

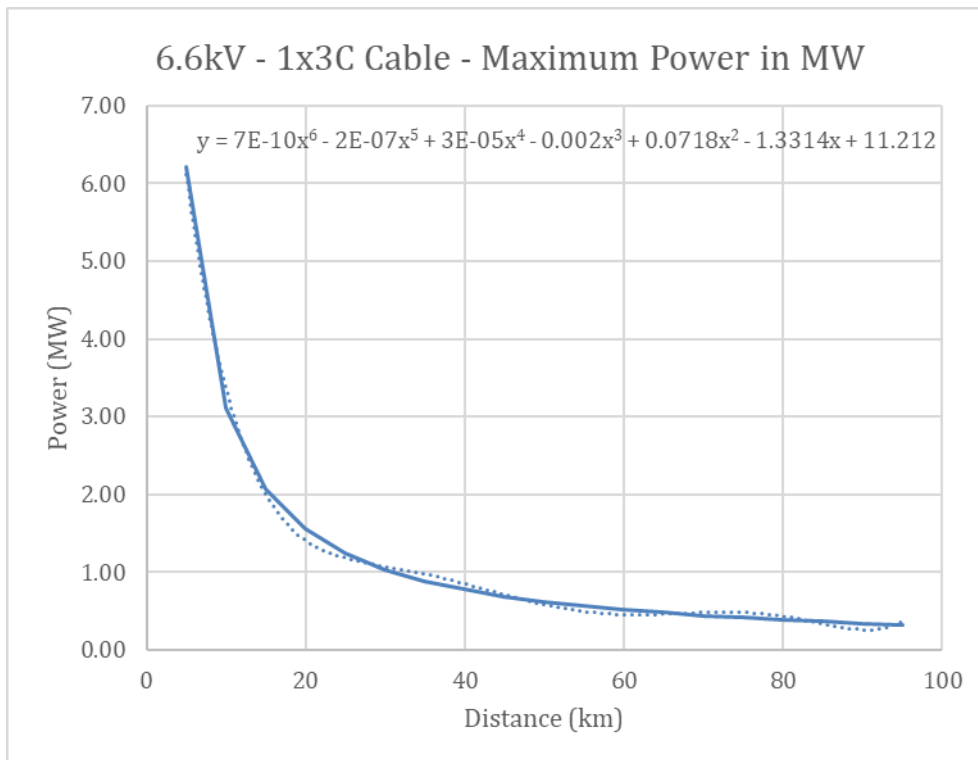


Figure 6-5: 6.6 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=2.5\%$

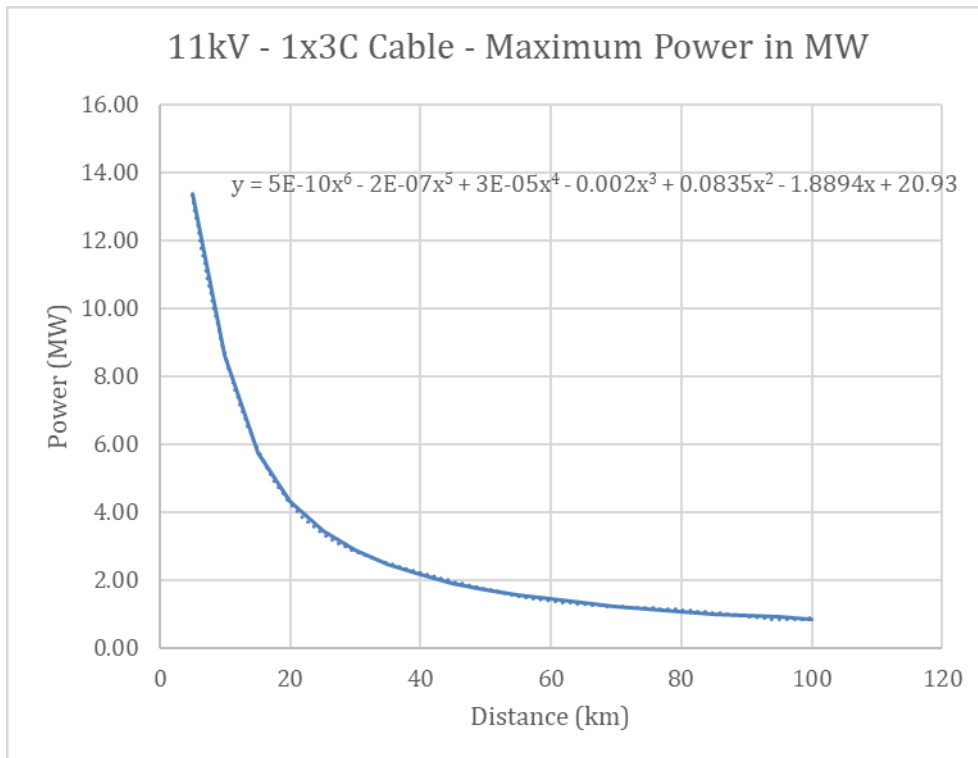


Figure 6-6: 11 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=2.5\%$

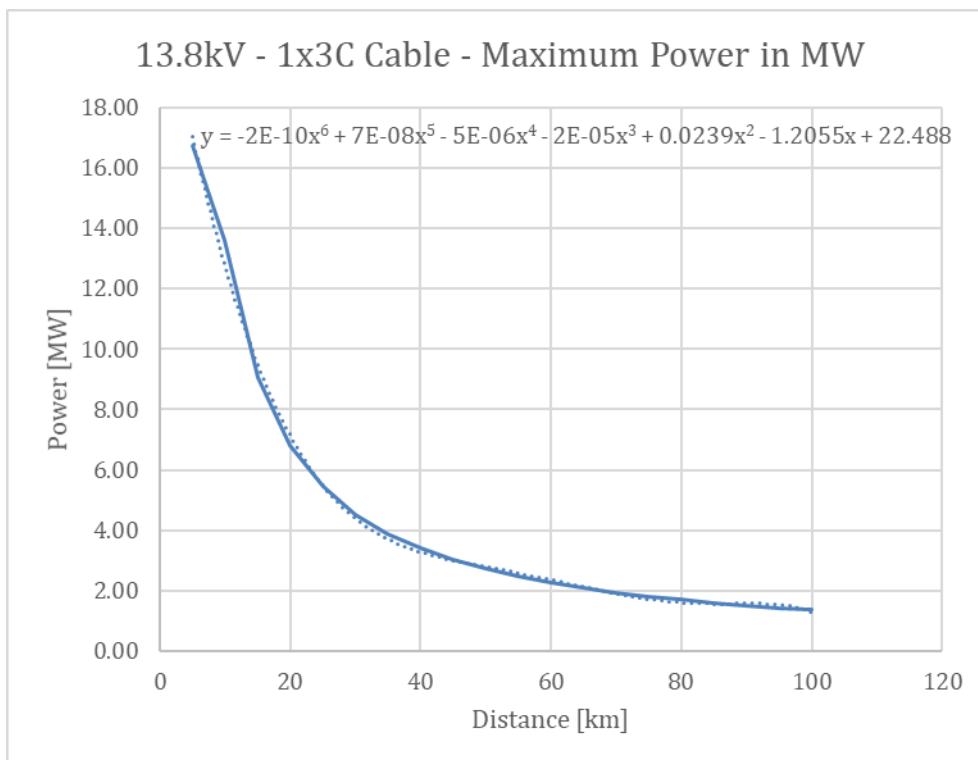


Figure 6-7: 13.8 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=2.5\%$

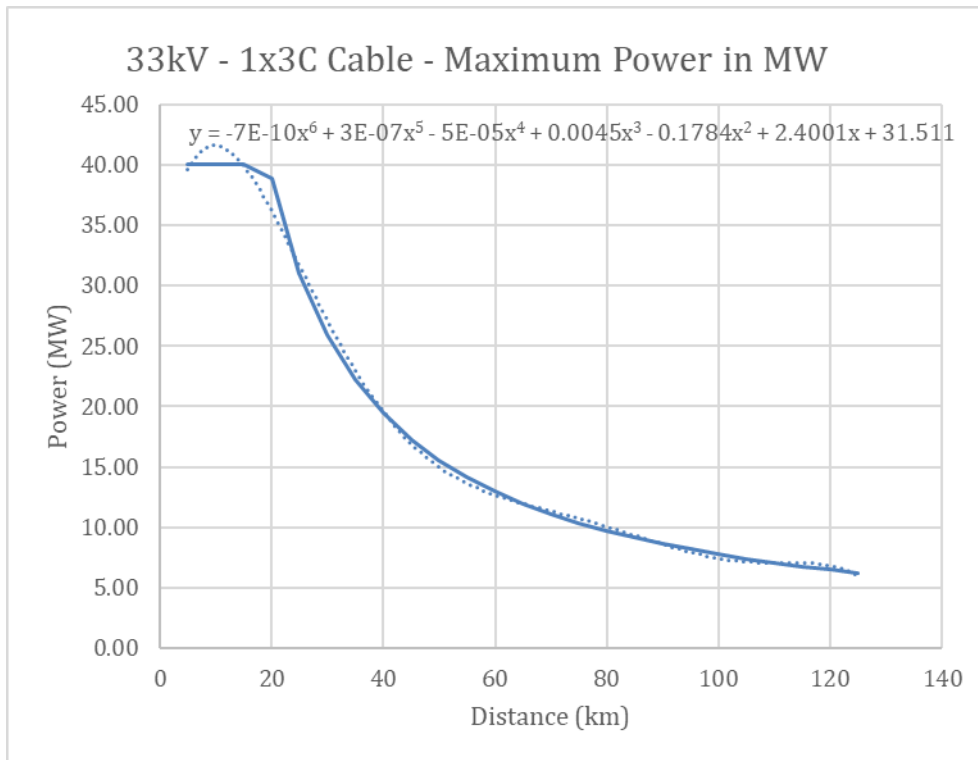


Figure 6-8: 33 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=2.5\%$

6.2.5 Best Fit Curves for $V_d=4\%$

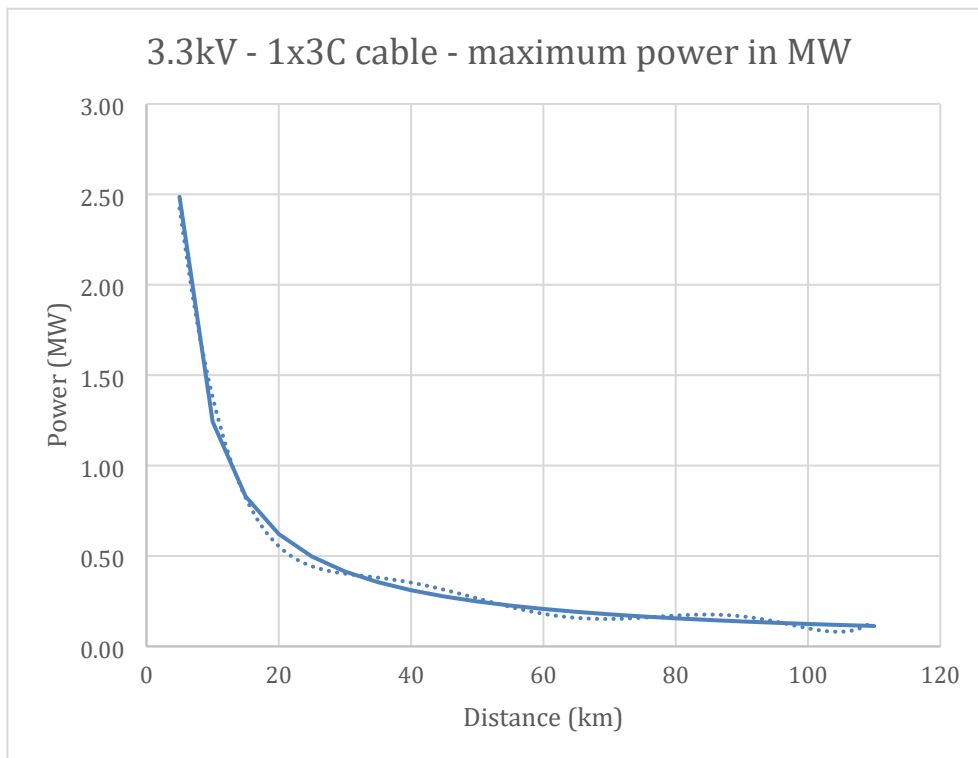


Figure 6-9: 3.3 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=4\%$

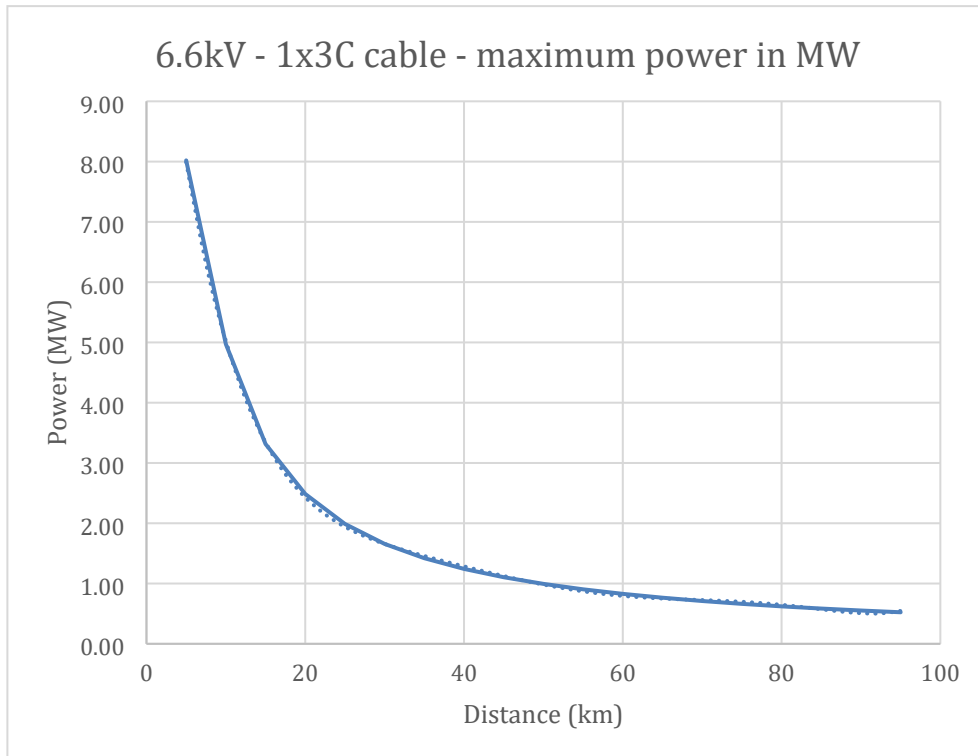


Figure 6-10: 6.6 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=4\%$

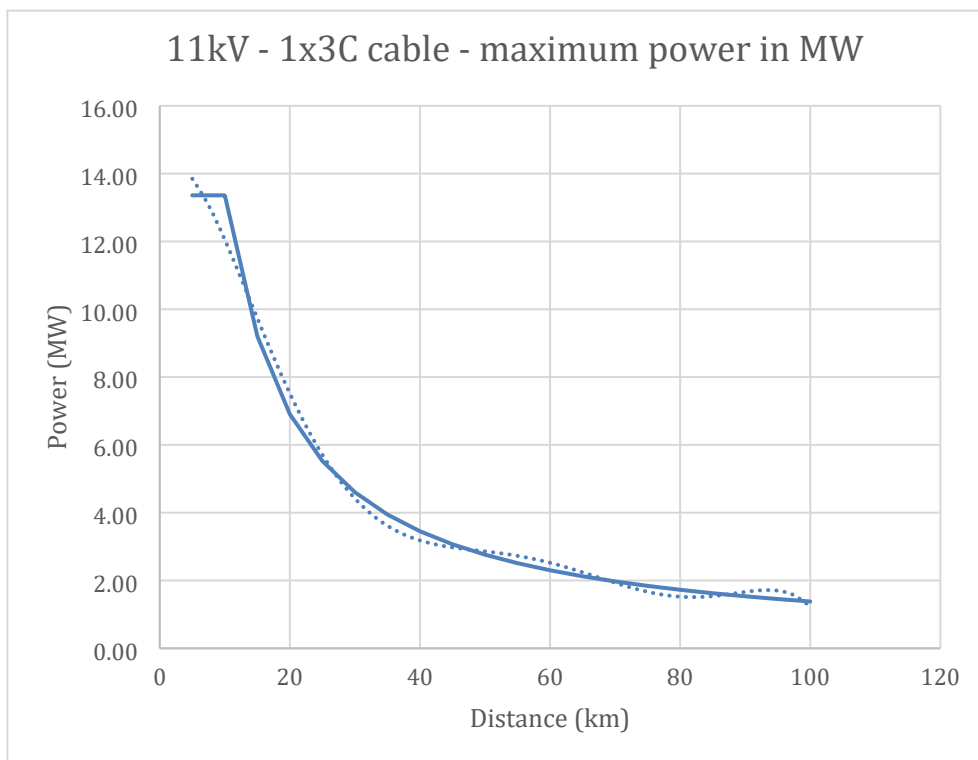


Figure 6-11: 11 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=4\%$

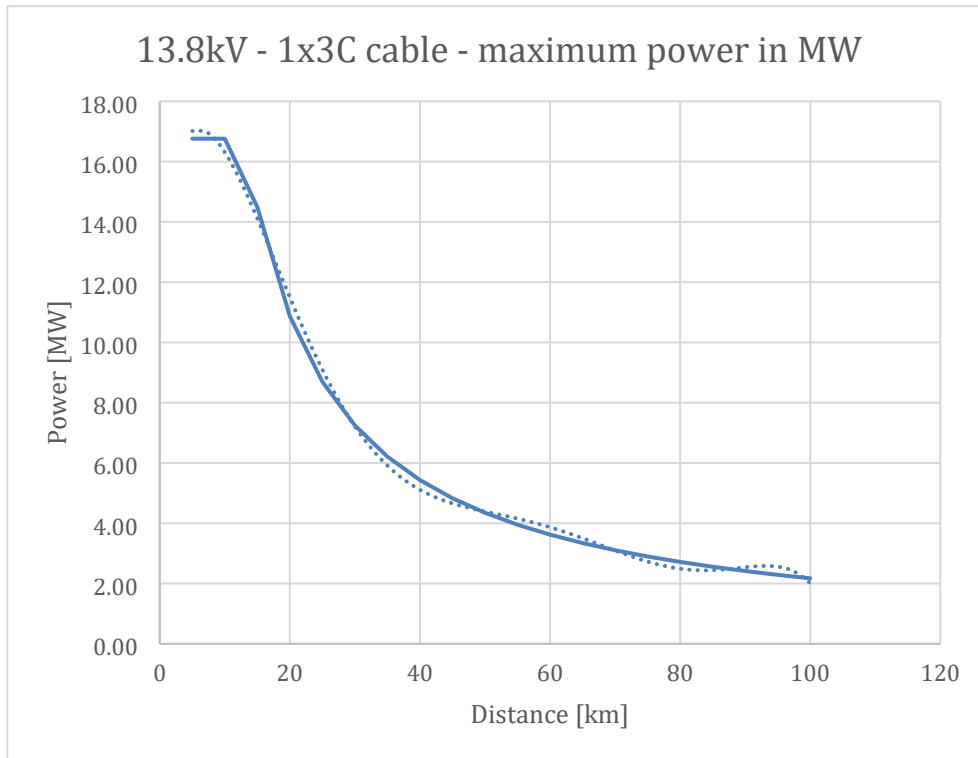


Figure 6-12: 13.8 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=4\%$

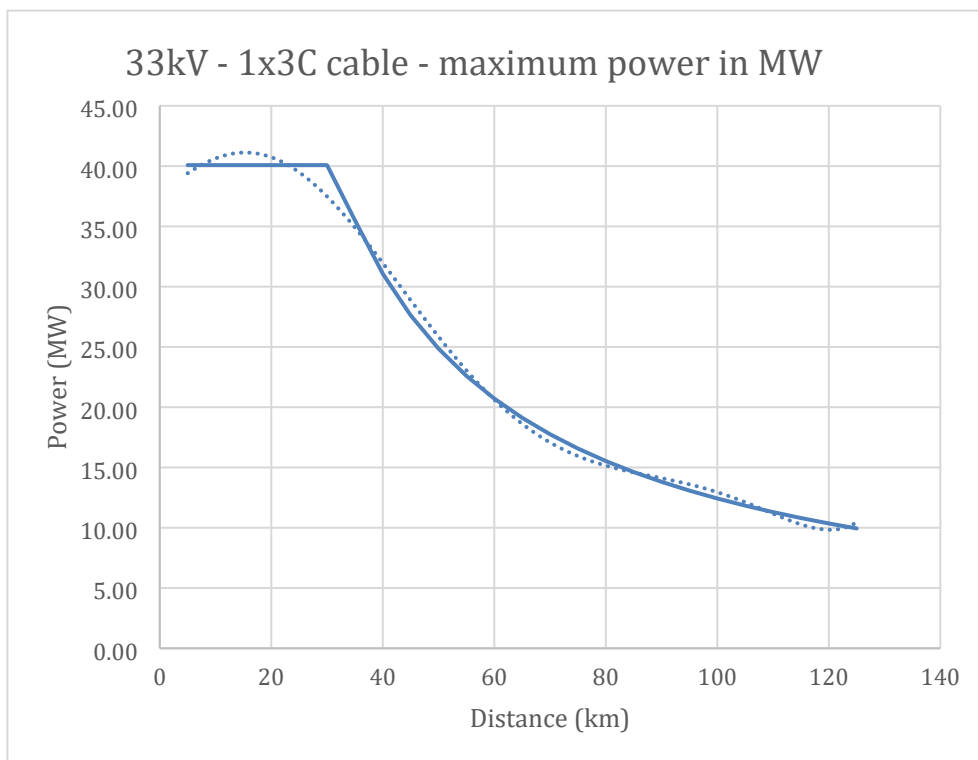


Figure 6-13: 33 kV - 1 off 3 Core Cable Maximum Power Transmission at Maximum $V_D=4\%$

6.2.6 Sub Hub Locations

The polynomial equations generated from each of these plots were utilised to draw a series of circles around assets with the radius of each circle based on that asset's power demand. The radii related to utilising 1 to 5 cables connected to each asset to generate the maximum distance from each asset to a Sub Hub. These circles were plotted, areas of overlap were analysed, and the Sub Hub infrastructure's location was determined on this basis.

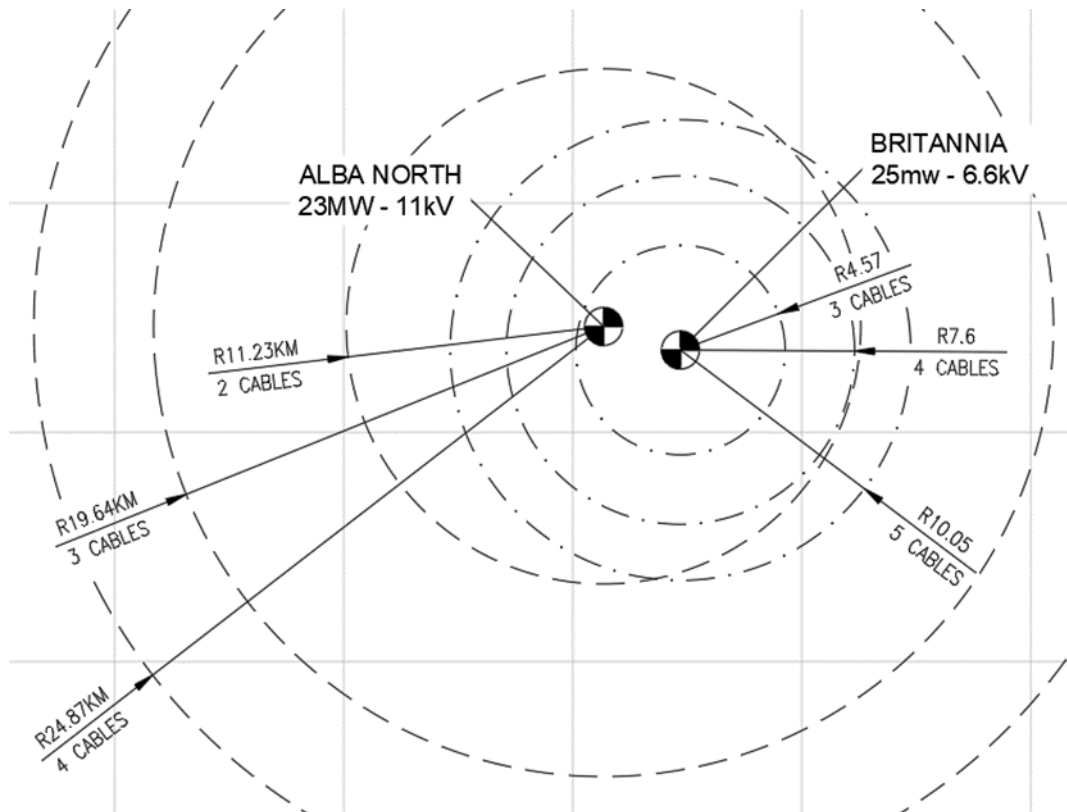


Figure 6-14: Example of Multiple Cables & associated Radii (for $V_d=4\%$)

Areas with high amounts of intersecting circles were viewed as good locations for centralised electrification / power distribution. Assets which fell outwith these areas were not considered for electrification using this concept.

A maximum basis of 3 cables to each asset were considered based on most assets having at least 2 main power generators, either gas turbines or reciprocating engines. A large proportion of assets have 3 connected power generators. In addition, a switchboard extension modification is considered minor for most assets evaluated.

To tie in assets that are outwith a Sub Hub's areas, more bespoke solutions for electrification are required, which do not suit the concept explored as part of this study.

6.2.7 Main Hub Location

The assessment for the Main Hub location is based on a maximum transmission distance of 100 km utilising GE's MVDC power transmission system. This allows for a standardised, controlled power transmission to be utilised multiple times.

Based on the use of this technology a maximum transmission length between the Main Hub and Sub Hubs is set at 100 km.

6.2.8 Water Depth, Varying Subsea Geography

During this analysis no allowance has been taken for subsea geography, water depth or variances in cable length to avoid objects. For the purposes of this assessment point to point distances have been considered.

By utilising a non-optimised power factor and a standard cable design, building additional conservatism into the analysis by taking a 5 to 10% reduction in cable length is considered excessive.

Through detailed power system modelling and developing bespoke cable designs, transmission distances can be improved. It is not considered however that the changes will be order of magnitude scale.

6.2.9 CNS Concept Area Clustering Assessment

An area in the Central North Sea region was chosen as the area utilised to develop the concept further and confirm if the methodology could be applied.

6.2.9.1 Maximum Radial Distances

Quadrant D in the CNS was identified as the test area for validating the methodology and a suitable location for a clustering assessment; Figure 6-15 indicates the maximum radial distance from the assets to a Sub Hub when the maximum voltage drop is set to 2.5%.

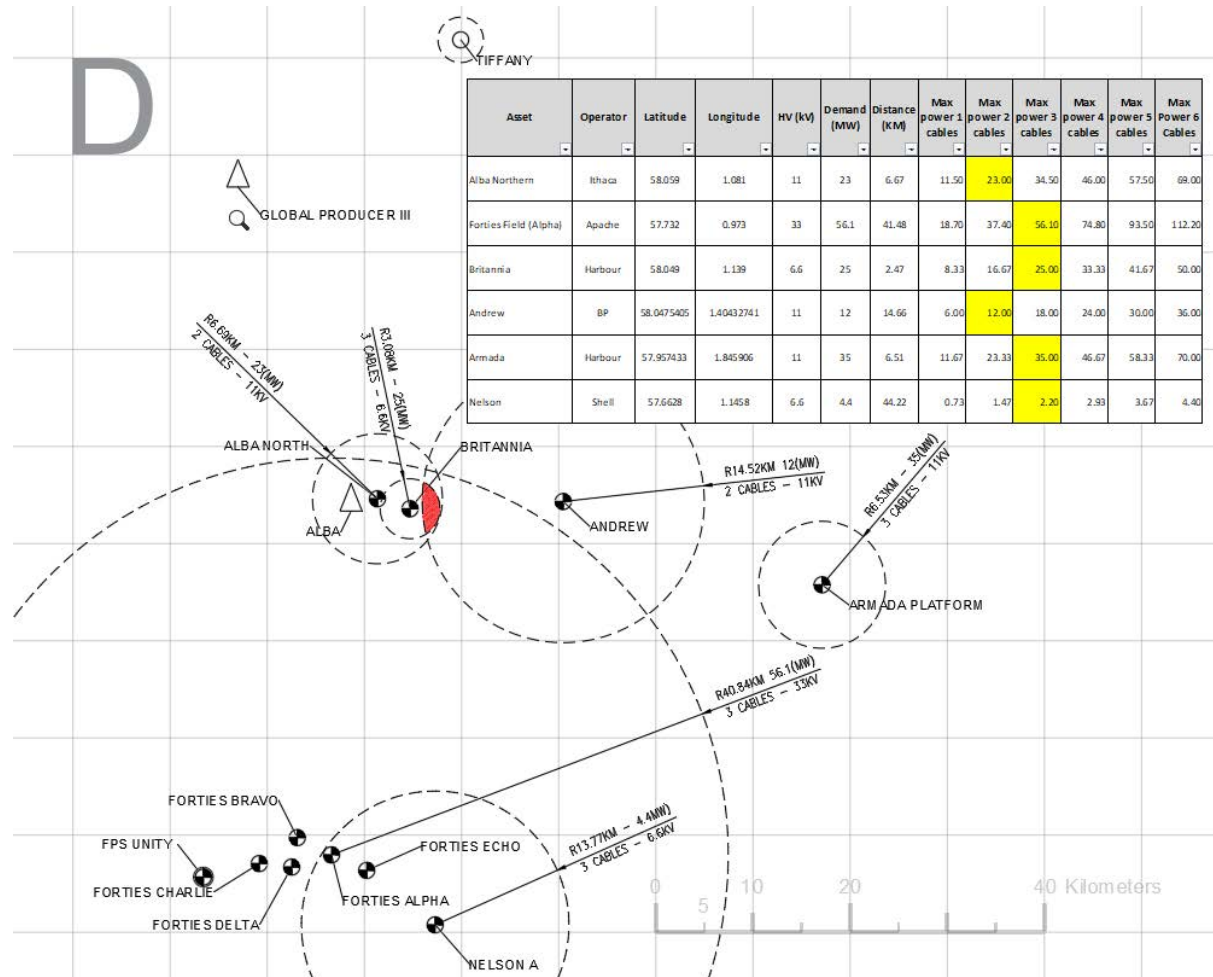


Figure 6-15: Quadrant D Asset Cluster – Maximum Radial Distances (for $V_d=2.5\%$)

The diagram produced from Figure 6-15 highlighted 2 main points:

1. The red area shows a location which maximises the number of intersection points for the assets evaluated in this region.
2. The location for a Sub Hub would allow power to be distributed to the five Forties Assets, Alba North, Britannia & Andrew.
3. Due to a combination of asset demand & geological location, the Armada & Nelson assets are outwith the intersection area & therefore considered not suitable candidates for including in this cluster.
4. If the exercise is repeated but with a less stringent maximum permissible voltage drop of 4% then the results are similar as shown in Figure 6-16 below.

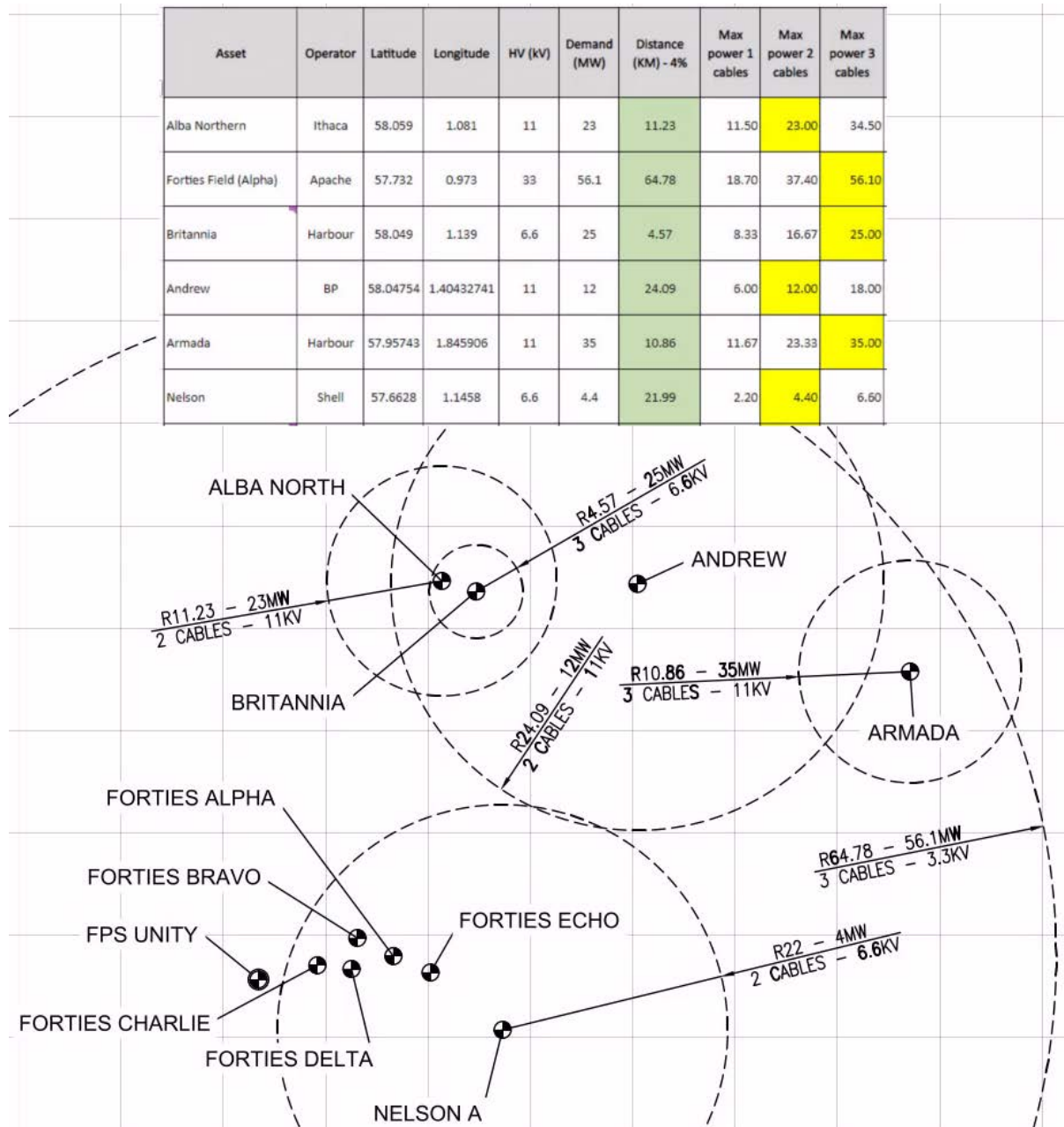


Figure 6-16: Quadrant D Asset Cluster – Maximum Radial Distances (for $V_d=4\%$)

The notable differences are:

- Both Nelson A and Armada now overlap with Andrew
- Armada now overlaps with Forties
- The region with maximum intersection points (shaded red) is larger, however, no additional assets are included

6.2.9.2 Maximum Cable Power

Locating a Sub Hub within the intersection area allowed for the calculation of the Maximum Cable Power; this was determined by measuring the radial distance between the assets & the Sub Hub and back calculating the actual power which could be transmitted through this distance of cable. This helps inform the maximum power available for asset electrification based on the distance and number of cables.

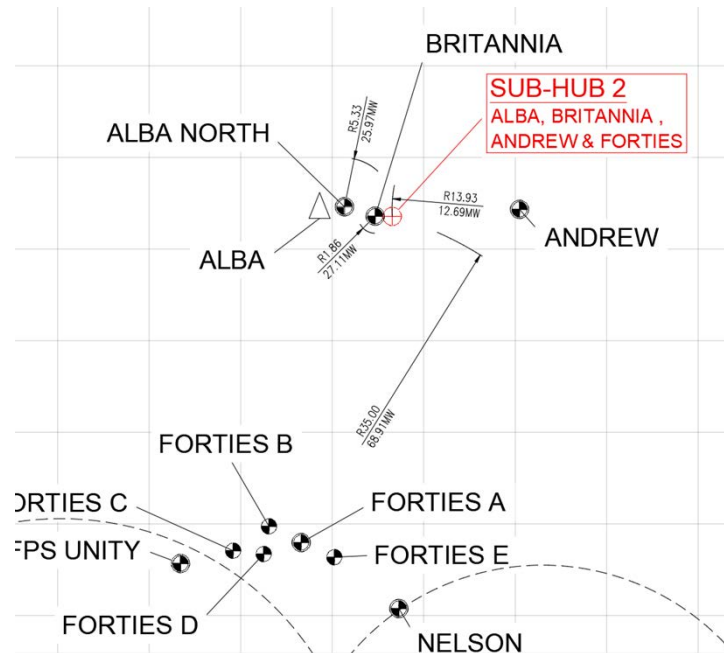


Figure 6-17: Quadrant D Asset Cluster – Maximum Cable Power

The method of identifying & analysing asset clusters & Hub locations was repeated across the OMF, CNS & SNS.

For the SNS, due to the lower power requirements, no variations in permissible voltage drop were explored.

6.3 Results

6.3.1 Central North Sea ($V_d=2.5\%$)

6.3.1.1 CNS - Base Case

The initial base case for the Central North Sea was to locate 1 No. Main Hub & 4 No. Sub Hubs capable of providing power to multiple assets. Figure 6-18 and Table 6-2 indicate the locations & associated water depths.

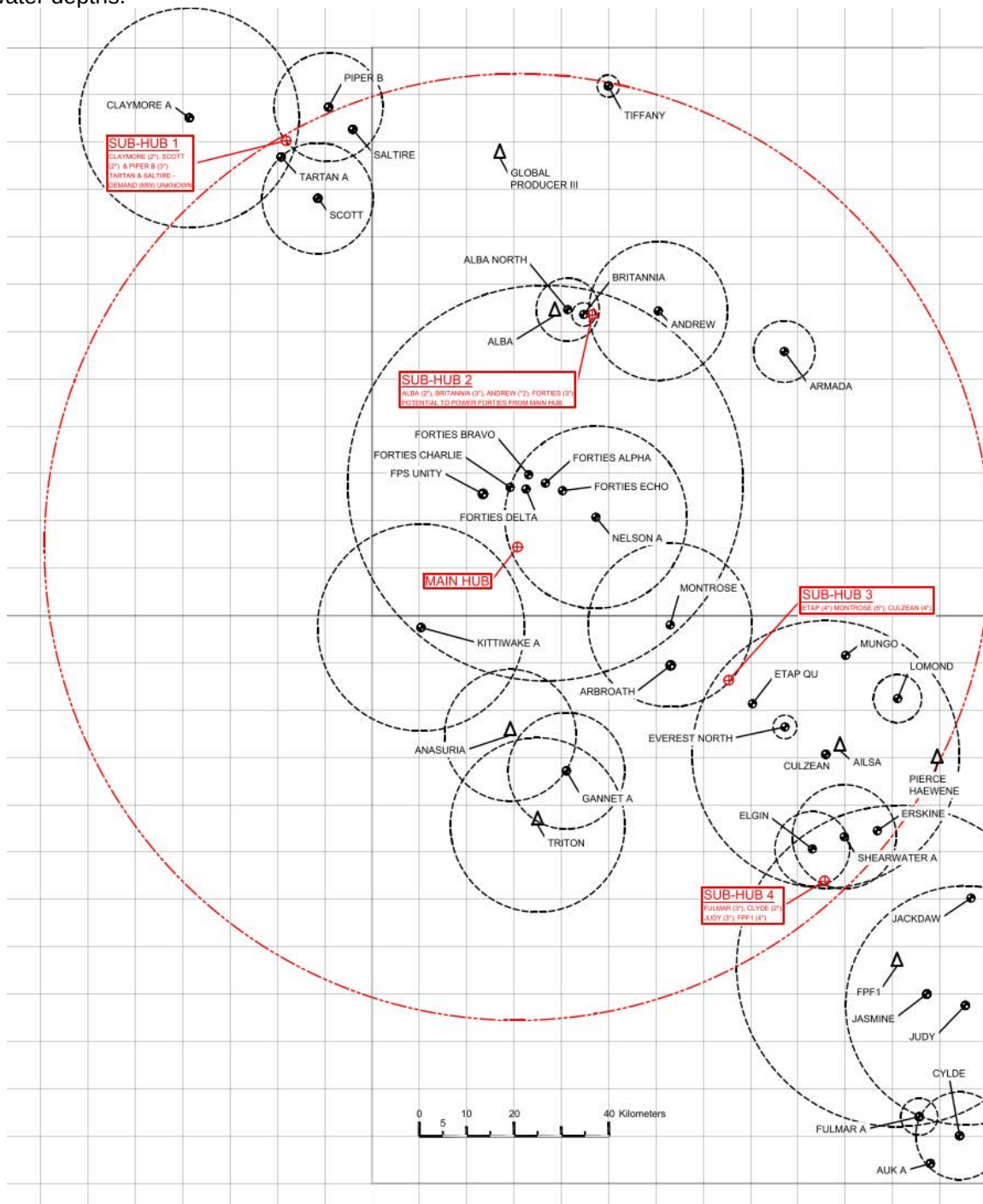


Figure 6-18: CNS – Base Case ($V_d=2.5\%$)

Sub Hub 1	Sub Hub 2	Sub Hub 3	Sub Hub 4
Claymore	Alba	ETAP	Elgin
Scott	Britannia	Montrose	Shearwater
Piper B	Andrew	Culzean	Judy
Tartan	Forties Assets	-	Jackdaw
-	-	-	FPF1

Table 6-2: CNS - Base Case Sub Hub Assets Clusters

6.3.1.2 CNS - Water Depths

The Main Hub & Sub Hub coordinates were cross-referenced against nautical charts & shared with Sevan to ensure the selected circular FPSO is suitable for mooring, motions, sea-state etc.

X - Long	Y - Latitude	Description	Water Depth (m)
0.900	57.592	Main Hub	104-106
0.094	58.401	Sub Hub 1	130 – 136
1.159	57.341	Sub Hub 2	133 - 137
1.584	57.341	Sub Hub 3	90 – 92
1.909	56.942	Sub Hub 4	87 – 90

Table 6-3: CNS Water Depths

6.3.1.3 Outer Moray Firth & Central North Sea – Alternative Option

An alternative layout was reviewed to include several Outer Moray Firth assets, namely the Buzzard, Golden Eagle & Captain Assets. Initial reviews indicated utilising 1 No. Main Hub was not feasible due to the geographical location & power demands of the OMF Assets. To meet the increased OMF demands, additional Main Hub & Sub Hubs are required.

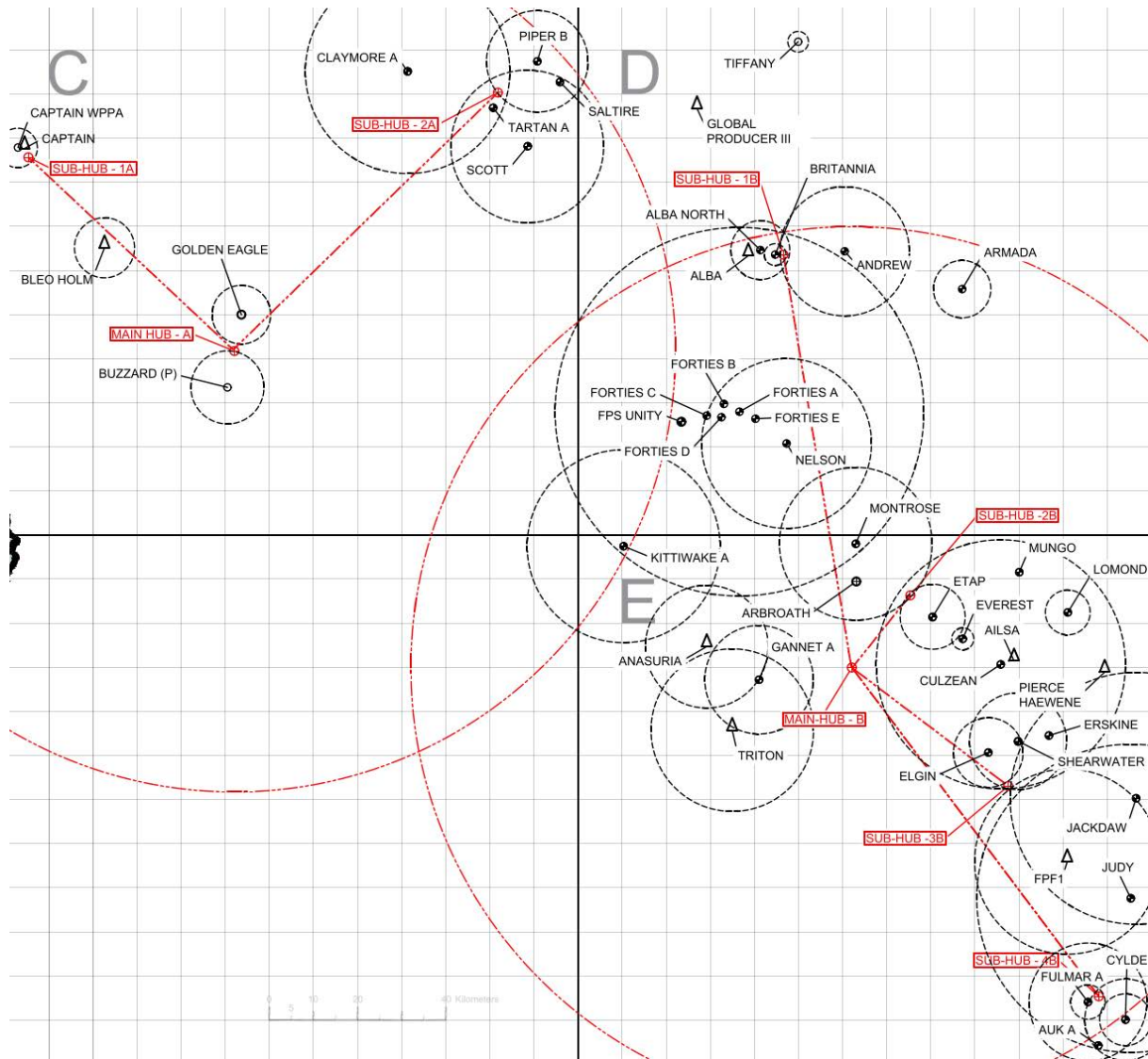


Figure 6-19: OMF & CNS Alternative Option ($V_d=2.5\%$)

Main Hub - A			Main Hub - B			
Main Hub	Sub Hub 1A	Sub Hub 2A	Sub Hub 1B	Sub Hub 2B	Sub Hub 3B	Sub Hub 4B
Buzzard	Captain	Claymore	Alba	ETAP	Elgin	Clyde
Golden Eagle	-	Tartan	Britannia	Montrose	Shearwater	Fulmar
-	-	Scott	Andrew	Culzean	Judy	Auk A
-	-	Piper B	Forties Assets	-	Jackdaw	-
-	-	-	-	-	FPF1	-

Table 6-4: CNS - Alternative Option – Sub Hub Cluster

As a result of the additional Main Hub 'A' & subsequently repositioning Main Hub 'B', extending the clustering assessment south & capturing the Clyde, Fulmar & Auk A assets is feasible. Due to their geographical location, these assets were not covered in the base case.

This development and expansion of the infrastructure results in an additional 6 assets being able to be tied into the power distribution system.

6.3.1.4 CNS - Wind Farm Locations

Data from Marine Scotland's 'Sectoral Marine Plan for Offshore Wind for Innovation & Targeted Oil & Gas Decarbonisation (INTOG)' /2/ report was overlaid onto the Clustering Maps, this highlights areas where potential wind projects targeting oil & gas decarbonisation of >100MW output are being considered.



Figure 6-20: CNS Base Case – INTOG Overlay ($V_d=2.5\%$)

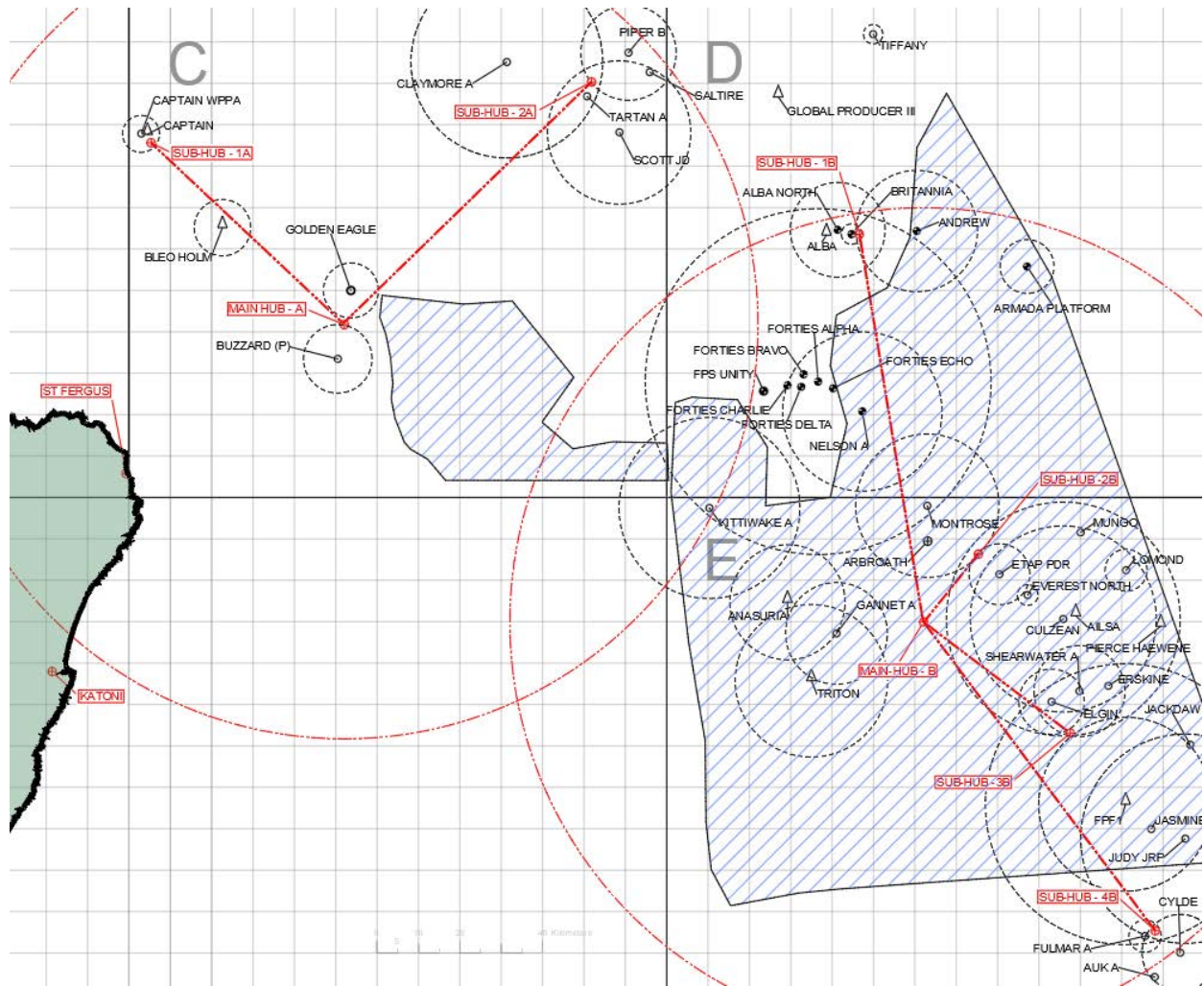


Figure 6-21: CNS Alternative option – INTOG Overlay ($V_d=2.5\%$)

6.3.1.5 CNS – Sub Hub Locations Base Case - Maximum Distance

The maximum distance assessment output for running a specific number of cables to each asset is included in Table 6-5. This outlines the maximum distance cables can run from a Sub Hub location whilst still meeting the platform power demands with a maximum permissible voltage drop of 2.5%..

Asset	Operator	Latitude	Longitude	HV (kV)	Distance (KM)	Max power 1 cables	Max power 2 cables	Max power 3 cables	Max power 4 cables	Max power 5 cables
Alba Northern	Ithaca	58.059	1.081	11	6.67	11.50	23.00	34.50	46.00	57.50
Forties Field (Alpha)	Apache	57.732	0.973	33	41.48	18.70	37.40	56.10	74.80	93.50
Britannia	Harbour	58.049	1.139	6.6	2.47	8.33	16.67	25.00	33.33	41.67
Andrew	BP	58.047	1.404	11	14.66	6.00	12.00	18.00	24.00	30.00
Captain	Ithaca	58.3068	-1.7705	11	4.46	14.00	28.00	42.00	56.00	70.00
Piper B	Repsol	58.4615	0.2509	13.8	4.54	17.50	35.00	52.50	70.00	87.50
Claymore	Repsol	58.4495	-0.2539	13.8	23.18	6.00	12.00	18.00	24.00	30.00
Montrose	Repsol	57.4517	1.3888	11	17.32	5.00	10.00	15.00	20.00	25.00
FPF1	Ithaca	56.781	2.109	6.6	33.91	1.00	2.00	3.00	4.00	5.00
Shearwater	Shell	57.032	1.9558	6.6	13.08	2.40	4.80	7.20	9.60	12.00
Judy	Chrysaor	56.6983	2.3375	11	25.27	3.33	6.67	10.00	13.33	16.67
ETAP	BP	57.2949	1.663	13.8	11.18	11.90	23.80	35.70	47.60	59.50
CULZEAN	Total	57.1901	1.9082	11	28.26	3.00	6.00	9.00	12.00	15.00
ELGIN	Total	57.0124	1.8422	11	7.90	10.33	20.67	31.00	41.33	51.67
SCOTT	CNOOC	58.2891	0.2005	11	11.73	7.50	15.00	22.50	30.00	37.50

Table 6-5: CNS Sub Hub Locations - Maximum Distance ($V_d=2.5\%$)

6.3.1.6 CNS – Sub Hub Locations Base Case - Maximum Power

The output of the maximum power assessment for running specific number of cables to each asset is included in Table 6-6. This outlines the maximum power that cables can be run from the final Sub Hub location.

Asset	Operator	Latitude	Longitude	HV (kV)	Demand (MW)	Distance (KM)	Max power 1 cables	Max power 2 cables	Max power 3 cables	Max power 4 cables	Max power 5 cables
Alba Northern	Ithaca	58.059	1.081	11	23	5.30	12.99	25.97	38.96	51.94	64.93
Forties Field (Alpha)	Apache	57.732	0.973	33	56.1	35.00	22.97	45.94	68.91	91.87	114.84
Britannia	Harbour	58.049	1.139	6.6	25	1.80	9.04	18.07	27.11	36.15	45.18
Andrew	BP	58.047	1.404	11	12	13.90	6.34	12.69	19.03	25.37	31.71
Captain	Ithaca	58.3068	-1.7705	11	28	4.46	14.00	28.00	42.00	56.00	70.00
Piper B	Repsol	58.4615	0.2509	13.8	35	11.40	11.74	23.49	35.23	46.98	58.72
Claymore	Repsol	58.4495	-0.2539	13.8	12	21.01	6.74	13.47	20.21	26.94	33.68
Montrose	Repsol	57.4517	1.3888	11	25	17.01	5.10	10.20	15.31	20.41	25.51
FPF1	Ithaca	56.781	2.109	6.6	4	23.62	1.22	2.45	3.67	4.90	6.12
Shearwater	Shell	57.032	1.9558	6.6	12	10.20	3.28	6.56	9.84	13.12	16.40
ETAP	BP	57.2949	1.663	13.8	59.5	7.05	15.16	30.32	45.47	60.63	75.79
Culzean	Total	57.1901	1.9082	11	15	25.80	3.27	6.53	9.80	13.07	16.33
Elgin	Total	57.0124	1.8422	11	31	8.80	9.56	19.12	28.68	38.25	47.81
Scott	CNOOC	58.2891	0.2005	11	15	13.90	6.34	12.69	19.03	25.37	31.71

Table 6-6: CNS Sub Hub Location - Maximum Power ($V_d=2.5\%$)

6.3.2 Central North Sea ($V_d=4\%$)

The analysis described in Section 3.1 was repeated for a less stringent maximum permissible voltage drop of 4%.

6.3.2.1 CNS – Base Case

For the initial base case with 1 No. Main Hub & 4 No. Sub Hubs the updated circles are shown in Figure 6-22 below.

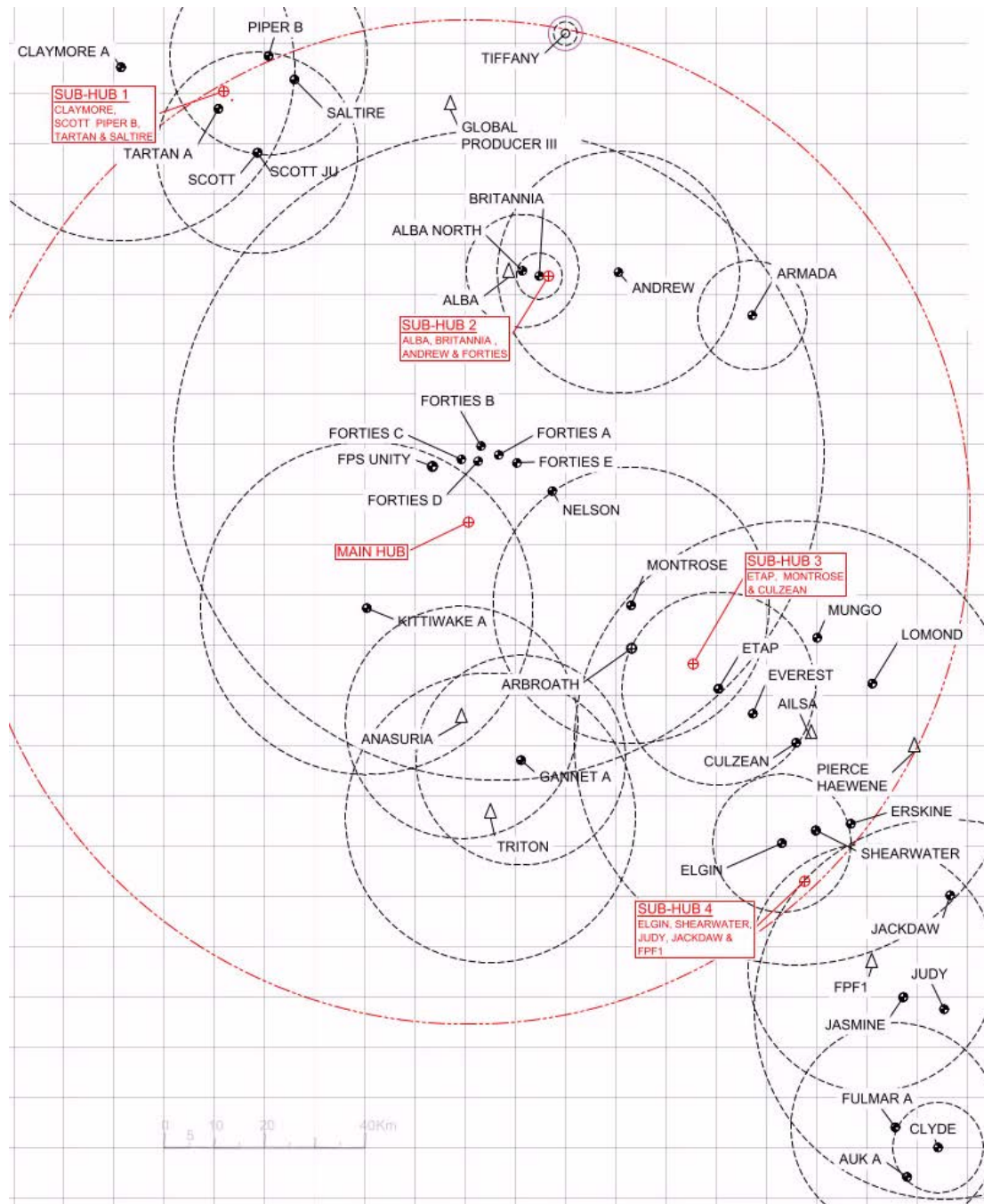


Figure 6-22: CNS – Base Case ($V_d=4\%$)

Although the corresponding circles have increased in diameter, this does not change the overall optimum clustering as seen with the lower permissible voltage drop. It does allow for some optimisation of Sub Hub locations.

6.3.2.2 OMF Alternative Option

For the alternative option, incorporating key OMF assets, the updated circles are shown in Figure 6-23 below. As with the base option, the larger circles do not change the analysis and optimum clustering.

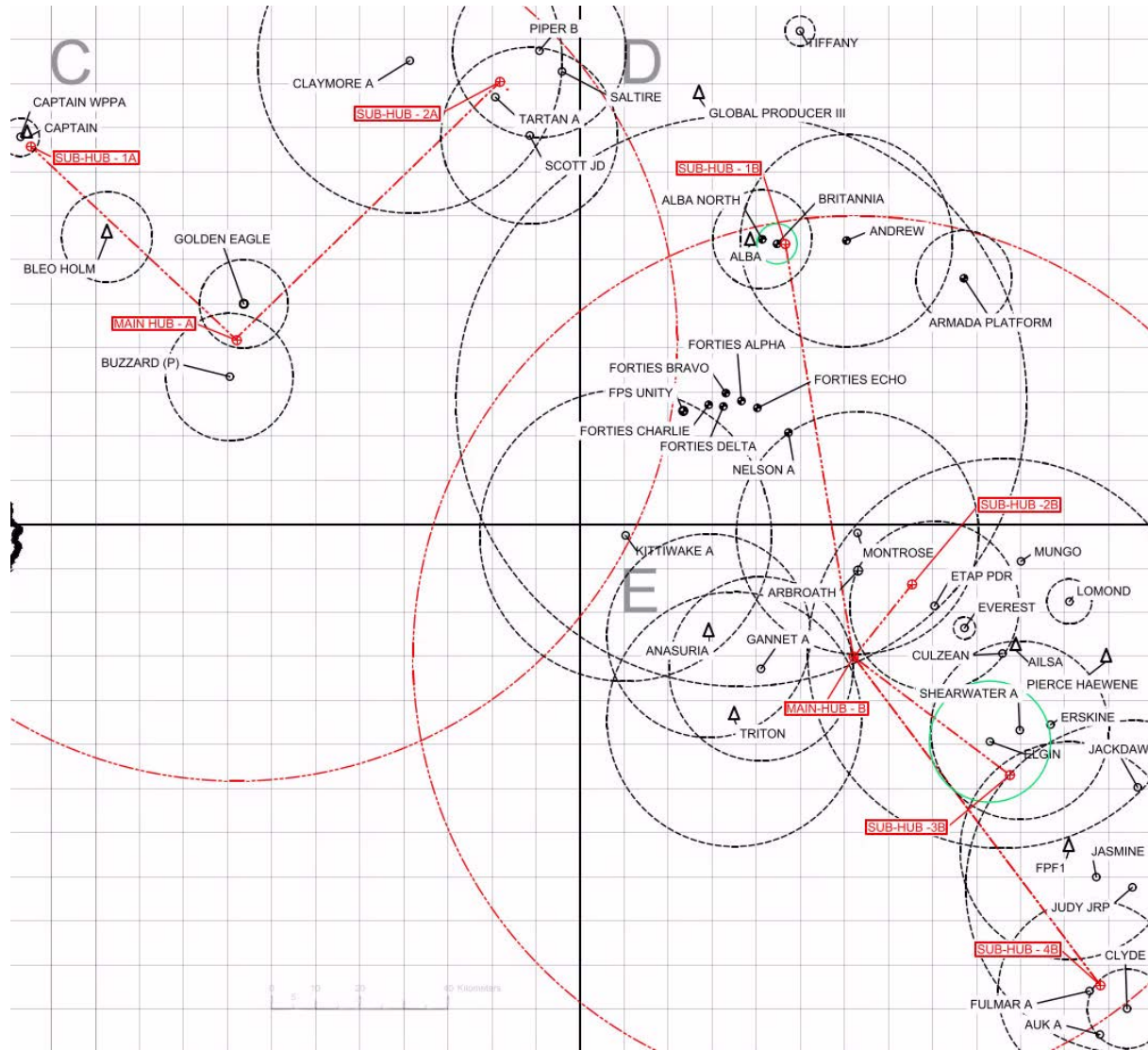


Figure 6-23: OMF & CNS Alternative Option ($V_d=4\%$)

6.3.2.3 Wind Farm Locations

The updated circles and wind farm areas are shown in Figure 6-24 and Figure 6-25 below for the Base Case and Alternative Option.

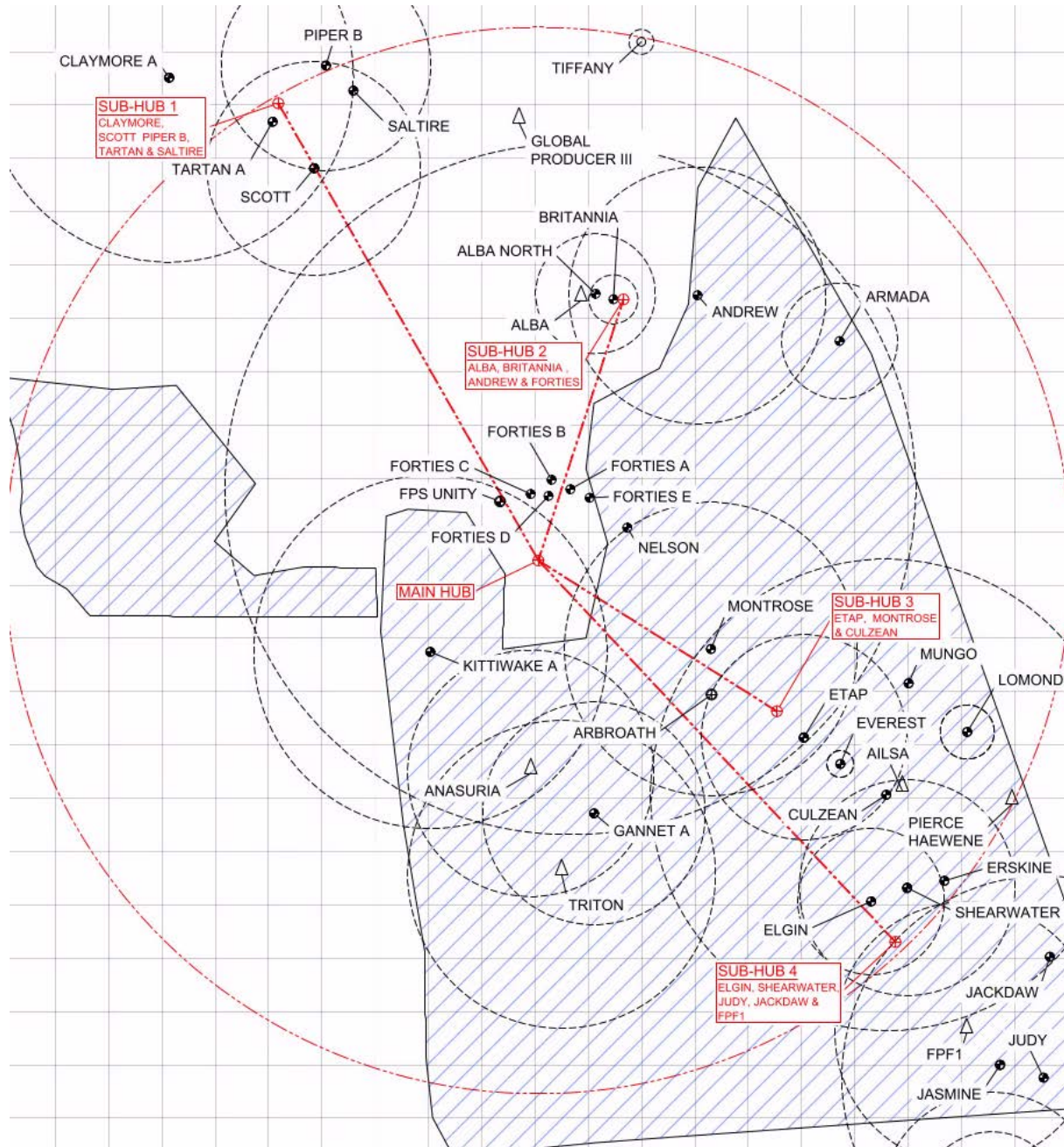


Figure 6-24: CNS Base Case – INTOG Overlay ($V_d=4\%$)

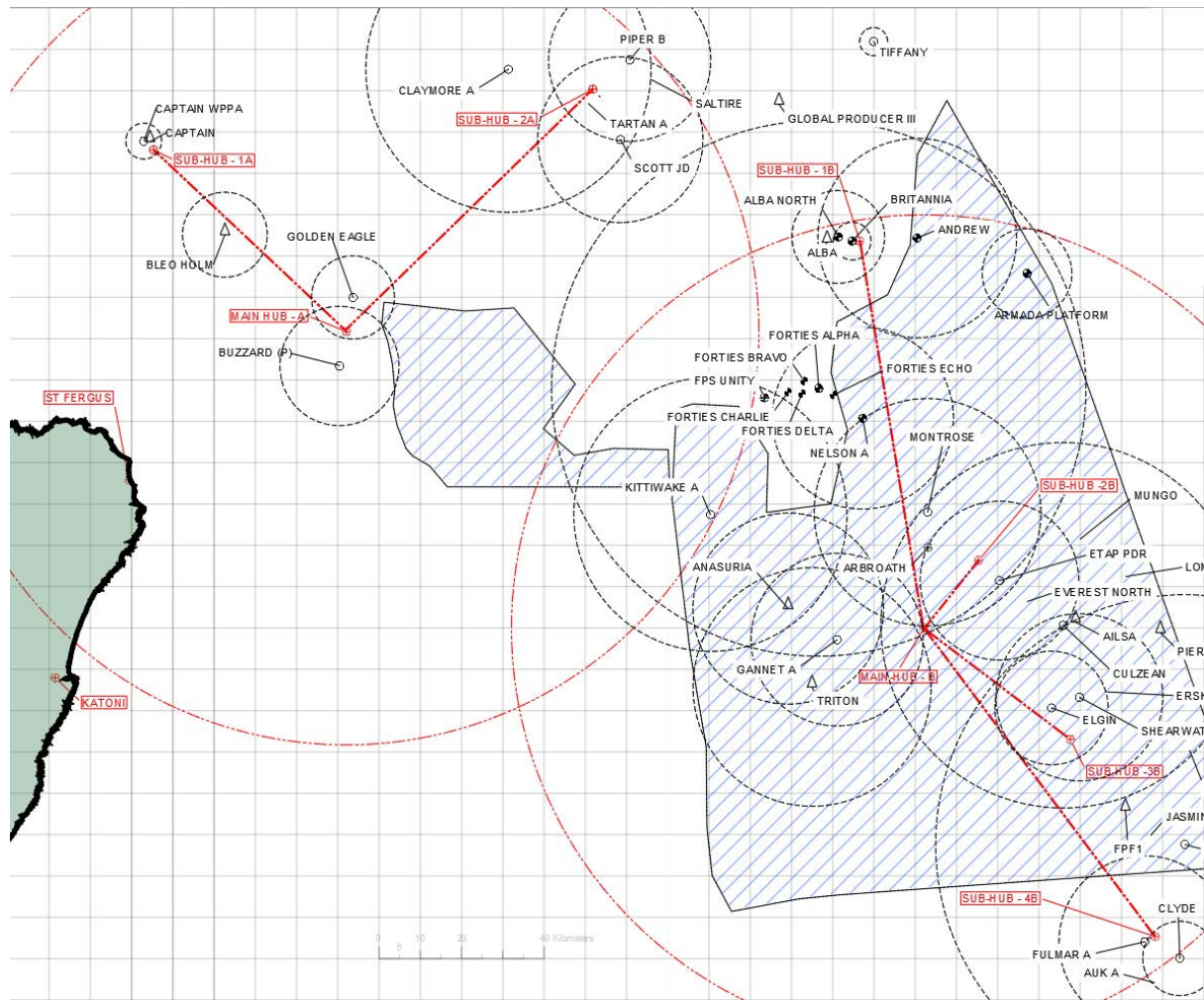


Figure 6-25: CNS Alternative option – INTOG Overlay ($V_d=4\%$)

6.3.2.4 CNS – Sub Hub Locations Base Case - Maximum Distance

The maximum distance assessment output for running a specific number of cables to each asset is repeated for a maximum permissible voltage drop of 4% with the results shown in Table 6-7.

Asset	Operator	Latitude	Longitude	HV (kV)	Demand (MW)	Distance (KM)	Max power 1 cables	Max power 2 cables	Max power 3 cables	Max power 4 cables	Max power 5 cables
Alba Northern	Ithaca	58.059	1.081	11	23	11.23	11.50	23.00	34.50	46.00	57.50
Forties Field (Alpha)	Apache	57.732	0.973	33	56.1	64.78	18.70	37.40	56.10	74.80	93.50
Britannia	Harbour	58.049	1.139	6.6	25	4.57	8.33	16.67	25.00	33.33	41.67
Andrew	BP	58.047540	1.4043274	11	12	24.09	6.00	12.00	18.00	24.00	30.00
Captain	Ithaca	58.3068	-1.7705	11	28	4.35	14.00	28.00	42.00	56.00	70.00
Piper B	Repsol	58.4615	0.2509	13.8	35	19.67	17.50	35.00	52.50	70.00	87.50
Claymore	Repsol	58.4495	-0.2539	13.8	12	34.57	6.00	12.00	18.00	24.00	30.00
Montrose	Repsol	57.4517	1.3888	11	25	27.50	5.00	10.00	15.00	20.00	25.00
FPF1	Ithaca	56.781	2.109	6.6	4	49.36	1.00	2.00	3.00	4.00	5.00
Shearwater	Shell	57.032	1.9558	6.6	12	20.23	2.40	4.80	7.20	9.60	12.00
Judy	Chrysaor	56.6983	2.3375	11	10	60.44	3.33	6.67	10.00	13.33	16.67
ETAP	BP	57.2949	1.663	13.8	59.5	19.22	11.90	23.80	35.70	47.60	59.50
CULZEAN	Total	57.1901	1.9082	11	15	44.20	3.00	6.00	9.00	12.00	15.00
ELGIN	Total	57.0124	1.8422	11	31	13.73	10.33	20.67	31.00	41.33	51.67
SCOTT	CNOOC	58.2891	0.2005	11	15	20.04	7.50	15.00	22.50	30.00	37.50

Table 6-7: CNS Sub-Hub Locations - Maximum Distance ($V_d=4\%$)

6.3.2.5 CNS – Sub Hub Locations Base Case - Maximum Power

The output of the maximum power assessment for running specific number of cables to each asset is included in Table 6-8. This outlines the maximum power that can be transmitted from the final Sub-Hub location based on a 4% maximum voltage drop and increasing numbers of cables.

Asset	Operator	Latitude	Longitude	HV (kV)	Demand (MW)	Distance (KM)	Max power 1 cables	Max power 2 cables	Max power 3 cables	Max power 4 cables	Max power 5 cables
Alba Northern	Ithaca	58.059	1.081	11	23	5.30	13.77	27.54	41.32	55.09	68.86
Forties Field (Alpha)	Apache	57.732	0.973	33	56.1	35.00	34.90	69.80	104.71	139.61	174.51
Britannia	Harbour	58.049	1.139	6.6	25	1.80	10.90	21.79	32.69	43.58	54.48
Andrew	BP	58.0475405	1.4043274	11	12	13.90	10.25	20.51	30.76	41.01	51.27
Captain	Ithaca	58.3068	-1.7705	11	28	4.46	13.98	27.95	41.93	55.90	69.88
Piper B	Repsol	58.4615	0.2509	13.8	35	11.40	15.79	31.58	47.37	63.16	78.96
Claymore	Repsol	58.4495	-0.2539	13.8	12	21.01	10.98	21.96	32.94	43.91	54.89
Montrose	Repsol	57.4517	1.3888	11	25	17.01	8.81	17.62	26.43	35.24	44.05
FPF1	Ithaca	56.781	2.109	6.6	4	23.62	2.05	4.10	6.15	8.19	10.24
Shearwater	Shell	57.032	1.9558	6.6	12	10.20	4.94	9.87	14.81	19.74	24.68
ETAP	BP	57.2949	1.663	13.8	59.5	7.05	17.00	34.00	51.00	68.00	85.00
Culzean	Total	57.1901	1.9082	11	15	25.80	5.47	10.93	16.40	21.87	27.34
Elgin	Total	57.0124	1.8422	11	31	8.80	12.56	25.12	37.68	50.24	62.80
Scott	CNOOC	58.2891	0.2005	11	15	13.90	10.25	20.51	30.76	41.01	51.27

Table 6-8: CNS Sub-Hub Location - Maximum Power ($V_d=4\%$)

6.3.3 Southern North Sea

6.3.3.1 SNS - Base Case

The Southern North Sea (SNS) sector has very different characteristics when compared to the Northern, Central North Sea and Outer Moray Firth sectors. The SNS is a gas producing area with multiple small wellhead platforms sending gas to central “gathering stations” where gas is then compressed and sent onshore for further processing. This means that the SNS has high numbers of platforms grouped into clusters each with much lower power and voltage requirements. Rather than distributing to individual platforms from the Sub Hub, the philosophy in the SNS is to power multiple platforms from a common High Voltage supply routed through the clusters with topsides or subsea transformers and switchgear used to step down to the low voltage required by the platform. This enables multiple clusters of platforms to be electrified from a single Sub Hub.

The clustering philosophy was applied to the SNS with the main gathering stations (e.g. Cleeton, West Sole, Leman, Cleeton) targeted when considering the location of Sub Hubs. Standalone assets with large demand (e.g. Cygnus) were also considered.

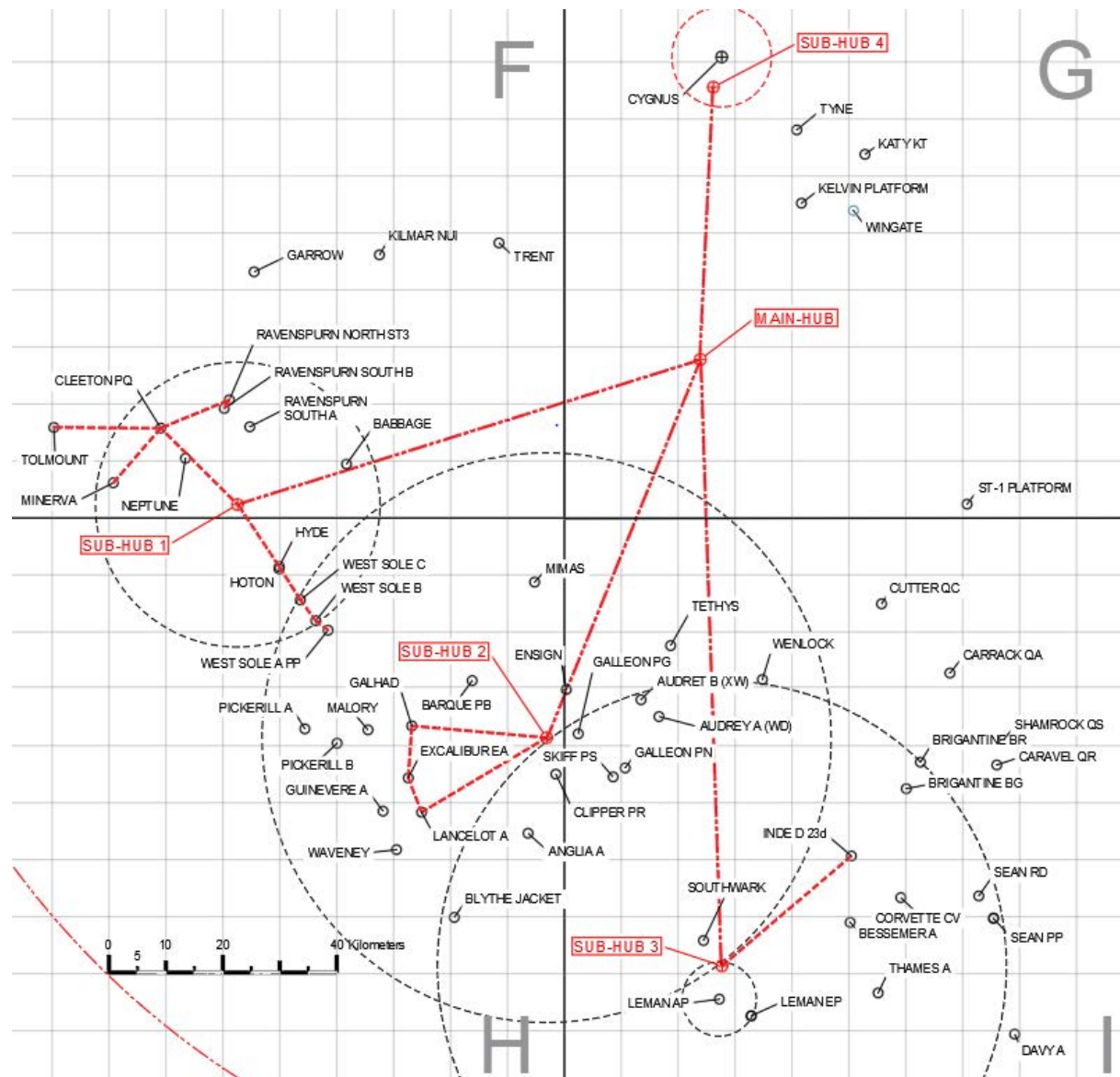


Figure 6-26: SNS Base Case

6.3.3.2 SNS - Water Depths

The water depths in the Southern North sector generally range from 10m – 45m, which is substantially shallower than the Central & Northern sectors which have depths in the range 80 – 100+m. The Water Depth directly impacts the type of infrastructure that can be installed in the region. Based on nautical charts for the region, the Main Hub was located in the deepest available water depths to maximise the options available when selecting the marine solution type.

X - Long	Y - Latitude	Description	Water Depth (m)
2.183	54.097	Main Hub	65 - 70
0.924	53.906	Sub Hub 1	40 – 45
1.715	53.516	Sub Hub 2	20 - 30
2.143	53.141	Sub Hub 3	25 – 30
2.263	54.524	Sub Hub 4	15 – 18

Table 6-9: SNS Water Depths

6.3.4 SNS – Wind Farm Locations

Data from the Department for Business, Energy & Industrial Strategy report 'Review of Consented Offshore Wind Farms in the Southern North Sea Harbor Porpoise SAC' /2/ report was overlaid onto the SNS Clustering Map, highlighting the proximity of offshore wind sites to the Hub locations.

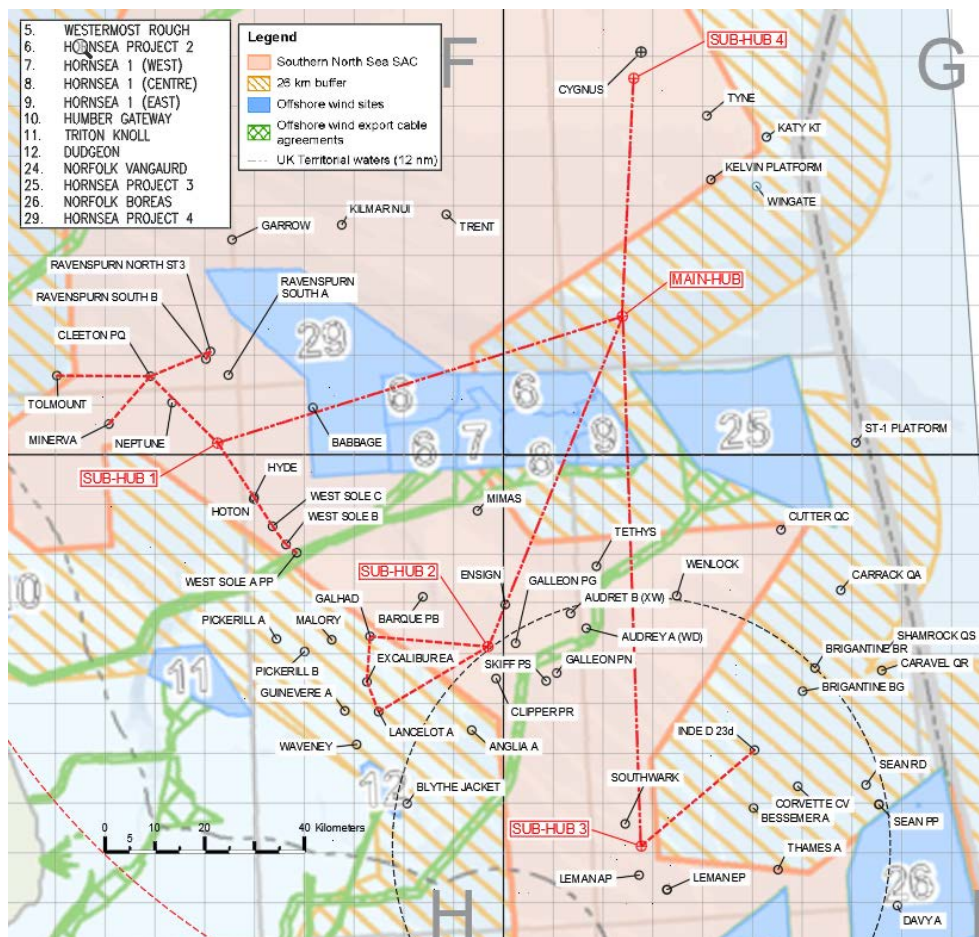


Figure 6-27: SNS with Wind Farm Overlay

6.3.5 SNS – Sub Hub Locations Base Case - Maximum Distance

Asset	Operator	Latitude	Longitude	HV (kV)	Demand (MW)	Distance (KM)	Max power 1 cables	Max power 2 cables	Max power 3 cables
Ravenspurn North	Perenco	58.059	1.081	6.6	1.5	18.88	1.50	3.00	4.50
Cleeton	Perenco	58.049	1.139	3.3	1.5	5.09	1.50	3.00	4.50
Lancelot	Perenco	53.4088	1.3755	3.3	0.1	63.93	0.10	0.20	0.30
Excalibur	Perenco	53.4637	1.3448	3.3	0.1	63.93	0.10	0.20	0.30
Galahad	Perenco	53.5455	1.3608	3.3	0.1	63.93	0.10	0.20	0.30
West Sole A	Perenco	53.7023	1.1508	3.3	0.3	22.77	0.30	0.60	0.90
West Sole B	Perenco	53.7181	1.1194	3.3	0.2	44.25	0.20	0.40	0.60
West Sole C	Perenco	53.7521	1.0809	3.3	0.2	44.25	0.20	0.40	0.60
Hyde	Perenco	53.8061	1.0287	3.3	0.2	44.25	0.20	0.40	0.60
Hoton	Perenco	53.8023	1.0278	3.3	0.2	44.25	0.20	0.40	0.60
Inde D	Perenco	53.3011	2.5007	3.3	0.2	44.25	0.20	0.40	0.60
Tolmount	Harbour	54.0398	0.4414	3.3	0.2	44.25	0.20	0.40	0.60
Cygnus	Neptune	54.569	2.29	11	19.15	8.78	9.57	19.15	28.72
Leman Alpha (Note 1)	Shell	53.0889	2.131	11	36.5	6.03	12.17	24.33	36.50

Table 6-10: SNS - Maximum Distance

Note 1 – Hosted Fields – Leman (A, B, C, D, E, F & G), Brigantines (BG & BR), Shamrock, Caravel, Corvette.

6.4 Discussion

The work carried out within this study has allowed multiple other scopes within the overall project to progress:

- Based on geographical location & water depth, the type of hull i.e. circular FPSO utilised for the Main Hub & Sub Hubs, could be formalised.
- The asset clustering enabled the overall power requirements of the Main Hubs & Sub Hubs to be determined. Subsequently, equipment selection & layout of the Main Hub & Sub Hubs could progress.
- Lengths & specifications of cabling requirements could be investigated based on the distance between Main Hub, Sub Hubs & Assets.
- Identification that the Sub Hubs in the SNS would need to be jack-up rigs due to the shallow water depths

6.5 Conclusion

The clustering assessment has shown it is technically feasible to group multiple assets within reach of a Sub Hub for the majority of assets in the OMF, CNS & SNS. It has also highlighted the significant difference between the infrastructure layout & philosophy for powering the OMF/CNS sector & the SNS.

From the assessment, it is considered that there are enough opportunities for electrification at platform voltage to be considered a feasible concept for future electrification of the North Sea.

6.6 Further Areas of Study

The alternative option for the CNS centring around the use of 2 No. Main Hubs was reviewed late in the study cycle. Additional modelling of the power demands may result in a revised arrangement of Main Hub & Sub Hub locations & quantities.

Obtaining better quality data from each operator relating to real power demands for all assets in the North Sea will result in better evaluation of this clustering and depending on the demand drivers a change in configuration could prove to be more effective.

6.7 Opportunities / Risks / Assumptions

AutoCAD combined with a Geolocation Map plugin was utilised to carry out the Clustering Assessment. During the study, various forms of data were gathered which were not in a format that is automatically compatible with AutoCAD.

Although the clustering method worked & provided the required information, there is the opportunity to investigate AutoCAD Map or alternative GIS based programs that may be more efficient & allow the data collected during the course of the study to be automatically uploaded into existing online Mapping platforms.

7. Typical Asset Distribution and Characterisation

7.1 Objective

In order to design a flexible and modular system, the Oil & Gas platforms (assets) under consideration shall be characterised according to key parameters: voltage, frequency, demand, and the factors that impact full electrification. This information, along with the geographical clustering discussed in Section 6 shall inform the Sub Hub requirements and feed into the Platform Modification Study in Section 13.

This study concentrates on assets in the three main regions for investigation: the Outer Moray Firth (OMF), the Central North Sea (CNS) and the Southern North Sea (SNS).

Only assets where the operator responded to the OGA with data have been included.

7.2 Methodology / Background

Data from Oil & Gas platform operators has been requested and provided via the OGA. The key data requested for this study was:

- Platform electrical demand
- Platform generation
- Platform direct driven equipment details
- Waste Heat Recovery details
- Process Heat input details
- Platform main voltage
- Platform operating frequency

In addition, publicly available information on operator websites, e.g. the Infrastructure Code of Practices (ICOPs), were retrieved to supplement the provided data.

7.2.1 Electrical Characterisation

The key electrical parameters have been characterised according to the following tables.

7.2.1.1 Frequency

Offshore Oil & Gas platforms either operate at 50Hz frequency (the UK grid frequency) or 60Hz (offshore and marine frequency). The majority of UK offshore assets in the CNS and OMF areas operate at 60Hz and therefore an islanded offshore network would operate at 60Hz to avoid the need for frequency conversion. In the SNS platforms are more typically 50Hz.

Range	Characterisation
50Hz	50
60Hz	60

7.2.1.2 Voltage

A range of main distribution voltages is used throughout the North Sea. The most common voltages are 6.6kV, 11kV and 13.8kV. There are some platforms without any High Voltage distribution, and there is one asset cluster within the study scope which operates a 33kV ring main. In the SNS platform voltages tend to be lower with the highest being 6.6kV.

Range	Characterisation	Examples
<1kV	Low Voltage (LV)	0.415V
1kV to 6.6kV	Medium Voltage (MV)	3.3kV, 6.6kV
>6.6kV	High Voltage (HV)	11kV, 13.8kV, 33kV

7.2.1.3 Demand

Electrical demand can vary widely across platforms. Higher demands are seen where large pumps and compressors are electrically driven. Here platforms can have demands greater than 30MW. Where a majority of the large rotating equipment is driven by standalone gas turbines then electrical demand is often lower. The general trend in the North Sea is for a reduction in electrical power demand as late life fields tend to have lower production rates. In the SNS where platforms are often small, single wellhead platforms, the loads are very low, typically just a few tens of kW.

Range [MW]	Characterisation
<0.5	Very Low Demand (VLD)
0.5-10	Low Demand (LD)
10-30	Medium Demand (MD)
>30	High Demand (HD)

7.2.2 Barriers to Full Electrification

There are three key areas identified which present issues for either full or partial electrification of an Oil & Gas platform. These are:

- Direct Gas Turbine driven equipment, e.g. large compressors
- A serviceable produced gas disposal route, e.g. sales export or re-injection
- Capability to accept subsea power cable

These areas have been determined through data requests or through examination of the published Infrastructure Code of Practice.

7.2.2.1 Potential Electrical Distribution Expansion

When considering electrification of an asset, the ability of the existing electrical distribution system to meet increased power demand is likely to be a limiting factor.

Switchgear, cables and transformers are all key electrical components that will have been designed to suit the rating of the system as originally intended. The ratings of these key components may limit the ability of a system to support additional electrical demand.

Existing switchgear has limited capacity for expansion based on the following:

- Continuous current rating – typically the amount of current the main busbars are rated to carry on a continuous basis under normal conditions
- Short circuit rating – the amount of current the main busbars and switching devices are rated to carry for a short time period under fault conditions (usually in the order of 1-3 seconds)

Additional electrical load on a system impacts both of these ratings. In this report, the continuous current rating will be used as a basis for understanding the capacity for expansion. For the purposes of this report the main switchboard capacity is seen as the key limiting item.

Not all main switchboard ratings have been provided as part of the data gathering process. To determine an estimation of capacity, typical ratings (low and high) will be used for each voltage. These will be then translated into additional power (MW) capacity by applying a power factor of 0.9.

7.2.2.2 Direct Drive Equipment

Utilising gas directly in gas turbines is widely implemented in the North Sea. Electrification of this equipment can be challenging based on the physical location of equipment on the platform. Typically gas turbine equipment is located in areas which are very challenging to remove without specialist lifting equipment, e.g. heavy lift vessels.

Partial electrification of assets can still be carried out whilst retaining direct drive equipment, however to maximise emissions reduction, replacement of these equipment items with electrically driven equipment would be necessary.

7.2.2.3 Gas Export / Gas Disposal

To fully or partially electrify assets a gas export route or method for gas reinjection would be required, otherwise gas would have to be flared.

If an asset does not have either of these systems available it will significantly impact the effectiveness of electrification.

7.2.2.4 Capability to accept subsea power cable

To provide platform electrification there must be a way to route electrical power cables from the seabed to the asset's topsides.

In the case of a fixed platform this can be provisioned through the use of new or existing risers or J-tubes.

For FPSOs there needs to be adequate provision in the turret and associated subsea infrastructure (i.e. spare mid-water arch clamps).

7.2.3 Platform Characterisation / Envelope Study

Scoring criteria has been applied to each asset based on its characteristics. The scoring will correspond to an asset electrification score. The scoring will be broken into the following 4 categories:

1. On asset power distribution capabilities
2. Direct drive equipment present
3. Gas export / disposal route available
4. Other challenges

Geographic location has not been considered here as this is the subject of analysis in the Asset Clustering study (Section 6). Geographical Location / Proximity to a Sub Hub has not been considered in this assessment as the locations proposed by Katoni are not expected to be final locations for infrastructure.

The scoring bands are evaluated based on the following criteria:

7.2.3.1 On asset power distribution capabilities

This assessment is carried out based on the electrical distribution infrastructure present on an asset.

If an asset has no direct drive demand, and a primary distribution voltage of 11kV or more, deemed to be capable of supplying all power to the asset, then this will be considered having a low impact score.

If the platform has a primary distribution voltage less than 11kV, with considerable direct drive demand, this is considered as having a high impact score.

In instances where the primary distribution voltage is LV (i.e. below 1kV), then this shall have an extremely detrimental impact on the score for OMF and CNS assets. SNS assets are tackled in a different methodology utilising a HV ring main to allow HV sources of power to be routed to these assets.

The scoring will be:

- 1 for assets with no direct drive equipment and an adequate distribution voltage
- 5 for assets with direct drive equipment and an adequate distribution voltage
- 10 for assets with direct drive equipment and an inadequate distribution voltage
- 100 for assets with an inadequate distribution voltage (which limits subsea power transmission)

7.2.3.2 Direct Drive Equipment

This assessment is carried out based on the presence of direct drive equipment on an asset. The scoring will be based on a ratio of direct drive power to platform main electrical generation capacity.

The scoring will be:

- 1 for assets with no direct drive equipment
- 5 for assets with direct drive equipment <50% of current electrical generation capacity
- 10 for assets with direct drive equipment >50% of current electrical generation capacity

7.2.3.3 Gas Disposal Facility

This assessment is carried out based on whether there is a gas export or other gas disposal route available.

The scoring will be:

- 1 for assets with an active gas export or disposal route
- 5 for assets with an inactive gas export or disposal route
- 10 for assets without any export or gas disposal route (where flaring is currently used)

7.2.3.4 Other Challenges

Other challenges or barriers to electrification are considered such as Assets with no ability to receive cables or an FPSO with no additional turret capacity.

The scoring will be:

- 0 for assets with no additional challenges
- 25 for assets with challenges which can be overcome
- 100 for assets which have challenges which cannot be overcome

Process heating requirements are not considered as a barrier to electrification as part of this study. It is considered a boiler system could be incorporated as a minimum on assets which require process heat.

7.2.3.5 Scoring Banding

The scoring range based on the criteria outlined in Section 7.2.3 ranges between 4 to 230 based on the criteria outlined. The score banding is considered as:

Score	Category	Description
≤10	A	Excellent candidate for electrification with this concept. Minor modifications required
10>x≤20	B	Good candidate for electrification with this concept. Moderate modifications required which may involve replacement of direct drive equipment or partial electrification
20>x≤30	C	Fair candidate for electrification with this concept. More than one modifications required which may involve replacement of direct drive equipment, no gas export route or partial electrification
30>x≤50	D	Poor candidate for electrification with this concept. Substantial modifications required which may be unfeasible
>50	E	Not a candidate for electrification, challenges exist which cannot be overcome

Table 7-1 Platform Characterisation Score Banding

7.3 Results

7.3.1 Outer Moray Firth

7.3.1.1 Claymore

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Electrical Characterisation
12	23.8	41.2	13.8	60	60-HV-MD

Platform Facilities per /4/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	None	Produced gas is compressed and reinjected

Electrification Characterisation Score

Power Distribution	5	HV distribution but has Direct Drive demand
Direct Drive	10	Ratio of 0.577 Direct Drive Demand to Generation
Gas Disposal	1	Has gas re-injection facilities
Other Issues	0	No issues identified
	16	Category B – Good

7.3.1.2 Piper

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
35	-	92	13.8	60	60-HV-HD

Platform Facilities per /5/.

Waste Heat Recovery	Yes	28.74MW rated from three units
Process Heating Medium	No	
Gas Export	Yes	Gas is used for gas lift, fuel gas and export

Electrification Characterisation Score

Power Distribution	1	HV distribution and no Direct Drive demand
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.1.3 Montrose

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
25.1	-	58.8	11	50	50-HV-MD

Platform Facilities per /6/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	Yes	Gas export to CATs

Electrification Characterisation Score

Power Distribution	1	HV distribution and no Direct Drive demand
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.1.4 Arbroath

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
0.36	-	0.86	0.415	50	50-LV-LD

Platform Facilities per /7/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	Yes	Gas export to Montrose platform

Electrification Characterisation Score

Power Distribution	100	LV distribution only
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	102	Category E – Not Feasible to Electrify

7.3.1.5 Bleo Holm

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
14.67	9.7	21.76	6.6	60	60-MV-MD

Platform Facilities per /8/.

Waste Heat Recovery	No	Units are out of service
Process Heating Medium	No	
Gas Export	Yes	Gas export to Frigg UK system

Electrification Characterisation Score

Power Distribution	10	No HV distribution to support Direct Drive demand
Direct Drive	5	Ratio of 0.46 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	100	No capacity within turret for subsea power cables
	116	Category E – Not Feasible to Electrify

7.3.1.6 Buzzard

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
60	-	99	11	60	60-HV-HD

Platform Facilities per /9/.

Waste Heat Recovery	Yes	13MW
Process Heating Medium	No	
Gas Export	Yes	Gas export to Frigg UK system

Electrification Characterisation Score

Power Distribution	1	HV distribution and no Direct Drive demand
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.1.7 Golden Eagle

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
27.7	-	68	6.6	50	50-MV-MD

Platform Facilities per /10/.

Waste Heat Recovery	Yes	8.5MW
Process Heating Medium	No	
Gas Export	Yes	Gas export to SAGE system

Electrification Characterisation Score

Power Distribution	1	No HV distribution but no Direct Drive demand
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.1.8 Captain

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
28	-	52	11	60	60-HV-MD

Platform Facilities per /11/.

Waste Heat Recovery	Yes	
Process Heating Medium	Yes	Fired boilers on FPSO
Gas Export	Yes	Gas export to Frigg system

Electrification Characterisation Score

Power Distribution	1	HV distribution and no Direct Drive demand
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.1.9 Britannia

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
14.5	92.2	32	6.6	60	60-MV-MD

Platform Facilities per /12/.

Waste Heat Recovery	Yes	Primary heating for process
Process Heating Medium	No	
Gas Export	Yes	Gas export to SAGE system

Electrification Characterisation Score

Power Distribution	10	HV distribution but has Direct Drive demand
Direct Drive	10	Ratio of 2.88 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	21	Category C – Fair

7.3.1.10 Alba North

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
21	-	46.8	11	60	60-HV-MD

Platform Facilities per /11/.

Waste Heat Recovery	No	Decommissioned
Process Heating Medium	No	
Gas Export	No	Gas is imported from Britannia

Electrification Characterisation Score

Power Distribution	1	HV distribution and no Direct Drive demand
Direct Drive	1	No Direct Drive Demand
Gas Disposal	10	Gas export is not in serviceable condition
Other Issues	0	No issues identified
	12	Category B – Good

7.3.1.11 Alba FSU

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
0.69	-	6.8	6	60	60-MV-LD

Platform Facilities per /11/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	N/A	

Electrification Characterisation Score

Power Distribution	1	MV distribution but no Direct Drive demand
Direct Drive	1	No Direct Drive Demand
Gas Disposal	N/A	No gas to dispose of
Other Issues	100	No provision for bringing subsea cables onboard
	102	Category E – Not Feasible to Electrify

7.3.2 Central North Sea

7.3.2.1 FPF-1

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
4	32.4	23.7	6.6	60	60-MV-LD

Platform Facilities per /11/.

Waste Heat Recovery	Yes	
Process Heating Medium	No	
Gas Export	N/A	

Electrification Characterisation Score

Power Distribution	10	MV distribution and Direct Drive demand
Direct Drive	10	Ratio of 1.37 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	21	Category C – Fair

7.3.2.2 Shearwater

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
12	29.0	26.2	6.6	60	60-MV-MD

Platform Facilities per /13/.

Waste Heat Recovery	Yes	12MW
Process Heating Medium	No	
Gas Export	Yes	Export to SEAL system

Electrification Characterisation Score

Power Distribution	10	MV distribution and Direct Drive demand
Direct Drive	10	Ratio of 1.11 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	21	Category C – Fair

7.3.2.3 Judy

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
10	41.8	22.4	11	60	60-HV-MD

Platform Facilities per /14/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	Yes	Export to CATS system

Electrification Characterisation Score

Power Distribution	5	HV distribution and Direct Drive demand
Direct Drive	10	Ratio of 1.87 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	16	Category B - Good

7.3.2.4 Gannet

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
21.5	-	54.5	11	60	60-HV-MD

Platform Facilities per /15/.

Waste Heat Recovery	Yes	5MW
Process Heating Medium	No	
Gas Export	Yes	Export via Fulmar pipeline

Electrification Characterisation Score

Power Distribution	1	HV distribution and no Direct Drive demand
Direct Drive	1	No Direct Drive demand
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	3	Category B - Good

7.3.2.5 Nelson

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
4.4	32	24	6.6	60	60-MV-LD

Platform Facilities per /16/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	Yes	Export via Fulmar pipeline

Electrification Characterisation Score

Power Distribution	10	MV distribution and Direct Drive demand
Direct Drive	10	Ratio of 1.33 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	21	Category C - Fair

7.3.2.6 ETAP

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
32	34	80	13.8	60	60-HV-HD

Platform Facilities per /17/.

Waste Heat Recovery	Yes	10MW
Process Heating Medium	No	
Gas Export	Yes	

Electrification Characterisation Score

Power Distribution	5	HV distribution and Direct Drive demand
Direct Drive	5	Ratio of 0.425 Direct Drive Demand to Generation
Gas Disposal	1	Has gas export
Other Issues	0	No issues identified
	11	Category B - Good

7.3.2.7 Auk

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
2.2	-	3	4.16	60	60-MV-LD

Platform Facilities per /18/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Export	No	Gas is flared

Electrification Characterisation Score

Power Distribution	1	MV distribution but no Direct Drive demand
Direct Drive	1	No Direct Drive Demand
Gas Disposal	10	No gas disposal route
Other Issues	0	No issues identified
	12	Category B - Good

7.3.2.8 Forties

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
56.1	42	60	33	50	50-HV-HD

Platform Facilities per /20/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Disposal	No	Gas lift facilities but no export or reinjection

Electrification Characterisation Score

Power Distribution	5	HV distribution and Direct Drive demand
Direct Drive	10	Ratio of 0.7 Direct Drive Demand to Generation
Gas Disposal	10	No gas export or reinjection
Other Issues	0	No issues identified
	25	Category C - Fair

7.3.2.9 Clyde

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
11	-	16.1	6.6	60	60-MV-MD

Platform Facilities per /19/.

Waste Heat Recovery	No	
Process Heating Medium	No	
Gas Disposal	Yes	Export via Fulmar pipeline

Electrification Characterisation Score

Power Distribution	1	MV distribution but no Direct Drive demand
Direct Drive	1	No Direct Drive Demand
Gas Disposal	1	Gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.2.10 Fulmar

Electrical Demand	Direct Drive Demand	Generation	Main Voltage	Frequency	Characterisation
7	-	24	6.6	60	60-MV-LD

Platform Facilities per /21/.

Waste Heat Recovery	No	Unit out of service
Process Heating Medium	No	
Gas Disposal	Yes	Export via SEGAL system

Electrification Characterisation Score

Power Distribution	1	MV distribution but no Direct Drive demand
Direct Drive	1	No Direct Drive Demand
Gas Disposal	1	Gas export
Other Issues	0	No issues identified
	3	Category A – Excellent

7.3.3 Southern North Sea

Due to the different approach undertaken for the Southern North Sea as outlined in the Platform Clustering study (Section 6), the scoring of assets will be carried out differently. The high power requirement assets will be directly targeted based on the existing infrastructure of the assets.

7.3.3.1 Electrical Characterisation Summary

Asset	Demand	Generation	Main Voltage	Frequency	Characterisation
Babbage	0.1	0.2	0.415	50	50-L-L
Cygnus	4.79	18.8	11	50	50-M-L
Clipper	1.7	3.35	0.415	50	50-L-L
Wingate	0.07	0.13	0.4	50	50-L-L
Leman	1.6	3	0.415	50	50-L-L
Ravenspurn	1.5	3.4	6.6	50	50-M-L
Cleeton	1.5	6.8	3.3	50	50-M-L
Waveney	<0.1	<0.1	0.4	50	50-L-L
Lancelot	<0.1	<0.1	0.4	50	50-L-L
Excalibur	<0.1	<0.1	0.4	50	50-L-L
Malory	<0.1	<0.1	0.4	50	50-L-L
Galahad	<0.1	<0.1	0.4	50	50-L-L
WSA	<0.3	<0.3	0.4	50	50-L-L
WSB	<0.2	<0.2	0.4	50	50-L-L
WSC	<0.2	<0.2	0.4	50	50-L-L
Hyde	<0.2	<0.2	0.4	50	50-L-L
Hoton	<0.2	<0.2	0.4	50	50-L-L
Inde 23A	<0.5	<0.5	0.4	50	50-L-L
Inde 18A	<0.2	<0.2	0.4	50	50-L-L
Inde 18B	<0.2	<0.2	0.4	50	50-L-L
Inde 23C	<0.2	<0.2	0.4	50	50-L-L
Inde 23D	<0.2	<0.2	0.4	50	50-L-L
Bessemer ¹	<0.2	<0.2	0.4	50	50-L-L
Davy	<0.2	<0.2	0.4	50	50-L-L
Wenlock	<0.2	<0.2	0.4	50	50-L-L
Leman 27A	<0.5	<0.5	0.4	50	50-L-L
Leman 27B ²					
Leman 27C ³	<0.1	<0.1	0.4	50	50-L-L
Leman 27D ³	<0.1	<0.1	0.4	50	50-L-L
Leman 27E ³	<0.1	<0.1	0.4	50	50-L-L
Leman 27F ³	<0.1	<0.1	0.4	50	50-L-L
Leman 27G ³	<0.1	<0.1	0.4	50	50-L-L
Leman 27H ³	<0.1	<0.1	0.4	50	50-L-L
Leman 27J ³	<0.1	<0.1	0.4	50	50-L-L
Tolmount	0.17	0.2	0.415	50	50-L-L
Rough ⁴	<3	7	3.3	50	50-M-L
Blythe	0.0514	0.128	0.4	50	50-L-L
Breagh ⁵	0.02	0.094	0.4	50	50-L-L
York	0.036	0.096	0.4	50	50-L-L

Notes

1. Bessemer is undergoing an engineering study for a renewable power system package.
2. 27B is being modified to become a compression hub
3. Assets are CoP.
4. Short CoP
5. Electrification ruled out previously due to Remote location and low power

7.3.3.2 Hub Electrification Issues Summary

Asset	Direct Equipment	WHR	Process Heat	Gas Export
Babbage /22/	No	No	No	Yes
Cygnus /23/	Unknown	Unknown	Unknown	Yes
Clipper /24/	Yes	No	No	Yes
Leman Alpha /25/	Yes	No	No	Yes
Ravenspurn North /26/	Yes	No	No	Yes
Cleeton	Unknown	No	No	Yes
West Sole A	No	Unknown	Unknown	Yes
Inde 23A /26/	Yes	Unknown	Unknown	Yes

Due to the infrastructure in the SNS, the majority of the high power demand requirements for platforms is driven by direct drive rotating machinery, specifically on Clipper, Leman Alpha and Inde 23A. These assets have been targeted specifically to promote electrification in this area with dedicated Sub Hubs assigned to these assets.

The issues outlined for the CNS and OMF are likely to be even more challenging due to the low distribution voltages on each of these assets with a HV connection required to allow electrification. Each of the key assets in the SNS are classified as C – Fair for electrification potential on this basis.

For suggested platform modifications for these assets see the Platform Modification Study (Section 13).

7.4 Discussion

7.4.1 Electrical Characterisation

7.4.1.1 OMF and CNS

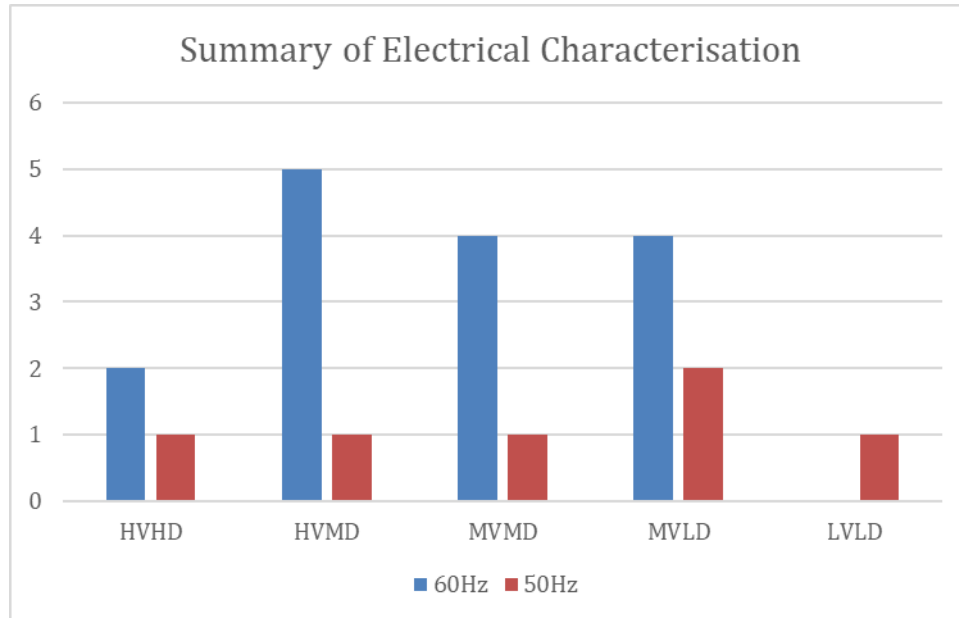


Figure 7-1: Summary of OMF and CNS Electrical Characterisation

As is shown in Figure 7-1 the 60Hz assets (76% of the platforms in this region) are primarily MV or HV with demands greater than 10MW. The 50Hz assets (24% of the platforms) generally have lower demands and are operating at lower voltages.

Only 19% of assets have demands greater than 30MW with the highest demand at 60MW. The mean demand for the 21 assets is 19.0MW.

7.4.1.2 SNS

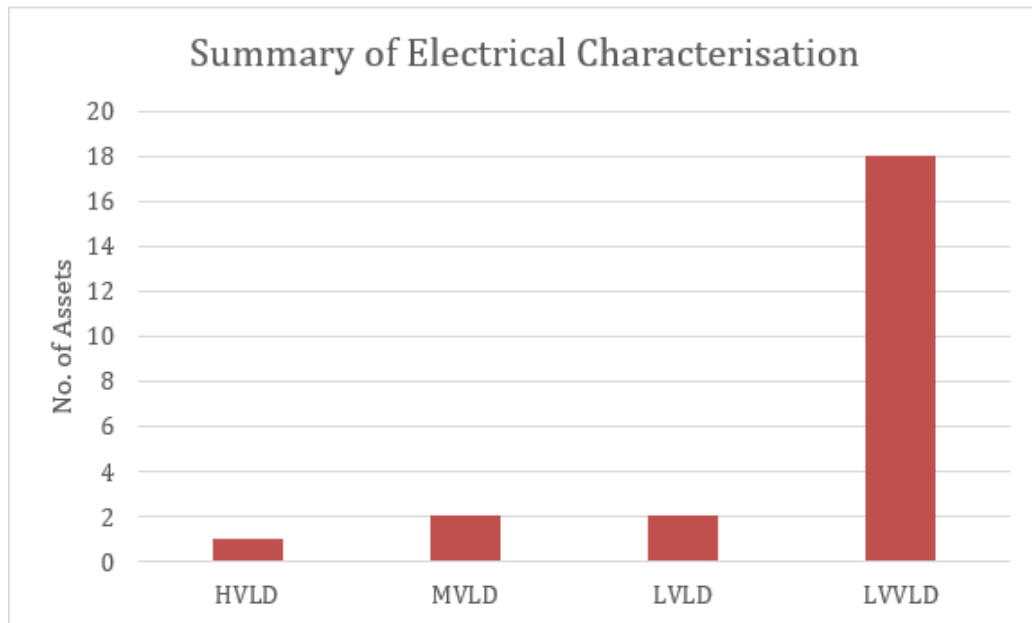


Figure 7-2: Summary of SNS Electrical Characterisation

In the SNS all assets included in the study scope are 50Hz. The majority of assets have Very Low Demand (<1MW) and are operating at LV. The gathering stations have a range of voltages from 3.3kV to 11kV, but the loads are lower when compared with the OMF and CNS, with the largest load being less than 5MW.

7.4.2 Barriers to Electrification

7.4.2.1 Direct Drive Equipment

In the OMF/CNS 43% of assets have Direct Drive Equipment. 66% of these are on assets with Medium Voltage systems which are unlikely to have the capacity to supply additional electrical power without modification or expansion. The remaining 33% are on High Voltage systems where there may be the possibility of supplying additional electrical loads depending on switchgear ratings.

In the SNS all of the gathering stations have Direct Drive gas compression equipment. These are all typically systems with only Low or Medium Voltage available and so are unlikely to be suitable for full electrification without further modification or expansion of their switchgear.

7.4.2.2 Waste Heat Recovery

WHR does not appear to be utilised within the SNS. In the OMF/CNS areas 48% of assets utilise this to input to their process heating. Typical values for this are 5-15MW which would need to be made up via the electrical distribution or standalone fired boilers if the requirement for GTs was completely offset.

7.4.2.3 Other Heat Sources

Only 1 asset in the OMF/CNS area dataset has fired boilers for heat input. It is assumed that where heat is required it is therefore either supplied by WHR or through electric process heaters already accounted for in the platform electrical demand figures.

7.4.2.4 Gas Disposal

All SNS assets have gas export capabilities due to the nature of the region.

In the OMF/CNS area dataset 86% of assets have gas disposal facilities. Providing gas disposal facilities on the 14% of assets that do not have them is likely to be technically challenging and have high CAPEX costs.

7.4.3 Capacity for Expansion

7.4.3.1 13.8kV Assets

The 13.8kV assets were evaluated against main switchboard ratings of 1250A and 2500A to determine potential capacity of expanded electrification.

Based on a 0.9 PF these have the ability to support 28.4MW electrical demand (1250A) to 56.8MW (2500A).

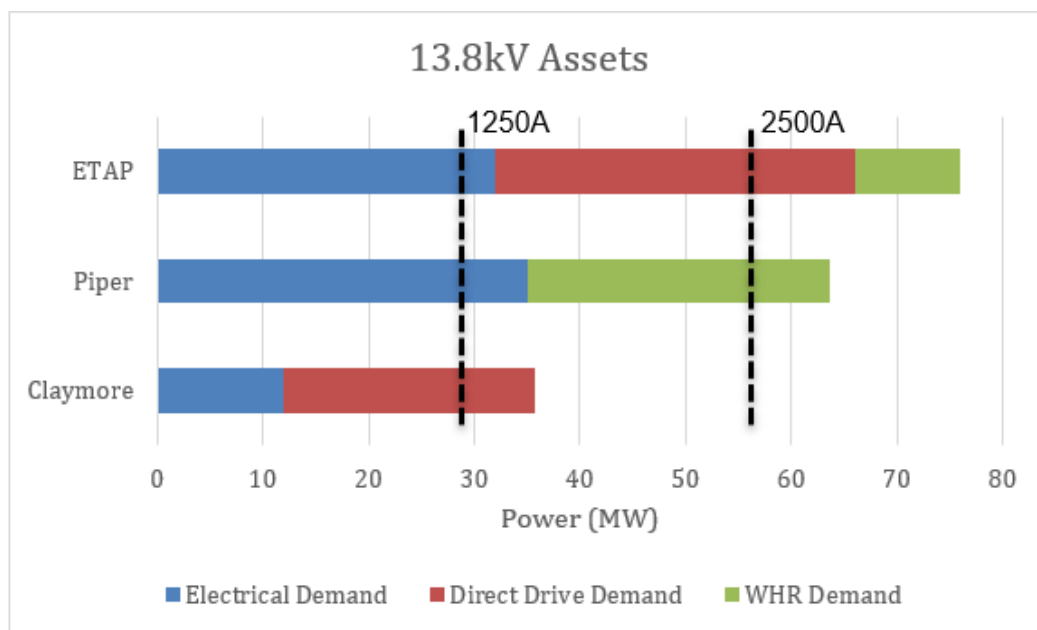


Figure 7-3: 13.8kV Asset Demands

This shows that 2 of the 3 assets at 13.8kV are unlikely to have sufficient capacity within the existing electrical distribution network to support the higher power demands.

7.4.3.2 11kV Assets

The 11kV assets were evaluated against switchboard ratings of 1250A and 2500A to determine potential capacity of expanded electrification.

Based on a 0.9 PF these have the ability to support 22.6MW electrical demand (1250A) to 45.2MW (2500A).

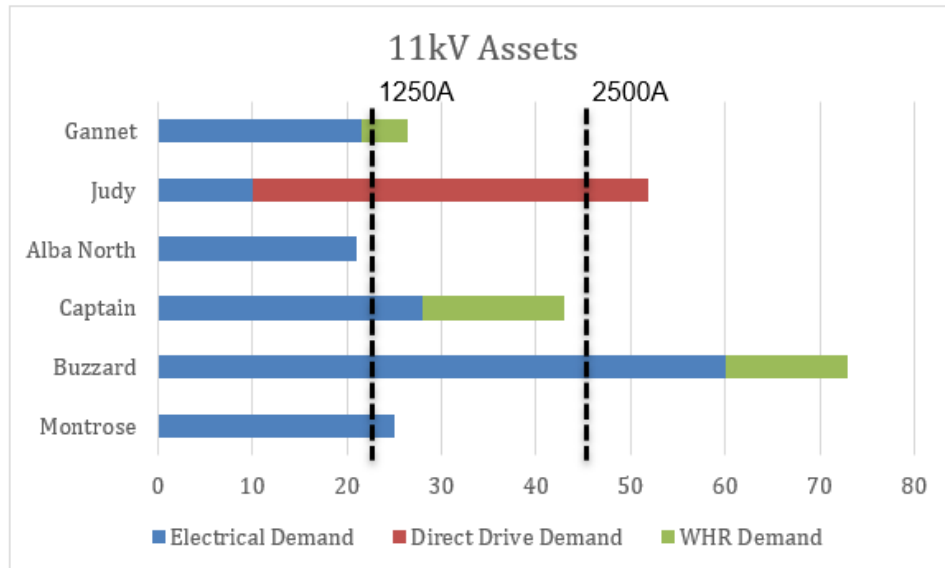


Figure 7-4: 11kV Asset Demands

This shows that 4 of the 6 assets may have sufficient capacity if they already have switchboards rated for the higher capacity (2500A). Full electrification is likely to be challenging for 2 of the 6 assets due to the high demand.

7.4.3.3 6.6kV Assets

The 6.6kV assets were evaluated against switchboard ratings of 1250A and 2500A to determine potential capacity of expanded electrification.

Based on a 0.9 PF these have the ability to support 13.6MW electrical demand (1250A) to 27.1MW (2500A).

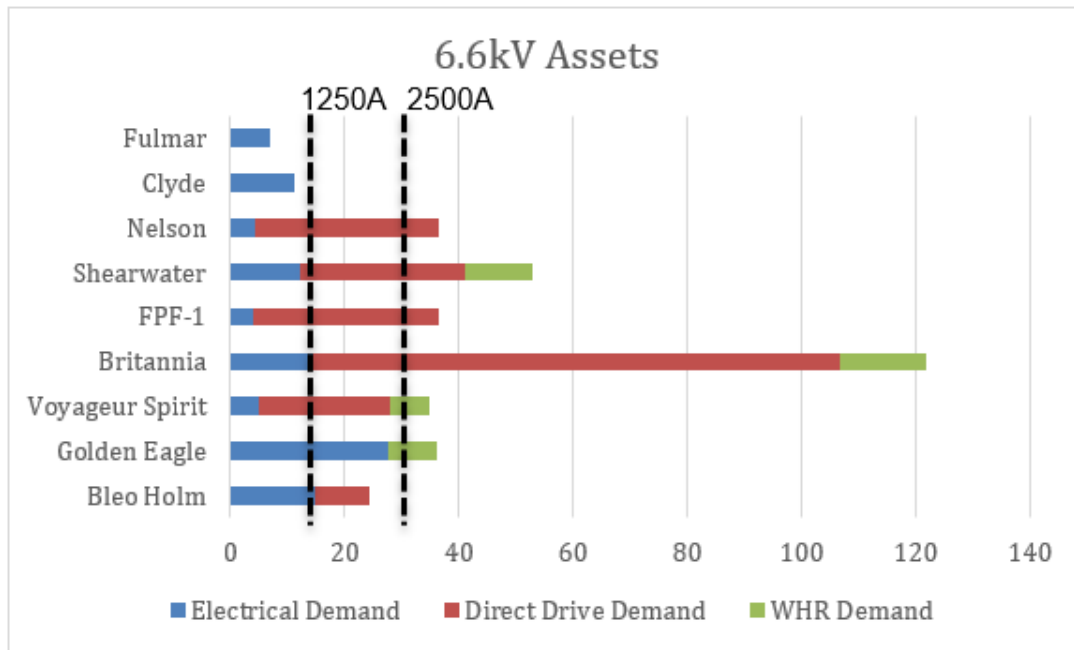


Figure 7-5: 6.6kV Asset Demands

This shows that full electrification for 6.6kV assets requiring additional electrical demand to support compressors or heating are unlikely to be able to meet that using their existing infrastructure.

7.4.4 Summary Scoring

The summarised scoring for each asset as per the methodology in Section 7.2.3 and the results in Section 7.3 are as shown in Table 7-2 below.

Asset	Power Distribution	Direct Drive Ratio	Gas Disposal Route	Other Barriers	Overall Score	Category
Claymore	5	10	1	0	16	B
Piper	1	1	1	0	3	A
Montrose	1	1	1	0	3	A
Arbroath	100	1	1	0	102	E
Bleo Holm	10	5	1	100	116	E
Buzzard	1	1	1	0	3	A
Golden Eagle	1	1	1	0	3	A
Captain	1	1	1	0	3	A
Britannia	10	10	1	0	21	C
Alba North	1	1	10	0	12	B
Alba FSU	1	1	1	100	103	E
FPF-1	10	10	1	0	21	C
Shearwater	10	10	1	0	21	C
Judy	5	10	1	0	16	B
Gannet	1	1	1	0	3	A
Nelson	10	10	1	0	21	C
ETAP	5	5	1	0	11	B
Auk	1	1	10	0	12	B
Forties	5	10	10	0	25	C
Clyde	1	1	1	0	3	A
Fulmar	1	1	1	0	3	A

Table 7-2 Asset Scoring Summary

This results in the following Category summary:

Type	Number of CNS/OMF Assets
A	8
B	5
C	5
D	0
E	3

Where:

- **Type A** – a High Voltage or Medium Voltage asset with a moderate or high electrical demand and no Direct Driven equipment. This describes several of the large assets in the CNS/OMF such as Piper, Montrose and Buzzard. This type of asset can be electrified with minimal modifications with costs likely to be <£10m.
- **Type B** – a High Voltage or Medium Voltage asset typically with moderate electrical demand but with either Direct Driven equipment or lack of an active gas disposal route. This describes 5 assets in the CNS/OMF area, including Claymore, ETAP and Alba North. This type of asset can be electrified but there are likely to be more extensive topsides modifications with costs likely to be <£30m.
- **Type C** – a High Voltage or Medium Voltage asset with a significant amount of Direct Driven equipment, exceeding the existing electrical system capacity, or without a gas disposal route. This describes 5 assets in the CNS/OMF area including Britannia, Shearwater and Forties. It also includes all of the key hubs in the SNS. This type of asset could be electrified but will

require major topsides modifications as well as additional electrical infrastructure, with overall costs likely to be <£100m

- **Type D** – no assets of this kind were identified in the data set. Such an asset would have significant barriers to electrification but could be considered if emissions reduction was deemed substantial.
- **Type E** – an asset with a significant barrier to electrification, typically either low voltage distribution or with an inability to route subsea cables to it. The 3 assets identified in this category are Arbroath, Bleo Holm and Alba FSU.

7.5 Conclusion

Based on an evaluation of the demand, the voltage level and the factors impacting on potential electrification, the following conclusions are drawn.

For the combined CNS and OMF assets studied:

Asset Type	Number of Assets	Percentage	Modifications	Modification Cost	Example Asset
A	8	38%	Minor	<£10m	Buzzard
B	5	24%	Moderate	<£30m	ETAP
C	5	24%	Major	<£100m	Britannia
D	0	0%	Substantial	>£100m	-
E	3	14%	N/A	Not Practical	Bleo Holm

Table 7-3 Electrification Envelope Summary

Due to the use of large gas compression equipment in the SNS all of the hub assets would require Major modifications to achieve full electrification.

In general, within the OMF/CNS area the distribution network should be 60Hz with frequency conversion considered for key assets. In the SNS, the distribution network should be 50Hz.

There is limited opportunity for expanding the electrical capabilities of Oil & Gas platforms without major upgrades to the electrical distribution. Platforms already operating at a higher voltage (e.g. 11kV or 13.8kV) are more likely to have the ability to support additional demand.

7.6 Further Areas of Study

Not all North Sea assets have been included in this report as data has not been provided. The work could be expanded to include additional assets should this data be made available. In particular getting accurate information for busbar ratings would assist in developing the evaluation of the asset's ability to support additional electrification.

7.7 Opportunities / Risks / Assumptions

- Some of the data in this report could contain errors due to the source of the information utilised. Where Katoni did not hold data for assets, or did not have permission for use, then information available in the public domain has been utilised.
- It is recommended to revise this full assessment on an asset-by-asset basis in detail with a complete understanding of current and future demands, as well as the other characteristics/barriers identified. Doing this may affect some of the scoring presented.

8. Renewables Generation Modelling Study

8.1 Objective

This study details analysis conducted based on historical performance data for offshore wind efficiency to determine what over provision of power is required to balance the variable nature of wind power, including allowance for maintenance in the offshore renewables network. This will be evaluated to characterise operating efficiency of the system, the backup power requirements supplied by conventional power generation and be utilised to leverage installed cost of wind power vs installed conventional power generation.

The modelling will evaluate the optimum configuration based on emissions reduction, reducing CAPEX costs via rationalisation of number of wind turbines required for offshore assets as well as ensuring security of platform supply.

8.2 Methodology / Background

Offshore wind data is available from various sources. The UK Government /27/ reports monthly average performance for renewables, which are issued quarterly. The most up to date information published runs until 3rd Quarter 2021.

	2020	2020	2020	2020	2021	2021	2021
	1st quarter	2nd quarter	3rd quarter	4th quarter	1st quarter	2nd quarter	3rd quarter
Cumulative Installed Capacity (MW)							
Offshore Wind	10,114	10,383	10,383	10,383	10,393	10,666	11,066
Generation (GWh)							
Offshore Wind	13,362	7,290	8,012	12,017	11,201	6,191	6,067
Load Factors (%)							
Offshore Wind	61.2	32.6	34.9	52.4	49.9	26.9	25.6
Average Generation (MW)							
Offshore Wind	6,186	3,382	3,628	5,443	5,188	2,871	2,829
Renewable share of electricity generation (%)							
Offshore wind	15.3	10.9	10.9	14.2	13.4	8.5	9.0

Table 8-1 UK Renewable Energy Trends (Offshore Wind)

Table 8-1 details the UK wind generation statistics from 2020 and 2021. It can be seen from the load factors that performance of wind is variable seasonally with load factors ranging from 25.6% to 61.2% of installed capacity. The load factor is determined based on:

$$\text{Load Factor} = \frac{\text{Actual Generation}}{\text{Total Generation Capacity}}$$

The historical trends of UK Offshore Wind are demonstrated in Figure 8-1. The average monthly load factor is 37.9% since 2010.

New installed floating wind farms such as Equinor owned and operated Hywind Scotland are reporting higher capacity factors with average capacity factors of over 50%. Between 2019 and 2020 Hywind Scotland reported an average capacity factor of 57.1% /28/. The limitation of installations such as Hywind are that 6 MW wind turbines have been utilised in a small 30 MW array, and utilising this as an example which is comparable to typical wind farm design would likely lead to an under provision of power.

The Dudgeon wind farm located off the East Coast of the UK is perhaps a more representative comparison to be made. The wind farm is a larger scale of offshore wind utilising the same wind turbines as Hywind /28/. The average capacity factor for Dudgeon is 48% /30/.

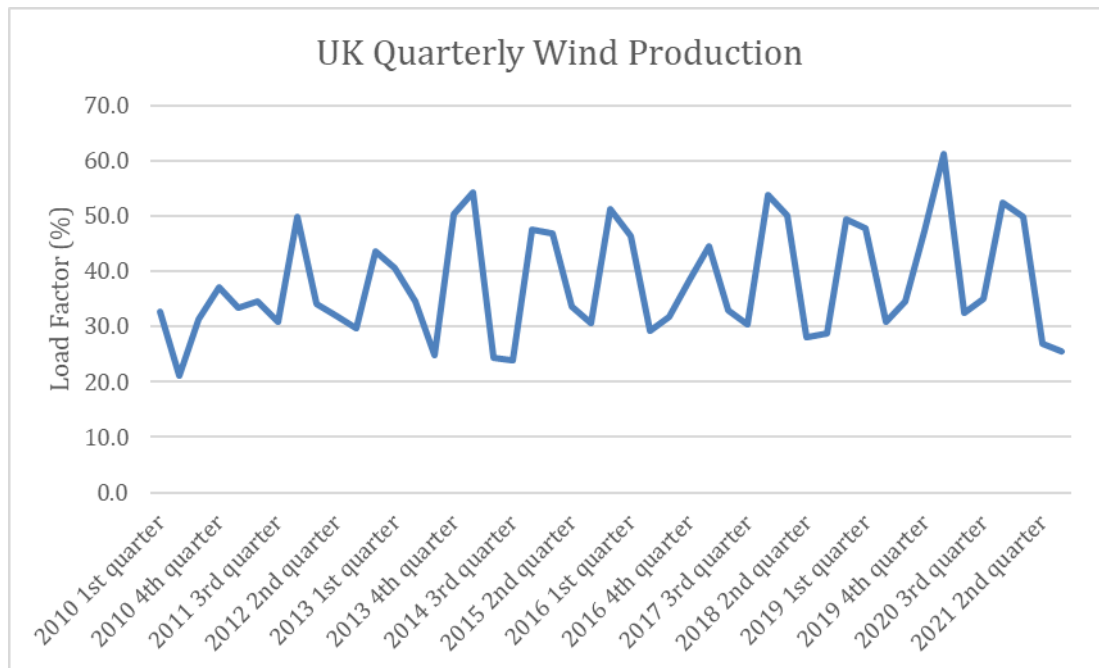


Figure 8-1 UK Historical Quarterly Trends

Information about specific wind farm performance for Dudgeon has been utilised for the purposes of all analysis work being conducted, as it is currently the wind farm which is located furthest away from the UK coastline.

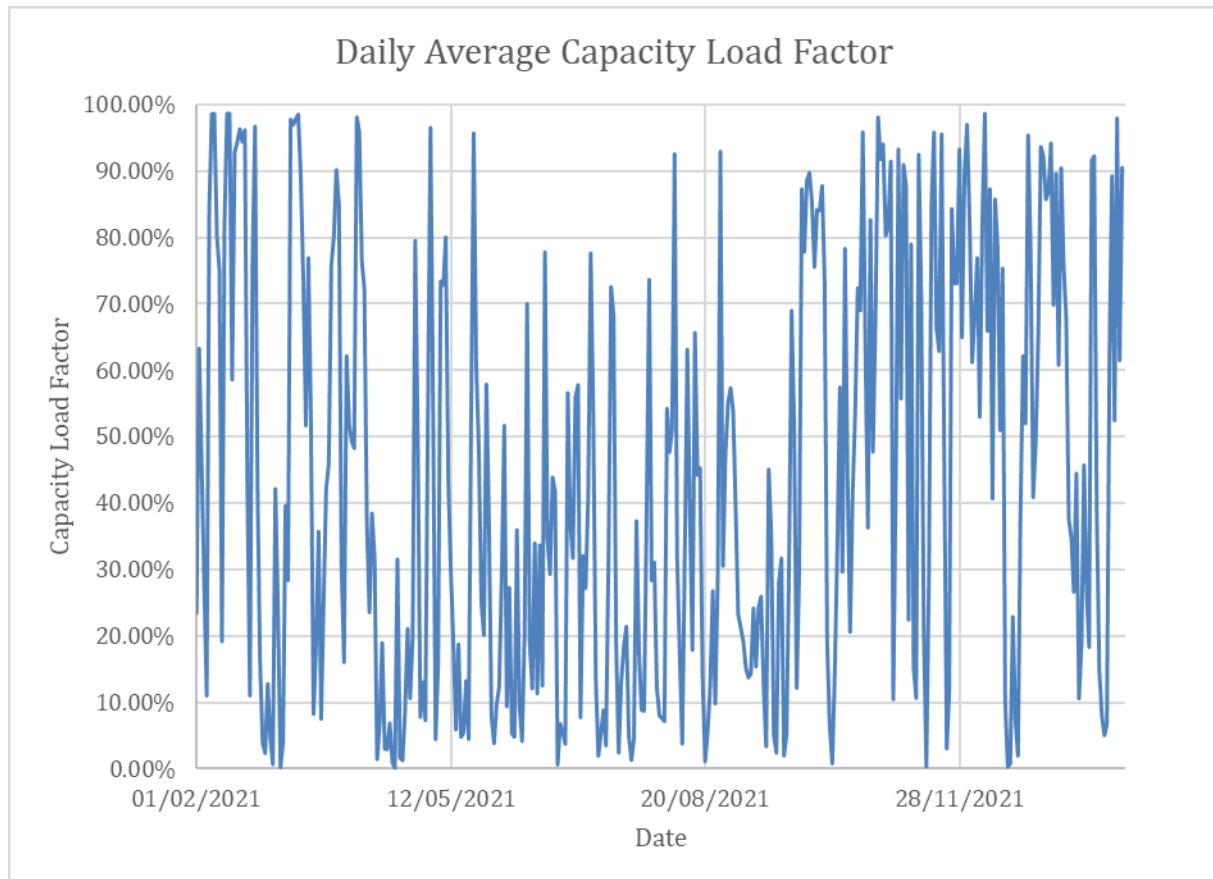


Figure 8-2 Daily Average Capacity Load Factor (Feb-21 to Feb-22)

Figure 8-2 demonstrates the yearly daily average load factor. This demonstrates that the output of the 400 MW wind farm is very variable with periods of >95% output, but also long periods of <10% output.

Output	Number of Days	% Year Average	% per year Actual
Greater than 95%	23	6.30	14.90
Greater than 50%	150	41.10	41.08
Less than 10%	71	19.45	28.37
Less than 5%	38	10.41	21.47

Table 8-2 Dudgeon Load Factor

Table 8-2 summarises statistical analysis which has been conducted on Dudgeon wind farm output. All data has been obtained from the Elexon BMRS portal /31/.

The number of days per load output is calculated as the number of days for which the output of the Dudgeon wind farm is greater than the percentage load factors. i.e. in the year period considered, for 23 days in total the average output was greater than 95%, or 6.3% of the year.

The percentage per year Actual is calculated by a different mechanism. Analysis has been conducted for the full year based on 30 minute output readings from the wind farm. In total approximately 65,000 data points exist for this period, which is split across the 4 substations which make up the Dudgeon wind farm. Approximately 17,000 data points have been evaluated for the totality of the wind farm per year.

The percentage per year actual is calculated based on the total number of instances of 30 minute segments being at the specified load factor criteria outlined in Table 8-2. As can be seen the time where the wind farm is outputting close to maximum is approximately 15% of the time, however the time where it is outputting at less than 5% load is also significantly increased.

The information contained in Table 8-2 is critical to performing the secondary generation power analysis and therefore calculating the OPEX cost for the system per annum.

8.2.1 CNS Basis

From the Platform Clustering Study (Section 6) the following has been identified as the target zone for electrification of the CNS:

Sub Hub Number	Asset Number	Number of Cables	HV (kV)	Demand (MW)	Distance (KM)	Total Amount of Power Available
1	1	3	13.8	12	23.2	18.00
1	2	3	11	15	11.7	22.50
1	3	3	13.8	35	4.5	52.50
2	4	3	11	23	6.7	34.50
2	5	3	6.6	25	2.5	25.00
2	6	3	11	12	14.7	18.00
2	7	6	33	56.1	41.5	112.20
3	8	4	13.8	59.5	11.2	47.60
3	9	5	11	25	17.3	25.00
3	10	4	11	15	28.3	12.00
4	11	5	6.6	12	13.1	12.00
4	12	3	11	31	7.9	31.00
4	13	3	6.6	3.5	20.0	4.23
4	14	4	6.6	4	33.9	4.00
				328.1		418.5

Table 8-3 CNS Power Demand

4 off Sub Hubs have been identified, with an estimation of approximately 420 MW worth of electrification opportunities. This Total Amount of Power Available is the maximum transmissible power through the cables being proposed at the asset operating voltage and an assumed power factor. It is typically higher than the actual electrical demand of the assets at present. This Total Amount of Power Available is the basis of the provision of the wind farm in the CNS region.

It is also assumed for the purpose of the analysis in this report that the electrical power demand from the assets will be constant and always at a maximum. In reality there will be fluctuations in demand due to process, maintenance and outages.

8.2.2 Wind Farm Basis

Utilising the Dudgeon wind farm design as the basis the wind farm would be configured in 9 turbine arrays of 6 MW wind turbines. Each array will be connected via a single 33kV cable to the Main Hub. The number of arrays will be based on the required installed power.

Four wind farm designs have been considered as part of this study, P_{95} , P_{50} , P_{10} and $P_{Optimised}$. The 65th Percentile was selected as the $P_{Optimised}$ value based on a rationalisation between installed wind power and OPEX costs for fuel. This value was identified after the first round of analysis was completed.

	Percentile	Load Factor	Supplementary Power (MW)	Installed Wind Power (MW)	Number of Turbines	Turbine Output (MW)	Turbines Per Array	Number of Arrays	Installed Capacity (MW)
P_{95}	95	98.40	418.5	425	71	6	9	8	432
P_{10}	10	0.20	418.5	209,265	34,878	6	9	3,876	209,304
P_{50}	50	33.90	418.5	1,235	206	6	9	23	1,242
$P_{Optimised}$	65	64.77	418.5	646	108	6	9	12	648

Table 8-4 Wind Farm Designs

Table 8-4 details the consideration of wind farm size based on the percentile load factor for Dudgeon. It can be seen that designing the wind farm for output based on the P_{10} value is not feasible with 210 GW of conventional power required to sustain 0.42 GW of wind power. Similarly, the installed cost of the P_{50} option would be considered to be excessive based on Dudgeon costs of £3.5m/MW /32/. The amount of supplementary power required to enable sustained operation is not considered to change based on the profiles considered. Full provision of 100% of the output is considered as necessary.

All further analysis has been conducted based on the P_{95} and $P_{Optimised}$ cases.

8.2.3 Supplementary Power

For the purposes of this study GE LM6000 Gas Turbines have been considered as the selected power generation equipment to minimise the footprint of installed power whilst choosing an industry standard component. Both a simple and combined cycle arrangement has been considered.

Based on rated output for the equipment the following information has been utilised in the assessment:

LM6000	Supplementary Power (MW)	Output Per Generator (MW)	Max. Number of Generators Operating	Generator Efficiency (%)
Simple Cycle	418.5	53.9	8.0	40.8
Combined Cycle	418.5	72.3	6.0	54.7

Table 8-5 Gas Turbine Characteristics

Simplified gas turbine performance curves have been created based on typical gas turbine performance details in lieu of receiving the specific curves from GE.

8.2.3.1 LM6000 Simple Cycle Performance Data

The following data has been utilised to perform the analysis of the Simple Cycle Gas Turbine

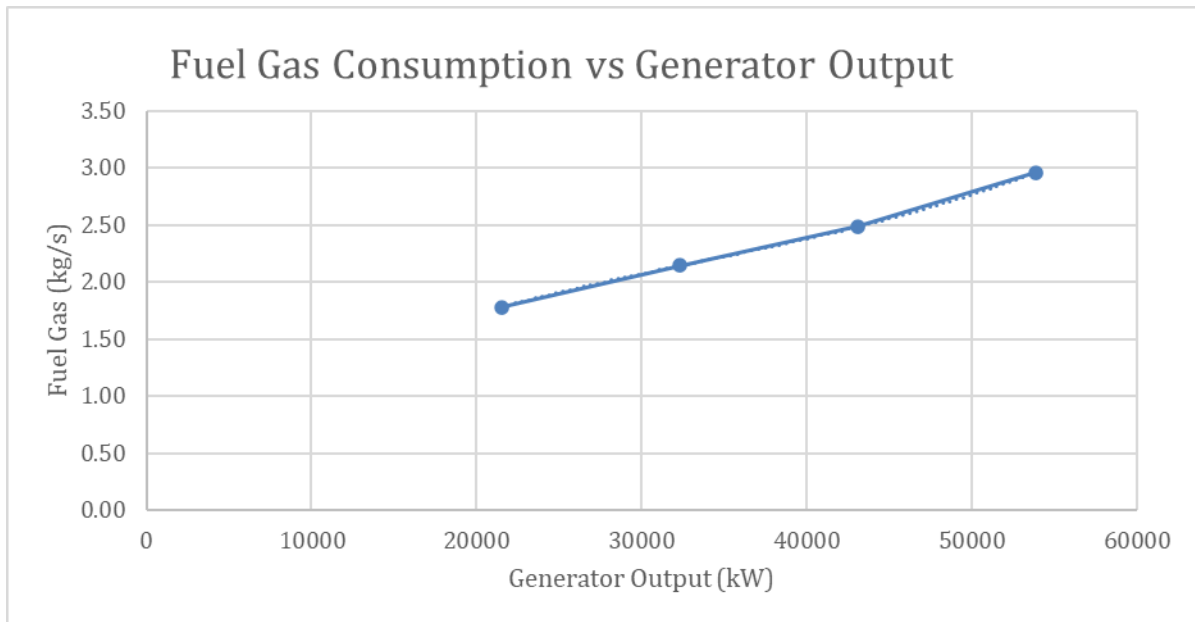


Figure 8-3 LM6000 Simple Cycle Fuel Gas Consumption

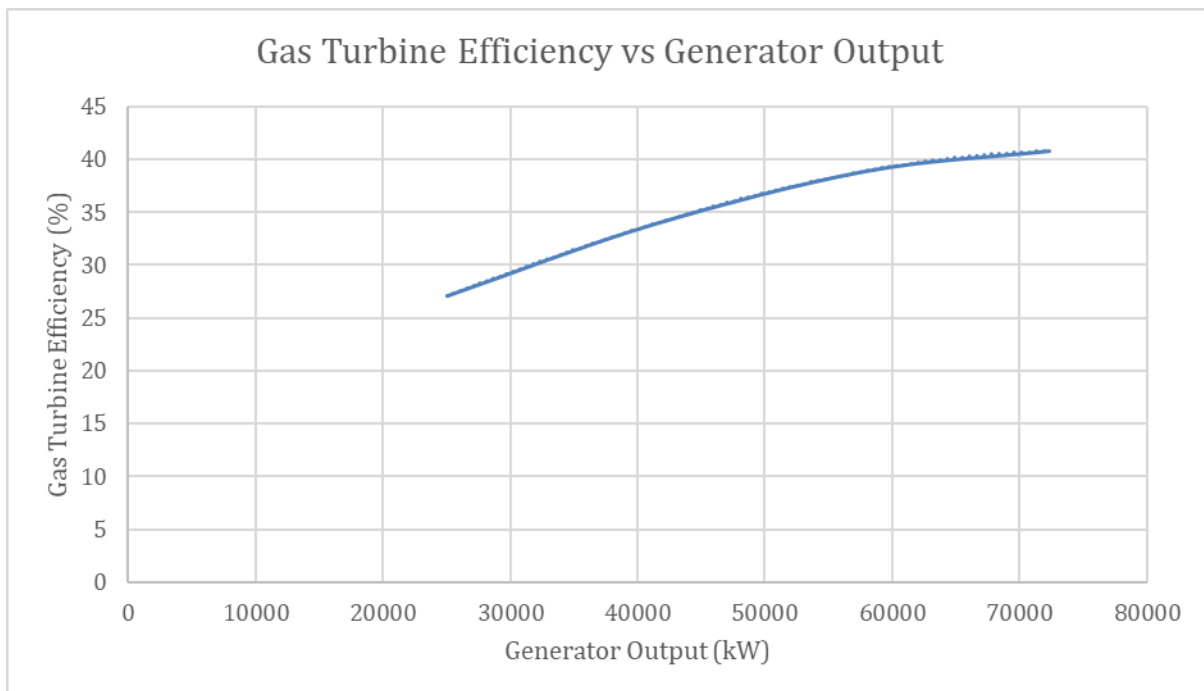


Figure 8-4 LM6000 Simple Cycle Efficiency

8.2.3.2 LM6000 Combined Cycle Performance Data

The following data has been utilised to perform the analysis of the Combined Cycle Gas Turbine

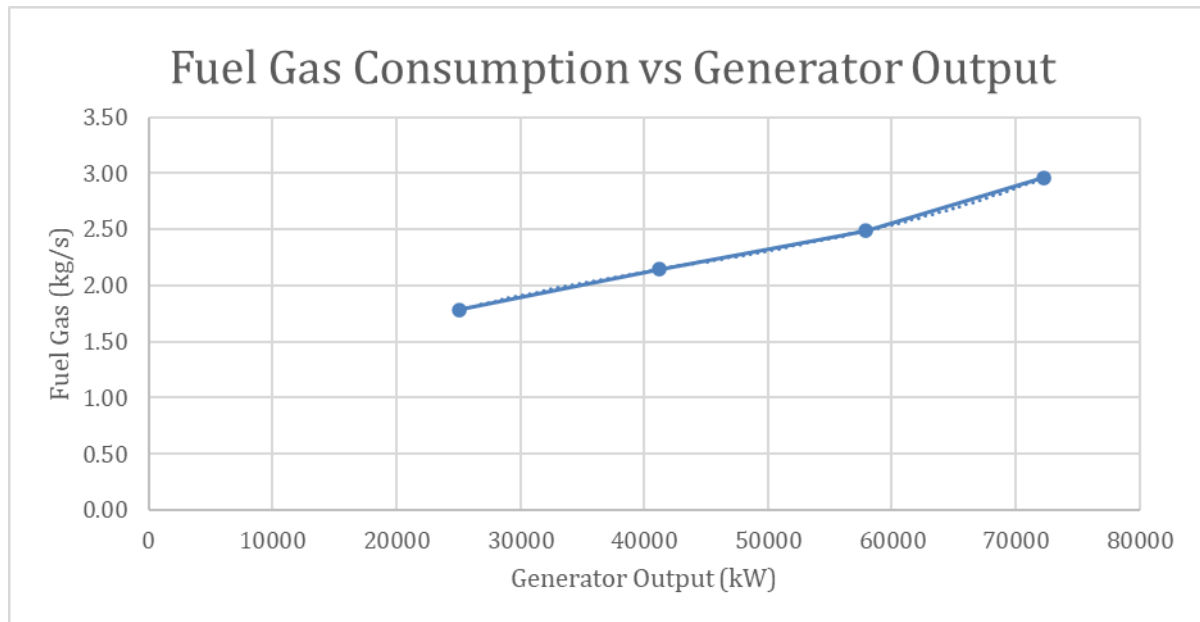


Figure 8-5 LM6000 Combined Cycle Fuel Consumption

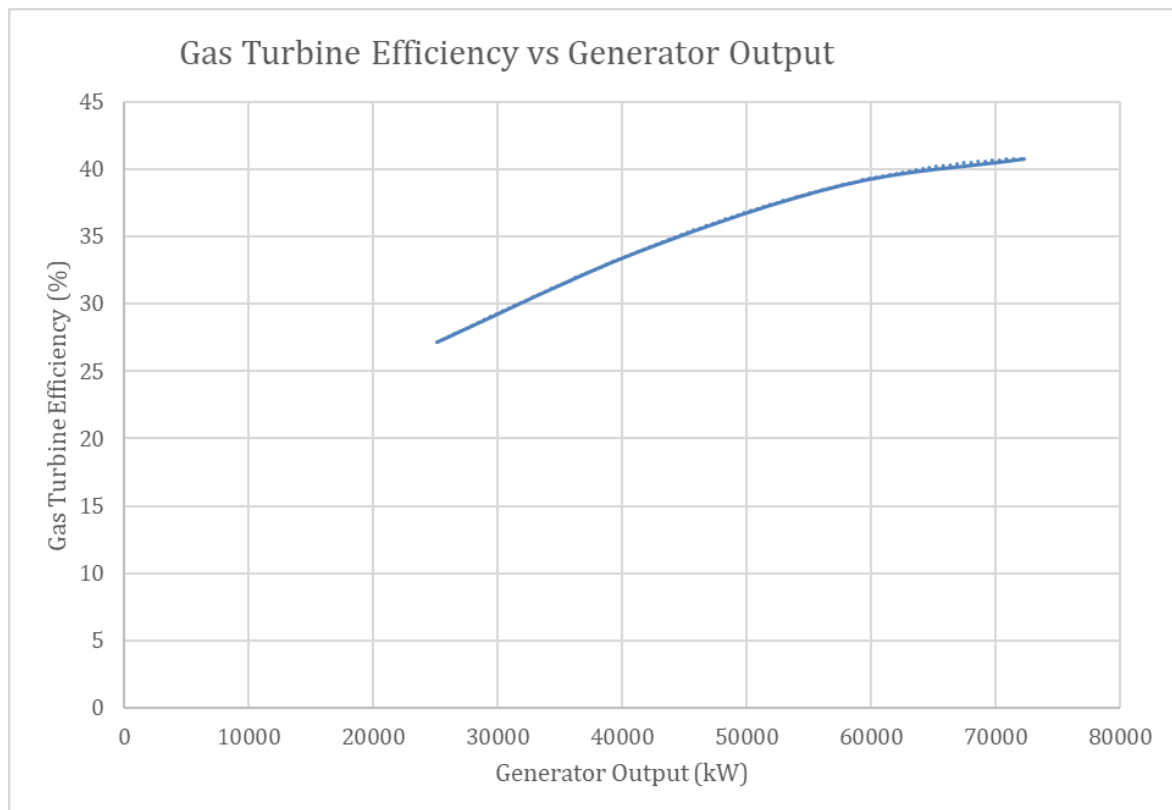


Figure 8-6 LM6000 Combined Cycle Efficiency

8.3 Results

This report aims to evaluate the following:

- Total installed supplementary power
- Operating time for the supplementary power system
- OPEX costs for the supplementary power system
- Estimation of total uptime of the system
- Determine the optimum installed wind capacity

Several configurations have been considered for total installed power capacity. The CNS region has been considered for this analysis.

8.3.1 Renewable Power Performance

Utilising the Dudgeon Wind Farm performance data has enabled detailed analysis at a 30 minute time step over a year from Feb-21 to Feb-22 to be performed. This is used as the basis for this study.

The analysis has evaluated:

- Wind Load Factor
- Wind Output
- Net Difference in Required Generation
- Number of Generators Required to Operate
- Fuel Demand
- Gas Turbine Efficiency
- Cumulative Fuel Consumption
- Potential Excess Generated Power

This analysis has been conducted utilising the P_{95} and $P_{Optimised}$ wind farm configurations for both simple and combined cycle gas turbines.

8.3.1.1 Wind Load Factor

The wind load factor for the period evaluated is covered in Table 8-2. A more detailed statistical breakdown is covered in this section.

Percentile	Load Factor (%)
99	98.7
90	96.9
80	92.6
70	75.5
60	52.66
50	33.9
40	20.9
30	11.3
20	4.2
10	0.8
1	0

Table 8-6 Dudgeon Wind Load Factor Percentile Basis

Table 8-6 demonstrates the 50th percentile relates to 34% output of the installed wind farm capacity.

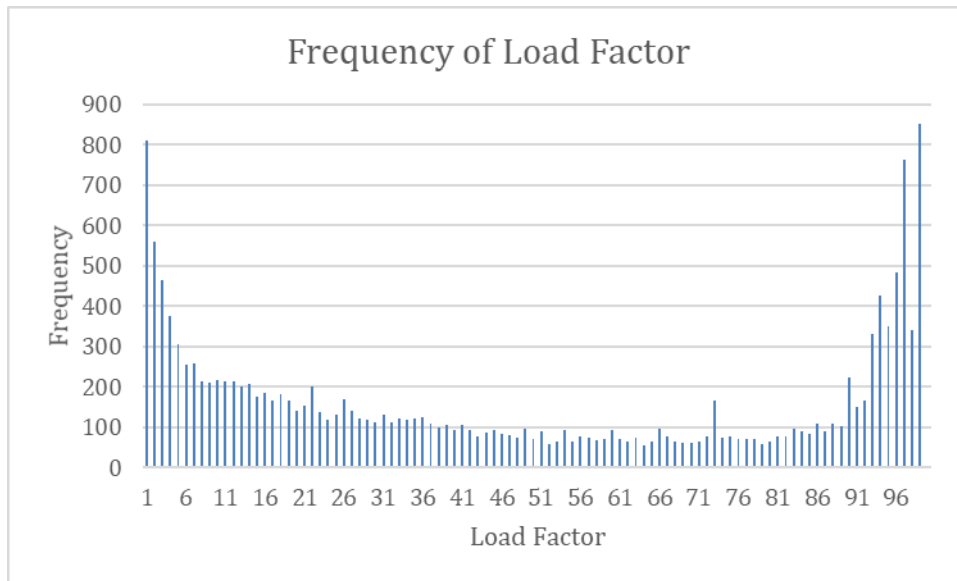


Figure 8-7 Frequency of Load Factor

Figure 8-7 demonstrates the frequency of the load factor based on the 17,000 dataset points. The most frequent output from the wind farm is either below 5% or above 90%. To supply reliable power into the power grid, the supplementary power generation system will be required to supplement the wind farm a large proportion of the time.

8.3.1.2 Wind Output

The power output from the installed wind power will vary based on installed number of wind turbines. The target power for the supply of the oil and gas assets is evaluated as 418.5 MW.

Percentile	Power Output (P_{95}) (MW)	Power Output ($P_{Optimised}$) MW
99	426.4	639.6
90	418.6	627.9
80	400.0	600.0
70	326.2	489.2
60	227.2	340.8
50	146.4	219.7
40	90.3	135.4
30	48.5	72.7
20	18.1	27.2
10	3.5	5.2
1	0.0	0.0

Table 8-7 Power Output From Wind Farm

Table 8-7 demonstrates if the wind farm is sized for the P_{95} case, the output of the wind farm will very rarely peak above the 418 MW required power output and in the event that it does the excess is approximately 8 MW. In this configuration supplemental power would be required approximately 90% of the time.

Table 8-7 also demonstrates that if the wind farm is sized for the $P_{Optimised}$ case, the output of the wind farm can exceed the required demand from the system by up to 220 MW. 35% of the time the supplementary power system would not be operational and there would be no requirement for import gas. This configuration would allow for alternative energy storage to potentially be utilised which could be utilised to supplement the power balance during operation. Discussion around use of this excess is captured in the Hydrogen Technology Study (Section 23).

8.3.1.3 Net Difference in Power Generated

Utilising the Wind Output information detailed in Table 8-7 the net difference in power generated between the renewables and consumption from the oil and gas platforms has been estimated based on the year of Feb-21 to Feb-22.

Figure 8-8 and Figure 8-9 detail this on a normalised daily average basis for clarity.

Figure 8-8 demonstrates that if the wind farm is sized for peak power output, then on only 13 days of the year the wind farm output would exceed the power consumed.

Figure 8-9 demonstrates that with the overprovision of wind on a basis of the 65th percentile on average the power output from the wind farm would be in excess of the consumed power 113 days of the year.

For both power differentials the same minimum points are experienced which requires the provision of supplemental power to be the same. This identifies that there is a balance between CAPEX, emissions reduction and OPEX required to determine the true optimal size of the wind arrays required to maximise the total emissions reduction of the system.

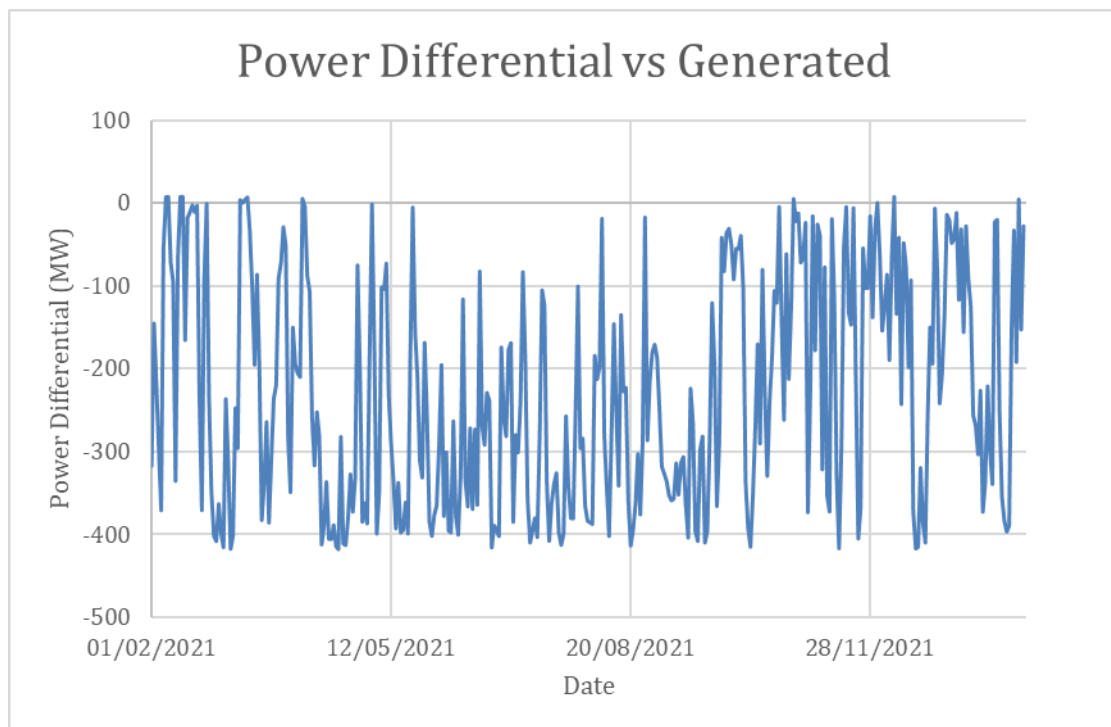


Figure 8-8 Average Day Power Differential P95 (Renewable vs Consumed)

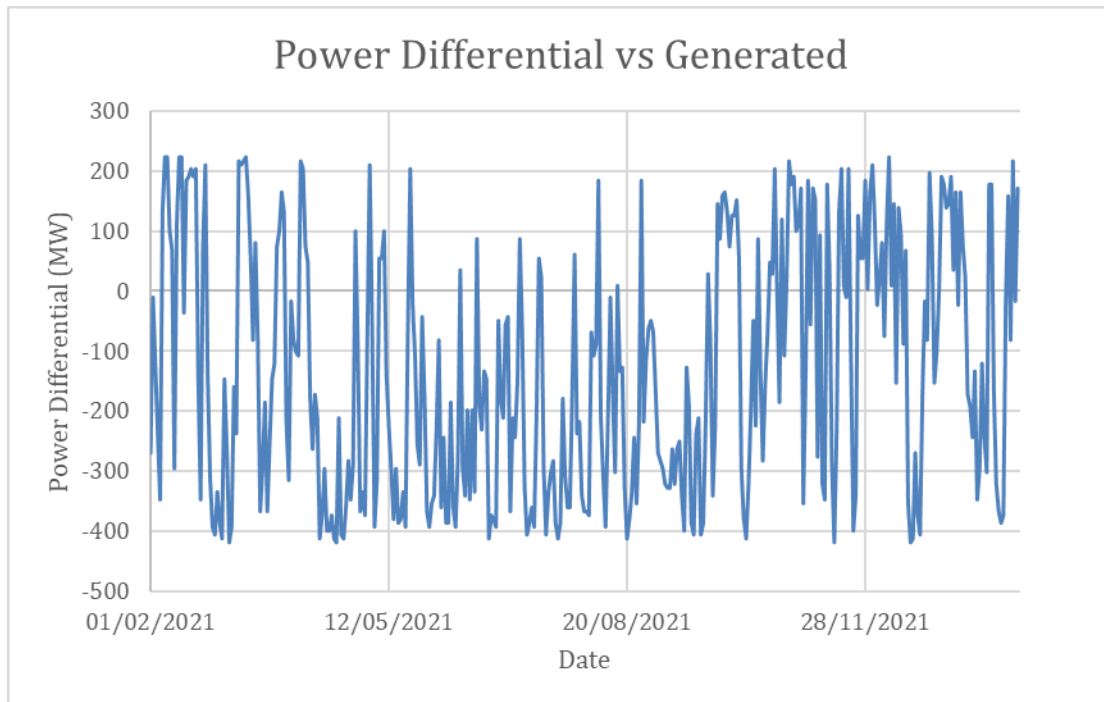


Figure 8-9 Average Day Power Differential $P_{Optimised}$ (Renewable vs Consumed)

8.3.1.4 Number of Generators Required to Operate

Based on the two wind farm configurations considered the number of generators required to operate to supplement the power being produced from the wind array has been calculated on 30 minute timesteps. To simplify the data for presentation the daily average number of generators operating is displayed.

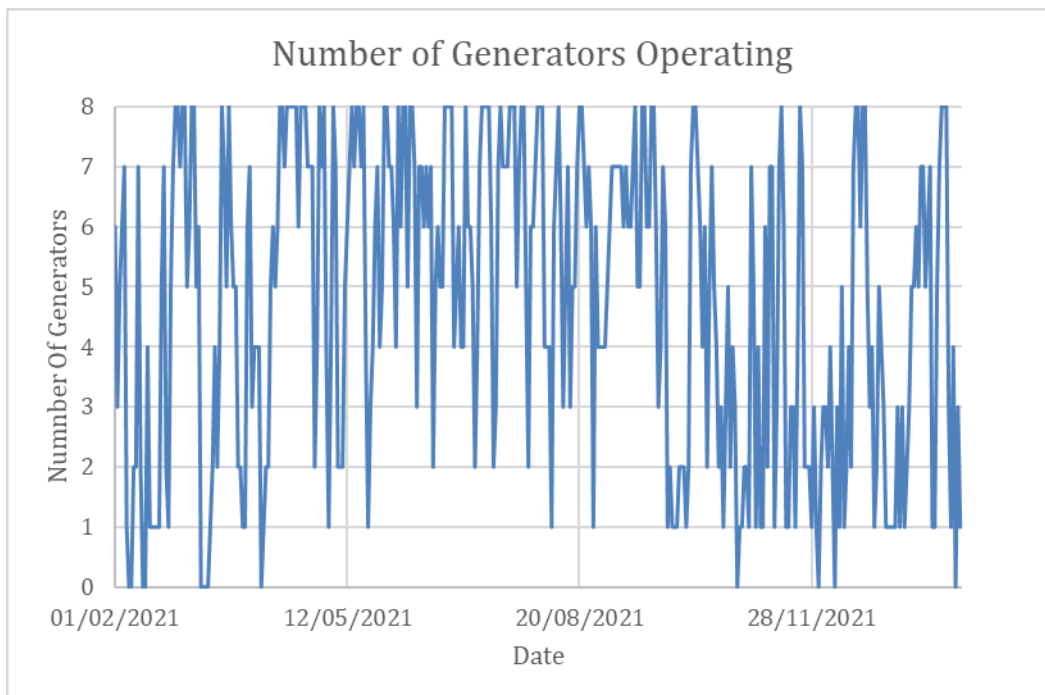


Figure 8-10 Number of Operational Generator P95 (Simple Cycle)

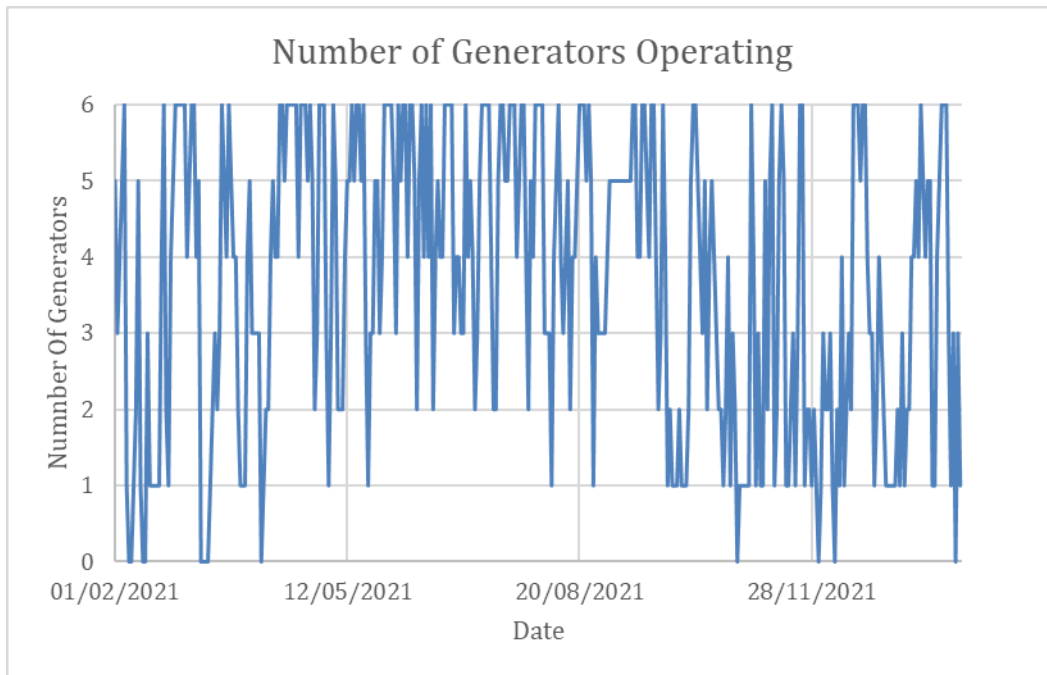


Figure 8-11 Number of Operational Generator P95 (Combined Cycle)

The mode number of generators is calculated for both the simple cycle and combined cycle and this demonstrates that the most common number of generators operating per year is the maximum number installed for the P₉₅ Case, of both 8 and 6 respectively.

For the simple cycle configuration, the number of days per annum where 8 generators are running is 69 days.

For the combined cycle configuration, the number of days per annum where 6 generators are running is 90 days.

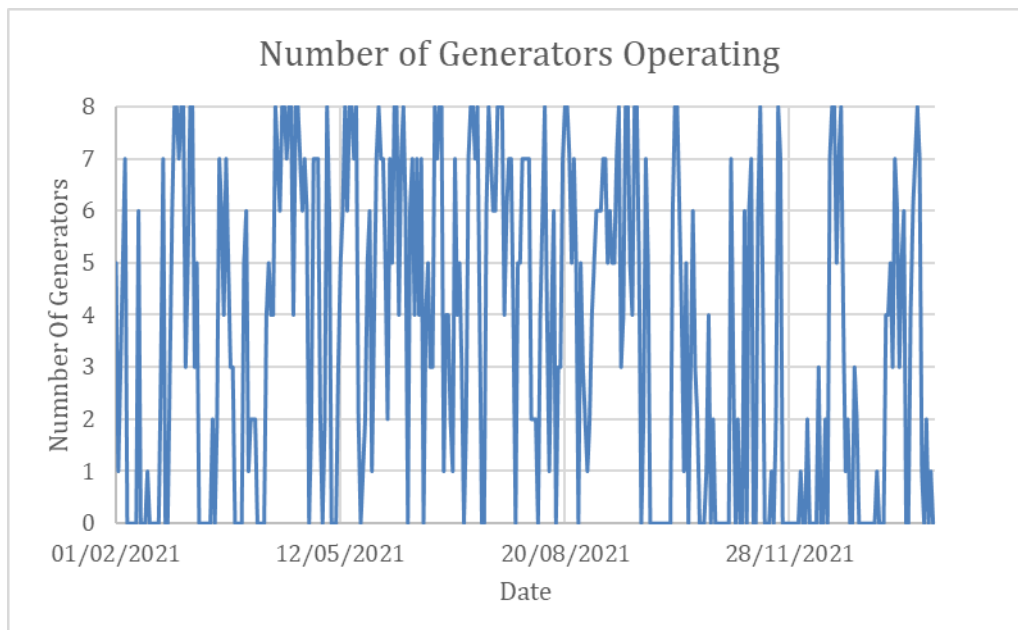


Figure 8-12 Number of Operational Generator P_{Optimised} (Simple Cycle)

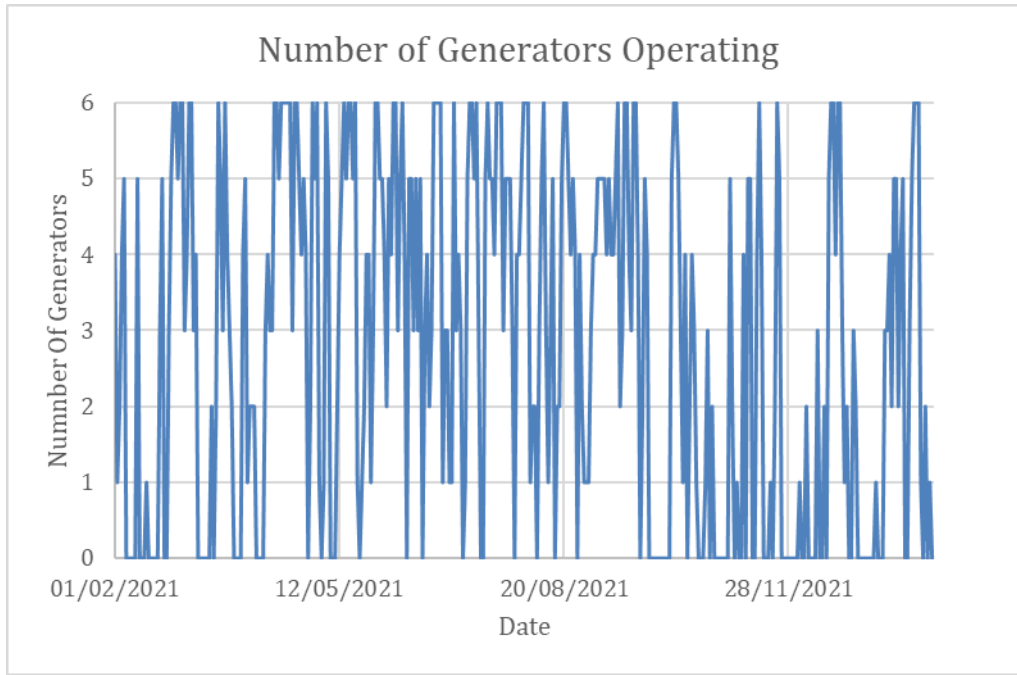


Figure 8-13 Number of Operational Generator $P_{Optimised}$ (Combined Cycle)

The mode number of generators is calculated for both the simple cycle and combined cycle, and this demonstrates that the most common number of generators operating per year for the $P_{Optimised}$ Case, is no generators for both configurations.

For the simple cycle configuration, the number of days per annum where no generators are running is 113 days. The number of days when 8 generators are running is 48 days per annum.

For the combined cycle configuration, the number of days per annum where no generators are running is 113 days. The number of days when 6 generators are running is 63 days per annum.

8.3.1.5 Fuel Gas Demand

Fuel gas demand for both the simple and combined cycle gas turbines have been calculated based on their performance curves, and a polynomial equation was determined from these curves. The fuel gas demand is calculated on a nominal load share basis based on the number of gas turbines operational. In practice there may be optimisations which can be made based on variable speed operation, however for the purposes of this assessment the load share basis is considered acceptable.

The number of operational generators is calculated as follows:

$$\text{Operational Generators} = \frac{-\text{Power Differential}}{\text{Generator Output}}$$

The number of generators calculated are then rounded up to the nearest whole number.

The fuel gas demand is then based on the polynomial equation developed from the curves multiplied by the power output per gas turbine.

$$\text{Fuel Demand} = \left(\frac{A * \text{Power Demand}^3}{\text{Op Gens}} + \frac{B * \text{Power Demand}^2}{\text{Op Gens}} + \frac{C * \text{Power Demand}}{\text{Op Gens}} + D \right) * \text{Op Gens}$$

Where A, B, C and D are the polynomial constants.

The maximum calculated fuel gas demand is 23 MMSCFD for the simple cycle configuration and 17.1 MMSCFD for the combined cycle configuration.

8.3.1.6 Gas Turbine Efficiency

The gas turbine efficiency is calculated in a very similar way to the fuel gas. Efficiency for both the simple and combined cycle gas turbines have been calculated based on their performance curves and a polynomial equation developed. The efficiency is calculated on a nominal load share basis based on the number of gas turbines operational. In practice there may be optimisations which can be made based on variable speed operation, however for the purposes of this assessment the load share basis is considered acceptable.

The number of operational generators is calculated based on Section 8.3.1.5 methodology.

The fuel gas demand is then based on the polynomial equation developed from the curves multiplied by the power output per gas turbine.

$$\text{Generator Efficiency} = \left(\frac{A * \text{Power Demand}^3}{Op\ Gens} + \frac{B * \text{Power Demand}^2}{Op\ Gens} + \frac{C * \text{Power Demand}}{Op\ Gens} + D \right)$$

Where A, B, C and D are the polynomial constants.

The maximum calculated efficiency is 40.8% for the simple cycle configuration and 54.8% for the combined cycle configuration.

The minimum calculated efficiency is 14.6% for the simple cycle configuration and 16.5% for the combined cycle configuration.

8.3.1.7 Cumulative Fuel Consumption

Utilising the 30 minute time step data for the Dudgeon wind farm annual production has allowed a detailed analysis of cumulative fuel gas demand.

Figure 8-14 details the wind power generation plotted against the base demand per annum. Based on the timestep period, the equivalent number of days with no import gas required is calculated as 37 days per annum.

This is a simplistic basis which is based on the ability for the gas turbines to cycle on and off without any specific requirement for low load operation. For the purposes of the analysis being conducted at this moment this is deemed to be an acceptable basis.

The calculated equivalent days are based on periods of operation where an excess of power is available from the wind farm in 30 minute timesteps. If there is an excess of power available this is noted and the total number of these 30 minute timesteps are divided by 48 to give the total number of equivalent days.

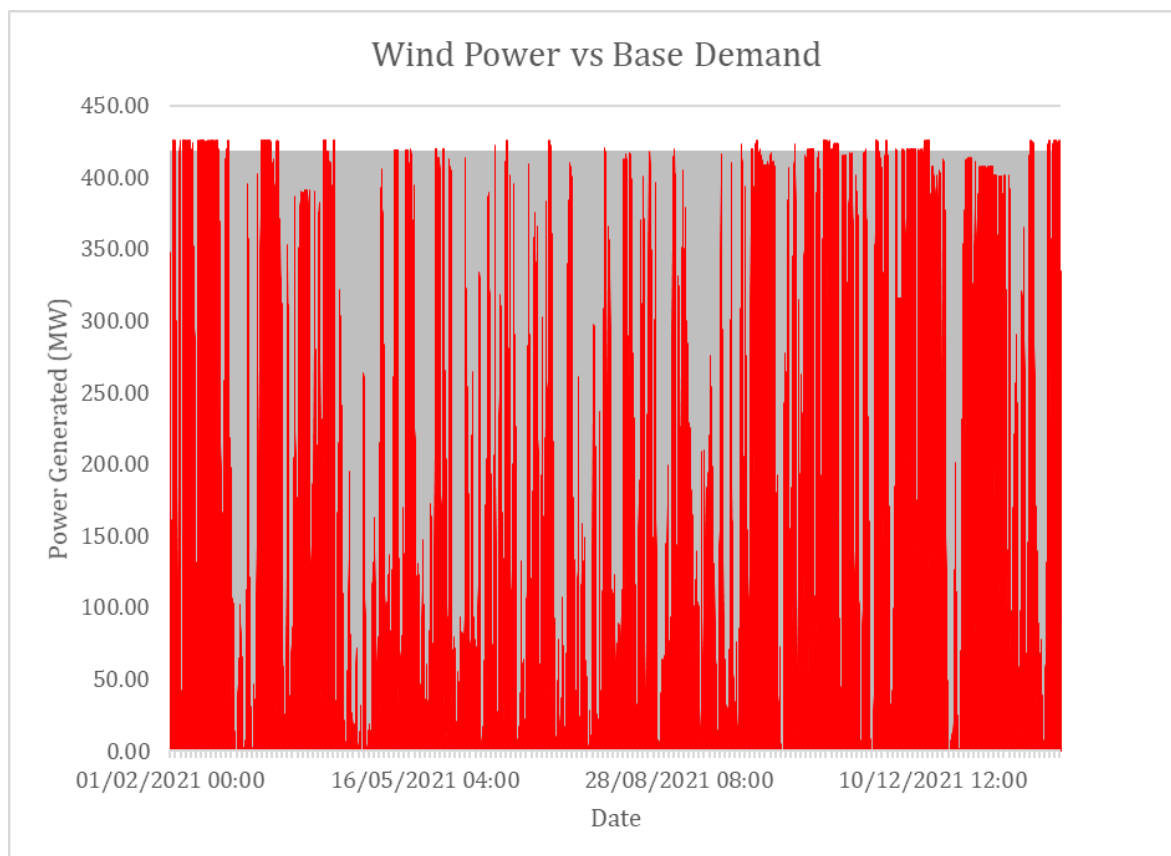


Figure 8-14 Wind Power Generation vs Base Demand (P_{95})

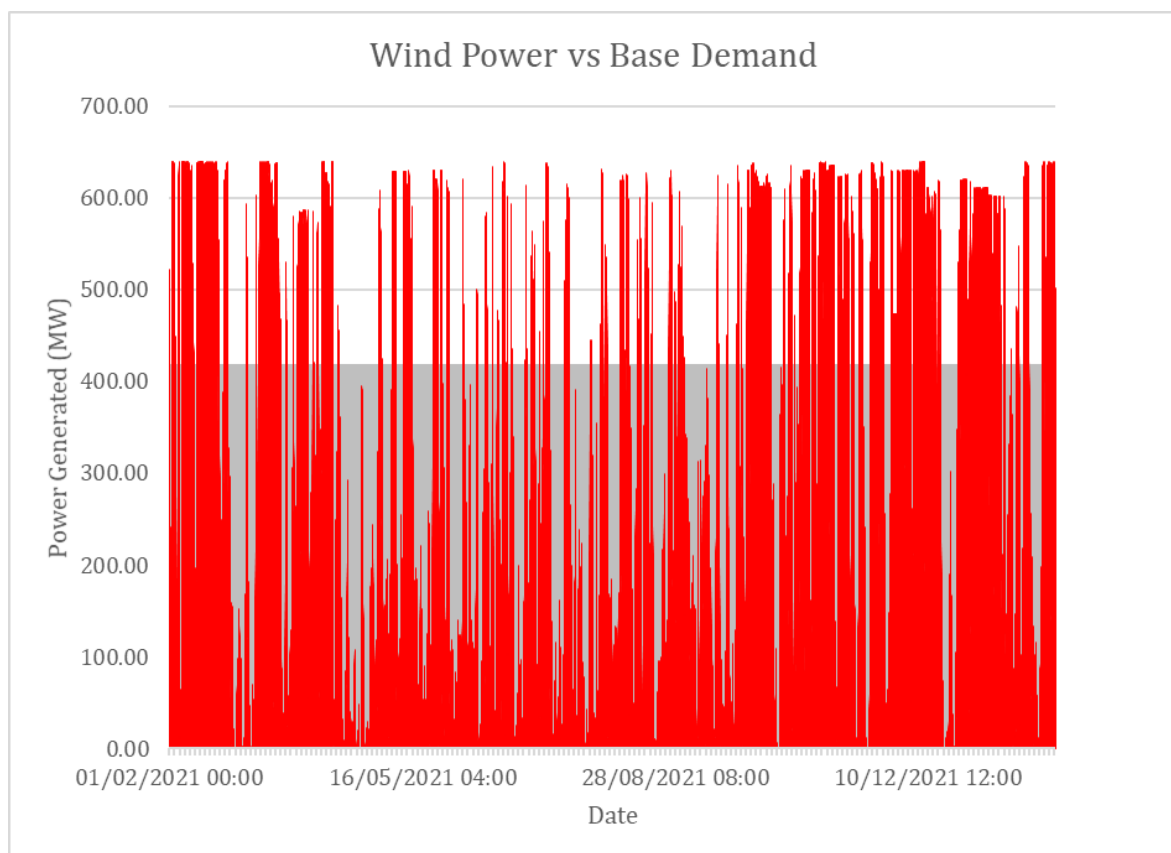


Figure 8-15 Wind Power Generation vs Base Demand ($P_{Optimised}$)

Figure 8-15 details the same analysis of the $P_{Optimised}$ configuration. The equivalent number of days of no import is 128 days per annum.

Based on the wind profiles considered the cumulative fuel gas demand for each of the wind farm configurations are detailed in Figure 8-16 and Figure 8-17.

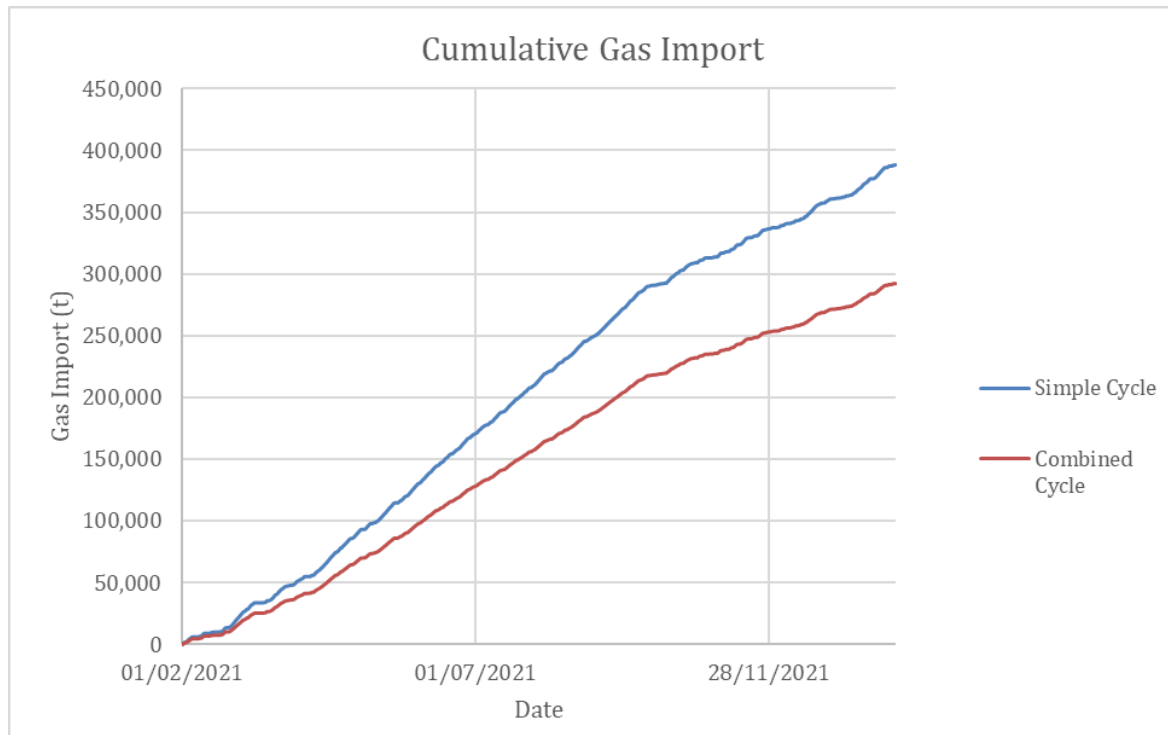


Figure 8-16 P_{95} Gas Import

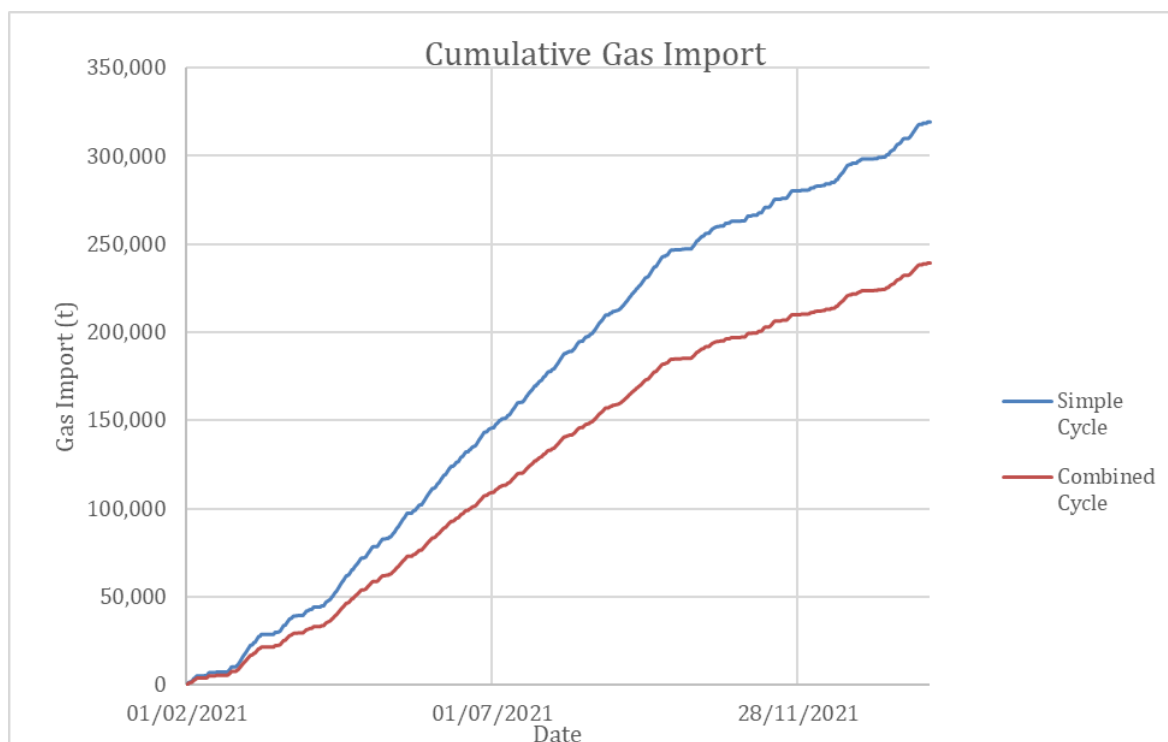


Figure 8-17 $P_{Optimised}$ Gas Import

		Import Gas (t)	Number of Therms (CCF)	Cost of Gas (£)
Simple	P ₉₅	388,282	149,569,545	134,612,590
Combined	P ₉₅	292,274	112,586,568	101,327,911
Simple	P _{Optimised}	319,192	122,955,656	110,660,090
Combined	P _{Optimised}	239,245	92,159,365	82,943,428

Table 8-8 Cost of Gas Import per Annum

Table 8-8 details the anticipated cost of import gas per year based on the unit price of £0.9 per therm.

A 25% reduction in fuel gas import costs can be achieved by utilising combined cycle gas turbines rather than simple cycle for both array configurations. There is additional complexity in operating and maintaining a combined cycle plant vs a simple cycle plant, this is covered in more detail in the Combined Cycle Offshore Power Study (Section 12).

There is a balance to be achieved between installed wind farm costs, over provision of power and import gas costs.

8.3.1.8 Potential Excess Generated Power

The excess power generated by the wind farm which is not consumed by the oil and gas users can be calculated and converted into a MWh value to quantify the potential for an alternative power storage technology to be utilised to better balance out the peaks and the troughs of the wind generation.

For the P₉₅ Case wind farm the maximum excess power generated is 7.85 MW, this is generated for the equivalent of 10.4 days per annum. For the P_{Optimised} Case wind farm the maximum excess power generated is 221 MW, again for the equivalent of 10.4 days.

Utilising the yearly production data, the total excess power has been calculated for each of the wind farm configurations. The sum of all positive generated 30 minute time periods divided by 2, have been calculated to determine the total excess power generated per year in MWh. From there this value has been divided by the number of hours per year to calculate the equivalent MW value to be attributed to an equivalent potential increase in available power.

	Peak Excess Power	MWh per annum	Equivalent MW
P ₉₅	7.85	4,428	0.5
P _{Optimised}	221	499,016	57.0

Table 8-9 Excess Power Generated by Wind Array

Table 8-9 details the potential for supplementary power to be utilised.

For the P₉₅ Case is it unlikely that there would be any benefit from incorporating a storage system, the total amount of power generated in excess is very low and would have minimal benefit to the system.

The P_{Optimised} Case would have merit in including a system which allows the conversion of generated power into potential energy. Utilising Hydrogen for this is explored, with the additional requirements and estimate of efficiency of this system in Section 23.

8.4 Discussion

The analysis presented in Section 8.3 outlines the performance of a wind farm with the performance equivalent of Dudgeon for a year. The analysis identified two cases, P_{95} and $P_{Optimised}$, to be utilised to examine the performance of a wind farm, determine the size of the power generation required to support continuous operations and predict the associated import gas costs.

To further detail this analysis a mathematical model has been developed to evaluate installed wind farm costs against OPEX costs to rationalise the optimal selection of wind farm size. This analysis is performed on both simple and combined cycle power generation systems with a sufficient installed size to adequately support full production from oil and gas assets in the event of no wind power available. Additional power storage / conversion e.g., using hydrogen is not built into this analysis. See Section 23 for this analysis.

Analysis has been considered on a 10 year project duration as this will provide the most influence on the cost of wind power installation. As longer project durations are considered, the impact of installing additional wind is more significant. 10 years is also considered the minimum project duration.

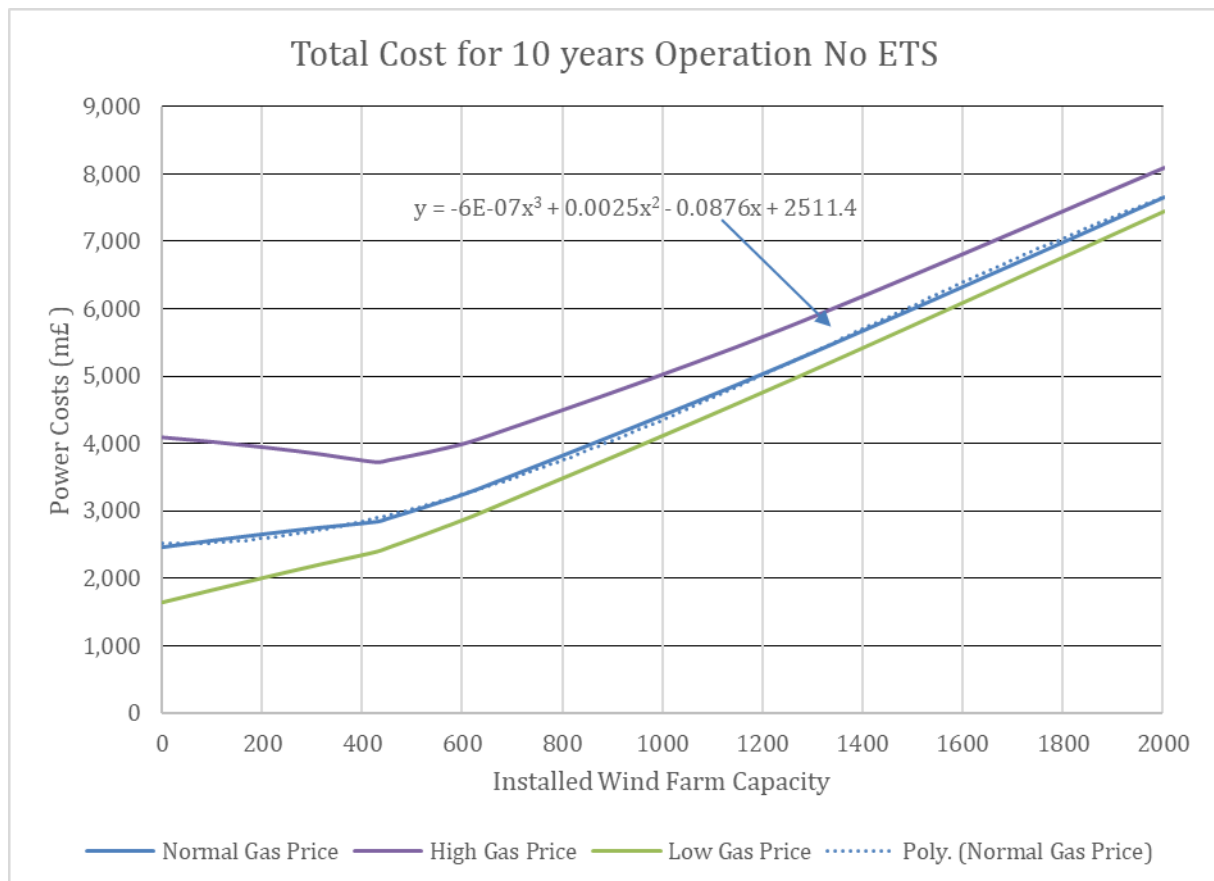


Figure 8-18 Project Energy Costs (10 Years) 420 MW Demand Simple Cycle

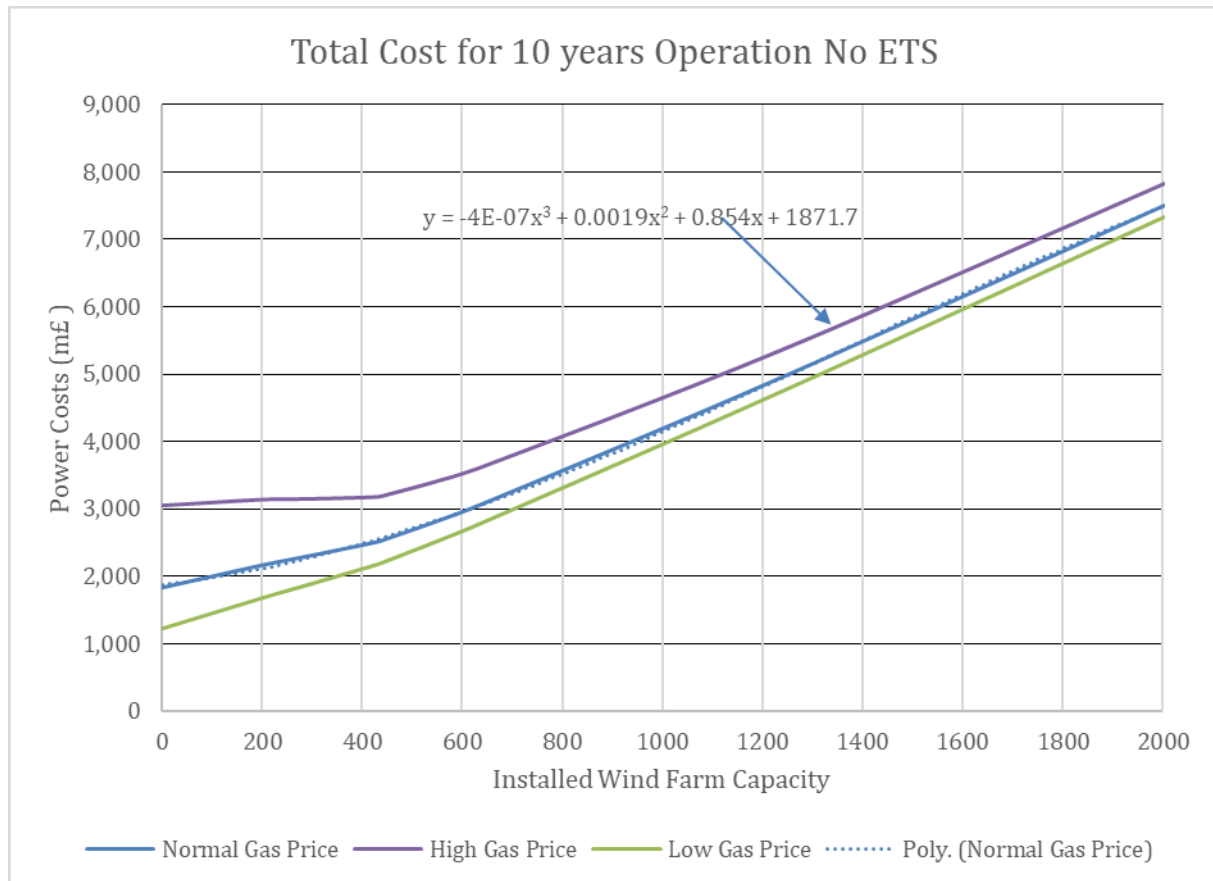


Figure 8-19 Project Energy Costs (10 Years) 420 MW Demand Combined Cycle

Figure 8-18 and Figure 8-19 details the relationship between total project costs and total capacity of installed wind over a 10 year period without considering ETS for both simple and combined cycle.

All analysis has been conducted utilising /34/:

- Wind farm costs £3.5m/MW /32/.
- Low – 60p/therm (May 17th 2021)
- Normal – 90p/therm (Sep 20th 2021)
- High – 150p/therm (Dec 6th 2021)

Current gas prices due to the ongoing Ukraine Conflict are not considered to be representative of future gas prices.

Figure 8-18 and Figure 8-19 demonstrates that for the normal and low gas prices that incorporating wind power into the system does not have a net reduction in cost of power, installing no wind power reduces the project costs. For Simple cycle only, higher gas prices result in installation of wind actually reducing the project costs to an optimum point which corresponds with the actual power demand of the system.

Additional analysis has been conducted building in the market price of UK ETS of £60/tonne (November 17th 2021) /33/ (also the average cost over the previous 12 month period).

When incorporating ETS the profiles of the Figure 8-20 demonstrates that for the Normal Gas Price and High Gas Price there is a net benefit to incorporating wind power into the energy mix if simple cycle generation is considered. For the Low Gas Price costs there is a negative impact in incorporating wind power, the total project power costs increase by approximately 7% from no wind power to 420 MW.

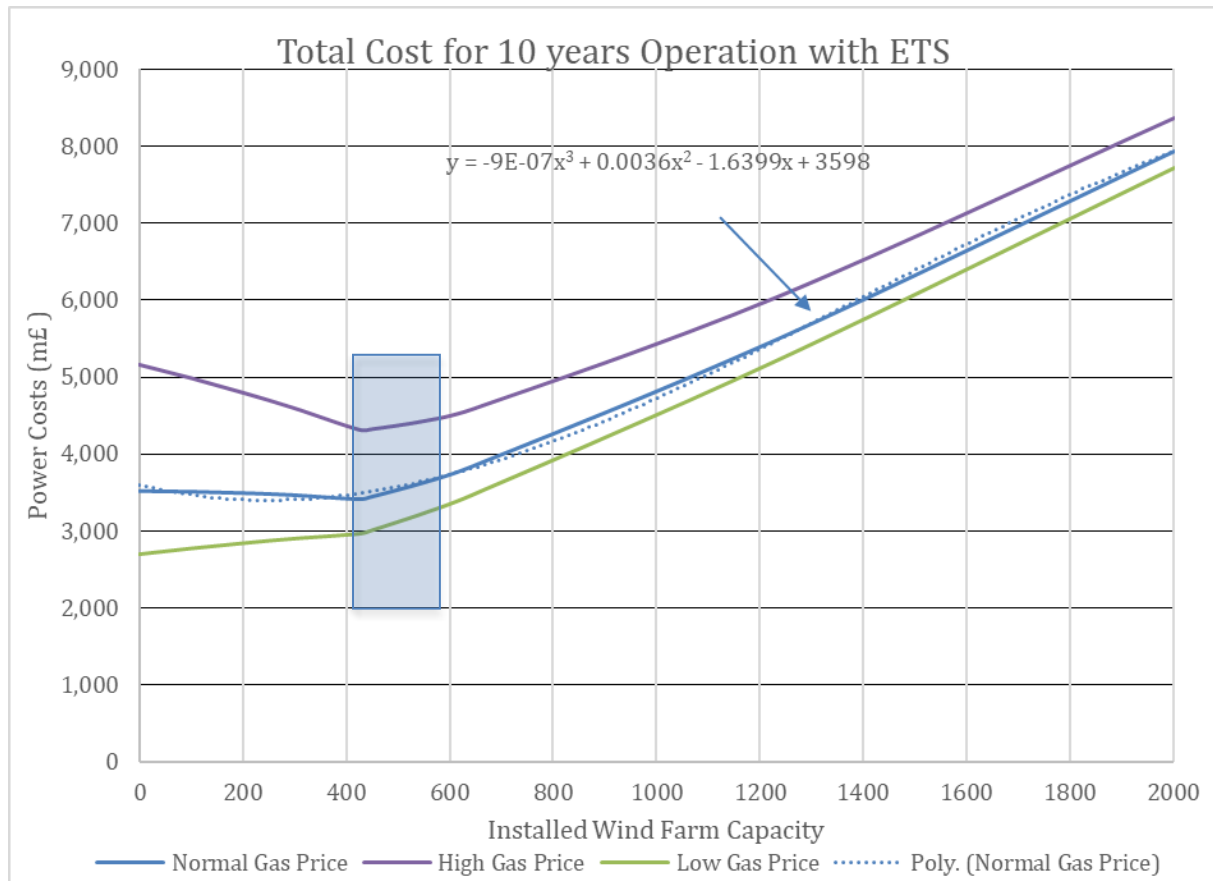


Figure 8-20 Project Energy Costs (10 Years) with ETS 420 MW Demand Simple Cycle

When incorporating ETS the profiles for combined cycle operation Figure 8-21 demonstrates that for the High Gas Price there is a net benefit to incorporating wind power into the energy mix. For the Normal and Low Gas Price costs there is a negative impact in incorporating wind power.

The increase in costs associated with incorporating wind power vs no wind power utilising combined cycle power generation is approximately 11% based on the installed cost of wind farm power.

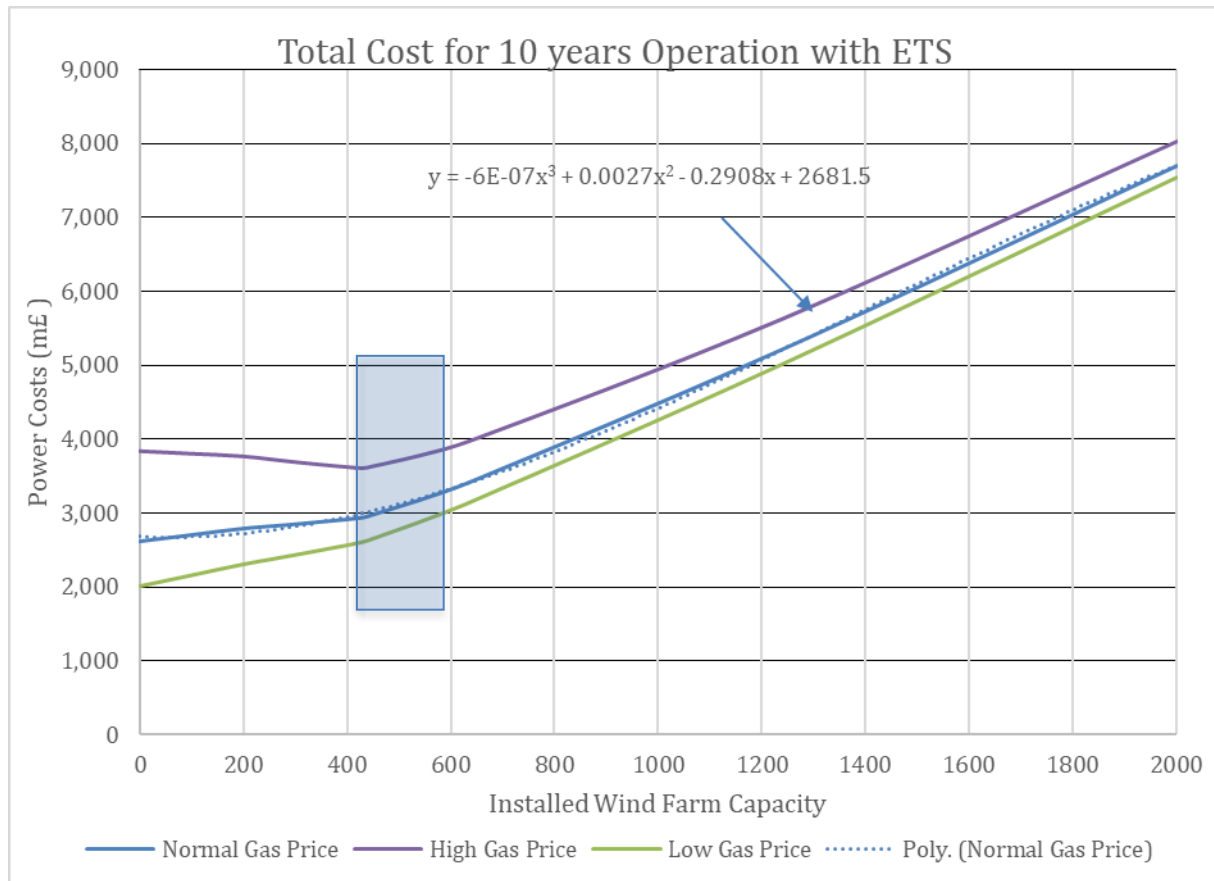


Figure 8-21 Project Energy Costs (10 Years) with ETS 420 MW Demand Combined Cycle

The ETS costs considered are the average from the 19th of May 2021 to 7th of March 2022. The peak ETS cost during this time period were £88 / tonne of CO₂ on the 18th of February. It is considered that over time the cost of ETS will gradually increase. This will further benefit the installation of wind to support the local power generation equipment.

It is considered the area highlighted in Figure 8-20 is the optimum provision of wind power into the CNS region for the electrification opportunities identified.

As outlined in 8.3.1.8 this analysis does not incorporate the additional savings in OPEX cost associated with gas import if an alternative storage means of over provision of power is incorporated. This has the potential to further reduce the amount of gas import, however the CAPEX cost of this system is required to be carefully considered to ensure that it does not become excessive. Refer to the Hydrogen Study (Section 23) for more detail.

Analysis of the total emissions reduction from the Main Hub from installation of wind is detailed in Figure 8-22 and Figure 8-23. This curve demonstrates that the largest reduction in emissions is between no wind installation and 420 MW, where at this point the gradient changes and the curve becomes flatter.

- Between 0 MW and 425 MW of installed wind there is a 45% reduction in emissions.
- Between 0 MW and 620 MW of installed wind there is a 55% reduction in emissions.
- Between 0 MW and 2000 MW of installed wind there is a 74% reduction in emissions.

By utilising combined cycle over simple cycle gas turbines it is considered there is a 4,500,000 tonne reduction in CO₂ emissions over 10 years.

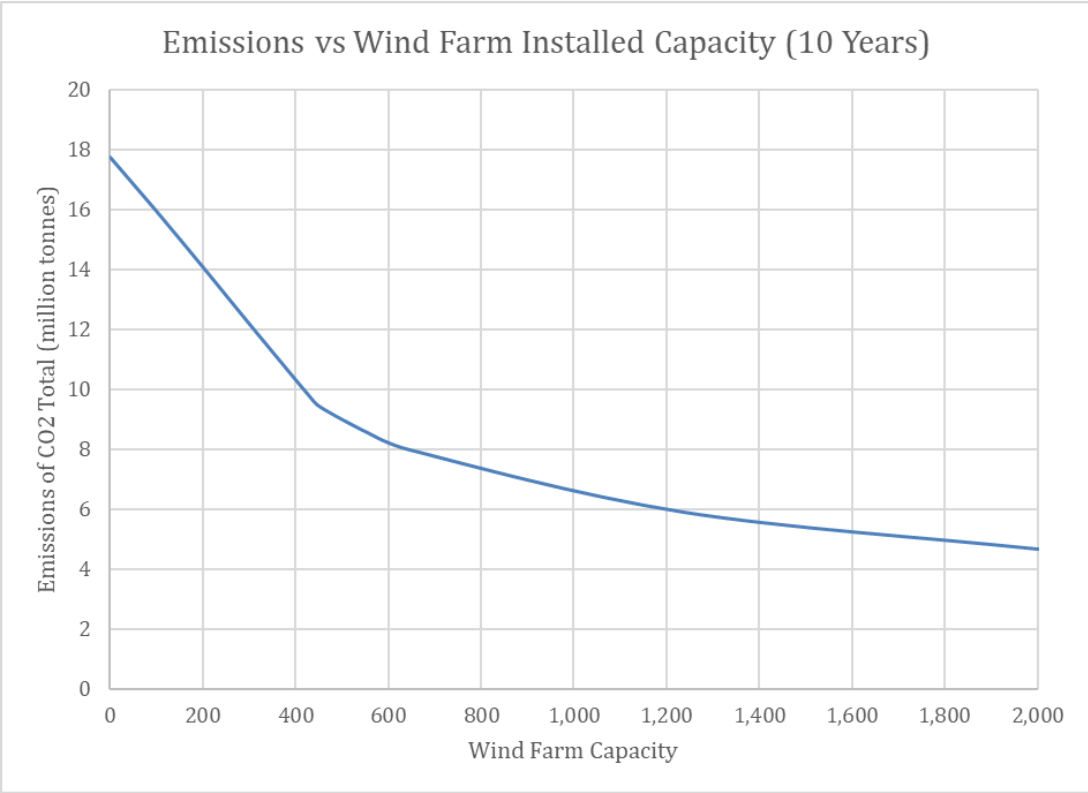


Figure 8-22 Total Emissions Reduction from Main Hub Simple Cycle

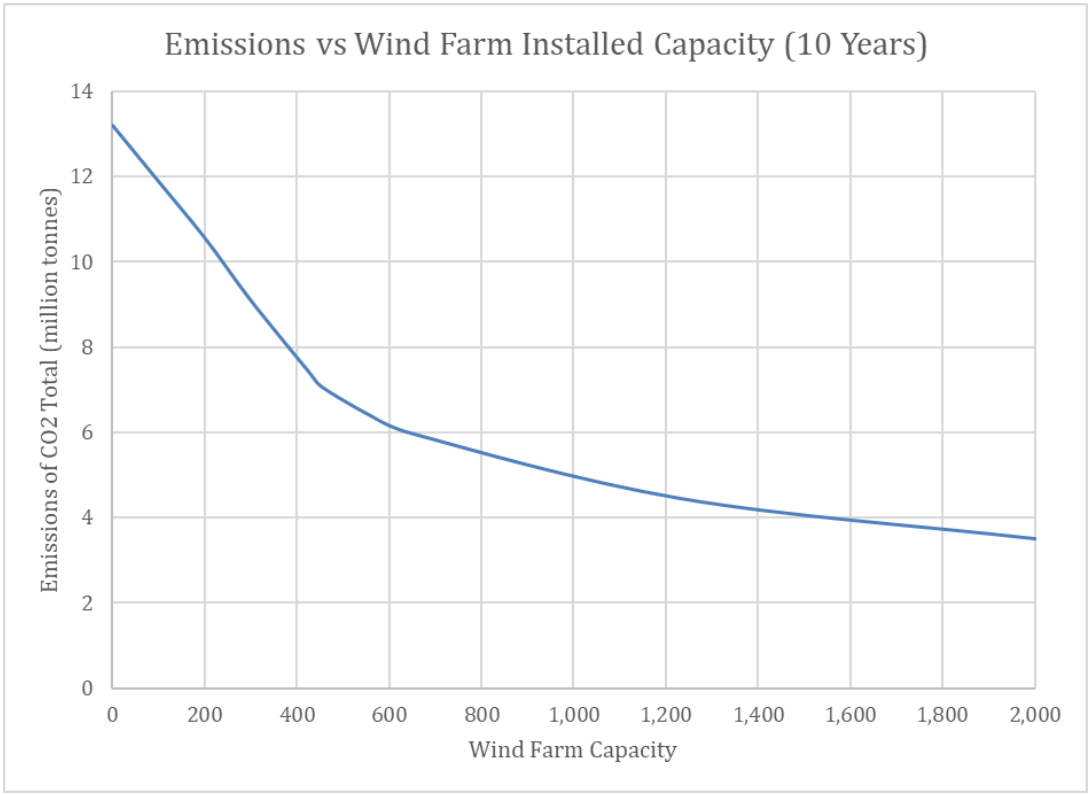


Figure 8-23 Total Emissions Reduction from Main Hub Combined Cycle

Similar analysis has been conducted for 15 and 20 year project durations. These graphs are included in Appendix 28.1 and 28.2.

By varying the cost of the wind farm installation costs, the optimum point has been determined where the Normal Fuel gas price with ETS is flat, therefore installation of wind power equates to be the same costs as import of fuel gas. This is demonstrated in Figure 8-24. The wind farm installation costs to reach this point are £2.75m/therm.

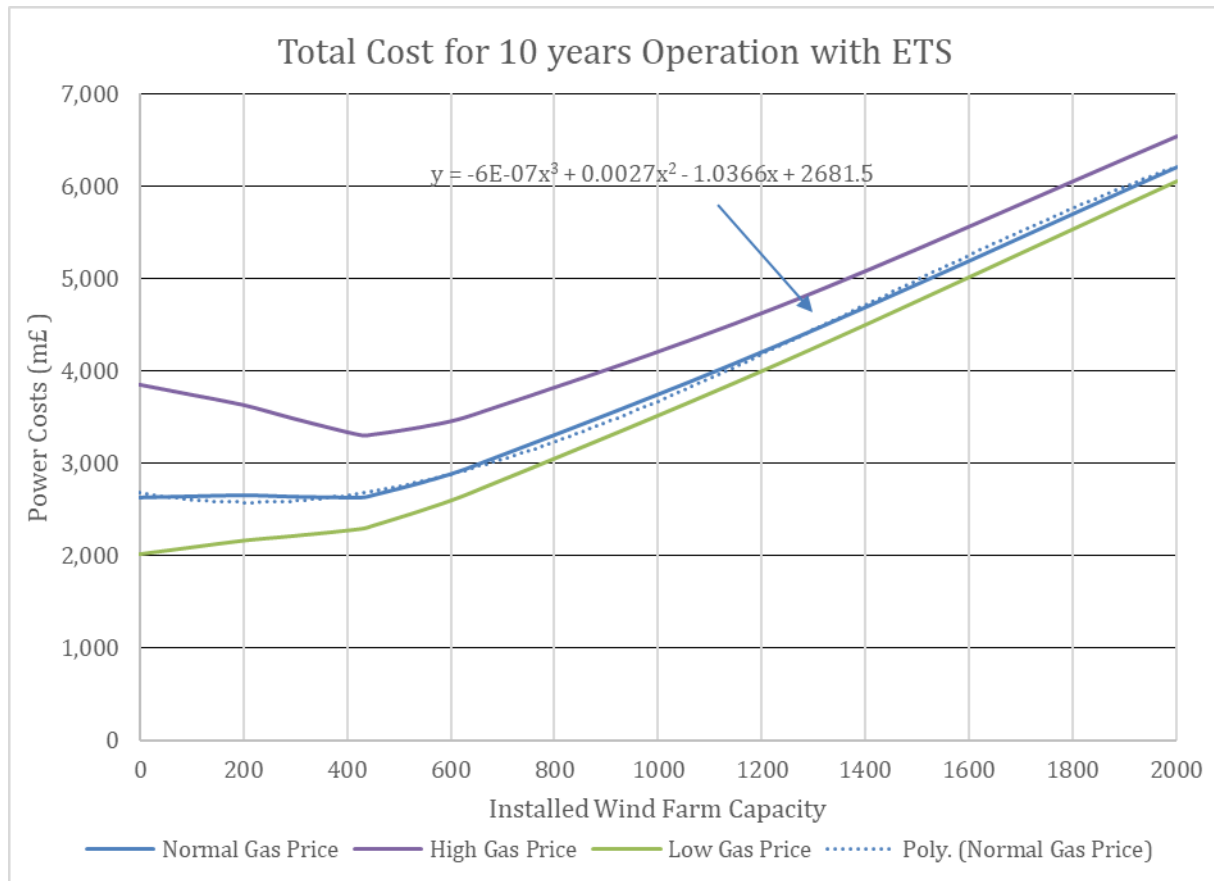


Figure 8-24 Wind Farm Cost Variance

8.5 Conclusion

This study has concluded that, based on the analysis performed, installation of wind power will increase the cost of power on a 10 year review period. The calculated power cost detailed in Figure 8-21 Project Energy Costs (10 Years) with ETS 420 MW Demand Combined Cycle creates a relationship between the OPEX costs for importing fuel gas and the CAPEX costs of installation of wind power. When taking into consideration higher thermal efficiency offered by utilising combined cycle power generation, this results in an approximate 11% increase in cost of power on the "Normal" basis used in the assessment.

It is however considered that utilising Dudgeon costs may be conservative as part of this assessment and that the offshore wind technology is developed and installed the costs associated with this will decrease. When this occurs, there will be more advantage using wind power vs conventional combined cycle gas turbine generation.

If floating wind farm installation costs can reach £2.75m/MW then the cost difference between no wind provision and 420 MW of wind provision would be zero, therefore the cost of installation of wind would be neutral for a 10 year project duration. Figure 8-24 demonstrates this point.

As wind power advances and new systems come online the CAPEX costs considered in this assessment will change, Hornsea 2 information when available and in operation would be a good comparison to consider. It is noted however Hornsea 2 is not a floating wind farm, however the operational performance would be a good comparison, in addition to the differential in cost between Hornsea 1 and 2.

It is considered that the optimal provision of wind power without storage provision is a wind farm sized to output 105% of the base demand.

Further expanding the analysis beyond 10 years demonstrates more significant benefits associated with wind power integration into the system. 15 and 20 year analysis have been conducted and are contained in Appendix 28.1 and 28.2.

Hywind was not considered as a good comparison as it only has 30 MW of installed capacity therefore maintenance campaigns, mechanical issues and outage of more complex designs are not considered comparable. The Life capacity factor of Hywind is 53.6% and Dudgeon is 48.1%.

The findings of this study will be utilised to study storage options and adoption of this will be utilised to assist with study to determine potential OPEX savings due to the installed capacity of wind. It is considered that the most appropriate way to achieve this is with hydrogen generation, which can be stored and produced to be combined with import gas to reduce the emissions of the gas turbines, reduce the quantity of import gas required which will ultimately reduce emissions and OPEX.

8.6 Further Areas of Study

The next areas for study are:

- Evaluate a larger dataset of actual wind turbine generation, 2021-2022 based on 2020-2021 that has a lower Load Factor, to provide a more conservative case.
- Detailed wind farm modelling and design based on selected location for Main Hub.
- Build maintenance periods for the wind farm into estimations to determine if this has any impact to the Cost of Energy.
- Consider additional sources of renewable power.
- Variations in electrical demand from assets
- Starting load assessment and requirement for this to be covered

9. Power Distribution Study

9.1 Objective

The purpose of this study is to describe the key components of the electrical power distribution network, including bulk transfer of power between Main Hub and Sub Hub, as well as the final connection between the Sub Hub and the assets.

As the intent of the project is to provide a solution that minimises topsides modifications on the assets, the Sub Hubs need a range of different technologies, including voltage step-down, frequency conversion, and reactive compensation, to provide electrical power within specified tolerances to ensure that the assets themselves can operate correctly.

The study shall also consider the different requirements of assets within the Central North Sea and Outer Moray Firth areas, compared to the assets serving the gas fields of the Southern North Sea.

9.2 Methodology / Background

Offshore power distribution is becoming an increasing aspect of many large-scale offshore developments including renewable generation projects (where power generated offshore is collected and then sent onshore) and oil & gas platforms (where power from shore is sent offshore). There are limited examples of offshore islanded networks where power is distributed across distances of a few kilometres. However, the concept explored in this project extends this to large quantities of power shared across distances up to 100km.

This study has been completed by taking existing concepts familiar to offshore electrical power networks and combining it with recent technological developments utilised within the renewables and power transmission and distribution industries with a particular focus on offshore technologies where size and weight of equipment are as important as the cost and function.

9.3 Discussion

9.3.1 Electrical Distribution Overview

As shown in the Typical Asset Distribution and Characterisation Study (Section 7) Oil & Gas platforms are provided with electrical systems which operate at a range of frequencies and primary voltages to meet electrical power demands which range from extremely low (<100kW) to relatively high (60MW).

Characteristic	Unit	Values
Frequencies	Hz	50, 60
Primary Voltages	kV	0.415, 3.3, 6.6, 11, 13.8, 33

The aim of the subsea power import is to provide sufficient electrical power to the asset, at the correct frequency and primary voltage.

As noted in Section 7, the overall energy demand of an asset is made up of the electrical power demand, as well as any other fuel input to direct driven equipment for pumping/compression or fired boilers for heating. Whilst providing low carbon submarine power to meet the electrical power demand will see emissions reduction, there are other reductions to be achieved if direct drive equipment and/or process heating can also be electrified. However, this often requires more extensive modifications which must be weighed up against the benefits.

In order to establish a base line design, the power import has been limited based on the number of main generators an asset has – this represents a practical limit to the number of power cables that can be reasonably connected without major upgrades or expansions being required.

The basic concept described in this study is as shown in Figure 9-1 below.

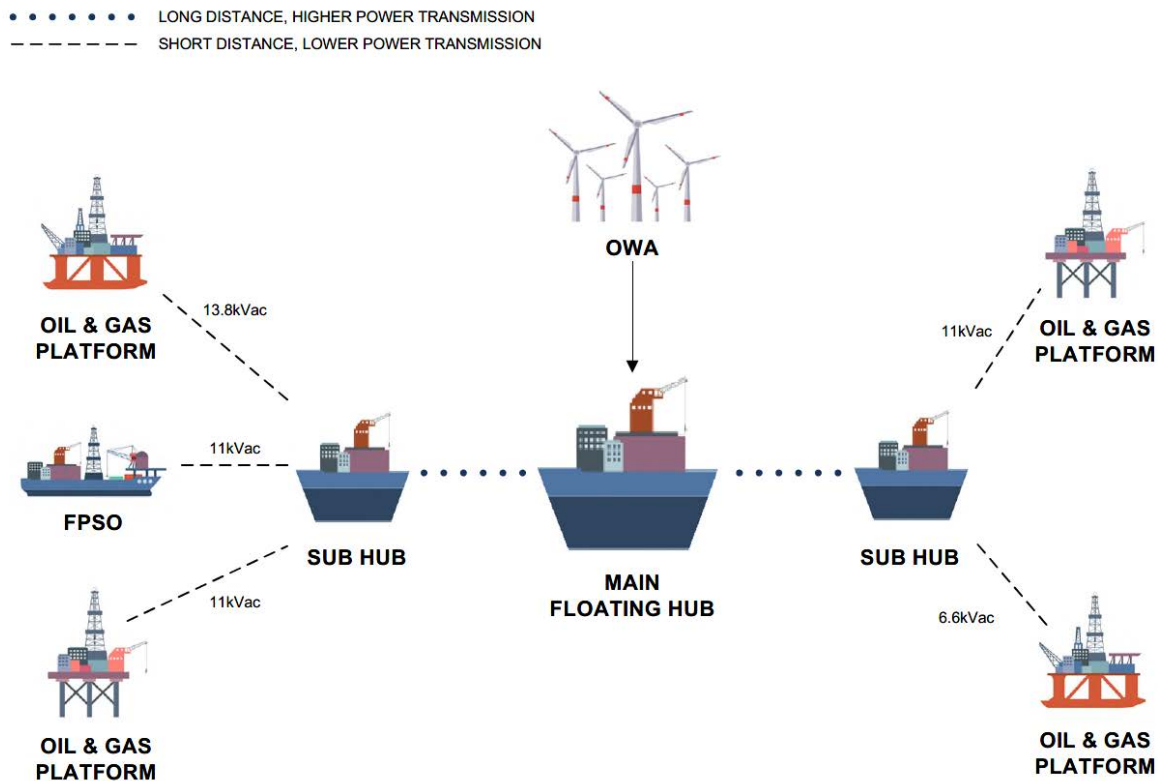


Figure 9-1: Power Distribution Concept for North Sea Electrification

A **Main Hub** is a large floating unit capable of handling large quantities of electrical power, some received from a floating wind farm, and some generated locally by conventional power plants. The Main Hub shall also likely incorporate a form of energy storage.

A **Sub Hub** is a smaller floating or jack-up type unit which receives electrical power from the Main Hub, and then transforms it to suit the requirements of the local assets it serves. From the Sub Hub, a number of submarine power cables run to each asset to provide a source of low carbon electrical power which replaces the need for primary generation on the asset.

Assets were clustered based on their ability to accept subsea power and their geographical location compared to each other. Based on this clustering the individual Sub Hub requirements were established, and from this, the Main Hub requirements were determined – refer to Section 6.

9.3.1.1 Example Cluster 1 – OMF/CNS

An example cluster and its associated electrical supply requirements is shown in Table 9-1 below. This shows how the Sub Hub power supply requirements and the Main Hub requirements were determined and relate to each other.

Asset	Asset Supply	Sub Hub	Sub Hub Supply	Main Hub
Claymore	12MW, 13.8kV, 60Hz	62MW, 13.8kV & 11kV, 60Hz	>62MW, 60Hz, >13.8KV	>367MW, 60Hz
Piper B	35MW, 13.8kV, 60Hz			
Scott	15MW, 11kV, 60Hz			
Forties Alpha	60MW, 33kV, 50Hz	169.5MW, 33kV, 11kV & 6.6kV, 50Hz and 60Hz	>169.5MW, 60Hz, >33kV	
Forties Charlie	60MW, 33kV, 50Hz			
Britannia	14.5MW, 6.6kV, 60Hz			
Alba North	23MW, 11kV, 60Hz			
Andrew	12MW, 11kV, 60Hz			
ETAP	47.6MW, 13.8kV, 60Hz	84.6MW, 13.8kV & 11kV, 50Hz & 60Hz	>84.6MW, 60Hz, >13.8kV	
Montrose	25MW, 11kV, 50Hz			
Culzean	12MW, 11kV, 60Hz			
Shearwater	12MW, 6.6kV, 60Hz	51.23MW, 11kV, 60Hz	>51.23MW, 60Hz, >11kV	
Jackdaw	4.23MW, 6.6kV, 60Hz			
FPF-1	4MW, 6.6kV, 60Hz			
Elgin	31MW, 11kV, 60Hz			

Table 9-1 Cluster 1 Overview

9.3.2 Main Hub to Sub Hub Bulk Power Transmission

The link between the Main Hub and the various Sub Hubs is a key part of the electrical network design. This link will need to carry relatively large quantities of power (up to 200MW) over long distances (up to 100km).

For the base case, Medium Voltage Direct Current (MVDC) has been selected as the most appropriate technology. This has many of the benefits of High Voltage Direct Current (HVDC) whilst reducing the costs of the cables and power electronics to compete more directly with conventional High Voltage Alternating Current (HVAC). MVDC utilises DC transmission voltages below +/-150kV.

DC cables have a higher power transfer capacity compared to AC cables meaning fewer or smaller DC cables can be used for transfer of the same amount of power. Use of DC also eliminates the need for reactive compensation for long submarine links with the Bridge technology at each end allowing for full control over voltage and power factor which will be highly beneficial for this project where power quality for the end user is critical.

Although MVDC is not used extensively offshore yet, the technology is ideal for bulk transfer of power at levels below that of continental interconnectors.

9.3.2.1 Other Options

Other options have been explored in previous studies, including:

- **HVAC** – a conventional transmission technology which is well established and already utilised to power offshore assets, particularly in the Norwegian sector of the North Sea. It has low topsides equipment costs, but this is offset by the higher submarine cabling costs. In addition, submarine HVAC cables have issues associated with charging currents and capacitances often requiring expensive topsides compensation schemes to offset voltage drop and other efficiency losses. /36/
- **HVDC** – typically used for very high power connections over long distances (e.g. bulk power interconnectors between countries) where the cost and space requirements for the AC/DC conversion equipment are less of a challenge.
- **Gas Insulated Transmission (GIT) lines** – these are capable of allowing very high transfer of power (up to 3000MW per three phase system) and avoid the disadvantages of regular AC transmission, however it is an untried technology for subsea applications and utilises SF6, a damaging greenhouse gas, use of which is being minimised elsewhere. /36/
- **Superconductors** – high temperature super conductor wires offer much higher power transmission capabilities compared to AC or DC cable. Like GIT however it is also untried for subsea transmission and requires substantial cooling infrastructure. /36/

None of these options are considered suited to the network proposed in this study due to their high infrastructure costs and lack of maturity.

9.3.3 Sub Hub to Asset Low Power Transmission

The final connection between the Sub Hub and the platforms themselves is a relatively low power, short distance connection and should be at the asset's native primary voltage. This means that all links between the Sub Hub and the Assets will be Medium Voltage AC, ranging from 3.3kV up to 33kV depending on the asset.

For the lower voltages, particularly 6.6kV and below, this means the transmission distance is very limited and has impacted on the clustering and Sub Hub locations.

Existing submarine electrical power cables exist for these voltages and power demands and there are operating examples within the North Sea, including:

- 33kV ring main cabling between assets within the Central North Sea
- 11kV cable between local assets within the Outer Moray Firth

9.3.4 Main Hub Electrical Power Functions

The Main Hub is required to deliver the following key electrical power functions:

- Offshore Wind Array reception facilities
- Local generation reception facilities
- Local storage interface
- Main Hub power distribution
- MVDC bridge feeders for connections to Sub Hubs

9.3.4.1 Offshore Wind Array Reception Facilities

The purpose of the OWA reception facilities is to receive the power produced by the strings of turbines, and step the array voltage of 33kV up to the Main Hub primary voltage of 132kV. 33kV switchboards will act as the primary interface point for the OWA with appropriate control, metering and protection functions provided here.

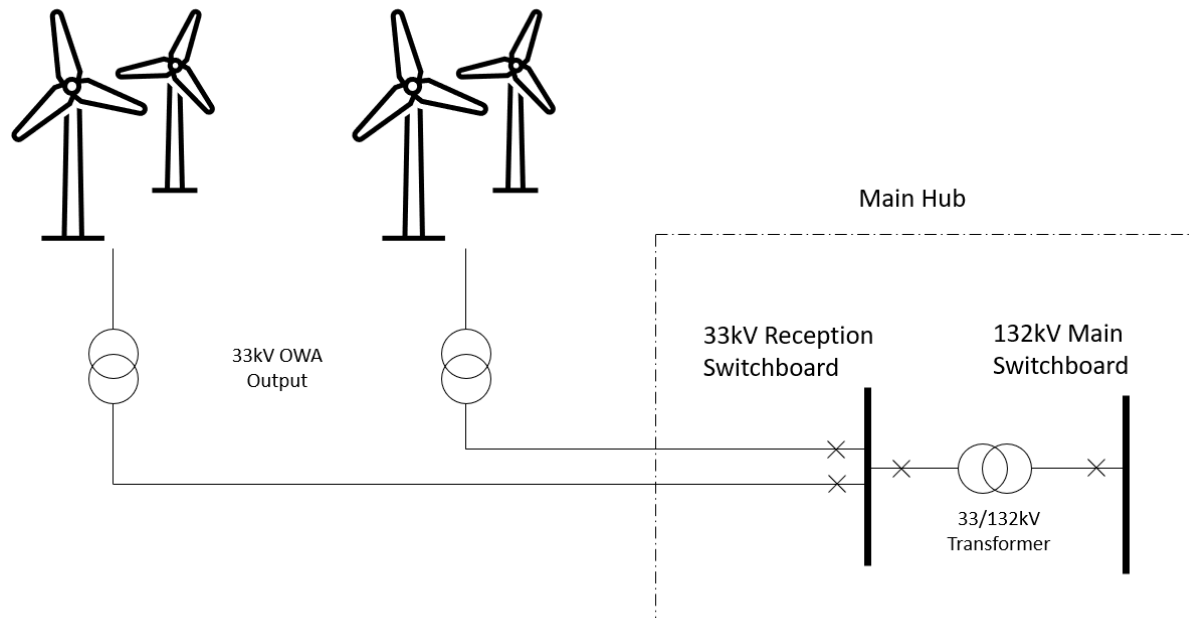


Figure 9-2: OWA Reception Facilities at Main Hub

Multiple OWA outputs will interface via a single 33kV switchboard and transformer to optimise the switchgear and transformer ratings.

Having protection, control and metering equipment on the Main Hub will simplify the requirements at the OWA itself and avoid the need for a dedicated offshore substation.

9.3.4.2 Local Generation Reception Facilities

The purpose of the local generation reception facilities is to receive the power produced by the individual Combined Cycle Gas Turbines (CCGT) and step up their output voltage of 13.8kV up to the Main Hub primary voltage of 132kV. 13.8kV circuit breaker panels will act as the primary interface point for each CCGT with appropriate control, metering and protection functions.

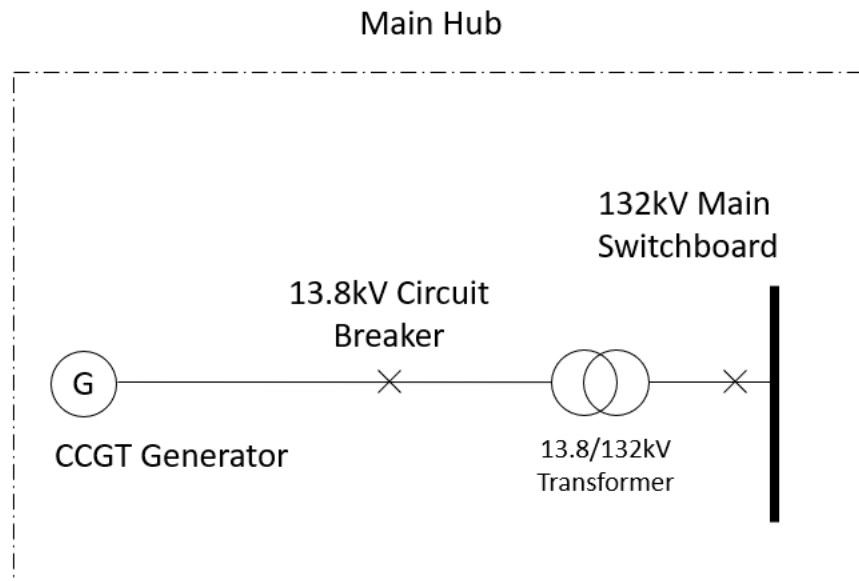


Figure 9-3: Local Generation Reception Facilities

Due to the large rating of the CCGT generator, each unit will require a dedicated circuit breaker and step-up transformer.

9.3.4.3 Local Storage Interface

Given the fluctuating nature of wind power, and the variance in electrical demand of an Oil & Gas asset, there is a requirement to have some storage located on the Main Hub to allow for smoothing of these peaks and troughs and limit times when local generation (a source of emissions) needs to be running. As discussed in the Modelling Report (Section 8), storage can also help with power quality and regulation.

There are several emerging technologies for offshore energy storage which may be appropriate for this application. Further study work will need to be done to understand the most appropriate.

Hydrogen technologies have been considered as part of this study but are not thought to be viable at this time. The most well-developed technology is chemical batteries along with an inverter interface, however this brings about challenges with cost, equipment space and weight requirements which will need to be considered in more detail.

It is anticipated that a Battery Energy Storage System (BESS) would, as shown below in Figure 9-4, interface with the Main Hub's 132kV switchboard for maximum flexibility. A BESS is a complete system incorporating the battery itself, a battery management system to monitor the status and health of the battery and an inverter for charging and discharging. It is anticipated that the BESS would be integrated into the overall system Energy Management System to maximise usage of the BESS abilities.

Examples of BESS offshore are the Goodwyn A platform's 1MWh lithium-ion battery, supplied by ABB /37/, and a 1.6MW/0.65MWh installation on an offshore support vessel /38/.

The cost and viability of large storage solutions, up to 50MW will need to be explored in further detail.

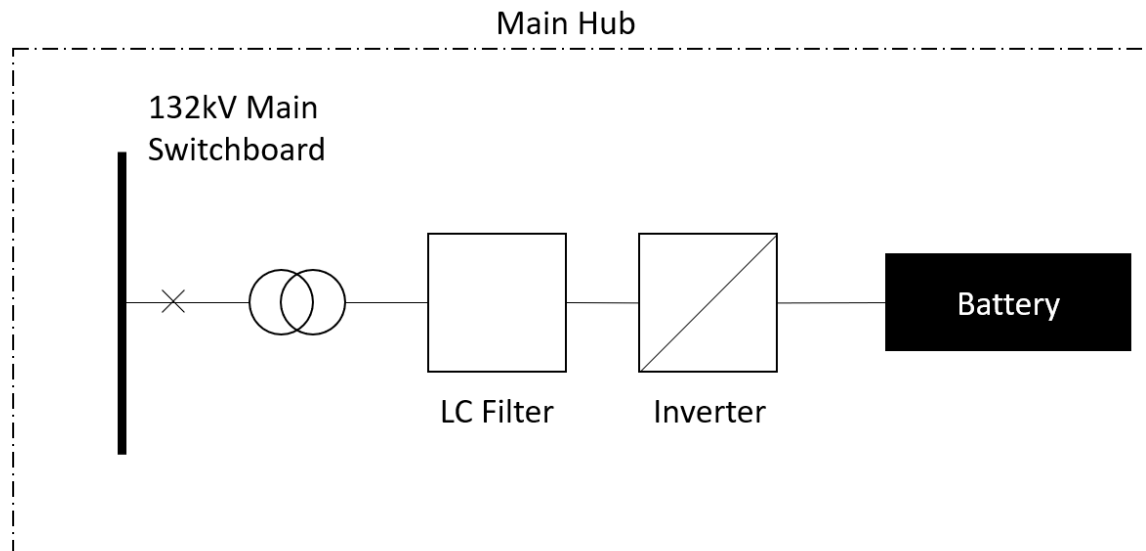


Figure 9-4: BESS Storage Interface on the Main Hub

9.3.4.4 Main Hub Distribution

The Main Hub Electrical distribution shall be formed of switchgear, transformers and connecting cabling. The overall Main Hub network is shown in the Single Line Diagram in Appendix A.

Arrangement and Ratings

The network has been simplified as far as possible. Current ratings for industrialised solutions limit the amount of power handled by the switchgear and so there are 2-off 132kV switchboards which each feed 2-off MVDC bridges. The generation (from the OWAs and power generators) as well as the storage shall be split evenly between the two systems.

In addition, the fault ratings of the switchboards will need to be considered, particularly with large quantities of generation tied in locally.

Switchgear	Example Type and Rating	Practical Power Limit
132kV Switchgear	Hitachi ELK-04 Up to 170kV, 4000A, 63kA	4000A current limit equates to 823MW at 132kV, 0.9PF
33kV Switchgear	ABB UniGear ZS2 Up to 36kV, 3150A, 31.5kV	3150A current limit equates to 162MW at 33kV, 0.9PF

During detailed design the interconnection of the two systems should be explored to determine whether having the ability to share power between the two systems would be beneficial, particularly for maintenance and other outages.

Switchgear

Standard industrial switchgear will be used where possible. Switchgear up to and including 33kV will be Metal-Enclosed Air Insulated Switchgear. The 132kV switchgear shall be Gas Insulated Switchgear as this is the most compact and weight efficient for offshore applications.

GIS is available from multiple vendors including Siemens, Hitachi and GE.

AIS is available from many manufacturers including Siemens, ABB, Schneider and Eaton

Transformers

Standard industrial liquid filled transformers will be used on the Main Hub. The ratings have been selected to remain within standard product lines as far as possible although initial discussions with manufacturers have indicated that large power transformers are typically bespoke and designed for each application.

Industry standard insulating materials (e.g. Midel) shall be used which shall limit the potential for fire in the offshore environment.

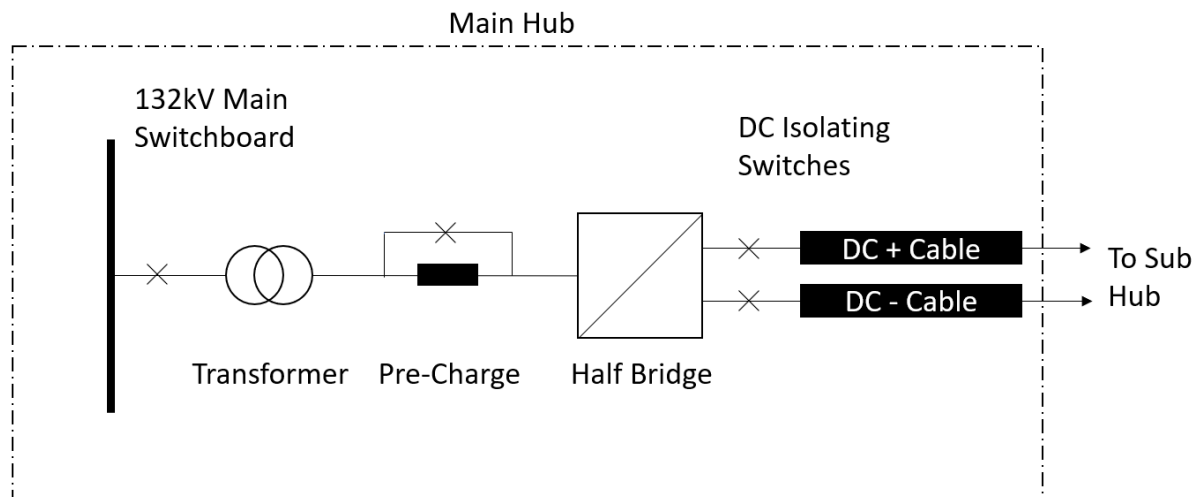
The rating of the transformers and their location indoors will dictate cooling requirements.

Power transformers are available from multiple vendors including ABB, Hitachi, Siemens, GE and Winder.

9.3.4.5 MVDC Bridge Feeders

An initial design for the MVDC Bridge has been provided by GE Power Conversion.

Each MVDC Bridge will be fed from a dedicated feeder circuit on the Main 132kV Switchboard.



Each system on the Main Hub comprises the following:

- Input transformer – to provide electrical isolation, appropriate winding and appropriate input voltage
- Pre-Charge Circuit – to prevent damage to the bridge input on initial energisation due to inrush current
- Half-Bridge – converts the AC supply to DC through a process of rectification using IGBTs
- DC Isolating Switches – provide isolation point for the subsea cables
- DC Cables (+/-) – carry the DC power subsea to the Sub Hub

Two concepts for 100MW and 200MW applications have been developed by GE and these are detailed in Table 9-2 below.

Power [MW]	Input Voltage [kV]	DC Current [A]	DC Cable Voltage [kV]	Bridge Towers
100	70	950	+/- 53	7x12 ST1500
200	132	700	+/- 150	18x12 ST750

Table 9-2 GE Power Conversion MVDC System Specifications

Each system will also have a dedicated control unit which will interface with the overall Energy Management System (EMS).

The MVDC concept proposed by GE has the following benefits:

- DC cable costs are lower compared to similarly rated AC cables
- System losses are lower as a result of using DC transmission
- The AC/DC conversion technology is proven in other industries and applications
- The system offers controllability and flexibility with complete voltage control and reactive power control
- The system decouples fault levels between the Main Hub and the Sub Hub
- The system is less costly, more compact and weighs less than similar HVDC technology

The proposed conversion technology is based around Voltage Source Converters using high power Insulated Gate Bipolar Transistors (IGBTs) which are rapidly switched to modulate a voltage waveform. This technology has the advantage of being able to control both real and reactive power and can work independently of a strong AC network (e.g. a grid connection) making it ideally suited to the islanded network proposed here. /36/

9.3.4.6 Sub Hub Electrical Power Functions

Each Sub Hub is required to deliver the following key electrical power functions:

- MVDC bridge input from Main Hub subsea connection
- Sub Hub power distribution including primary distribution and asset service distribution, comprising:
 - o Step down transformers to match voltage
 - o Frequency converters to match frequency
 - o Submarine HVAC cable compensation

9.3.4.7 MVDC Bridge Input

An initial design for the MVDC Bridge has been provided by GE Power Conversion.

The output from the DC Bridge will be connected to the Sub Hub's primary switchboard and be the source of primary power on the Sub Hub including for local systems and for the supply to the assets.

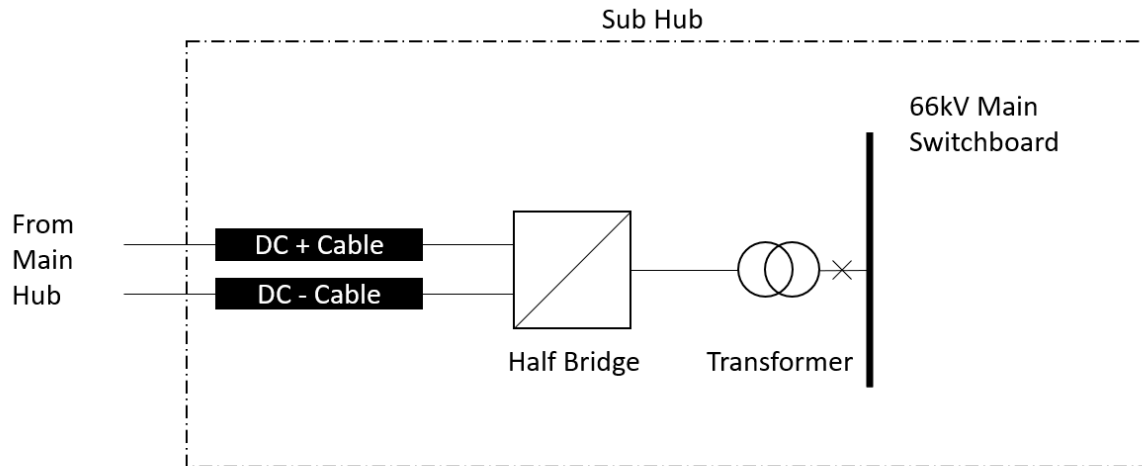


Figure 9-5: Sub Hub MVDC Bridge

The system on each Sub Hub comprises the following:

- DC Cables (+/-) – carry the DC power subsea from the Main Hub – cable isolation and control is from the Main Hub so no DC switches are provided at the Sub Hub
- Half-Bridge – converts the DC current back to AC through a process of inversion using IGBTs
- Output transformer – to provide the appropriate input voltage to the Sub Hub a step-down transformer may be required

Note: for the 100MW system which operates at close to 66kVac, a step-down transformer is not required except for the Sub Hub which has primary distribution at 33kVac. For the 200MW system which operates at 132kVac, a step-down transformer will be required.

9.3.4.8 Sub Hub Distribution

The Sub Hub Electrical distribution shall be formed of switchgear, transformers and connecting cabling or bus duct.

Primary Switchgear

The primary distribution shall consist of a single main switchboard, operating at either 66kV or 33kV depending on the Sub Hub power requirements. This shall receive power from the MVDC Bridge output and then distribute it to the various step-down transformers.

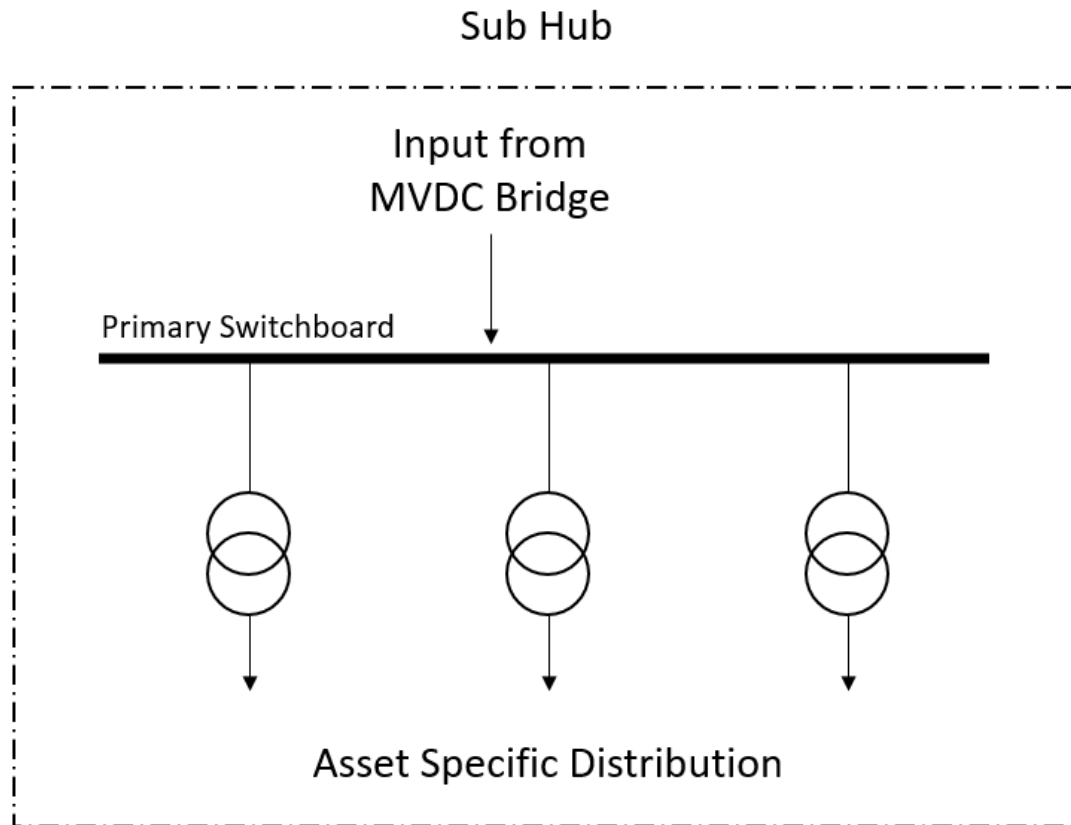


Figure 9-6: Sub Hub Primary Distribution

It is also anticipated that auxiliary systems on the Sub Hub will be fed from a power supply derived from the primary switchboard.

It is not intended to connect any local generation to the primary distribution on the Sub Hub. Any emergency power shall be connected to auxiliary/emergency switchboards operating at lower voltage. The use of local storage connected at the Sub Hub should be investigated in more detail. Having distributed storage may help with system resilience and fault ride-through.

The primary switchboard on the Sub Hub shall be rated for the MVDC Bridge output. 66kV Switchgear shall be Gas Insulated (GIS) whilst 33kV Switchgear shall be Air Insulated (AIS).

Primary Switchboard Continuous Current Ratings have been determined based on an assumed Power Factor of 0.9 and are summarised in Table 9-3.

MVDC Input Rating [MW]	Primary Voltage [kV]	Nominal Current [A]	Switchboard Rating [A]
100	33	1944	2500
100	66	972	1250
200	66	1944	2500

Table 9-3 Sub Hub Primary Switchboard Ratings

Transformers

Transformers shall step down voltage from the primary distribution to the various Asset service voltages. Ratings and specifications shall be selected for consistency as far as possible. On the Sub Hub the transformers are likely to be located external and so materials, specification, construction etc will need to take this into account.

The Sub Hub transformers will be Delta-Delta wound and will have impedances selected to provide appropriate fault level attenuation to the downstream switchboards. The earthing arrangement for the Sub Hub electrical network will need further study.

Asset Distribution

The Sub Hub distribution shall be designed to meet the needs of the connected assets but where possible shall use repeatable/modular blocks to reduce costs and complexities. The following blocks have been identified:

13.8kV Block

See Figure 9-7. This shall have 2-off 50MVA rated transformers supplying a 13.8kV switchboard with bus tie. This shall allow the transformers to be operated at 2x50% under normal circumstances with the option to switch to 1x100% if one transformer needs to be taken down for maintenance or inspection. Each bus of the 13.8kV switchboard shall have at least one outgoing connection for connection to submarine cables to an asset.

11kV Block

See Figure 9-8. This shall have 1-off 50MVA transformer supplying a 11kV switchboard without bus-tie. The transformer shall operate as 1x100% with no redundancy. The 11kV switchboard shall have at least two outgoing connections for supplies to assets.

6.6kV Block

See Figure 9-9. This shall have 1-off 20MVA transformer supplying a 6.6kV switchboard without bus-tie. The transformer shall operate as 1x100% with no redundancy. The 6.6kV switchboard shall have at least two outgoing connections for supplies to assets.

Non-Standard

Other distribution will be provided to meet specific requirements that are not repeated across a number of Sub Hubs. This includes 33kV distribution and a larger 6.6kV distribution.

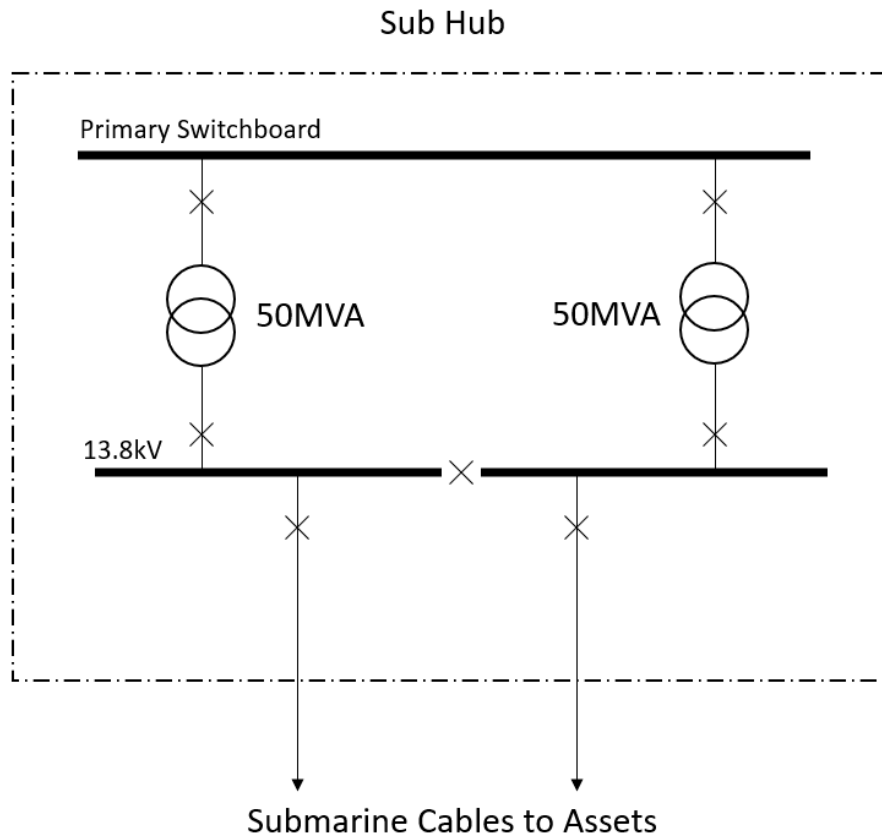


Figure 9-7: 13.8kV Distribution Block

9.3.4.9 Voltage Regulation

Tap changing is one of the simplest ways to regulate voltage. Adjusting the transformer tap means to adjust the output voltage by a small percentage, up or down, from the nominal output voltage. If higher voltage is required on the Oil & Gas asset then the transformer tap at the Sub Hub can be adjusted to increase the sending end voltage which will result in a higher voltage at the platform.

An On Load Tap Changer is a device which allows for the transformer tap setting to be adjusted with the transformer energised and online. This is typically achieved through a motor driven device which responds to requests from a controller. In the network discussed here it is anticipated that the overall Power Management System would be in control of any OLTCs fitted to distribution transformers.

OLTCs are mechanical devices and as such will require ongoing inspection and maintenance. Maintenance intervals are typically linked to number of operations and hence if there are many voltage fluctuations in the network there will be shorter intervals between servicing. Modern devices incorporating vacuum switching technology have reduced maintenance requirements and some models, e.g. the MR VACUTAP VR is marketed as being maintenance free for almost all network applications.

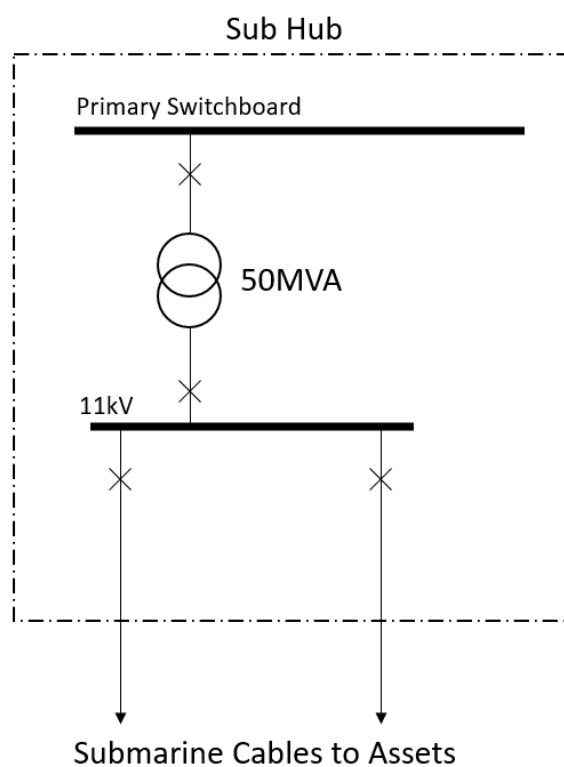


Figure 9-8: 11kV Distribution Block

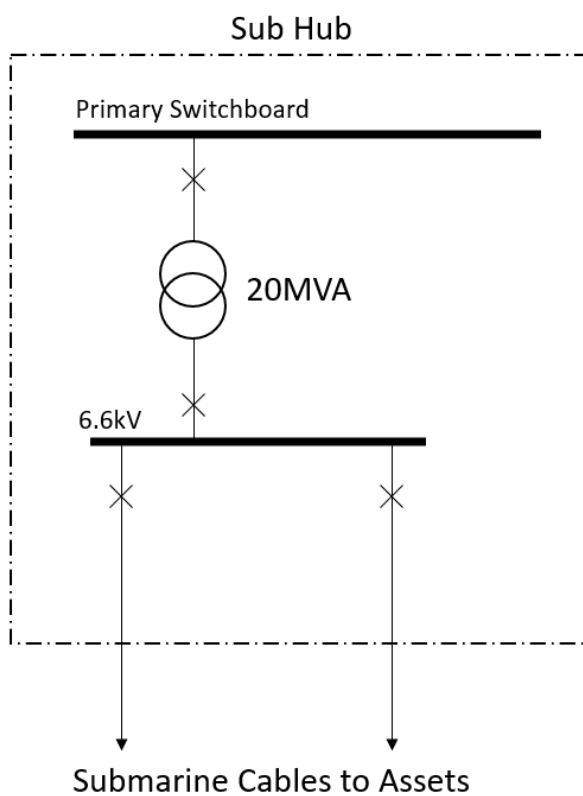


Figure 9-9: 6.6kV Distribution Block

9.3.4.10 Frequency Conversion

For CNS/OMF region the Main Hub and Sub Hub primary distribution will operate at 60Hz. This is the standard marine/offshore frequency and the majority of assets studied utilise 60Hz. A small number of CNS/OMF assets operate at 50Hz and will therefore need to be supplied at 50Hz to avoid compatibility issues with the on-asset equipment.

Frequency converters are available from a number of manufacturers, including GE, ABB and Siemens. This is an established technology for connecting between 50Hz grids and 60Hz applications (e.g. shore to ship power supplies).

As an example, ABB offer the PCS 6000 Static Frequency Converter (SFC) series in a package rated up to 7MVA with multiple modules able to operate in parallel for higher ratings. Each 7MVA module has the following details:

Model	Power [MVA]	Width [mm]	Depth [mm]	Height [mm]	Weight [kg]
PCS 6000 SFC-7000	7	4900	1200	2500	5200

9.3.4.11 Reactive Compensation for Subsea Cables

Static compensation has been identified as a requirement for some of the submarine cables to mitigate against the capacitance effects of the subsea cables.

It may be beneficial to combine static compensation with storage to provide multiple benefits to the system and increase the utility of the installed power electronics equipment. /39/

9.3.5 Distribution within the Southern North Sea

The Southern North Sea sector has very different characteristics when compared to the Northern and Central North Sea sectors.

The SNS is a gas producing area with multiple small wellhead platforms (typically unmanned) sending gas to “gathering stations” where it is then compressed and sent onshore. In some cases, the compression stage is onshore.

The wellhead platforms have minimal electrical requirements, in the order of less than 50kW. Historically this power demand has been met by local gas or diesel generation requiring ongoing maintenance and fuelling. More recently renewable packages have been deployed to power some of these platforms through a mixture of wind turbines, solar panels and a storage platform /40/. This shift to renewable technology enables assets to become NUI on a more permanent basis.



Figure 9-10: Wind and solar on the Cutter QC Platform (reference /40/)

9.3.5.1 Clusters and Hubs

The gathering stations are detailed in the following table with estimated demands provided by the operators via OGA.

Cluster	Gathering/Hub Station	Estimated Demand [MW]
West Sole	West Sole Alpha	0.3
Ravenspurn	Ravenspurn North	1.2
Cleeton	Cleeton	1.2
Leman	Leman Alpha	1.6
Inde	Inde 23A	<0.5

Table 9-4 SNS Clusters and Hubs

9.3.5.2 Existing Electrification

There is already some electrification within the Southern North Sea, with some satellites supplied with power from the main hub asset. Examples of this include:

- A 3.3kV link between West Sole Alpha and the Hoton platform, a distance of around 12km
- A link between Cleeton and Minerva, a distance of around 13km
- A 6.6kV ring main between Ravenspurn North and the ST2 and ST3 assets, a distance of around 13km

Some of this infrastructure has suffered from failure, for example an existing 3.3kV ring main between Cleeton and the Ravenspurn South satellites is no longer in service due to a cable failure.

In general therefore it is advantageous to provide a flexible power network within the SNS with the potential for ring mains or branches allowing better flexibility and the ability to meet the requirements of more assets.

9.3.5.3 Stranded Assets

For stranded assets in this area it is likely to be more economic to achieve carbon reductions by retrofitting with a suitably sized renewable generation package. Combined with storage these can provide reliable power at the demand values seen for the satellite wellhead platforms, e.g. <50kW.

The cost (CAPEX and OPEX) of a small renewable package would need to be compared to the cost of submarine cabling and a containerised switchgear and transformer solution.

This is outwith the scope of this study and the base case is to supply all suitable assets via subsea power from a Sub Hub.

9.3.5.4 Radial Circuit vs Ring Circuit

Electrical distribution networks can typically either be arranged radially or in a ring.

In a radial circuit the platforms would be connected one after the other in a daisy chain. This is the simplest arrangement and minimises the number of cables required; however, technical challenges include increased cable size (particularly for the first one or two runs of cable in the circuit which are often the longest) to carry current and mitigate volt drop. A radial circuit may also be limited in how much expansion it can support should there be additional demand later.

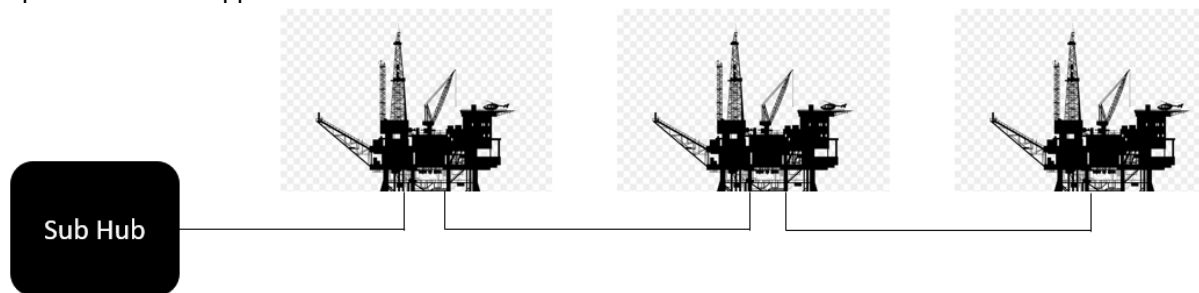


Figure 9-11: Radial Circuit

In a ring circuit, the final platform on the circuit is connected back to the source, creating a ring. This increases the number of cables to be installed; however, a ring circuit is more flexible and overall cable sizes may reduce as the current can be split whilst also mitigating volt drop. Ring circuits can more easily expand to accommodate additional assets. They also better suit a more geographic spread of assets.

Overall for submarine cable schemes the additional cost of cable installation will outweigh any benefits of reducing cable size or providing additional resilience in the network. However, the use of ring circuits in the SNS will be evaluated where the geographic spread of platforms makes this more attractive.

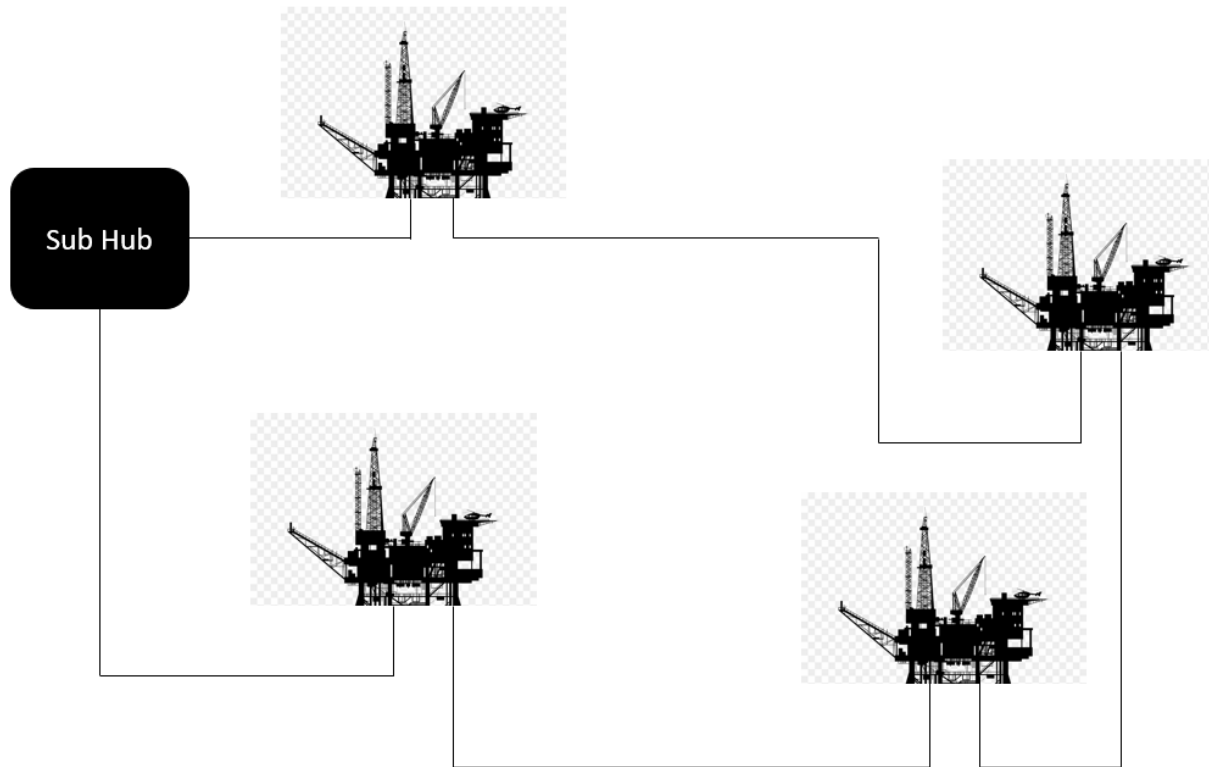


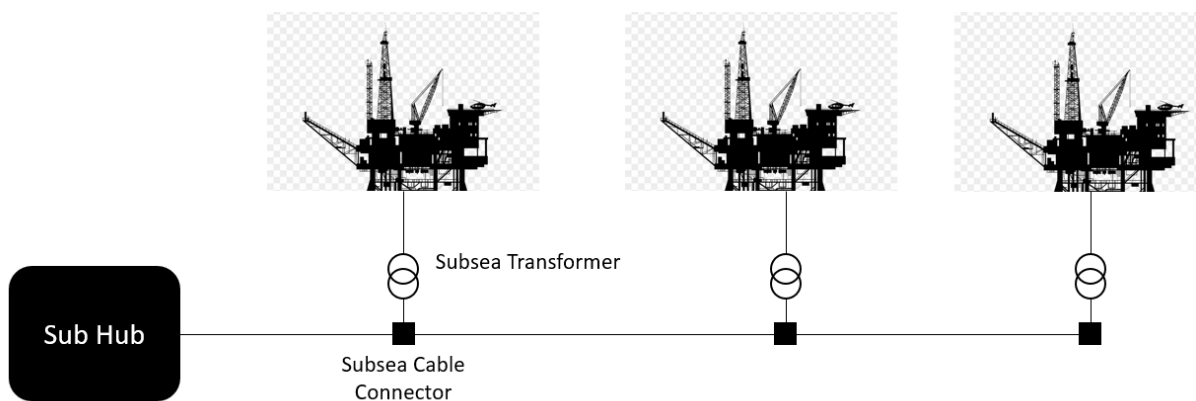
Figure 9-12: Ring Circuit

9.3.5.5 Platform Interfaces

Whether a radial or ring topography is selected, there is a requirement to interface the high voltage cable with the LV infrastructure on the platform. This will require a step-down transformer and associated switchgear.

Subsea Interface

Having the interface subsea reduces both cabling requirements and topsides modifications, at the cost of increasing the cost and complexity of the subsea installation.



Underwater Connectors

With increasing integration of offshore renewables there are increased options on the market for connection of submarine cables. Previously underwater joints were limited to straight through connections of two cables (often joining a dynamic cable to a static cable, or joining sections of static cable). New technologies offer subsea jointing of multiple cables.

The MacArtney GreenLink Hub is an example of an underwater subsea socket that can house multiple cables and can be expanded over time.

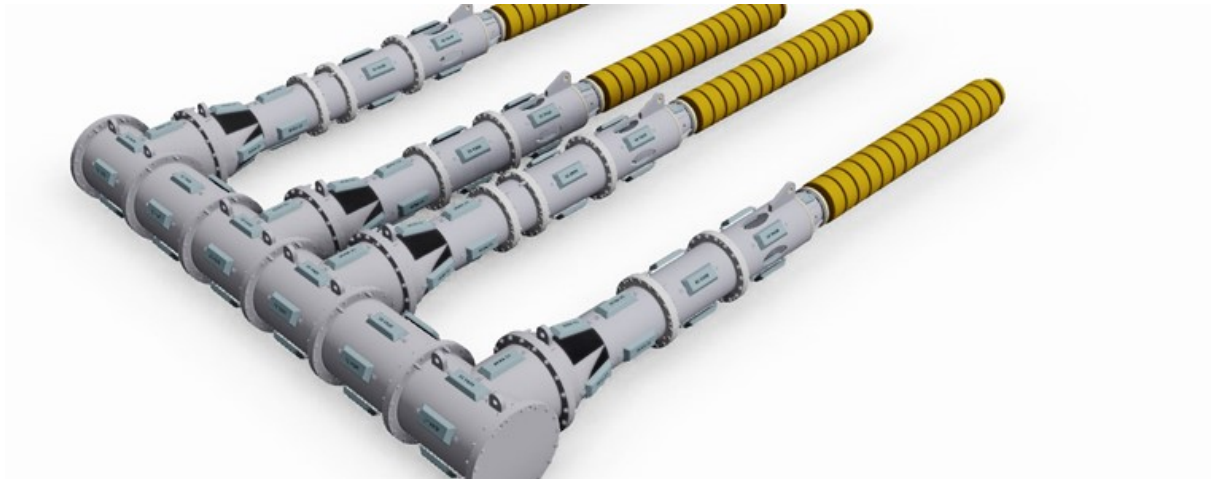


Figure 9-13: MacArtney GreenLink Hub (image courtesy: MacArtney Underwater Technology)

Subsea Transformers

As part of subsea infrastructure, for example wellhead injection pumps, subsea transformers rated 2-5MVA have been developed and installed.

With advances in requirements there are now models on the market, or in development, for much higher ratings and depths. Both Siemens and Hitachi offer units rated up to around 100MVA and 145kVac which are rated for deep water /41/ /42/. Units at these ratings have not yet been proven in service in terms of reliability.

Subsea transformers are around five times the cost of an equivalent surface transformer /43/.

Topsides Interface

As an alternative to subsea transformers, containerised transformers (often integrated with the required switchgear and protection) can be utilised where there is sufficient available deck space. For example, transformers of up to 4MVA rating can be integrated along with suitable switchgear into a 10ft container. /44/

An example of a containerised transformer is shown in Figure 9-14. An example of this interface arrangement is shown in Figure 9-15.



Figure 9-14: Containerised Transformer (image courtesy: Crestchic)

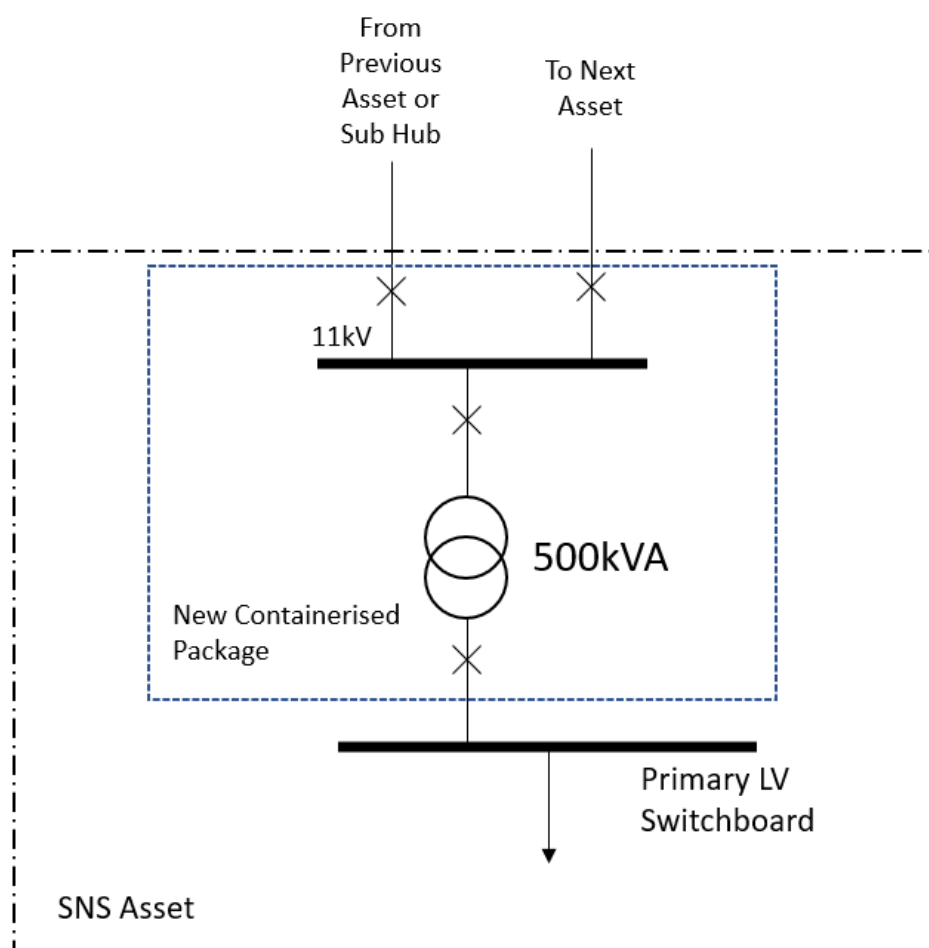


Figure 9-15: Topsides Interface Example for SNS Asset

9.3.5.6 Example Cluster 2 – SNS

The following area of the SNS was studied in more detail to determine an appropriate power configuration.

The hubs covered are:

- Ravenspurn North
- Cleeton
- West Sole

Additionally, this area includes the remote platforms Babbage and Tolmount. The geographical spread of the assets is shown in Figure 9-16.

Due to the geographic spread and low electrical power demands there is no value to having a ring main arrangement in this area. Instead, three separate radial circuits (A, B and C) are proposed. These are detailed in Table 9-5.

Circuit	Hub	Nominal Voltage	Electrified	Already Electrified
A	Cleeton	11	Neptune, Cleeton, Ravenspurn South A, Ravenspurn South B, Ravenspurn South C Tolmount	Minerva (from Cleeton)
B	Ravenspurn North	6.6	Ravenspurn North, Babbage	ST2 and ST3 (from Ravenspurn North)
C	West Sole A	11	Hyde, West Sole C, West Sole B, Swest Sole A	Hoton (from West Sole A)

Table 9-5 Radial Circuit Details

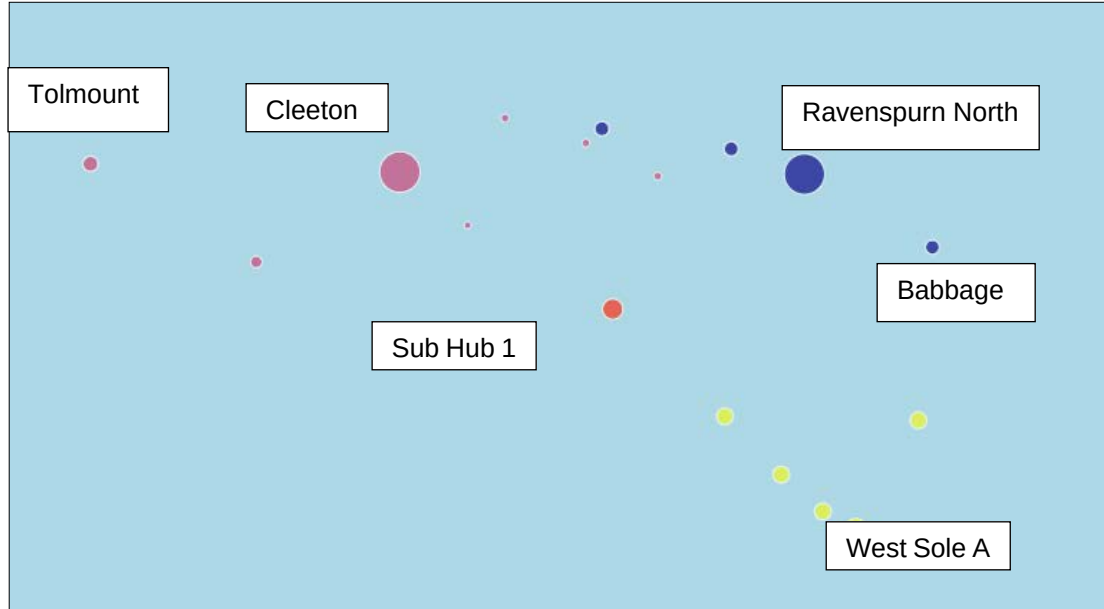


Figure 9-16: SNS Sub Hub 1 Cluster with Key Assets Labelled

An approximate cable routing for the three circuits is shown in Figure 9-17 with the 11kV circuits running to West Sole A and Tolmount and a 6.6kV circuit running to Babbage. Existing electrical power cables are shown as dashed lines, e.g. between Cleeton and Minerva.

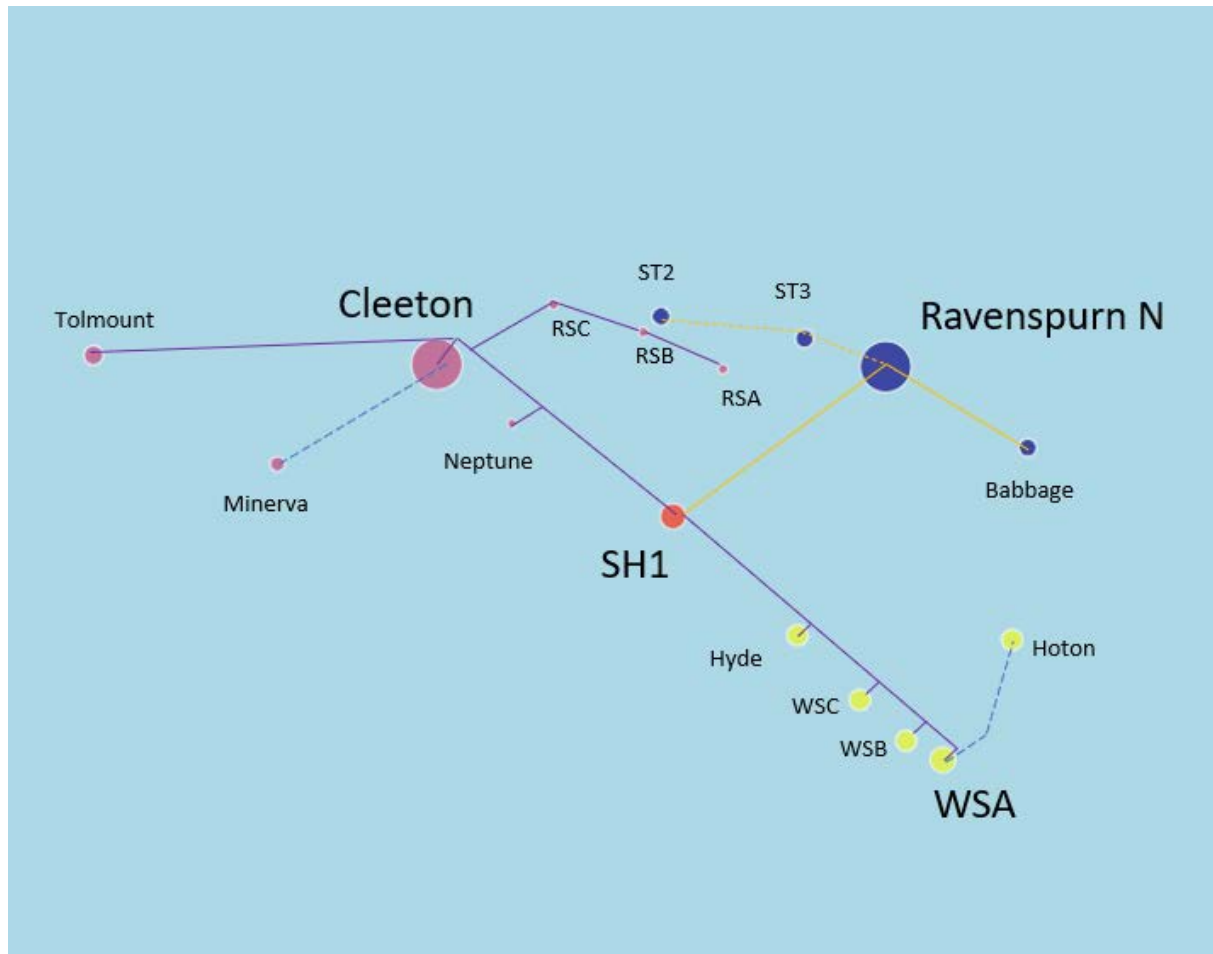


Figure 9-17: Radial Circuits for Cleeton, Ravenspurn N and West Sole

It is proposed that switchgear and transformers in containerised form be located on each platform.

Cables and nominal operating voltages have been selected based on limiting the volt drop at the furthest point to within 2.5%. Preliminary cable sizes are shown in Table 9-6.

kV	From	To	Distance [km]	Power [MW]	Current [A]	CSA [sqmm]	Volt Drop (V/km)	Volt Drop	Volt Drop (%)
11	SH1	WSA	27.2	1.1	68	240	8.43	229.33	2.08%
11	SH1	TOL	37.8	1.64	101	500	6.03	228.08	2.07%
6.6	SH1	RSN	18.1	1.644	169	630	8.00	144.81	2.19%

Table 9-6 SNS Cluster Cable Sizing

9.3.6 Local Platform Power Quality Issues

9.3.6.1 Retaining Platform Generation

No allowance has been made within the study work completed so far for local generation being retained on platforms. There are some potential benefits to this, including:

- Security of supply
- Ability to support large motor starting
- Power factor correction
- Reactive power compensation

However, retaining embedded generation may also cause issues for power flows and protection schemes, for the overall Energy Management System, and for fault levels at the Sub Hub level. It may also make the regulation and revenue model more complex.

9.3.6.2 Platform Voltage Control

A key parameter to be measured will be the receiving voltage at the platform's primary distribution. The tolerance defined in IEC 61892 of +/- 2.5% has been used as the basis for equipment selection and modelling as part of this study work. It is recognised however that the platform receiving voltage will need to be monitored to allow the sending voltage to be appropriately regulated. This monitoring should be incorporated as part of the topsides modifications to receive submarine power.

9.3.7 Conclusion

This study has determined the basic electrical power network arrangements and equipment for use in both the CNS/OMF region and the SNS region.

In both regions the Main Hub will be a floating unit incorporating wind farm reception facilities, local generation, local energy storage and the feeders to the power electronic conversion units for feeding the Sub Hubs.

The Sub Hubs each have an input from the Main Hub where the bulk transmission power is converted to AC and then transformed by a combination of transformers and frequency converters to meet the requirements of the local Oil & Gas assets.

In the CNS/OMF region the final supply to the asset will be a direct AC connection at the asset's native voltage and frequency. Appropriate numbers of cables will be run to meet the power demand. These submarine power cables will interface directly with the primary distribution on the asset.

In the SNS region the Sub Hub will supply multiple radial circuits each of which will then supply multiple Oil & Gas assets which in the SNS typically operate at lower voltages and with lower demands. On asset containerised switchgear and transformers will be used to interface with the existing asset electrical distribution.

9.3.8 Further Areas of Study

- Reliability and operability of switchgear and other electrical equipment and the provision of e.g. spare cubicles, bus ties and interconnectors, to be developed in greater detail
- Equipment rating and design optimisation, e.g. selection of common transformer ratings to suit multiple applications across different Sub Hubs
- Requirements for frequency converters, reactive compensation
- Determining impact of retaining and incorporating local platform main generation

10. Electrical Distribution Modelling Study (CNS/OMF)

10.1 Objective

The purpose of this study is to describe how the electrical network has been modelled, outline the study scenarios considered as part of the power system analysis and present the findings of the completed power analysis study work.

The purpose of completing these power system studies is to understand the technical feasibility of powering offshore Oil & Gas platforms via an intermediary power network capable of collecting and distributing bulk power from renewable sources of generation, along with conventional generation for standby power and system integrity.

The findings from this report will validate the technical feasibility of the overall solution, as well as inform equipment ratings and selection used to build up the physical designs for the Main Hub and Sub Hubs. In addition, there are challenges associated with bulk distribution of power in an offshore setting, particularly around submarine cables, which need to be better understood as part of this study work.

It is expected that the outcome of this study work will be recommendations for further, more detailed and complex studies, considering the technical details of the network which cannot yet be fully determined based on the high-level nature of modelling completed to date.

It is noted that the Medium Voltage Direct Current (MVDC) network has not yet been modelled in detail as additional data is required from supporting vendors.

10.2 Methodology/Background

10.2.1 Software

DlgSILENT PowerFactory 2022 Version 1 software has been used to model the network and complete the analysis.

10.2.2 Model

10.2.2.1 System Description

A partial model of Central North Sea (CNS) cluster 1 was developed in DlgSILENT PowerFactory 2022 Version 1 software using the data and assumptions described in this section.

For the purposes of this study the connection between the Main Hub and Sub Hub has been modelled as High Voltage Alternating Current (HVAC) with power transmission at 132kV.

For initial analysis the model was limited to a detailed model of the Main Hub and Sub Hub 2 as shown in Figure 10-1 below. Sub Hub 2 includes final distribution to platforms at 33kV, 11kV and 6.6kV levels and was therefore considered to be a worst case. As Main Hub 132kV Switchboard A will also feed Sub Hub 1, this was modelled in as a lumped load.

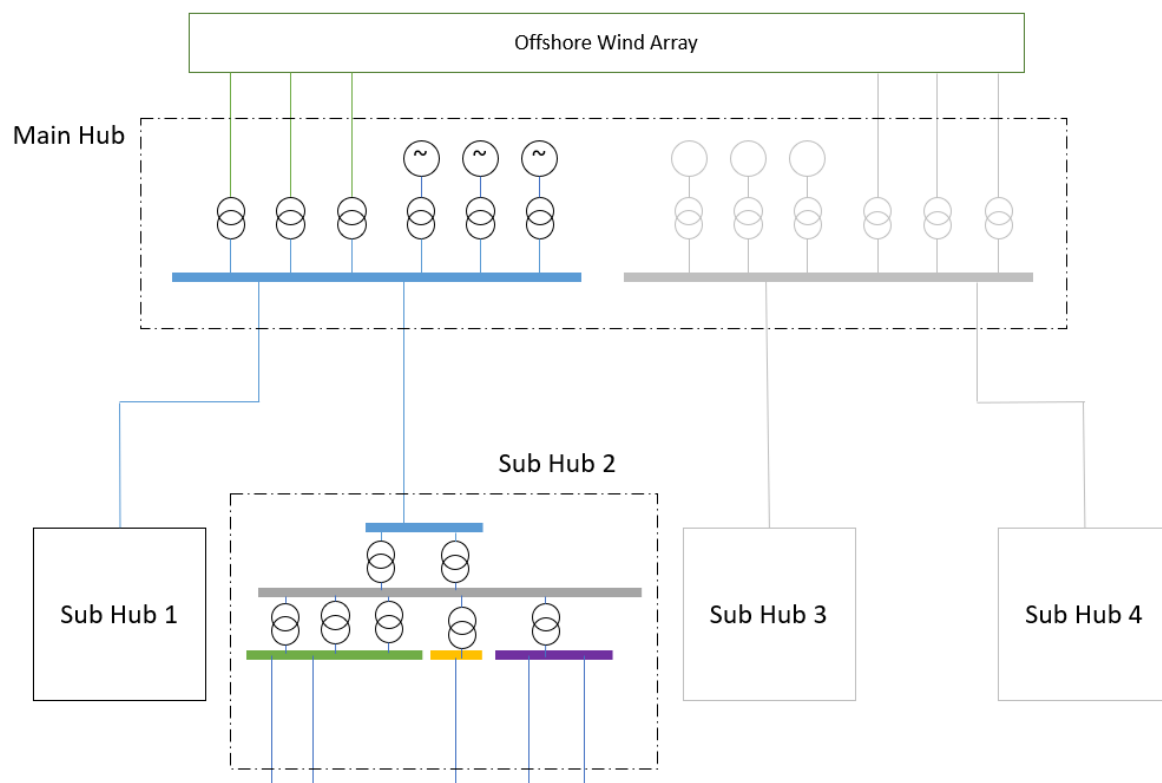


Figure 10-1: Overview of CNS Cluster 1

10.2.2.2 Offshore Wind Array

The offshore wind array (OWA) has not been modelled in detail at this stage. The inputs to the Main Hub from the OWA are modelled as constant power sources with the available Real and Reactive Powers fixed for each study scenario. In reality, the OWA will be a dynamic power input that will need to be actively monitored and managed.

The OWA has been sized at 425 MW installed capacity. It is assumed for the purposes of modelling and distribution topology that these arrive at the Main Hub at 33kV.

The following OWA outputs have been used as inputs into the model with the assumption being that the power from the OWA is distributed evenly across all 6-off transformers (3-off for Sub Hub 1 and Sub Hub 2).

Case	Capacity Rating [%]	OWA Output [MW]
Maximum Output	100%	425
Minimum Output	0%	0

Table 10-1 OWA Output

As part of future study work it is recommended that the OWA output be optimised to suit the power and transmission distance. For example, having a 66kV or 132kV output from the OWA would reduce the cabling requirements.

10.2.2.3 AC Generators

The power source for the Main Hub is 6-off GE LM6000 combined gas and steam turbine units each driving a single alternator. The data used in the model is based on a Brush BDAX unit operating at 13.8kV, as well as some typical operational data utilised from DlgSILENT library data.

The key generator data is summarised in Table 10-2 below:

Parameter	Symbol	
Rating	-	60 MW / 1 pu
Rated Power Factor	PF	0.86
Maximum Reactive Capability	Qmax	49.2 MVar / 0.82 pu
Maximum Reactive Capability	Qmin	-26.4 MVar / -0.44 pu
Subtransient Reactance (sat)	Xd''	0.116 pu
Transient Reactance	Xd'	0.162
Synchronous Reactance	Xd	1.97
Negative Sequence Reactance	X2	0.14
Negative Sequence Resistance	R2	0.039
Zero Sequence Reactance	X0	0.068
Zero Sequence Resistance	R0	0.006
Stator Resistance	Rst	0.002
Machine Type (IEC 60909)	-	Turbo Series 1

Table 10-2 AC Generator Data

10.2.2.4 Battery Energy Storage System (BESS)

A 66.5 MVA battery energy storage system has been included within the DIgSILENT model, consisting of 380 x 175 kVA string inverters. The capability curve of the inverters is shown in Figure 10-2.

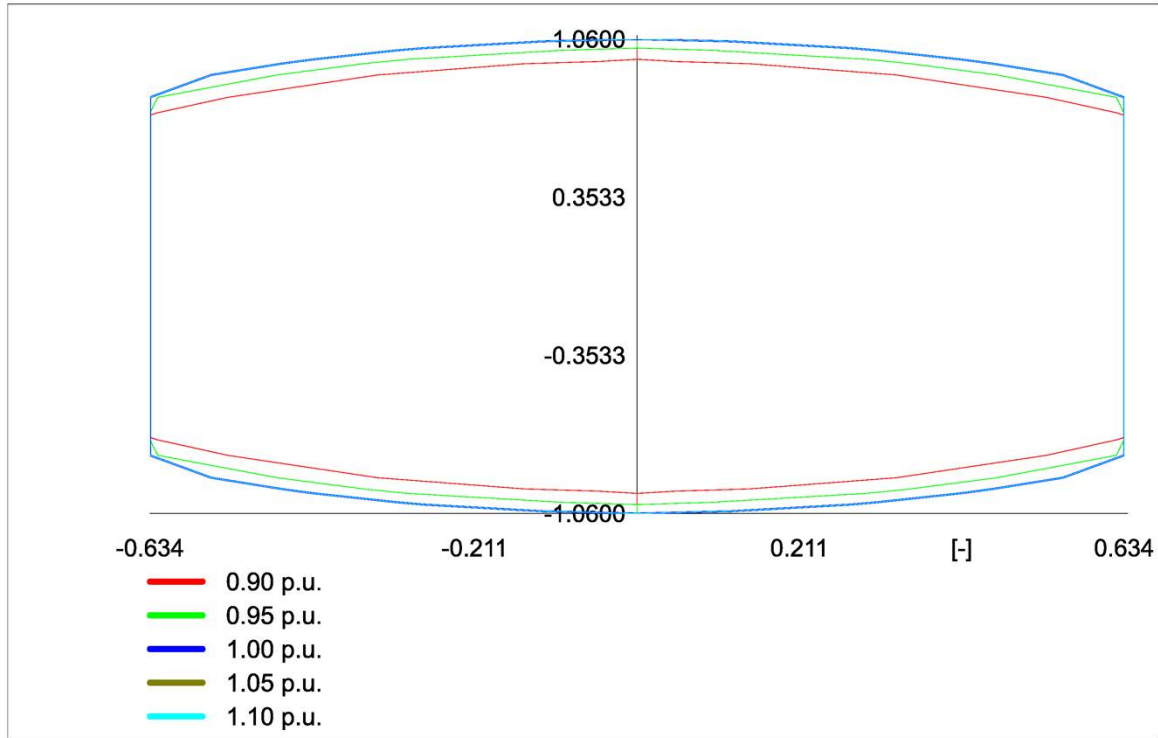


Figure 10-2: 175 kVA inverter P/Q capability curve

10.2.2.5 Transformers

Transformers have been selected based on consultation with Original Equipment Manufacturers (OEMs) to suit the operating voltage level and estimations of MVA rating. Where possible the number of transformer sizes have been reduced to simplify specification and procurement. This may result in some transformers being of a higher rating than the platform demand requires. This can be further assessed.

The transformer impedance and X/R ratios were assumed based on standard values given in /45/ and /46/, respectively. Copper losses are calculated within DIgSILENT based on the X/R ratio of the transformer. No load current of all transformers assumed at 0.3% of Full Load Current (FLC).

On Load Tap Changes (OLTCs) have been included on the Sub Hub transformers to allow for voltage regulation.

Type	Quantity	Rating [MVA]	Voltage Ratio (kV)	Impedance [%]	X/R	OLTC Capability
A	6	150	33/132	15	45	N/A
B	6	70	13.8/132	11	25	N/A

Table 10-3 Main Hub Power Transformer Data

Type	Quantity	Rating [MVA]	Voltage Ratio (kV)	Impedance [%]	X/R	OLTC %Z Range/ %Z per Tap
-	2	150	132/66	15	45	N/A
H	2	90	66/35	12	25	±12% / 1.5%
J	1	50	66/11.5	11	25	±12% / 1.5%
F	1	20	66/7	8	18	±12% / 1.5%

Table 10-4 Sub Hub 2 Power Transformer Data

10.2.2.6 Switchgear

Switchgear has been selected based on consultation with OEMs to suit the operating voltage level and estimations of rated current and short circuit current. These selections will be verified as part of the Power Systems analysis work.

Type	System Voltage [kV]	Manufacturer	Model	Insulation Type	Breaker Type	Voltage Rating [kV]	Current Rating [A]	Short Circuit Rating (3s) [kA]	ip Rating [kA]
A	132	Hitachi	ELK-04	GIS	SF6	145	Up to 3150	40	104
B	66	Hitachi	ELK-04	GIS	SF6	72	Up to 3150	40	104
C	33	ABB	UniGear ZS2	AIS	VCB	36	Up to 3150	31.5	82
D	13.8	ABB	UniGear ZS1	AIS	VCB	17.5	Up to 4000	50	130
E	11	ABB	UniGear ZS1	AIS	VCB	12	Up to 4000	50	130
F	6.6	ABB	UniGear ZS1	AIS	VCB	7.2	Up to 4000	50	130

Table 10-5 Switchboard Types

Note 1: the ip rating has been calculated based on 2.6 times the Short Circuit Rating, in accordance with IEC 62271-1 /47/.

10.2.2.7 Circuit Breakers

It is assumed that circuit breaker short circuit ratings will match or exceed the associated switchgear rating.

10.2.2.8 Platform Loads

For the purposes of the study work completed at this stage platforms have been mostly modelled as lumped loads comprising of a mix of both static and motor loads to give a reasonable representation of the load.

Platform	Intake Bus Continuous Rating [A]	Intake Bus Short Circuit Rating [kA]	MW	PF
Sub Hub 1	N/A	N/A	62	0.89
Forties Alpha A	1500	25	71	0.9
Forties Alpha B	1500	25	71	0.9
Britannia	2500	40	15	0.9
Alba North	2460	40	28	0.9
Andrew	Unknown	Unknown	15	0.9

Table 10-6 Platform Load Summary

Note 1: Sub Hub 1 has been modelled as a general load, rated at the maximum platform power + 5%; taking into account system losses.

10.2.2.9 Induction Machine and Dynamic Load

For the motor starting study the largest Direct On Line (DOL) in a Sub Hub has been identified and modelled an Induction Machine (IM), with a dynamic mechanical load, to allow for motor starting simulations to be analysed. These motors have been modelled based on library data held by Katoni and typical DlgSILENT data.

Sub Hub	Platform	Rating (kW)	Poles	PF (pu)	Efficiency	FLC (A)	LRC (pu)
2	Alba North	4900	2	0.87	0.957	309	3.72

Table 10-7 Sub Hub Large DOL Motor Nameplate Data

Type	Pole Pairs	Moment of Inertia (kgm ²)	Stator Reactance (pu)	Stator Resistance (pu)	Magnetising Reactance (pu)
Single Cage Induction	1	100	0.16	0.007	6.24

Table 10-8 Induction Motor Equivalent Circuit Data (RMS study)

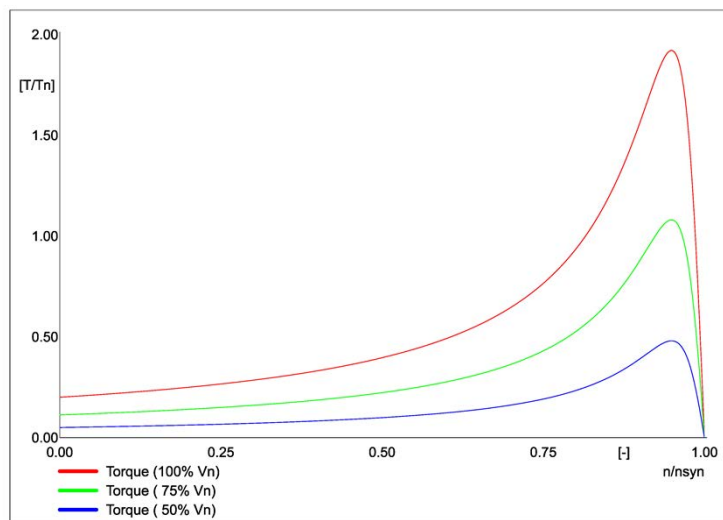


Figure 10-3: Starting Torque curve of IM

Type	Torque at Standstill (pu)	Minimum Torque (pu)	Synchronous Speed Torque (pu)
Pump Load	0.12	0.05	0.58

Table 10-9 Mechanical Load Data (RMS study)

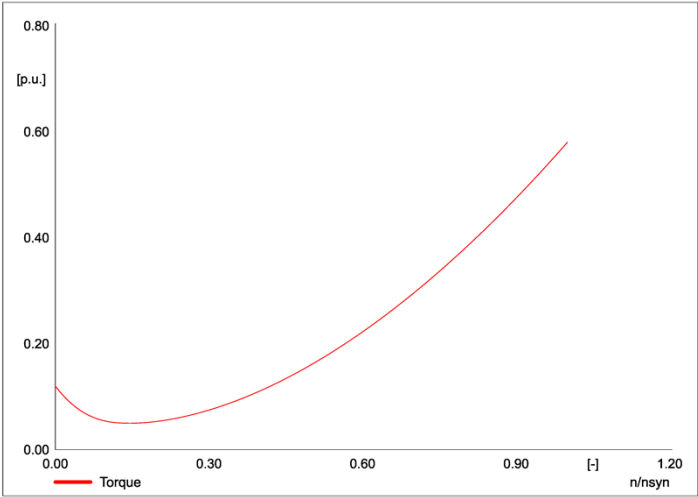


Figure 10-4: IM Mechanical Load

10.2.2.10 Submarine Cables

Cable ID	Type	Rated Voltage (kV)	Circuit Length (km)	Conductor CSA (mm ²)	Cables per circuit	Capacity per cable (kA)
C1H2_C	A	132	43	1000	1	0.674
C1H1_C	B	132	99	400	1	0.537
FA-A_C	C	33	35	800	2	0.881
AN_C	D	11	6.28	630	2	0.795
A_C	D	11	14	630	2	0.795
B_C	D	11	2.97	630	2	0.795

Table 10-10 Submarine Cable Summary Data

Note 1: Each platform circuit is modelled with a minimum of two cables per circuit; however, in some cases it may be feasible for a one cable circuit.

Note 2: All submarine cables have been modelled as bonded at both ends

Note 3: Cable ID B-C has an operating voltage of 6.6 kV and modelled as an 11 kV rated cable, due to limited manufacturer data.

10.2.2.11 Topsides Cables

Topsides cables on the Main Hub and Sub Hub have been ignored for the purposes of this model. Compared to the submarine cables these will be very short run cables introducing little additional impedance at the operating voltages described.

10.2.2.12 Reactive Compensation

A 20 MVar reactive compensator has been added to the receiving end of Sub Hub 1 to counter the capacitive effects of the 132kV submarine cable. In some loadflow cases 35 MVar of reactive power compensation has been added to the Main Hub due to the reduced capability of the curtailed wind farm output - resulting in additional need for VAr absorption.

Compensation methods are discussed in Section 10.4.1.2.

10.2.3 Study Methodology

10.2.3.1 Cable Ampacity and Electrical Characteristics

Without specific manufacturer design data each sub-sea cable has been modelled based on data contained within /48//49//50/.

Each sub-sea cable is modelled within DIgSILENT as a separate cable system, with the cable and surrounding pipe material types, thicknesses and geometric spacings defined (as shown in Figure 10-5).

An impedance and admittance matrix is formed within DIgSILENT, with the resultant values compared and tuned to the Resistance, Inductance and Capacitance (RLC) data provided by manufacturer datasheets – giving the electrical characteristics detailed in Table 10-11. An ampacity calculation was carried out to determine the thermal limits, and thus maximum loading of the cable (as defined in Table 10-10).

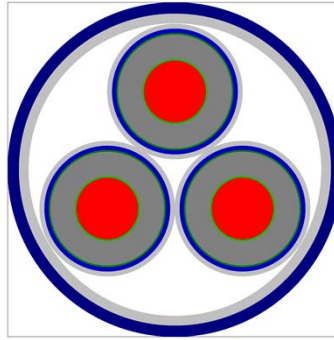


Figure 10-5: DlgSILENT Sub-Sea Cable Geometric Makeup

Type	DC resistance (Ohms/km)	Positive Sequence AC Resistance (Ohms/km)	Positive Sequence Inductance (mH/km)	Positive Sequence Capacitance (uF/km)
A	0.015	0.029	0.327	0.248
B	0.043	0.054	0.386	0.17
C	0.022	0.035	0.298	0.365
D	0.028	0.039	0.289	0.689

Table 10-11 Electrical Characteristics of Cable Types

10.2.3.2 Load Flow

A Load Flow Study shall be run to determine:

- Real Power Flows
- Reactive Power Flows
- Voltage Drops
- Suitability of Equipment Ratings

Methodology

Frequency Control

The MW power/frequency control is managed in DlgSILENT using a Power-Frequency. The frequency of the system is sampled at the Main Hub 132 kV bus, with the active power distribution managed via generation merit orders. A merit order of 1 signifies that all generators in that order will produce their full MW capability until the capability limit is reached, and then the next merit order generation will aim to fill the gap. In the case of excess MW on the system, the generators with the lowest merit order will reduce their production, or as is the case with BESS – absorb the excess. The merit orders are as follows:

- Off-shore wind generation – 1
- Gas Turbine Generators – 2
- BESS – 3

It is noted that the exception to this is where the off-shore wind generators are set with a fixed MW/MVAr setting to determine the approach to excess MW on the system.

Voltage control

The system voltage control is managed in DlgSILENT using the combination of a generic station controller and on load tap changers. The voltage at the 132 kV bus is set (station controller) according to the loading of the system, with higher loadings resulting in increased voltage drops the 132 kV bus can be set up to 2% higher than nominal to compensate. Individual platform load variations are then managed by use of on load tap changers relative to the platform.

It is noted that the in the loadflow cases the tap changers are utilised to keep platform voltages as close to 1 pu. In practice a dead-band tolerance may be introduced to prevent over-use of the tap changers.

Voltages across the system are deemed to be within acceptable tolerances as defined in Table 10-12.

Power Excess/Shortfall

Excess/shortfall power is managed by utilising a 70 MVA main platform BESS and in some cases additional static reactive compensation.

Criteria

For the load flow the criteria established in IEC 61892-1:2019 /53/ shall be applied to determine the viability of the solution. These are summarised in Table 10-12 below.

Characteristic	Value (%)	Applicability
Voltage Tolerance	+6/-10	Steady state voltage tolerance on switchboards on both the Main Hub and Sub Hubs
Primary Distribution Voltage Tolerance	+2.5/-2.5	Steady state voltage tolerance at the main HV switchboard of the platform supplied from a Sub Hub

Table 10-12 Load Flow Voltage Criteria

The sub-sea cables shall be assessed against the following conditions:

- **Loading** – the percentage of the cable's rated current carrying capacity utilised under the load flow conditions.
- **Efficiency** – is a measure of the received/sending MW across each cable. Though hard limits do not exist, it provides a good indication of the suitability of selected cable length, type, size, installation method, as well as the requirement for additional compensation.
- **Volt Drop** – the percent reduction in voltage between the sending end of the cable and the receiving end; at higher voltages this is typically dominated by the reactive component of cable impedance.

Load Flow Study Cases

The five study cases defined in Table 10-13 were identified and configured within the modelling software.

Study ID	Platform Demand	Wind Output	Main Hub Generation	BESS	Bus Configuration
LF2A	70% at 0.9PF lag	100% at 0.95PF lead	0 in service	Charging	Normal
LF2B	70% at 0.9PF lag	0%	3 in service	Discharging	Normal
LF3A	30% at 0.95PF lag	100% at 0.95PF lead	0 in service	Charging	Normal
LF3B	30% at 0.95PF lag	100% at 0.95PF lead	0 in service	Charging	Normal
LF3C	30% at 0.95PF lag	0%	2 in service	Discharging	Normal

Table 10-13 Load Flow Case Summary

10.2.3.3 Short Circuit

Overview

A fault level analysis has been carried using the IEC 60909 /54/ calculation method, to determine the maximum and minimum fault levels at each bus within the network. The purpose of this study is to determine the required withstand ratings for the switchgear and identify whether fault limiting equipment is required within the network; as well as providing the minimum system strength for use within the motor starting study (discussed in Section 10.2.3.4).

Methodology

The following presents the methods employed during the calculation of the maximum and minimum fault level calculations performed using DIgSILENT. It should be noted both cases represent extremely onerous conditions and are unlikely to exist given the number of inputs and outputs to the system. They are used to define equipment withstand levels should the worst-case situation arise.

Maximum Fault Level

This study represents the normal, worst-case operating condition of the site and is intended to identify the maximum short circuit level that is experienced by each switchboard and main HV and MV switchboards. The study case is based on the following settings:

- All possible parallel operating synchronous generators in service.
- Type 3 Doubly Fed Induction Machines (DFIG) as the source of wind power generation, with a sub-transient fault contributing factor of 3 times the total rated MVA capacity of the wind farm.
- Motor fault contribution at 2.8 MVA/MW at maximum load conditions. This figure represents a 70/30 motor/static split, with an average locked rotor current contribution of 4 pu.
- Maximum Voltage factor for MV & HV $c = 1.1$ and LV = 1.05 (as per IEC 60909, table 1).
- Calculation method C is used for X/R values for I_p (as per IEC 60909, section 4.1.3.2).

Minimum Fault Level

This study represents the minimum fault level, operating condition of the site and is intended to identify the range of fault levels that can occur on site, with the results used in determining the system strength during the motor starting study. The study case is based on the following settings:

- One synchronous generator in service.
- Type 4 – full size converter as the source of wind power generation, modelled as a constant current source (as per IEC 60909). The constant current is assumed at 1 pu of available wind power capacity during minimum WTG operation (5%).
- Motor fault contribution at excluded.
- Minimum Voltage factor for MV & HV $c = 1.0$ and LV as 0.95 (as per IEC 60909, table 1).
- Calculation method C is used for X/R values for I_p (as per IEC 60909, section 4.1.3.2).

10.2.3.4 Motor Starting

Overview

A static motor starting simulation is used to assess the worst possible voltage dip on the system, resulting from a large DOL motor start, and can be used to assess if the drop will result in unacceptable undervoltage conditions during the start.

Assessment Criteria

In order to demonstrate satisfactory performance, the system is configured, and should perform as follows:

- Voltage drop at the main busbars should not exceed 10%
- Voltage drop at the motor terminals should not exceed 15%

- Motor started against the minimum number of generators expected under normal operation. In this case this is one gas generating unit.
- DOL starting voltage

Study Scenario

The 4.9MW DOL motor (as detailed in section 10.2.2.9) located on Alba North was started against the minimum short circuit case, using a grid element connected at the local Alba North 11 kV bus. This represents a very onerous starting condition for the network and is unlikely to be attempted in practice.

10.3 Results

10.3.1 Load Flow

10.3.1.1 LF1: Ratings and Operational constraints

This section is intended to test the system in the most onerous conditions. Iterative load-flow cases are carried out to determine the following constraints and limits:

- The maximum and minimum range of 132 kV voltage control. This is achieved by simulating heavy unbalance at the Main Hub 132 kV sending bus. With Sub Hub 1 operating with 30% system loading and Sub Hub 2 operating at 70%, - and vice versa - the maximum and minimum steady state operating voltages of the 132 kV bus are determined for the proceeding cases.
- Platform loads are individually increased to maximum load (100%), with the system load held at 70%. In these 5 cases the minimum required tap setting maximum cable loadings are determined.
- Platform loads are individually decreased to minimum load (30%), with the system load held at 70%. In these 5 cases the maximum required tap settings are determined.

Transformer Loading and Tap Setting Range Summary

Transformer ID.	Rating (MVA)	% Max Loading	On-load Tap Min	On-load Tap Max
SH2-TRX-6601	90	98	-8	2
SH2-TRX-6603	50	71	-5	0
SH2-TRX-6604	50	37	-4	1
SH2-TRX-6605	20	92	-3	2

Table 10-14 LF1 Transformer Loading Summary

Cable Operating Characteristic Summary

Cable ID	Voltage (kV)	Loading (%)	Efficiency (%)	Note
AN_C1	11	103.9	95.89	1
A_C1	11	55.6	94.94	
B_C1	6.6	91.5	97.40	
FA_C1	33	78.6	94.41	

Table 10-15 LF1 Cable Loading Summary

Note 1: The cable rating calculated in DigSILENT – using the Neher-McGath method - is 795 A. Manufacturer data suggests a thermal rating of 860 A can be achieved. A detailed thermal analysis is recommended for all modelled cables prior to install.

10.3.1.2 LF2A: Maximum Load, Maximum Wind Farm Contribution

Scenario details:

- 70% platform demand at PF=0.90 lag
- 100% wind farm MW output

Real and Reactive Power Flows

Values for real and reactive power flow throughout the network are shown on the Single Line Diagram in Appendix 28.6.

Generator Loading Summary

Generator ID	Real Power (MW)	Reactive Power (MVar)	PF
WF1	74.7	-9	0.99 lead
WF2	74.7	-9	0.99 lead
WF3	74.7	-9	0.99 lead
BESS	-26.43	-5	0.98 lead

Table 10-16 LF2A Generator Loading Summary

Busbar Operating Voltage and Loading Summary

Main and Sub Hub Main Buses

Busbar ID	Rated Voltage (kV)	Operating Voltage (pu)	Loading (%)	Note
Cluster 1 Intake	132	1.015	8.3	
Cluster 2 Intake	132	0.99	11.7	
MH1-ESB-1321-1	132	1.02	20.7	
MH1-ESB-1321-2	132	1.02	24.1	
MH1-ESB-3301	33	1.01	41.4	1
SH2-ESB-0601	7	0.979	25.3	
SH2-ESB-1101	11.5	1.012	28.1	
SH2-ESB-1102	11.5	1.009	14.9	
SH2-ESB-3301	35	1.015	28.2	

Table 10-17 LF2A Main and Sub Hub Main Bus Summary

Note 1: This bus is also representative of the operating conditions of identical sister busses.

Platform Intake Buses

Busbar ID	Rated Voltage (kV)	Operating Voltage (pu)	Loading (%)	Note
Forties Alpha-A Intake	33	1.008	63.9	1
Alba Northern Intake	11	1.008	46.1	
Andrew Intake	11	0.997	25	
Britannia Intake	6.6	1.004	25.4	

Table 10-18 LF2A Platform Bus Summary

Note 1: Forties Alpha-A is also representative of the operating conditions of Forties Alpha-B.

Power Factor

The power factor remains at a healthy operating region at all busses within the system; the exception to this is at the 132 kV sending end of C1H1_C – where the power factor is operating at 0.56 leading, with the main hub absorbing 70 MVar. This can be attributed to the charging current demand of the cable (increased with length) and lower reactive power demand of the Sub Hub 1 load. Comparing this behaviour with circuit C1H2_C shows the interactions of the cable and load characteristics, with C1H2_C operating at a sending PF of 1 (the cable charging current is provided via inductive load).

Transformer Loading and Tap Setting Summary

Transformer ID.	Rating (MVA)	% Loading	On-load Tap setting	Note
MH1-TRX-3301	150	49.7	N/A	1
SH2-TRX-6601	90	63.1	-4	1
SH2-TRX-6603	50	47.1	-3	2
SH2-TRX-6604	50	24.6	-2	2
SH2-TRX-6605	20	62.6	-1	

Table 10-19 LF2A Transformer Loading Summary

Note 1: These transformer operating conditions are representative of identical paralleled transformers with identical generation and loadings.

Note 2: SH2-TRX-6603 & SH2-TRX-6604 have been rated at 50 MVA, however they may be de-rated to closer to their required operating load, depending on manufacturing and network resilience.

Cable Operating Characteristic Summary

Cable ID	Voltage (kV)	Loading (%)	Efficiency (%)	Capacitive Losses (MVar)	Note
H1C1	132	67.9	90.61	114.3	
H2C1	132	109.4	98.05	68.7	1
AN_C1	11	71.3	97.03	0.2	
A_C1	11	38.6	98.15	0.5	
B_C1	6.6	64	98.15	0	
FA_C1	33	54.4	96.14	5.7	2

Table 10-20 LF2A Cable Loading Summary

Note 1: The cable rating calculated in DigSILENT – using the Neher-McGath method - is 674 A. Manufacturer data suggests a thermal rating of 825 A can be achieved. A detailed thermal analysis is recommended for all modelled cables prior to install.

Note 2: 33 kV FA-A is also representative of the operating conditions of 33 kV FA-B

10.3.1.3 LF2B: Maximum Load, Minimum Wind Farm Contribution

Scenario details:

- 70% platform demand at PF 0.9 lag
- 0% wind farm output at PF=0.95 leading (absorbing MVar)
- 3 Main Hub generators in circuit to meet demand

Real and Reactive Power Flows

Values for real and reactive power flow throughout the network are shown on the Single Line Diagram in Appendix 28.8

Generator Loading Summary

Generator ID	Real Power (MW)	Reactive Power (MVar)	PF
MH1-CGT-0001	60.2	-7.6	0.99 lead
MH1-CGT-0002	60.2	-7.6	0.99 lead
MH1-CGT-0003	60.2	-7.6	0.99 lead
BESS	17.3	-8.7	0.89 lead

Table 10-21 LF2B Generator Loading Summary

Busbar Operating Voltage and Loading Summary

The differences in the operating voltages at each bus is negligible when compared with the previous LF2A case in Section 10.3.1.2. Table 10-22 presents the exceptions to this as the reactive and active power flow is controlled at the Main Hub.

Busbar ID	Rated Voltage (kV)	Operating Voltage (pu)	Loading (%)
CGT1, CGT2 & CGT3	13.8	1.007	63

Table 10-22 LF2B Bus Operating Summary

Power Factor

The power factor characteristics of the system are near identical to the previous case.

Transformer Loading Summary

The differences in transformer loading is negligible when compared with the LF2A case in Section 10.3.1.2. Table 10-23 presents the exceptions to this due to the primary power generation source changing on the Main Hub.

Transformer ID.	Rating (MVA)	% Loading	On-load Tap setting	Note
MH1-TRX-1301	70	86.1	N/A	1

Table 10-23 LF2B Transformer Loading Summary

Note 1: These transformer operating conditions are representative of identical paralleled transformers with identical generation and loadings.

Cable Operating Characteristic Summary

Identical to the LF2A case in Section 10.3.1.2.

10.3.1.4 LF3A: Minimum Load, Maximum Wind Farm Contribution

Scenario details:

- 30% platform demand at PF 0.95 lag
- 100% wind farm MW output

Generator Loading Summary

Generator ID	Real Power (MW)	Reactive Power (MVar)	PF	Note
WF1	74.7	-24.6	0.95 lead	
WF2	74.7	-24.6	0.95 lead	
WF3	74.7	-24.6	0.95 lead	
BESS	-137	-17.6	0.99 lead	1

Table 10-24 LF3A Generator Loading Summary

Note 1: The net power in this case shows the amount of additional power available/to be absorbed by the system. In this case the BESS is overloaded beyond its rated capability at 207%. Options for utilising this Net power are discussed in Section 23.1.

Busbar Operating Voltage and Loading Summary

Main and Sub Hub Main Buses

The operating voltages in this scenario are presented in Table 10-25. Note that for minimum loading cases the loading factor has not been considered.

Busbar ID	Rated Voltage (kV)	Operating Voltage (pu)	Note
Cluster 1 Intake	132	1.016	
Cluster 2 Intake	132	1.002	
MH1-ESB-1321-1	132	1	
MH1-ESB-1321-2	132	1	
MH1-ESB-3301	132	0.973	
SH2-ESB-0601	7	0.963	
SH2-ESB-1101	11.5	0.978	
SH2-ESB-1102	11.5	0.982	
SH2-ESB-3301	35	0.966	1

Table 10-25 LF3A Main and Sub Hub Main Bus Summary

Note 1: SH2-ESB-3301 is also representative of the operating conditions of SH2-ESB-3302.

Platform Intake Buses

Busbar ID	Rated Voltage (kV)	Operating Voltage (pu)	Note
Forties Alpha-A Intake	33	1	1
Alba Northern Intake	11	1	
Andrew Intake	11	1	
Britannia Intake	6.6	1	

Table 10-26 LF3A Platform Bus Summary

Note 1: Forties Alpha-A is also representative of the operating conditions of Forties Alpha-B.

Power Factor

The PF at the sending terminals of H2C1 and HC21 sub-sea cables are 0.26 and 0.71, respectively. This can be attributed to reduced inductive demand at platforms, resulting in the need for increased reactive power absorption at the Main Hub.

Transformer Tap Summary

Loading is not presented in this case, due to the reduced demand. The tap change settings detailed in Table 10-27 were necessary to maintain healthy platform voltages.

Transformer ID	Case 2A an 2B On-load Tap setting	Case 3A On-load Tap setting
SH2-TRX-6601	-4	3
SH2-TRX-6603	-3	1
SH2-TRX-6604	-2	1
SH2-TRX-6605	-1	2

Table 10-27 LF3A Transformer Tap Summary

Note 1: SH2-TRX-6601 tap setting is representative of identical paralleled transformers with identical loadings.

Cable Operating Characteristic Summary

Cable ID	Loading (%)	Efficiency (%)	Capacitive Losses (MVar)	Note
H1C1	71.2	81.94	112.2	1
H2C1	57.4	98.56	68.1	
AN_C1	29	100.00	0.2	
A_C1	15.5	100.00	0.5	
B_C1	25.8	100.00	0	
FA_C1	22.1	97.25	5.4	

Table 10-28 LF3A Cable Operating Summary

Note 1: Cable loading is still an important factor to consider at a reduced load – especially at high voltage - as the cable capacity can be dominated by charging currents and lack of natural reactive compensation from the net inductive load. The constant capacitive losses with a lower resistive and inductive load in this case also factor significantly in the reduced efficiency.

10.3.1.5 LF3B: Minimum Load, Wind Farm Curtailment

This case presents similar network characteristics to the previous study case; however, the wind-farm MW input has been curtailed. The BESS is operating within its rated capacity.

Due to the lower MVar absorption of the wind-farm, an additional 35 MVar reactive compensation element (reactor) has been included in the Main Hub.

Table 10-29: LF3B Generator Loading Summary

Generator ID	Real Power (MW)	Reactive Power (MVar)	PF	Note
WF1	28.6	-9.4	0.95 lead	
WF2	28.6	-9.4	0.95 lead	
WF3	28.6	-9.4	0.95 lead	
BESS	0	-69.4	0	
Main Hub Reactor	0	35	N/A	

10.3.1.6 LF3C: Minimum Load, Minimum Wind Farm Contribution

Scenario details:

- 30% platform demand
- 0% wind farm output
- 2 Main Hub generators in circuit to meet MW demand.

Generator Loading Summary

Table 10-30: LF2B Generator Loading Summary

Generator ID	Real Power (MW)	Reactive Power (MVar)	PF	Note
MH1-CGT-0001	42.9	-30.8	0.81 lead	
MH1-CGT-0002	42.9	-30.8	0.81 lead	
BESS	0	-36.5	0	
Main Hub Reactor	0	35	N/A	1

Note 1: In this case additional compensation is needed to absorb the excess reactive power of the system.

The differences in the operating voltages at each bus is negligible when compared with the LF2A study case in Section 10.3.1.2. Table 10-31 presents the exceptions to this as the load reactive and active power flow is controlled at the Main Hub.

Table 10-31: LF2B Bus Operating Summary

Busbar ID	Rated Voltage (kV)	Operating Voltage (pu)
CGT1, CGT2 & CGT3	13.8	0.948
BESS	0.8	0.939

Power Factor

The power factor characteristics of the system are near identical to the previous case.

Transformer Loading Summary

The differences in transformer loading is negligible when compared with the LF3A study case in Section 10.3.1.4. Table 10-32 presents the exceptions to this due to the primary power generation source changing on the Main Hub.

Table 10-32: LF2B Transformer Loading Summary

Transformer ID	Rating (MVA)	% Loading	On-load Tap setting	Note
MH1-TRX-1301	70	79.7	N/A	1

Note 1: These transformers operating conditions are representative of identical paralleled transformers with identical generation and loadings.

Cable Operating Characteristic Summary

Identical to the LF3A study case in Section 10.3.1.4.

10.3.2 Short Circuit

10.3.2.1 Maximum Fault Levels

The results for the maximum fault study case are shown in Appendix 28.12 with summary findings detailed in Table 10-33 and Table 10-34 below.

Table 10-33: Maximum Fault Levels at System Buses

Busbar ID	Type	Max 3ph Ik'' (kA)	% of Bus Thermal Capacity	Max 3ph ip (kA)	% loading of bus rated ip
MH1-ESB-3301	C	19.56	52.3	50.67	61.78
CGT1	D	42.01	78.3	109.11	87.3
MH1-ESB-1321-1	A	9.64	19.84	24.46	23.5
Cluster 1 Intake	A	4.51	10.1	10.21	9.8
Cluster 2 Intake	A	6.75	14.8	15.92	15.3
SH2-ESB-6601	B	10.09	17.9	24.59	18.9
SH2-ESB-3301	C	10.02	29.1	25.17	30.7
SH2-ESB-1101	E	21.42	40.3	54.75	42.1
SH2-ESB-1102	E	20.04	40.9	51.56	39.7
SH2-ESB-0601	F	22.29	45.4	56.89	45.5

Table 10-34: Maximum Fault Levels at Platform Buses

Busbar ID	Max 3ph Ik'' (kA)	% of Bus Thermal Capacity	Max 3ph ip (kA)	% loading of bus rated ip
Forties Alpha Intake	7.49	24.7	17.59	27.1
Alba Northern	13.18	29.2	29.8	28.7
Andrew	7.9	17.8	17.07	16.4
Britannia Intake	14.23	25.9	32.25	25.8

Note: Intake bus ratings for platforms Andrew and Britannia are based on Sub Hub sending bus design ratings and not known data.

10.3.2.2 Minimum Fault Levels

The results for the minimum fault study case are shown in Appendix 28.13 with summary findings detailed in Table 10-35 below.

Table 10-35: Minimum Fault Levels at System and Platform Buses

Busbar ID	Min 3ph Ik'' (kA)	Min 3ph ip (kA)
MH1-ESB-3301	3.67	9.7
CGT1	21.64	55.5
MH1-ESB-1321-1	1.16	3.04
Cluster 1 Intake	0.98	2.45
Cluster 2 Intake	1.07	2.75
SH2-ESB-6601	1.91	4.94
SH2-ESB-3301	2.88	7.5
SH2-ESB-1101	7.75	20.23
SH2-ESB-1102	7.75	20.23
SH2-ESB-0601	10.21	26.51
Forties Alpha Intake	2.21	5.35
Alba Northern	5.44	12.78
Andrew	3.97	8.77
Britannia Intake	7.06	16.54

10.3.3 Motor Starting

10.3.3.1 Motor Start on Alba North

The following results for motor starting are presented in Figure 10-6 and Figure 10-7 below:

- Active power at the 4.9MW motor
- Reactive power at the 4.9MW motor
- Voltage at the Alba North main HV switchboard
- Voltage at the 4.9MW motor terminals
- Current at the 4.9MW motor
- Speed of the 4.9MW motor
- Torque of the 4.9MW motor (mechanical and electrical)

The results show that the motor takes approximately 25 seconds to start with a maximum voltage reduction at the Alba North HV switchboard of 0.855 pu.

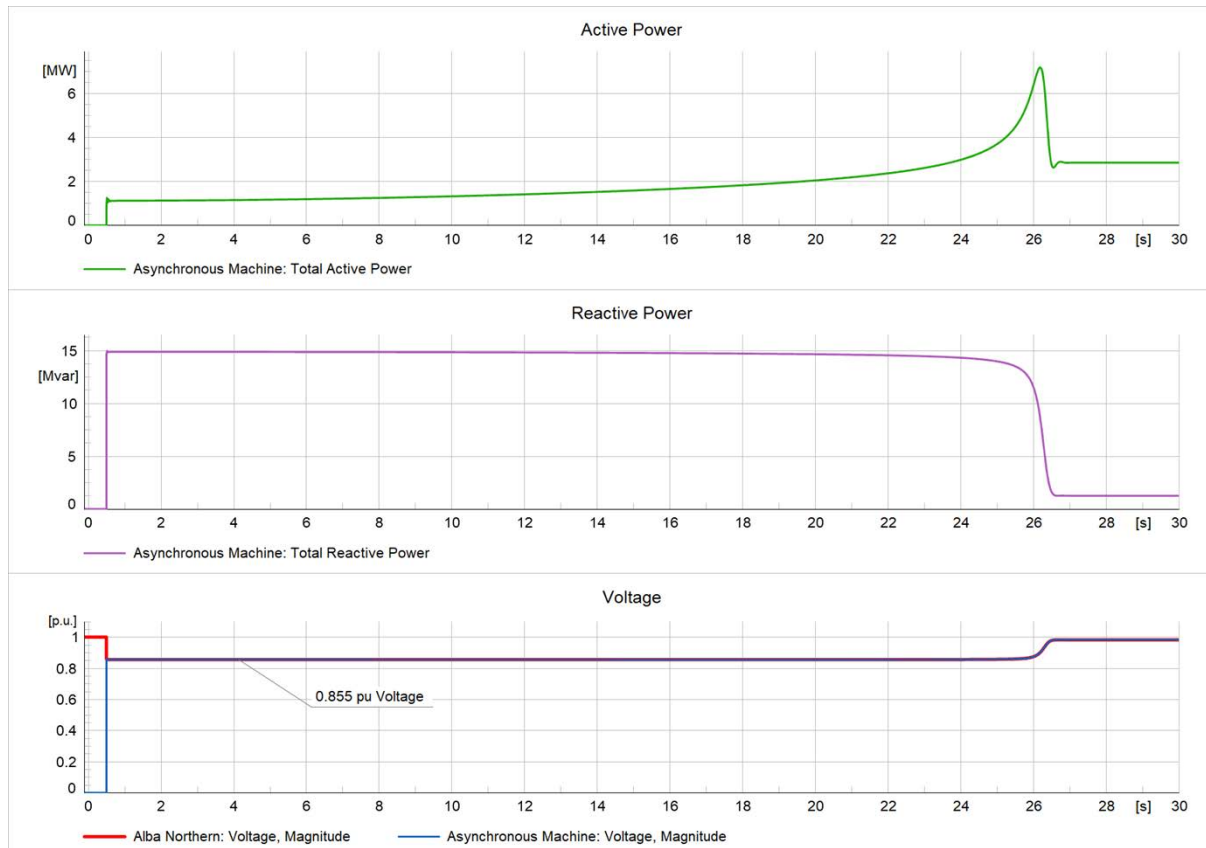


Figure 10-6: Active Power, Reactive Power and Voltage Results

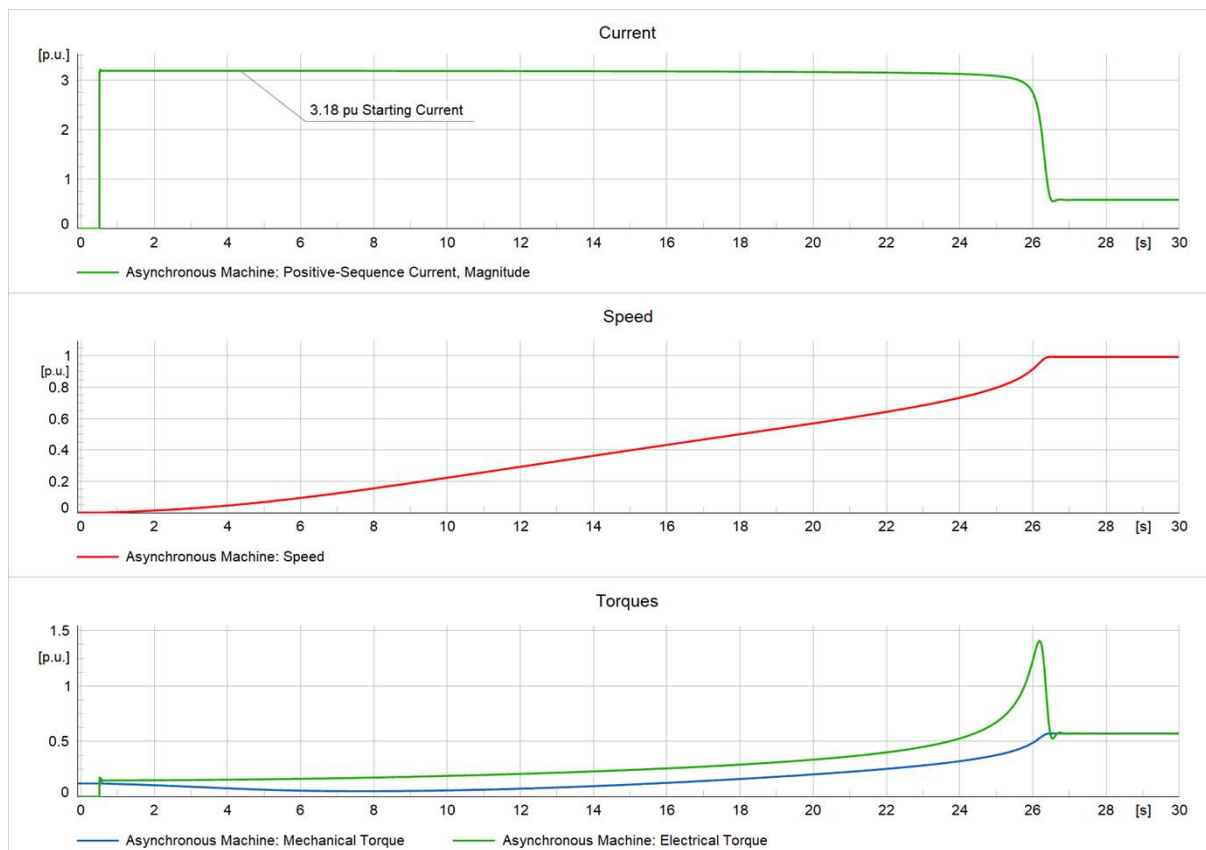


Figure 10-7: Current, Speed and Torque Results

10.4 Discussion

10.4.1 Network Voltages

The load flow studies have shown that utilising basic voltage control via Main Hub generation and storage (storage capability is a topic for further study) allows Main Hub and Sub Hub voltages to be controlled effectively. On Load Tap Changers installed on the transformers used for platform power distribution allow platform intake buses to be kept within the $\pm 2.5\%$ criteria for the cases studied.

The transformers responsible for platform regulation have been chosen to have secondary voltage rated around 5% above nominal. This is necessary to account for the voltage drop in the submarine cables running to the assets, especially when approaching maximum load.

Note: Additional voltage control could be realised with tap changers (on load or off load) on an intermediate 132/66kV step down transformer at the incomer to the Sub Hub, but the studies completed show that this facility is not necessary.

10.4.1.1 Submarine Cable Voltages, Loadings and Efficiencies

The efficiency of the H1C1 cable between Main Hub and Sub Hub 1 is typically lower than other submarine cables due to its length, and thus reactive demand.

There are cases where the power delivery to several platforms may be met with one sub-sea 3C cable. This presents an opportunity for revision to the two cable per circuit modelling approach. This will require specific manufacturer data for cables exceeding the maximum CSA sizes provided in standard manufacturer datasheets and referenced in Table 10-10.

10.4.1.2 Reactive Compensation for Subsea Cables

Static compensation has been added into the model at the incomer to Sub Hub 1 (a fixed value of 20 MVar) to mitigate against the capacitance effects of the long subsea cables. In some cases with curtailed or no wind farm power delivery the need for reactive power absorption is provided by an additional 35 MVar reactor on the main hub.

The wind farm may harness the capability to operate at reduced leading power factor – a greater level of detail is needed in order to assess the potential operating characteristics of the Wind Turbine Generators (WTG), as well as detail of the associated transmission system.

Possible methods of adding reactive compensation to a network include:

- **Shunt Capacitors** – mechanically switched devices that can improve load-ability and voltage regulation of lines and alleviate the burden on generators absorbing/producing VARs.
- **Static Compensators** – Static Compensator (SC) is the term used to refer generally to both a Static VAr Compensator (SVC) – which uses thyristor-controlled reactors and capacitors, and Static Synchronous Compensators (STATCOM) – which can be considered a synchronous voltage source behind a reactance.

The defined compensation requirements of SC can be split into two performance criteria:

- Voltage control in order to maintain suitable voltage regulation and allow the enhancement of the maximum possible power flow
- Improvement of transient stability of the system – increasing stability margins and power oscillation damping

Both of these factors involve control of the terminal voltage of the compensator – however, the control method employed differs. STATCOMs elicit faster control, superior flexibility and overall better performance when compared with a SVC, but may prove unnecessary according to the system requirements.

10.4.1.3 Transformer Ratings and Tap Settings

The study has determined that the transformers are operating within their rating and determined that typical tap ranges are sufficient to allow for the required voltage control.

Transformer tap ranges can be tailored after assessment of all clusters to determine the best overall approach.

Transformer impedances for transformers in this range can be specified to allow or restrict fault current contribution based on switchgear ratings and system strength contribution.

10.4.2 Equipment Ratings

The short circuit studies demonstrate that the fault currents (both initial symmetrical (I''_k) and peak (i_p)) are within the selected equipment ratings.

The highest short circuit results are seen at the 13.8kV switchboard which acts as the incomer from the gas turbines, along with the 11kV switchboards on the Sub Hub.

The equipment selected is from the manufacturer's "standard" range of products and means that weight and footprint can be kept to a minimum.

No requirement for fault limiting devices has been identified.

10.4.3 Motor Starting

The simple motor starting study completed here shows that the large DOL motor on Alba North can be started against the Sub Hub 2 network without exceeding the voltage limits. However, further study work is required to understand the full extent of the impact of starting a large motor, on other platforms connected to the same Sub Hub, and on the ability of the network to deliver sufficient VARs from the Main Hub.

A more detailed transient simulation considering detailed synchronous generator Automatic Voltage Regulator (AVR) and Governor dynamics, as well as the potential of reactive support from Battery Energy Storage System(s) (BESS) and discharging capacitive energy stored within sub-sea cables. It is expected the case demonstrated in section 10.3.3 presents an overly conservative approach.

10.4.4 Other Discussions Points

10.4.4.1 Local Platform Power Quality Issues

The majority of platforms in the modelled network have relatively large gas turbines as their primary source of power. These have the potential to contribute to system stability through the ability to deliver VARs or to strengthen the voltage closer to the consumers. However, their presence in the network may also increase fault currents and cause further transient issues as the wind farm contribution varies. For the purposes of the model any local generation on the platforms has been ignored.

The study has relied on the use of On Load Tap Changes to regulate the voltage received at the platforms. This can be done in simulation, however, to achieve in practice will require live monitoring of the platform voltages to allow for correct operation.

10.4.4.2 Solutions for Net Power

In a dynamic system fed by renewable power there will be periods when excess power is generated (i.e. the output of the wind farm exceeds that of the platform's total power demand).

This excess power will need to be accounted for, ideally utilising it in a useful way, with a number of possible options discussed here:

- **Utilise excess power to produce hydrogen via electrolysis of sea water** – this hydrogen could then be used in a hydrogen generator or fuel cell to produce electrical power during periods of low wind
- **Charging up flywheels for mechanical storage** – some work has been completed to understand whether storing energy as kinetic energy using flywheels is a possibility for offshore¹
- **Utilise conventional battery storage for chemical storage** – charging a battery bank using excess power, which could then be discharged as required
- **Incorporating battery storage with a STATCOM for improved network control** – an appropriately connected STATCOM could mitigate stability and voltage fluctuations on the network with energy storage allowing the unit to operate across all four quadrants
- **Utilise innovative storage solutions** – the FLASC system² is a hydro-pneumatic storage system that can be incorporated into a floating platform, or it may be possible to incorporate pumped storage utilising the cargo tanks of the Sevan Floating Production Storage and Offloading (FPSO) design
- **Incorporate a connection to another network, either offshore or shore connection** – although conceived as an islanded system, there would be benefits into connecting into other offshore networks, or to the onshore grid, which would mean that power could be exported/imported as required and offset the need for local generation or storage. An added benefit would be the extra resilience of the network with backup from shore, as well as the ability to extend the useful life of the wind farm beyond that of the oil & gas platforms
- **Power other services/utilities** – for example, run carbon capture/storage compression facilities, sea water injection or booster compression facilities on or near the Main Hub using excess power
- **Other innovative solutions** – for example, charging points for electrically powered offshore vessels

¹<https://www.dendanskemaritimefond.dk/wp-content/uploads/2016/02/FINAL-report-The-Danish-Maritime-Fund.pdf>

² <https://www.offshoreenergystorage.com/>

10.5 Conclusion

The power system modelling completed and detailed in this report shows that it is technically feasible to meet the power demand requirements of platforms at their native operating voltage without introducing additional equipment on the platforms themselves. Voltage regulation can be achieved primarily through the use of On Load Tap Changers installed at transformers on the Sub Hubs as well as by specifying a higher nominal secondary voltage for the transformers.

The study has identified that the network will benefit from reactive compensation and energy storage deployed strategically to help regulate transient changes – however, the potential exists for a combined system that meets the requirements of both (as discussed in Section 10.4.1.2 and Section 23.1). Further study work is required to determine the exact impact and requirements for these aspects, as well as consider the ability of the wind farm input and local generation controls to assist with system integrity.

Voltages and power flows can be maintained on all Main and Sub Hub busses through effective use of the generating and/or energy storage equipment. Delivery voltages at each platform can be maintained within tight tolerances by use of OLTC devices.

The system modelled here is based on High Voltage AC transmission with minimal control. A further area of study is to consider the use of MVDC where the power electronics involved would likely offer significantly improved control over network characteristics whilst presenting additional challenges which would require more detailed study.

10.6 Further Areas of Study

10.6.1 Additional Power System Study Types

- Dynamic interactions between fluctuating OWA inputs, gas turbine generation and energy storage.
- Cable and transformer energisation studies – reactors in/out of circuit
- Motor starting study – voltages within the wider network
- Submarine Cable harmonics
- Protection settings and coordination
- Grid code type study pack for the connected wind generation – high and low voltage ride through (VRT), reactive power capability, ability to operate at a specified power factor, frequency variations, fast fault current injection

10.6.2 Additional Power System Modelling

10.6.2.1 Further Development of the CNS Cluster

- Different strategies for storage placement throughout the network should be explored to optimise their usage. This could include storage on the Main Hub, on Sub Hubs or a combination.
- To complete more detailed dynamic studies the turbine governor/generator AVR, and detailed dynamic models of the BESS and OWA will need to be modelled in detail.
- Expand to include more detailed consideration of Sub Hub 1, 3 and 4.

10.6.2.2 MVDC Distribution Architecture

An alternative proposal for bulk transmission of power over long distances subsea is utilising Medium Voltage DC. This is a proven technology onshore and is being explored by various OEMs for offshore application. This would require modelling of the full DC bridge and the characteristics of the power electronics at sending and receiving end to then understand the impact on the electrical network.

10.7 Opportunities / Risks / Assumptions

10.7.1 Opportunities

The study indicates that both reactive compensation and energy storage are needed for optimum operation of the network. There are opportunities available to combine these technologies into a single application which would provide benefits around space and weight saving whilst also simplifying the network architecture.

The study has highlighted the opportunities for the use of an integrated power management system with full network data and control to enable optimum and efficient operation.

The study presents opportunities to introduce new and emerging technologies, particularly around energy storage, to meet the requirements of dealing with excess power generated by the wind farm.

Retention of local generation on the platform presents an opportunity for more optimal reactive power contribution and voltage stability, but with added control complexity and the risk of reverse power flows or increased fault levels.

10.7.2 Risks

The output characteristics and ability to control (or not) the wind farm output represents a potential risk to the network.

11. Electrical Modelling Study (SNS)

11.1 Objective

The purpose of this study is to complement the Electrical Distribution Modelling (Section 10) in assessing technical challenges associated with electrification of Oil and Gas platforms within the North Sea. The Southern North Sea (SNS) provides different technical challenges when compared with the CNS region previously studied. This is due to closer cluster proximity and relatively lower power requirements of the platforms.

11.2 Methodology/Background

11.2.1 Software

DlgSILENT PowerFactory 2022 Version 1 software has been used to model the network and complete the analysis.

11.2.2 Model

11.2.2.1 System Description

A partial model of Southern North Sea (SNS) cluster 1 was developed in DlgSILENT PowerFactory 2022 Version 1 software using the data and assumptions described in this section.

The system is modelled at the incoming 33 kV bus, with upstream represented as a 33 kV Grid element within DlgSILENT. The Main Hub for this system has not been modelled; with the analysis focused on maintaining healthy system characteristics within the platform distribution network.

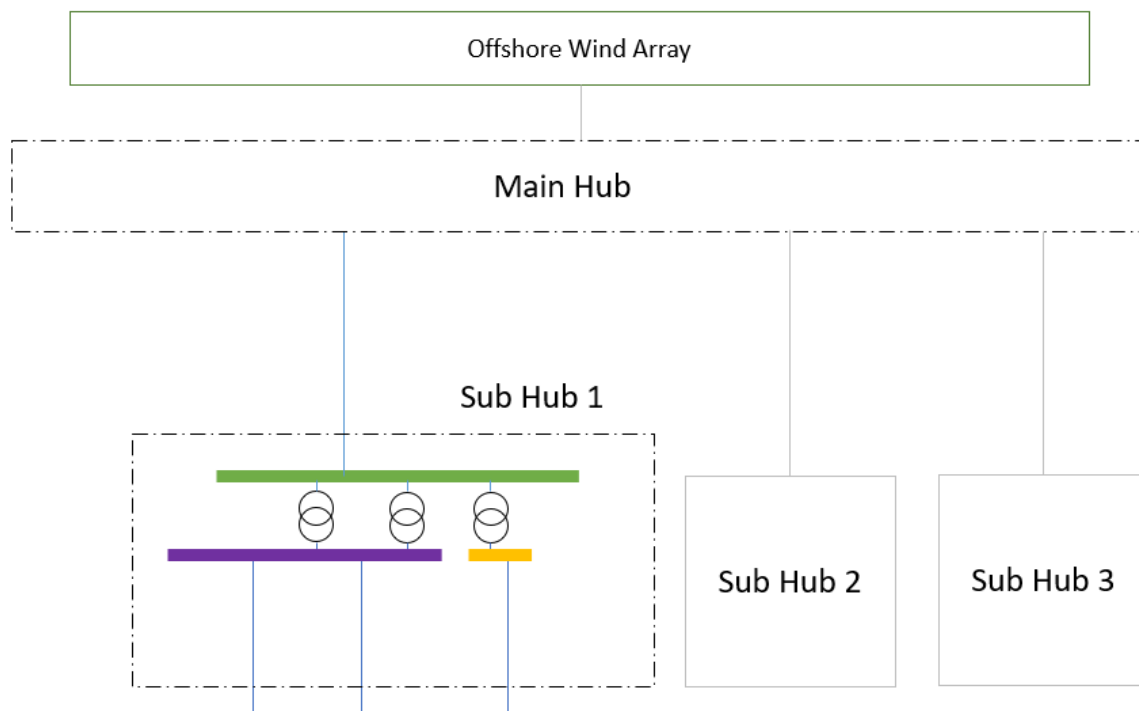


Figure 11-1: Overview of SNS Cluster 1

Due to the low voltages and low power demands on a majority of the SNS assets it is not practical to run cables to the platform at their native operating voltage. Instead, a high voltage cable will be run with compact containerised transformers and switchgear installed on the platforms. Free deck space for this will need to be assessed on each platform. As an alternative, subsea transformers may be utilised though these are more expensive than topsides equipment. The modelling in this report assumes all

equipment is topsides with the arrangement shown in Figure 11-2, Figure 11-3 and Figure 11-4 below. Existing electrification which exists in this area is not shown in these figures but has been accounted for in the model at a high level.

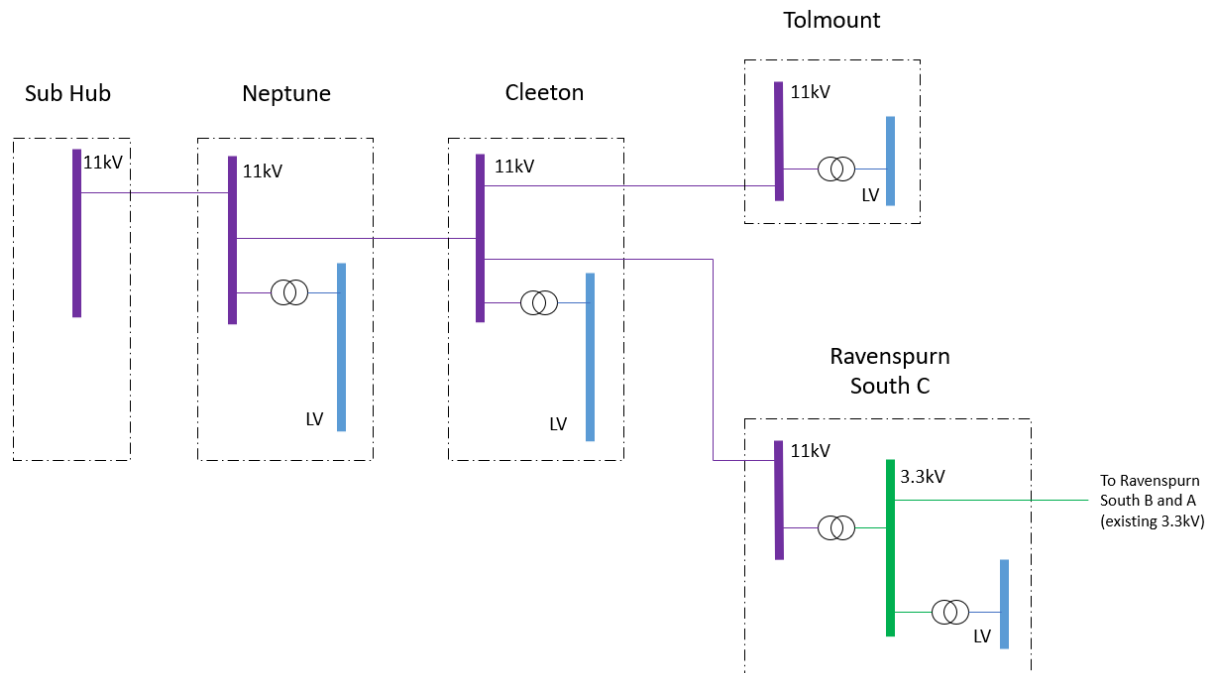


Figure 11-2: 11kV Network to Neptune, Cleeton and Tolmount

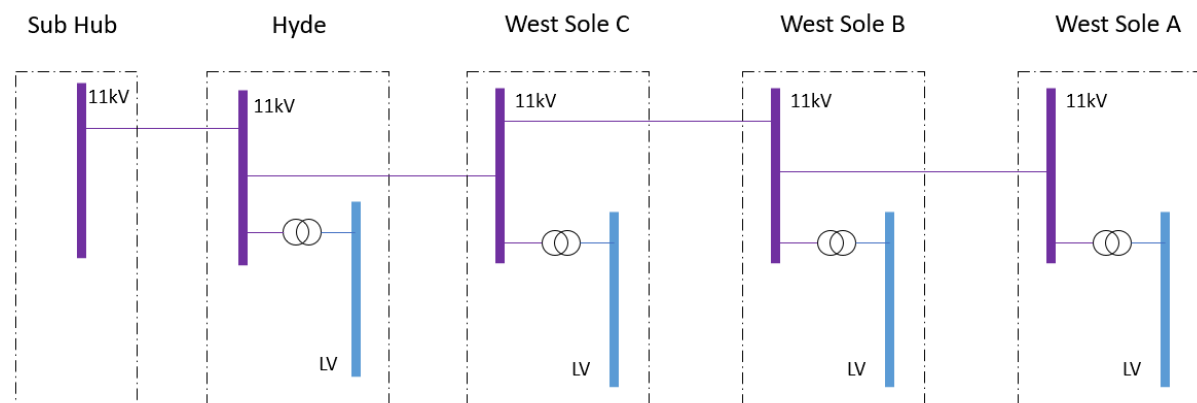


Figure 11-3: 11kV Network to Hyde and the West Sole assets

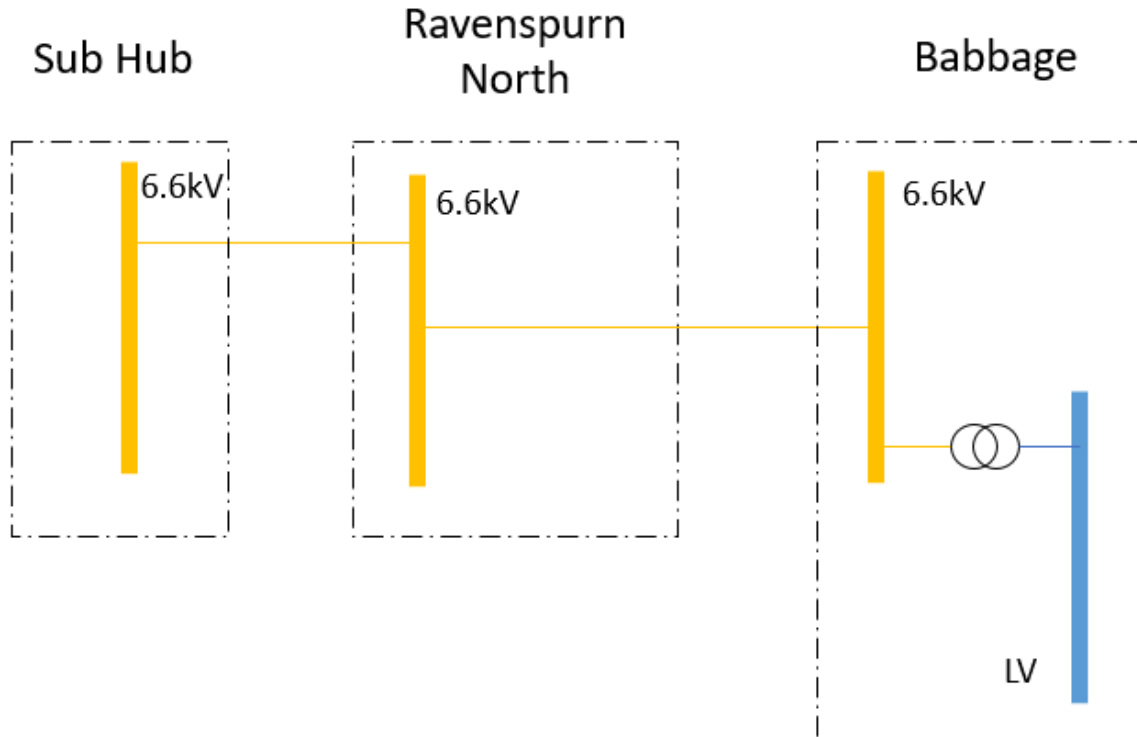


Figure 11-4: 6.6kV Network to Ravenspurn North and Babbage

11.2.2.2 Grid Element

The power source for the Sub Hub is modelled within DlgSILENT as a grid equivalent element with a connection voltage of 33 kV.

The key grid characteristics is summarised in Table 11-1 below:

Table 11-1: AC Grid Data

Parameter	Symbol	
Voltage	PF	33 kV / 1 pu
Grid Strength	MVAsc	100 MVAsc
X/R Ratio	-	15

11.2.2.3 Transformers

Transformers have been selected based on typical ratings contained within DlgSILENT and where necessary complimented with data recommended in engineering standards and best practices. Where possible the number of transformer sizes have been reduced to simplify specification and procurement. This may result in some transformers being of a higher rating than the platform demand requires. This can be further assessed.

The transformer impedance and X/R ratios were assumed based on standard values given in /45/ and /46/, respectively. Copper losses are calculated within DlgSILENT based on the X/R ratio of the transformer. No load current of all transformers assumed at 0.3% of Full Load Current (FLC).

On Load Tap Changes (OLTCs) have been included on the Sub Hub transformers to allow for independent voltage regulation; depending on feeder loadings.

Table 11-2: Sub Hub Power Transformer Data

Type	Quantity	Rating [MVA]	Voltage Ratio (kV)	Impedance [%]	X/R	OLTC %Z Range/ %Z per Tap
A	2	2	33/11	6	15	±5% / 2.5%
B	1	2	33/6.6	6	15	±5% / 2.5%

Table 11-3: Network Power Transformer Data

Type	Quantity	Rating [MVA]	Voltage Ratio (kV)	Impedance [%]	X/R	OLTC %Z Range/ %Z per Tap
C	1	2	11/3.3	6	15	±5% / 2.5%
D	1	0.75	11/3.3	5	10	N/A
E	6	0.5	11/0.415	4	7.5	N/A
F	1	0.5	6.6/0.415	4	7.5	N/A
G	3	0.315	3.3/0.415	4	5	N/A

11.2.2.4 Switchgear & Ring Main Units (RMUs)

Switchgear has been selected based on consultation with OEMs to suit the operating voltage level and estimations of rated current and short circuit current. These selections will be verified as part of the Power Systems analysis work.

Table 11-4: Switchboard & RMU Types

Type	System Voltage [kV]	Manuf	Model	Breaker Type	Voltage Rating [kV]	Current Rating (Switch/Breaker) [A]	Iw/3s [kA]	ip Rating [kA]
A	33	ABB	UniGear ZS2	VCB	36kV	1250 A	25	63
B	11	ABB	UniGear ZS1	VCB	12kV	630 A	31.5	80
C	6.6	ABB	UniGear ZS1	VCB	7.2kV	630 A	31.5	80
D	11/6.6	Schneider	RN2d	SF6	12kV	630/200 A	21	52.5

11.2.3 Platform Loads

For the purposes of the study work completed at this stage platforms have been mostly modelled as lumped loads comprising of a mix of both static and motor loads to give a reasonable representation of the load.

Table 11-5: Platform Load Summary

Platform	kW	PF
Babbage	144	0.9
Cleeton	1200	0.9
Hoton	15	0.85
Hyde	200	0.9
Minerva	100	0.85
Neptune	35	0.9
Ravenspurn North	1200	0.9
Ravenspurn South A	45	0.9
Ravenspurn South B	45	0.9
Ravenspurn South C	45	0.9
Ravenspurn North ST2	150	0.85
Ravenspurn North ST3	150	0.85
Tolmount	170	0.9
West Sole A	300	0.9
West Sole B	200	0.9
West Sole C	200	0.9

11.2.3.1 Submarine Cables

The following table provides the length and type of cable used for each circuit within the model. It is noted one cable is used per circuit in all cases. Cable type definitions and the associated electrical characteristics are detailed in section 11.2.4.1.

Table 11-6: Submarine Cable Summary Data

Cable ID	Type	Circuit Length (km)
CLE_RAVSC_C	D	7
CLE_TOL_C	D	18.7
HYD_WSC_C	D	6.9
NEP_CLE_C	C	6.8
RAVN_BAB_C	D	10.8
RAVSB_RAVSA_C	D	5.5
RAVSC_RAVSB_C	D	5.5
SH1_HYD_C	B	13
SH1_NEP_C	B	12.3
SH1_RAVN_C	A	18.1
WSB_WSA_C	D	2.7
WSC_WSB_C	D	4.6

Note 1: All submarine cables have been modelled as bonded at the sending and receiving end.

Note 2: Cables with <11 kV operating voltage have been modelled as 11 kV rated cables, due to limited manufacturer data.

11.2.3.2 Topsides Cables

Topsides cables on the Sub Hub have been ignored for the purposes of this model. Compared to the submarine cables these will be very short run cables introducing little additional impedance at the operating voltages described.

11.2.3.3 Reactive Compensation

No Reactive compensation is included within the SNS system.

11.2.4 Study Methodology

11.2.4.1 Cable Ampacity and Electrical Characteristics

Without specific manufacturer design data each sub-sea cable has been modelled based on data contained within /48//49//50/.

Each sub-sea cable is modelled within DIgSILENT as a separate cable system, with the cable and surrounding pipe material types, thicknesses and geometric spacings defined (as shown in Figure 10-5).

An impedance and admittance matrix is formed within DIgSILENT, with the resultant values compared and tuned to the Resistance, Inductance and Capacitance (RLC) data provided by manufacturer datasheets – giving the electrical characteristics detailed in Table 10-7. An ampacity calculation was carried out to determine the thermal limits, and thus maximum loading of the cable (as defined in Table 11-6).

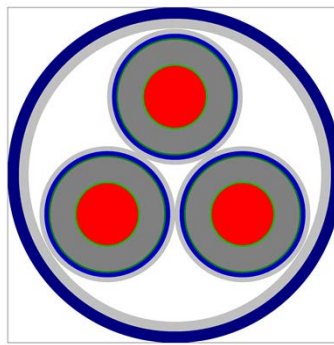


Figure 11-5: DIgSILENT Sub-Sea Cable Geometric Makeup

Table 11-7: Electrical Characteristics of Cable Types

Type	Cable CSA (mm ²)	Cable Capacity (A)	Rdc (Ω /km)	R1 (Ω /km)	L1 (mH/km)	C1 (uF/km)
A	630	795	0.027	0.039	0.29	0.69
B	185	440	0.093	0.101	0.325	0.436
C	95	305	0.181	0.186	0.34	0.32
D	35	175	0.492	0.497	0.395	0.226

11.2.4.2 Load Flow

A Load Flow Study shall be run to determine:

- Real Power Flows
- Reactive Power Flows
- Voltage Drops
- Suitability of Equipment Ratings

Methodology

The upstream Main Hub network has been simplified as a 33 kV grid element – connected to the Sub Hub 33 kV bus. The purpose of the loadflow cases in this report is in determining the suitability of electrification of the SNS, and therefore modelling of the Sub Hub and the downstream distribution network is sufficient in the assessment. The Active and Reactive power requirements of the system are provided by the grid, with the results analysed to determine the compensation requirements (if any) during the various cases.

Criteria

For the load flow the criteria established in IEC 61892-1:2019 /53/ shall be applied to determine the viability of the solution. These are summarised in Table 11-8 below.

Table 11-8: Load Flow Voltage Criteria

Characteristic	Value (%)	Applicability
Voltage Tolerance	+6/-10	Steady state voltage tolerance on switchboards on both the Main Hub and Sub Hubs
Primary Distribution Voltage Tolerance	+2.5/-2.5	Steady state voltage tolerance at the main HV switchboard of the platform supplied from a Sub Hub

The sub-sea cables shall be assessed against the following conditions:

- **Loading** – the percentage of the cable's rated current carrying capacity utilised under the load flow conditions.
- **Efficiency** – is a measure of the received/sending MW across each cable. Though hard limits do not exist, it provides a good indication of the suitability of selected cable length, type, size, installation method, as well as the requirement for additional compensation.
- **Volt Drop** – the percent reduction in voltage between the sending end of the cable and the receiving end; at higher voltages this is typically dominated by the reactive component of cable impedance.

Load Flow Study Cases

The three study cases defined in Table 11-9 were identified and configured within the modelling software.

Table 11-9: Load Flow Case Summary

Study ID	Platform Demand	OLTCs	Bus Configuration
LF1	70% at 0.9PF lag	N/A	Normal
LF2	30% at 0.95PF lag	N/A	Normal
LF3	Max/Min Unbalance	In service	Normal

11.2.4.3 Short Circuit

Overview

A fault level analysis has been carried using the IEC 60909 /54/ calculation method, to determine the maximum and minimum fault levels at each bus within the network. The purpose of this study is to determine the required withstand ratings for the switchgear and identify whether fault limiting equipment is required within the network.

Methodology

The following presents the methods employed during the calculation of the maximum and minimum fault level calculations performed using DiGSILENT. It should be noted both cases represent approximate fault levels expected for the system modelled. Further modelling of the upstream Main Hub would be required before the suitability of equipment ratings can be confirmed.

Maximum Fault Level

This study represents the normal, worst-case operating condition of the site and is intended to identify the maximum short circuit level that is experienced by each MV switchboard, and associated Protection Devices (PD). The study case is based on the following settings:

- Grid element fault level as per section 11.2.2.2 (100 MVA_{sc}).

- Motor fault contribution at 2.8 MVA/MW at maximum load conditions. This figure represents a 70/30 motor/static split, with an average locked rotor current contribution of 4 pu.
- Maximum Voltage factor for MV $c = 1.1$ and LV $= 1.05$ (as per IEC 60909, table 1).
- Calculation method C is used for X/R values for I_p (as per IEC 60909, section 4.1.3.2).

11.3 Results

11.3.1 Load Flow

11.3.1.1 LF1: Maximum Load

Scenario details:

This case assesses the system requirements at an aggregated maximum load.

- 70% platform demand at PF=0.90 lag.
Where the platform is supplied via an existing platform configuration, and circuit details are unknown – the load will be modelled directly at the providing platform – with a reduced power factor of 0.85 lag (to account for additional cable reactance). The exact power factors for this case can be observed in Section 28.14.
- Grid element used as reference bus and voltage control.

Real and Reactive Power Flows

Values for real and reactive power flow throughout the network are shown on the Single Line Diagram in Appendix 28.6.

Power Requirements and PF Summary

With the voltage on the 33 kV bus retained at 1 pu the overall power demand of the system equates to 3.1 MVA, at a power factor of 0.99 lead. Therefore, no reactive power compensation is deemed necessary in this case. Note this requirement may change when the incoming cable circuit from the Main Hub is considered.

Busbar Operating Voltage and Loading Summary

The following table shows the voltages at each bus remaining within the voltage constraints detailed in section 11.2.4.2 - under heavy load conditions.

Table 11-10: LF1 Sub Hub and Platform MV Bus Summary

Busbar ID	Nominal Voltage (kV)	Operating Voltage (pu)	Loading (%)
Babbage 6.6 kV	6.6	0.981	1.6
CLE-3.3 kV	3.3	0.978	26.5
Cleeton 11 kV	11	0.992	10
Hyde 11 kV	11	1.018	5.6
Neptune 11 kV	11	1.007	10
Ravenspurn N 6.6 kV	6.6	0.995	17.8
Ravenspurn SA 3.3 kV	3.3	0.982	1
Ravenspurn SB 3.3 kV	3.3	0.992	2
Ravenspurn SC 11 kV	11	0.989	1
Ravenspurn SC 3.3 kV	3.3	1.01	3
SH1-ESB-0601	6.6	1.038	16.8
SH1-ESB-1101	11	1.022	9.7
SH1-ESB-1102	11	1.026	5.4
SH1-ESB-3301	33	1	4.3
Tolmount 11 kV	11	0.984	1.1
West Sole A 11 kV	11	0.992	2.1
West Sole B 11 kV	11	0.995	3.3
West Sole C 11 kV	11	1.002	4.5

Power Factor

The power factor throughout the system remains within an acceptable value.

Transformer Loading and Tap Setting Summary

Table 11-11: LF1 Transformer Operating Data Summary

Transformer ID.	Rating (MVA)	% Loading	Off-load Tap setting
BAB-TRX-0001	0.5	23.2	0
CLE-TRX-0001	2	48	0
HYD-TRX-0001	0.5	31.1	0
NEP-TRX-0001	0.5	5.7	0
RAV-TRX-0001	0.8	15.4	-1
RSA-TRX-0001	0.3	11.6	0
RSB-TRX-0001	0.3	11.5	0
RSC-TRX-0001	0.3	11.3	0
SH1-TRX-3301	2	60.2	-1
SH1-TRX-3302	2	33.5	-1
SH1-TRX-3303	2	63.8	-2
TOL-TRX-0001	0.5	27.3	0
WSA-TRX-0001	0.5	47.9	0
WSB-TRX-0001	0.5	31.8	0
WSC-TRX-0001	0.5	31.5	0

Note 1: The tap setting in this case represents the need for adjustment to the nominal impedance of the transformers. Load flow case 3 (section 11.3.1.3) presents a case where on-load tap changers are required on certain transformers due to the variability of the system loads.

Cable Operating Characteristic Summary

The cable operating characteristics show acceptable levels of efficiency and very low cable loading percentages – even at maximum (diversified) load; showing voltage regulation is the limitation factor for when selecting a CSA size. The 6.6 kV cable 'SH1_RAVN_C' shows a significantly higher voltage drop and lower efficiency than all other modelled cables – due to the lower operating voltage and largest operating current on this system.

Table 11-12: LF1 Cable Operating Data Summary

Cable ID	Loading (%)	Efficiency (%)	Capacitive Losses (kVAR)	Voltage Drop (%)
CLE_RAVSC_C	3.5	99.60	70.9	0.3
CLE_TOL_C	5.4	98.12	188.3	0.9
HYD_WSC_C	16.2	98.45	72.6	1.6
NEP_CLE_C	20.6	98.69	99.2	1.4
RAVN_BAB_C	5.8	98.55	39.2	1.4
RAVSB_RAVSA_C	3.7	99.08	2.2	0.9
RAVSC_RAVSB_C	7.2	98.03	2.2	1.9
SH1_HYD_C	8	99.17	270.2	0.8
SH1_NEP_C	14.3	98.65	251.7	1.5
SH1_RAVN_C	14.1	97.33	211.8	4.3
WSB_WSA_C	7.6	99.69	27.5	0.3
WSC_WSB_C	12	99.18	47.3	0.8

Note 1: Capacitive losses shows the capacitive reactance produced by each cable, and thus, required to be absorbed by the system. In most cases the inductive reactive load provides compensation for a portion of this power.

11.3.1.2 LF2: Minimum Load

Scenario details:

This case assesses the system requirements at an aggregated minimum load.

- 30% platform demand at PF=0.95 lag.
Where the platform is supplied via an existing platform configuration, and circuit details are unknown – the load will be modelled directly at the providing platform – with a reduced power factor of 0.9 lag (to account for additional cable reactance).
- Grid element used as reference bus and voltage control.

Real and Reactive Power Flows

Values for real and reactive power flow throughout the network are shown on the Single Line Diagram in Appendix 28.6.

Power Requirements and PF Summary

With the voltage on the 33 kV bus reduced to 0.972 pu the overall power demand of the system equates to 1.51 MVA, at a power factor of 0.87 lead. The lower power factor in this case can be attributed to the reduced inductive load on the system; therefore, requiring the grid to absorb 755 kVAR. A PF of 0.87 is deemed acceptable for the purpose of this study; though it is necessary to model the Main Hub to determine the capability of the generation/storage equipment to absorb this additional capacitive energy.

Busbar Operating Voltage

The following table shows the voltages at each bus remaining within the voltage constraints -detailed in section 11.2.4.2 - under light load conditions. This is achieved by exclusively adjusting the voltage at the 33 kV bus to 0.972 pu; with transformer tap settings remaining in identical positions detailed in the LF1 case (see Table 11-11).

Note bus/switchgear loading are not included in this table due to the reduced demand of the system.

Table 11-13: LF2 Sub Hub and Platform MV Bus Summary

Busbar ID	Nominal Voltage (kV)	Operating Voltage (pu)
Babbage 6.6 kV	6.6	1.008
CLE-3.3 kV	3.3	0.997
Cleeton 11 kV	11	1.002
Hyde 11 kV	11	1.004
Neptune 11 kV	11	1.006
Ravenspurn N 6.6 kV	6.6	1.013
Ravenspurn SA 3.3 kV	3.3	1.013
Ravenspurn SB 3.3 kV	3.3	1.017
Ravenspurn SC 11 kV	11	1
Ravenspurn SC 3.3 kV	3.3	1.024
SH1-ESB-0601	6.6	1.024
SH1-ESB-1101	11	1.008
SH1-ESB-1102	11	1.005
SH1-ESB-3301	33	0.972
Tolmount 11 kV	11	0.999
West Sole A 11 kV	11	0.994
West Sole B 11 kV	11	0.995
West Sole C 11 kV	11	0.998

Power Factor

The operating power factor at the Sub Hub 11 kV sending busses is low due to the capacitive demand of the 11 kV cables and the lack of counter-balancing inductive load. The Sub Hub 6.6 kV sending bus shows a power factor of 0.99 lead – reinforcing the delicate balance between capacitive demand of the cable and inductive load on the system. In this case – the overall power factor of the system is considered acceptable.

Transformer Loading and Tap Setting Summary

The transformer loadings are not considered due to the lightly loaded nature of this study case. Transformer tap settings are identical to Table 11-11 – with voltage regulation being achieved by adjustment of the 33 kV bus on the Sub Hub.

Cable Operating Characteristic Summary

Table 11-14: LF2 Cable Operating Data Summary

Cable ID	Loading (%)	Efficiency (%)	Capacitive Losses (kVAR)	Voltage Drop (%)
CLE_RAVSC_C	2	99.78	72.3	0.1
CLE_TOL_C	5.5	96.84	193.1	0.2
HYD_WSC_C	6.9	99.36	71.3	0.6
NEP_CLE_C	9	99.41	100.1	0.4
RAVN_BAB_C	2.5	99.33	40.9	0.5
RAVSB_RAVSA_C	1.5	100.00	2.3	0.4
RAVSC_RAVSB_C	2.9	99.31	2.3	0.8
SH1_HYD_C	5	99.33	261	0.1
SH1_NEP_C	7.8	99.16	248.1	0.2
SH1_RAVN_C	5.6	98.64	212.4	1.1
WSB_WSA_C	3.1	99.90	27.5	0.1
WSC_WSB_C	4.8	99.68	47.1	0.3

Note 1: Capacitive losses shows the capacitive reactance produced by each cable, and thus, required to be absorbed by the system. In most cases the inductive reactive load provides compensation for a portion of this power.

11.3.1.3 LF3: Maximum/Minimum Unbalance

Scenario details:

This case assesses the system requirements with uneven load distribution via the three Sub Hub transformers; demonstrating the limitations of using 33 kV voltage control exclusively to maintain healthy voltages throughout the network. The following loadings have been applied

- Feeder SH1_NEP_C, fed from Sub Hub transformer SH1-TRX-3301 is supplying 70% platform demand at PF=0.90 lag (as per the LF1 case)
Where the platform is supplied via an existing platform configuration, and circuit details are unknown – the load will be modelled directly at the providing platform – with a reduced power factor of 0.9 lag (to account for additional cable reactance).
- The remainder of the system is loaded at 30% at PF=0.95 lag (as per the LF2 case).
Where the platform is supplied via an existing platform configuration, and circuit details are unknown – the load will be modelled directly at the providing platform – with a reduced power factor of 0.9 lag (to account for additional cable reactance).
- Grid element used as reference bus, with voltage control provided via the grid element and Sub Hub transformer on-load tap changers.

Real and Reactive Power Flows

Values for real and reactive power flow throughout the network are shown on the Single Line Diagram in Appendix 28.6.

Power Requirements and PF Summary

With the voltage on the 33 kV bus reduced to 0.98 pu the overall power demand of the system equates to 2.07 MVA, at a power factor of 0.99 lead.

Busbar Operating Voltage and Tap change

This case demonstrates the requirement and additional flexibility afforded with Sub Hub transformers supplemented with on-load tap changers. The following table shows the voltages at each bus before and after the following tap adjustments are made:

- SH1-TRX-3301 tap position changed from -1 to -2 – which equates to -5% impedance.

It is noted the remaining busses not fed from this transformer are unchanged, and remain within the desired steady state voltage tolerances

Bus/switchgear loadings are not considered in this case.

Table 11-15: LF3 Sub Hub and Platform MV Bus Summary

Busbar ID	Nominal Voltage (kV)	Operating Voltage pre tap change (pu)	Operating Voltage post tap change (pu)
Babbage 6.6 kV	6.6	1.016	1.016
CLE-3.3 kV	3.3	0.955	0.984
Cleeton 11 kV	11	0.97	0.999
Hyde 11 kV	11	1.011	1.011
Neptune 11 kV	11	0.985	1.013
Ravenspurn N 6.6 kV	6.6	1.022	1.022
Ravenspurn SA 3.3 kV	3.3	0.958	0.989
Ravenspurn SB 3.3 kV	3.3	0.968	0.999
Ravenspurn SC 11 kV	11	0.967	0.996
Ravenspurn SC 3.3 kV	3.3	0.987	1.017
SH1-ESB-0601	6.6	1.032	1.032
SH1-ESB-1101	11	1	1.028
SH1-ESB-1102	11	1.013	1.013
SH1-ESB-3301	33	0.98	0.98
Tolmount 11 kV	11	0.961	0.99
West Sole A 11 kV	11	0.997	0.997
West Sole B 11 kV	11	0.999	0.999
West Sole C 11 kV	11	1.003	1.003

11.3.2 Short Circuit

11.3.2.1 Maximum Fault Levels

The results for the maximum fault study indicate fault levels across the system are well within switchgear/RMU thermal capacity and peak current (ip) ratings. An SLD of the results are shown in Appendix 28.19 with summary findings detailed in Table 10-33.

Table 11-16: Maximum Fault Levels at System Buses

Busbar ID	Type	Max 3ph Ik'' (kA)	% of Bus Thermal Capacity	Max 3ph ip (kA)	% loading of bus rated ip
Babbage 6.6 kV	D	0.565	1.6	0.853	1.6
CLE-3.3 kV	D	2.518	7	5.349	10.2
Cleeton 11 kV	D	1.045	2.9	2.046	3.9
Hyde 11 kV	D	1.136	3.1	2.384	4.5
Neptune 11 kV	D	1.214	3.4	2.585	4.9
Ravenspurn N 6.6 kV	D	1.379	3.5	3.015	5.7
Ravenspurn SA 3.3 kV	D	0.322	0.9	0.477	0.9
Ravenspurn SB 3.3 kV	D	0.546	1.5	0.821	1.6
Ravenspurn SC 11 kV	D	0.754	2.1	1.212	2.3
Ravenspurn SC 3.3 kV	D	1.423	3.9	2.654	5.1
SH1-ESB-0601	C	2.606	4.9	6.655	8.3
SH1-ESB-1101	B	1.567	2.9	3.993	5
SH1-ESB-1102	B	1.51	2.8	3.862	4.8
SH1-ESB-3301	A	1.872	4.4	4.794	7.6
Tolmount 11 kV	D	0.482	1.3	0.728	1.4
West Sole A 11 kV	D	0.622	1.7	0.991	1.9
West Sole B 11 kV	D	0.693	1.9	1.126	2.1
West Sole C 11 kV	D	0.842	2.3	1.433	2.7

11.4 Conclusion

The power system modelling completed and detailed in this report shows that it is technically feasible to meet the power demand requirements of platforms at their native operating via the installation of submarine cables and modular RMU/Transformer coupled units.

Voltage regulation can be achieved utilising 33 kV voltage control (this may be achieved by manipulation at higher voltages – as is the case with the CNS case presented in Section 10) and via on-load tap changers integrated with the Sub Hub transformers. It is noted the voltage/impedance adjustment is lower in magnitude, when compared with the CNS cases, and therefore a tap range of $\pm 5\%$ on these transformers should suffice.

The study omitted the use of reactive compensation in the model as the voltage regulation used was sufficient, and the power factor of the grid element was deemed acceptable. It is noted the ability of the upstream network to absorb this level of reactive power will be dependent on the submarine cable run from the Main Hub and on the Main Hub generation/storage characteristics. Modelling upstream of the Sub Hub was not part of the scope for this study.

Ultimately feasible, due to the lower power density of the network, the project suitability will be dependent on cost/environmental considerations.

12. Combined Cycle Offshore Power Study

12.1 Objective

The objective of this study is to investigate the potential for incorporating combined cycle power generation, as opposed to simple cycle, to increase the efficiency of the gas turbines to be utilised for local power generation on this project.

The study will achieve the following:

- Determine the additional equipment required to incorporate the secondary heat recovery step
- Evaluate the increased efficiency of the combined cycle system and estimate the associated reduced fuel gas consumption and emissions reduction
- Identify potential additional complexity and maintenance requirements

This study will not evaluate layout aspects in detail as this was covered in the Main Hub Design Report (Section 15).

12.2 Background

12.2.1 Simple Cycle Versus Combined Cycle Gas Turbines

A simple cycle gas turbine (SCGT) combines a fuel source with air which is then ignited. The resultant gases are then expanded through a turbine to generate electricity. All exhaust gas is routed to atmosphere via an exhaust stack with no energy recovery.

A combined cycle gas turbine (CCGT) is the same as a simple cycle except the waste heat from the turbine exhaust is recovered to generate steam to drive a steam turbine and generate additional electrical power – known as a heat recovery steam generator (HRSG).

At best efficiency point (BEP) SCGTs have efficiencies between 33 and 42% (LHV) whereas CCGTs offer efficiencies between 50 and 60% /55/.

The additional equipment used by a CCGT results in significantly greater weight and space requirements than a SCGT.

As can be seen from the CCGT PFD in Section 12.2.3, more equipment is required for a CCGT system compared to an SCGT system which can increase operating complexity and maintenance requirements.

As the HRSG system operates at very high temperatures, poor water chemistry and frequent cycling can lead to shortened life of the HRSG components due to fatigue and corrosion /57/. Thermal stresses usually occur in two scenarios:

1. Differences in temperature across and through components leading to different rates of expansion – usually worst in heat exchanger coils and tube to header connections
2. Quenching of condensate in hot sections

The temperature differentials are largest at cold start-up, and this is where the greatest thermal stresses occur, hence, frequent cycling can impact the fatigue life of the system.

It can be seen from the Renewables Generation Modelling (Section 8) that significant cycling of the GTs is required due to the stochastic nature of wind energy production. It is therefore important that the design and operation of the system accounts for this variability in load requirements and potential cycling.

The assumed load sharing system in the Renewables Generation Modelling Report emphasised maximising efficiency; however, if cycling is considered an issue, a balance may need to be struck between efficiency and reducing cycling of the CCGTs. This is discussed further in Section 12.5.

Traditionally, CCGTs have been used to meet base load requirements but with the increased use of variable renewable energy in power systems, CCGTs are used more and more in load following and cycling service /63/. This has resulted in CCGTs being better designed for cycling. Examples of improved design include the following /64/:

- Spring supports for coils and headers rather than fixed
- Optimising component thickness
- Improved condensate management and drain design

Additionally, CCGTs typically take longer to start-up compared to SCGTs (1.5 – 3 hours versus 30 minutes) /58/. The GT section of a CCGT can start up as per SCGTs, however, the steam turbine section can take longer to ramp-up due to having to bring the steam system up to temperature, which means it can take longer for the CCGT to reach full efficiency. This combined with potential frequent cycling of the GTs could mean that it is difficult to take advantage of the full efficiency of a CCGT.

12.2.2 Gas Turbines in the Offshore Oil and Gas Industry

Offshore platforms have traditionally used aeroderivative gas turbines (GTs) in simple cycle operation. Where heating is required on the platform, the GTs are often paired with some form of waste heat recovery (WHR) to heat the heating medium used on the platform.

The popularity of SCGTs offshore is due to space and weight concerns outweighing fuel gas consumption and emissions concerns, particularly at the time that most platforms were built - many more than 40 years ago.

Typical set up on O&G platforms is to combine the SCGTs with a WHRU. A WHRU uses the high temperature exhaust gas from the GT to heat the platform heating medium which is then distributed to platform heat users. The use of a WHRU effectively increases the efficiency of the GT power generation; however, it is common for the platform process heating requirements to decline over time resulting in reduced efficiency gains from using the WHRU, or in some cases the WHRU is removed from use. Table 12-1 below summarises an example of this for a North Sea Oil and Gas Platform

Year of Operation	GT Power Demand (MW)	Waste Heat Recovery (MW)	Effective Efficiency (%)
Year 1 Operation	14.5	14	55.5
2022 Operation	11.5	8	42

Table 12-1 - Platform Power Generation and WHR Requirement Over Time

Note - The effective efficiency is an estimated efficiency if the combined GT output and WHR was all provided by the turbine.

It can be seen from Table 12-1 that the process heating requirements have declined by approximately 50% from year 1 to now, resulting in a decrease in the effective efficiency of the power generation from 55.5% to 42%. In many cases the decline in process heat requirements is much greater and often the WHRUs are no longer in use, resulting in a more drastic decline in the effective efficiency.

With declining production rates, high fuel prices, increased concern regarding GHG emissions and the implementation of an emissions trading scheme (ETS); the efficiency of offshore power generation has become far more important. Additionally, this project presents an opportunity to provide a greenfield design which can better accommodate the extra space and weight of a CCGT system.

12.2.3 Combined Cycle GT System PFD

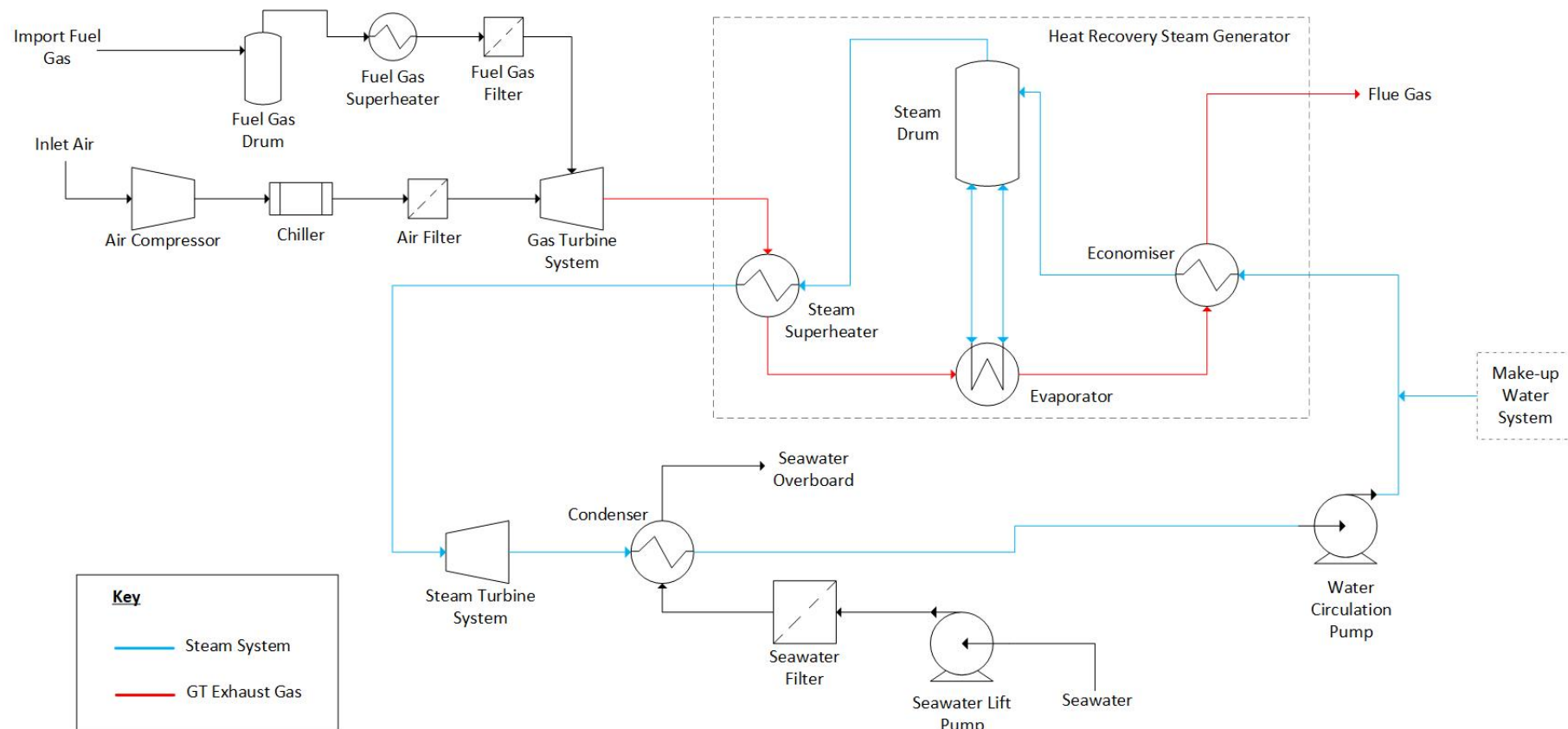


Figure 12-1 - Typical CCGT PFD

12.2.4 LM6000 GT

The LM6000 aeroderivative GT has been selected as the basis for the local power generation on the main hub.

The LM6000 GT was selected for the following reasons:

- Proven technology - tried and tested in the oil and gas industry and many operational hours
- High reliability and availability
- Simple design - reducing maintenance and operational complexity
- Universal and modular packaging
- High efficiencies
- Capacity larger than conventional offshore oil and gas GTs
- Fuel flexibility – able to run on partial hydrogen fuel

The LM6000 GT is available in simple cycle or combined cycle configurations.

Below is a list of key LM6000 PF simple cycle specifications /56/:

Net Output (MW)	44.7
Net Efficiency (% LHV)	41.4
Reliability	99.8
Availability	98.7

Table 12-2 LM6000 PF Simple Cycle Specs

Below is a list of key LM6000 PF+ combined cycle specifications /56/:

Net Output (MW)	72.4
Net Efficiency (% LHV)	55.3
Reliability	99.8
Availability	98.7

Table 12-3 LM6000 PF Combined Cycle Specs

12.2.5 Centralised Versus Decentralised Power Generation

One of the major aspects of the design approach for this project is the centralisation of the power generation equipment i.e., all power generation equipment for the installations will be located on the main hub as opposed to each individual installation using its own power generation equipment.

There are potential advantages to the centralised system compared to the existing decentralised system, namely:

- Sharing resource and sub-systems
- Higher operational efficiency – Operating closer to efficiency point as multiple units with a much larger demand.

12.2.5.1 Efficiency Improvements

Many installations are operating their power generation equipment outside of optimal operating points. This is because many systems are oversized for current energy requirements and lack operating flexibility due to minimising the number of GTs as part of the topsides design because of space and weight constraints.. This reduces the overall efficiency of power generation equipment and results in additional emissions and costs associated with fuel gas consumption.

Centralising the power generation equipment for multiple installations results in the parallel operation of more GTs than normal e.g., 6 GTs vs the usual 2-3. This allows for additional flexibility when energy requirements are reduced, either through reduced demand over time or when an installation is shut down, which can ensure that operating points and efficiency can be maintained at more optimal levels.

For example, using data from the Renewables Generation Modelling Report, the operating efficiency of the CCGTs were estimated for 100%, 70% and 30% of total design load. The results are shown in the following table:

% of Total Design Load	No. of Operating CCGTs	CCGT Operating Efficiency
100	6/6	55.3
70	5/6	52.4
30	2/6	54.2

Table 12-4 - Average CCGT Operating Efficiency vs % of Total Load (Centralised Power Generation)

The table below shows the results for a typical platform design based on 2 x SGT 400s:

% of Total Design Load	No. of Operating GTs	GT Operating Efficiency
100	2/2	28.1
70	1/2	32.7
30	1/2	21

Table 12-5 - GT Operating Efficiency vs % of Total Design Load (Typical Platform Design)

It can be seen from the tables that with the centralised design the combined operating efficiency of the CCGTs is stable and remains relatively close to optimal whereas for the typical platform design the operating efficiency of the GTs is less stable and the efficiency is low at the 30% of design load point.

12.2.5.2 Sharing Resource and Sub-systems

Centralising the power generation equipment allows for resource (e.g., operators) and sub-systems (e.g., fuel gas) to be shared across each of the GTs. This could potentially reduce OPEX per MWh as fewer total operators will be required and the sharing of sub-systems should result in less equipment to operate and maintain.

12.3 Methodology

A comparative analysis of CCGTs with SCGTs was carried out, utilising the Renewables Generation Modelling (Section 8) calculation model as a basis.

The Renewables Generation Modelling Report used data for the Dudgeon Wind Farm to model the power generation system for this project and analyse the interaction between wind power generation and local power generation using CCGTs or SCGTs.

CCGT and SCGT local power generation were compared against the following metrics:

- Fuel gas costs
- Emissions
- UK Emissions Trading Scheme (ETS) costs

Both cases are compared against a total power demand of 418.5 MW which is based on the target zone identified from the Platform Clustering Study (Section 6).

The Renewables Generation and Modelling (Section 8) concluded that a wind provision of approximately 105% of the base load requirement was optimal. This is referred to as the P₉₅ case and will form the basis for the comparison of the two systems in this study.

The calculation model was also used to assess the impact that designing the load sharing system to reduce cycling may have on the efficiency of the local power generation system.

Refer to the Renewables Generation Modelling (Section 8) for details of the methodology and assumptions used.

CO₂ emissions were estimated by multiplying the estimated fuel gas consumption rate converted to a yearly basis and the equivalent CO₂ produced by burning a kg of natural gas, assumed to be 2.5 kg CO₂ / kg Natural Gas /61/.

The ETS costs were calculated by multiplying the yearly CO₂ emissions by the ETS clearing price, taken as to be 60 £/tonne /62/.

For more detail on the UK ETS refer to the Cost of Energy Determination study (Section 20)

Fuel gas costs were estimated based on a price of 90 pence a therm.

12.4 Results

The following table of results are based on a 418.5 MW required capacity and installed wind power of 432 MW (P_{95}):

	Simple Cycle	Combined Cycle
Fuel Cost (£MM/Yr)	134	101
Emissions (Mtn/Yr)	971	731
ETS Cost (£MM/Yr)	58	44

Table 12-6 CC vs SC (Fuel Costs, Emissions, ETS Costs)

	CCGT vs SCGT
Fuel Cost Saving (£MM/Yr)	33
Emissions Reduction (%)	24.7%
ETS Cost Saving (£MM/Yr)	14
Total Cost Saving (£MM/Yr)	47

Table 12-7 - CC vs SC (Costs Savings and Emissions Reduction)

The above results are based on a simple load sharing system which minimises the number of CCGTs required to load share, which results in significant cycling.

The graph below shows the number of operating generators over a period of a week:

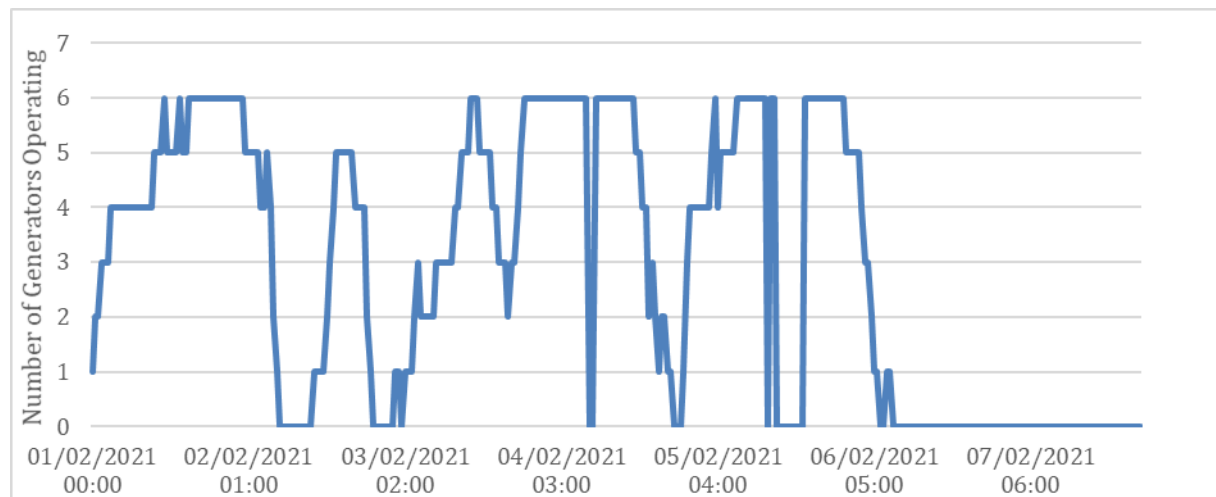


Figure 12-2 Operational Generators Trend

The graph shows the significant amount of GT cycling required to meet the required load capacity. It can also be seen that the time between cycles can vary with as little as half an hour between start-up and shutdown of CCGTs and some much longer periods.

If cycling is deemed to be an issue due to thermal stresses and fatigue life concerns, then it may be necessary to operate the CCGTs in a way that minimises cycling at the cost of reduced efficiency.

A less variable load sharing system which assumes that all the minimum number +1 and +2 CCGTs operate and share load when the wind power cannot meet the full required capacity was modelled. The SCGTs information is the base SCGT production as cycling is considered to be less of a concern.

The results were as follows:

	Simple Cycle	Combined Cycle	Combined Cycle (n+1)	Combined Cycle (n+2)
Fuel Cost (£MM/Yr)	134	101	107	112
Emissions (Mtn/Yr)	971	731	775	810
ETS Cost (£MM/Yr)	58	44	46.5	49

Table 12-8 - CC vs SC Alt. Load Share (Fuel Costs, Emissions, ETS Costs)

	CCGT (n+1) vs SCGT	CCGT (n+2) vs SCGT
Fuel Cost Saving (%)	20.15	16.42
Emissions Reduction (%)	20.19	16.58
ETS Cost Saving (%)	19.83	15.52
Total Cost Saving (%)	20.16	16.51

Table 12-9 - CC vs SC Alt. Load Share (Cost Savings and Emissions Reduction)

It can be seen from the above results that the costs and emissions are still lower compared to simply using SCGTs when the CCGTs are modelled to reduce cycling.

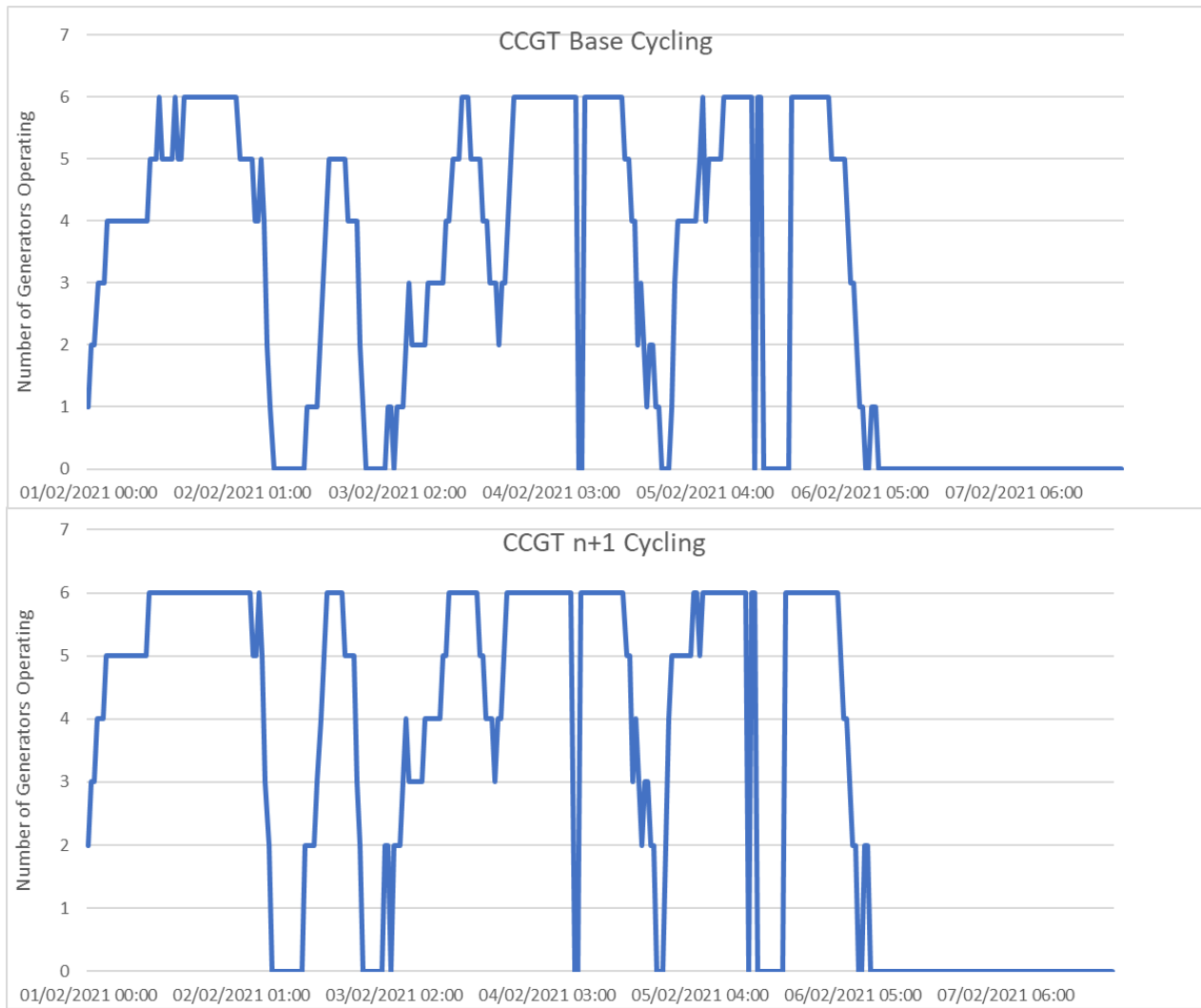


Figure 12-3 - Operational generators Trend Alt. Load Share (n+1)

As can be seen from Figure 12-3, there is still significant cycling of the CCGTs with 8 cycles in a week and days where multiple cycles are required, however the basic cycling has been reduced with the n+1 configuration of operating generators in load sharing. This is due to how frequently the wind power can fluctuate between exceeding the load capacity requirement and producing zero power.

Figure 12-4 details a similar arrangement with n+2 turbines operational, which shows even more reduction in cycling with smoother curve profiles.

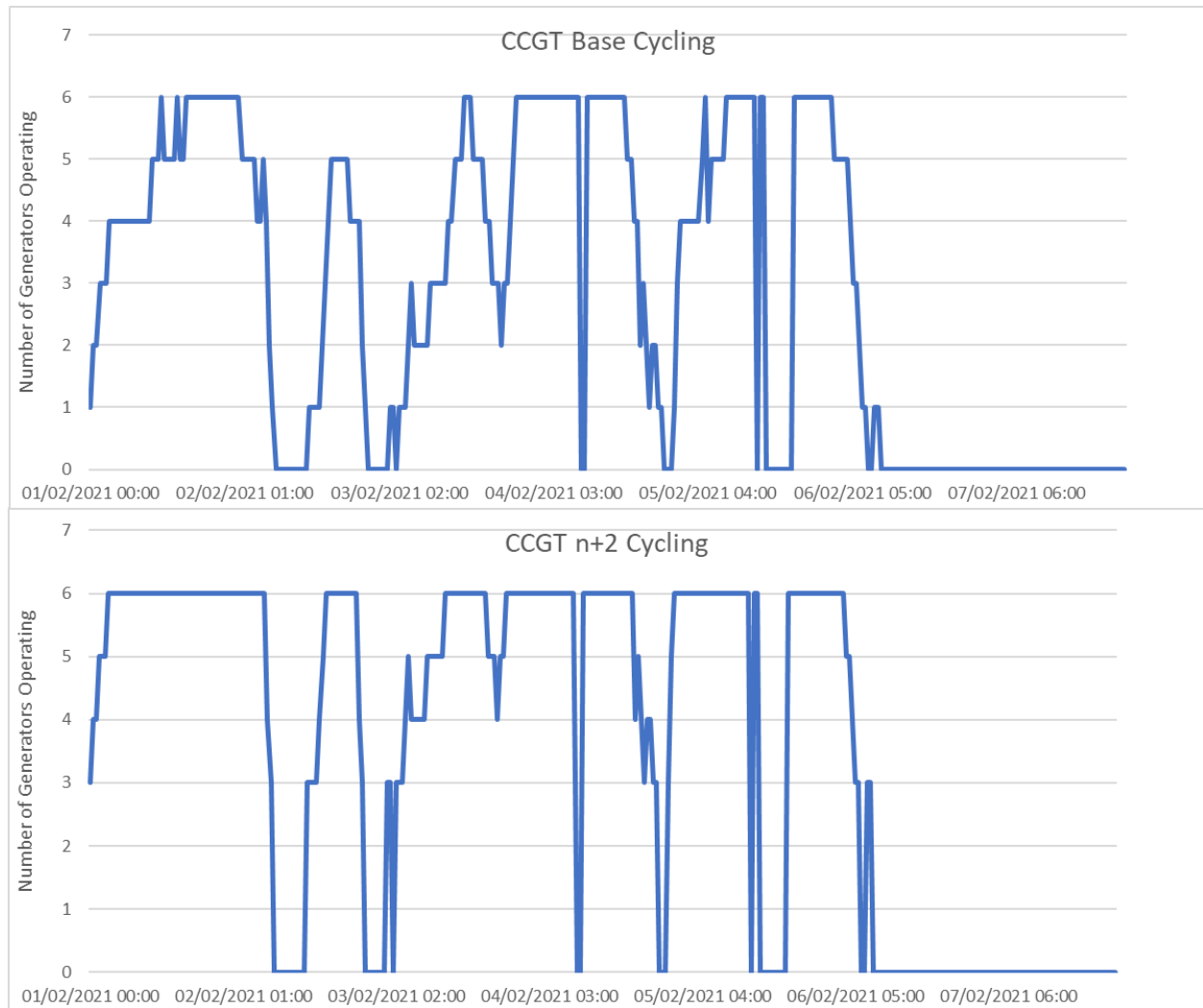


Figure 12-4 Operational generators Trend Alt. Load Share (n+2)

A potential hybrid system could be utilised to reduce cycling of the CCGTs, a combination of CCGTs and SCGTs could be used, with CCGTs in constant operation providing a base load and SCGTs cycled to meet required capacity when wind power capacity is not sufficient. This however would impact emissions more significantly and would result in a smaller than estimated wind array input.

The results of the modelling do not consider any impact that slow start-up / ramp-up time of the CCGT steam turbine will have on the overall efficiency.

Modelling the impact of steam turbine start-up / ramp-up is complex, and sufficient data was not available to model this effectively. The model is therefore over optimistic in its estimation CCGT efficiency, which should be noted whilst analysing the above results.

Residual heat in the steam system which will be retained due to insulation, in addition to the potential addition of electric heaters to maintain system temperature and operating conditions to essentially prime the system have not been considered in the design.

12.5 Discussion

12.5.1 Emissions and Fuel Costs

The results of modelling SCGTs versus CCGTs for a 418.5 MW required capacity show that the use of CCGTs over SCGTs result in potential emissions, fuel cost and ETS cost savings of 24.7%. Refer to Table 12-7.

However, these results are based on a load sharing system with unrestricted cycling which effectively maximises efficiency, and no impact of slow start-up / ramp-up of the steam turbine system.

A complex dynamic model to better predict the impact of slow start-up / ramp-up of the steam turbine could not be effectively modelled; however, it is likely that this would reduce the average efficiency of the CCGTs resulting in increased emissions, fuel and ETS costs compared to the values predicted by the model. Further work must be carried out in future to understand the impact this may have on the efficiency of the CCGTs.

Table 12-8 and Table 12-9 show that operating the turbines in a load sharing system that reduces cycling can lead to reductions in overall efficiency, with emissions, fuel cost and ETS higher than the base CCGT case, however still significantly less than using just SCGTs.

It is critical that the PMS design is optimised to rationalise cycling as much as possible, and constantly rotate operating machines to aggregate the run time on each generator as a poor design could lead to significant reductions in overall efficiency of the CCGTs and potential increased maintenance.

At very low load requirements it would not be practical to share power across all 6 CCGTs, and a potential supplementary power transfer system, such as a battery bank, may prove to be beneficial to again smooth out the cycling curves.

However, Figure 12-3 and Figure 12-4 demonstrate that, due to the variable nature of wind energy production, significant cycling is still required even when the model is configured to minimise cycling. This means that if CCGTs are to be used to load follow, they must be carefully designed for cycling regardless of the load sharing system used, by implementing the types of design features listed in Section 12.2.1. Additionally, the PMS must be designed properly to ensure CCGT reliability and power availability under significant cycling.

12.5.2 Operation and Maintenance

Due to the additional HRSG system on a CCGT compared to a SCGT there are additional operating and maintenance requirements and associated costs.

The following table was adapted from the Renewables Generation Modelling study (Section /98/) and based on the supplementary power requirement determined in the Platform Clustering Study (Section 6):

LM6000	Supplementary Power (MW)	Output Per Generator (MW)	Max. Number of Generators Operating
Simple Cycle	418.5	53.9	8.0
Combined Cycle	418.5	72.3	6.0

Table 12-10 - CC vs SC Number of Generators

OPEX data for several CNS platforms was provided by the OGA. Using this data, we can make an estimate of the operating costs required for the main hub local power generation for both CCGT and SCGTs.

From the OGA data, the estimated OPEX for the platforms, associated with their GTs, ranges from approximately £0.5 – 1 million per GT per year.

The additional maintenance cost for a CCGT is estimated to be approximately treble the cost of an SCGT due to the additional steam turbine.

Using the upper range estimate for OPEX costs for GTs of £1M per GT per year, the operating costs for local power generation on the main hub are estimated to be as follows:

LM6000	Max. Number of Generators Operating	OPEX (£M/yr)
Simple Cycle	8.0	8
Combined Cycle	6.0	18

Table 12-11 - CC vs SC OPEX Estimate Excluding Fuel

OPEX, excluding fuel costs are estimated to be approximately £10m per year greater using CCGTs rather than SCGTs.

This is compared to the estimated potential fuel and ETS cost savings of £47m; however, with the combination of the potential impact of cycling on the efficiency of the CCGTs and the additional OPEX costs, SCGTs could be more comparable than the initial modelling suggests.

12.5.3 Space and Weight

The space and weight requirements of a CCGT compared to a an SCGT are significantly greater due to the additional equipment required.

Table 12-12 below is an equipment list of the major items of equipment associated with a CCGT:

Item Description	Number	Dimensions LxWxH (m)	Total Weight (tonnes)
LM6000 Gas Turbine Module	1	18 x 6.8 x 6.7	Est. 1,000
Heat Recovery Steam Generator	1	HOLD	
Steam Turbine	1	12 x 4 x 5	
Steam Condenser	2	4 x 1.5 x 2	30

Table 12-12 - CCGT Equipment List Summary

For an SCGT, the LM6000 Gas Turbine Module is the only major item of equipment; however, to meet the 418.5 MW capacity, 8 SCGTs are required compared to 6 CCGTs.

Additionally, it is not anticipated that the footprint savings of using SCGTs over CCGTs will result in the ability to select a smaller platform, since the electrical equipment takes up a substantial share of the total topsides footprint.

12.5.4 Capital Cost

The estimated capital costs for a 418.5 MW system using CCGTs vs SCGTs is shown in Table 12-13:

GT Type	No. Off	Total Cost (£m)	Amortised Costs per Unit (£m)
SCGT	8	160	304
CCGT	6	192	353

Table 12-13 - CC vs SC Capital Cost Estimate

Amortised costs are calculated over a 10 year period including for OPEX, fuel and ETS costs

$$Cost_{Am} = Cost_{CAPEX} + \left(\frac{(Cost_{Maint} * n_{gen} + Cost_{Fuel} + Cost_{ETS}) * years}{n_{gens}} \right)$$

12.6 Conclusion

The study has concluded that the use of CCGTs over SCGTs has potentially large benefits for cost and emissions reductions associated with fuel gas consumption (up to 25%) and these significantly outweigh the additional capital costs of CCGTs.

The analysis conducted would have to be rationalised using a more detailed gas turbine cycling model. It is considered that cycling issues will affect both SCGTs and CCGTs, however the impact may be more significant to CCGTs therefore some of the efficiency gains may be overestimated compared to real operation which will be impacted by the PMS and ramp rates. The PMS must be designed effectively to ensure the CCGTs operate efficiently with significant cycling.

The additional space and weight are not considered a significant issue for this project as using CCGTs over SCGTs will not result in the selection of a smaller marine solution for the Main Hub so no significant capital cost savings would be made.

Due to the stochastic nature of wind energy production the CCGTs must be designed for significant operational cycling to ensure good efficiency and reliability is maintained. The PMS must also be designed effectively to ensure CCGT reliability and power availability while minimising potential efficiency losses compared to the model.

13. Platform Modification Study

13.1 Objective

The purpose of this study is to evaluate the potential modifications required for offshore oil and gas platforms to electrify their complete topside energy requirements and study the implications of reducing or eliminating the requirement to operate local generation.

The platform modifications will be evaluated based on the following considerations:

- Ability to provide partial electrical power requirements
- Ability to provide full electrical power requirements
- Ability to supply all electrical power and process heating requirements
- Requirement for retention of on asset power generation (normal and emergency)

13.2 Methodology / Background

This report was completed by way of a desktop study, considering general and specific examples of power usage offshore and gathering an understanding of the required topsides modifications. Previous Katoni study experience has been drawn on and illustrative case studies have been provided.

This study evaluates the key areas which are required to be considered as part of platform electrification. All platforms will have specific requirements. The purpose of this study is to outline the areas of existing facilities which will have to be considered for modifications to maximise the impact from electrification.

Electrification is not simply providing a source of low carbon power to an asset, it is the opportunity to better utilise on platform resources to promote production efficiency and reduce emissions.

The study has been split into three key areas:

- Receipt of Subsea Power to an asset
- Maximising the use of Subsea Power
- Reducing emissions / optimising the process

Each area of study considers the equipment modifications required, and then the implications for the existing electrical infrastructure.

Where appropriate, equipment dimensions, weights and budgetary costs have been provided to help illustrate the identified changes.

Case studies for assets considered to be representative of common challenges are included in this report to outline the scale of the modifications required.

13.2.1 Topsides Energy Usage

Topsides energy usage can be split into three main categories, as follows:

1. Electrically powered equipment
2. Direct drive equipment
3. Process heating input

Each platform is unique and not every platform has all the above energy requirements – only electrical power users are common to all platforms.

Work completed under the Typical Asset Distribution and Characterisation Study (Section 7) analysed a number of platforms to determine different types of assets in the North Sea. A summary of this analysis is presented in Figure 13-1.

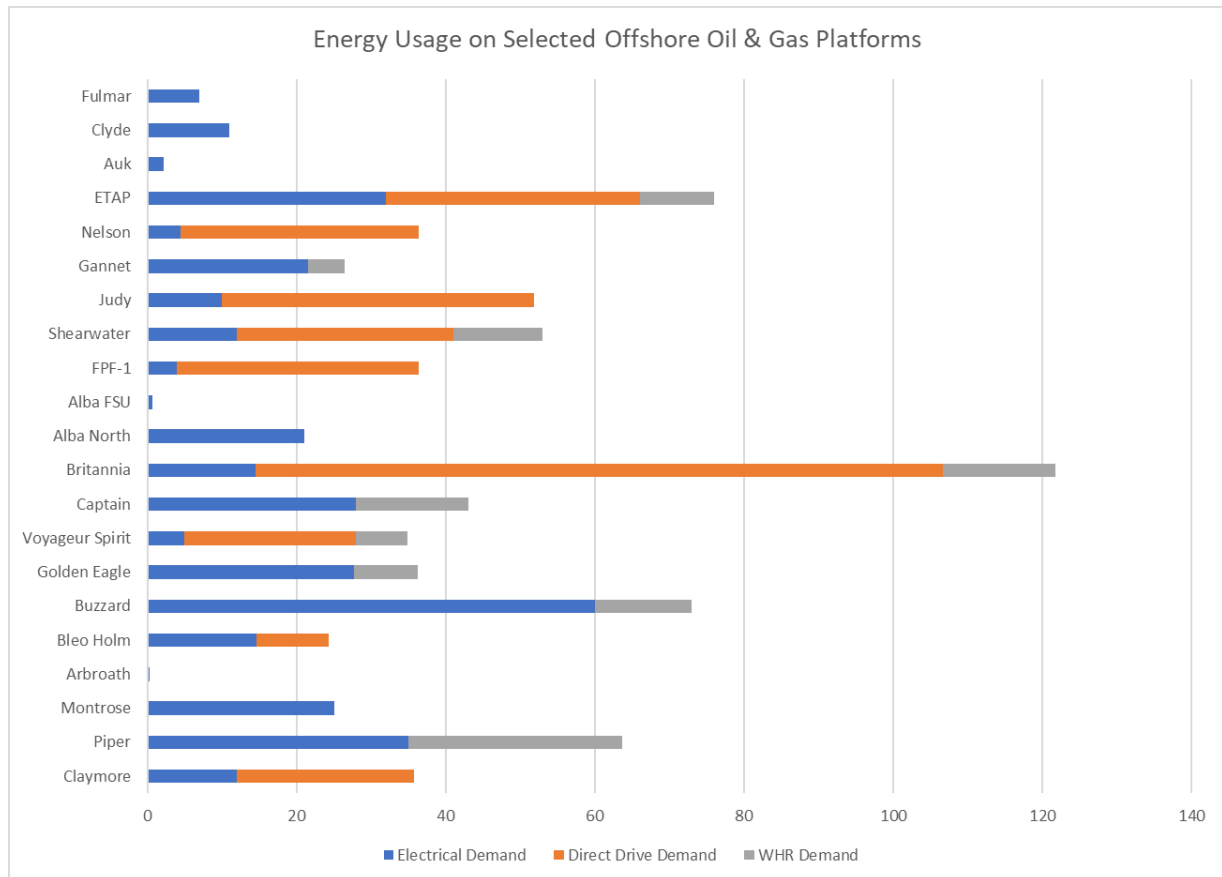


Figure 13-1: Estimated Energy Usage on Selected Offshore Oil & Gas Platforms

13.2.1.1 Electrical Power Users

Electrical power users on offshore platforms are generally supplied with power by on-platform Gas Turbine Generators (GTs) or Diesel Generators (DGs), depending on the power demand and the availability of fuel gas.

On offshore oil and gas assets the majority of small to medium power demand applications (typically below 5MW) are met by electric drives. This includes pumps, compressors, centrifuges, etc.

In some instances, applications use hydraulic or air power. However, in most cases these ultimately derive from electrical power with platform air compressors and hydraulic pumps often being electrically driven.

This process equipment is included in the overall electrical power demand of an asset and is met by the asset generation. These are all supplied from the asset's electrical distribution network at either High Voltage (for large pumps and compressors) or Low Voltage (for lower power demands). In the case where the platform is electrified via subsea cable then the electrical network, and therefore the process users, will also be electrified without any requirement for additional modification.

13.2.1.2 Direct Drive Equipment

Larger rotating equipment offshore is typically driven directly by gas turbines. The equipment driven by these GTs are typically major items of equipment such as export compression trains and main oil line (MOL) pumps which exceed 5MW.

As demonstrated in Figure 13-1, the ratings of this equipment often match or exceed the total electrical power demand on a platform. Integrating these into a fully electrified topsides will be challenging and require extensive modifications.

13.2.1.3 Process Heating

Where process heating is required on an offshore platform, heat is usually supplied to users via a heating medium such as water, aqueous glycol, steam, or hot oil. This heating medium is typically heated to high temperatures via gas or oil-fired heaters. Alternatively, the heating medium is heated via a waste heat recovery unit fitted to the exhausts of the platform GTs.

Where the power requirement of the on-platform GTs that utilise WHR is reduced or completely removed this will affect the ability to meet the process heating load. The impact of this and the modification options are discussed in more detail in Section 13.4.4.1.

13.2.2 Further Impacts of Electrification

Beyond the direct impact on energy usage on a platform, the move away from conventional, local generation has an impact on other areas, including consumption of gas and the requirement for flaring.

These areas are also explored in this report due to their relationship with electrification.

13.2.2.1 Gas Disposal

When an asset is electrified the use of produced gas for fuel is drastically reduced or removed altogether. This excess gas must be used in some way, either exported for sales or for use elsewhere, reinjected into the wells, or flared. Flaring is strictly regulated, and its reduction is being strongly driven at a regulatory level so other options must be explored, particularly for platforms that do not have any active gas export route.

13.2.2.2 Flare Gas Recovery

Flare gas recovery involves extracting useful substances (such as methane, LPGs and sulphur dioxide) from the waste gas stream prior to combustion at the flare. These substances can be used in the process, turned into a fuel, or be sequestered. Extracting these prior to combustion reduces flaring and eliminates some of the worst contributors to greenhouse gas emissions. Examples of waste gas to flare include blanketing gas and purge gas.

13.2.3 Receipt of Subsea Power

The overall philosophy of this project is to minimise topsides modifications on existing Oil & Gas assets to encourage the uptake of electrification. The relatively high CAPEX cost of brownfield modifications, along with the lack of space and weight capacity on a large proportion of assets, means that accommodating large topsides electrical infrastructure is not going to be attractive or even possible in some cases. This is especially true for aging assets with limited expected life.

The concept pursued for this project is to locate most electrical equipment (e.g. transformers, reactors, frequency converters) on the local Sub Hub, with the aim of achieving minimal modifications required to be made to the platform itself to accept subsea power.

However, some modifications are still required and are outlined in this section. The level of modification depends on the existing electrical distribution architecture, its ratings and layout.

13.2.4 Minor Modifications

In the case where the high voltage switchboard has a suitable incomer (typically a main generator incomer) and is sufficiently rated then the electrical modifications are minor. In such a case the incomer can be modified to suit the new duty, with relays and other control equipment replaced or upgraded.

See Section 6.1.1 for a Case Study detailing this level of modification.

13.2.5 Moderate Modifications

In the case where there is no suitable or spare incomer on the main HV switchboard then there will be a requirement for a moderate level of modification. In this case a switchboard extension or additional switchgear tier will need to be installed for the subsea cable incomer(s). These would be provided with appropriate protection and controls and then tied into the existing distribution. The ease of achieving this modification will depend on the existing switchgear manufacturer and type, its layout and rating, and the free space around it within the switchroom.

See Section 6.1.2 for a Case Study detailing this level of modification.

13.2.6 Major Modifications

In the case where the switchboard cannot easily be extended, or is of insufficient rating to handle the electrical demand (especially in the case where direct driven equipment is converted to electric drive) then more significant modifications will be required.

In this case a new HV Switchboard will be required, to receive subsea power and distribute as appropriate. There may need to be modifications to re-route/re-cable existing connections to other switchboards depending on ratings and locations. In most cases there shouldn't be a need for additional transformers as the subsea power will arrive at the same voltage as platform voltage. However, in some cases, particularly to meet large electrical demand, it may be better to deliver subsea power at an elevated voltage and step it down via transformers on the asset.

See Section 6.1.3 for a Case Study detailing this level of modification.

13.2.7 SNS Solution

In the case of the Southern North Sea (SNS) assets, these typically have a low power demand and as a result often only have low voltage or medium voltage distribution (3.3kV or 6.6kV at most). For these assets it is not practical to run subsea power import to match the asset voltage as the efficiency would be too poor and losses in the cable intolerable when compared to installation costs.

Instead, it is proposed that there would need to be subsea power distributed at High Voltage, with reception switchgear and a step-down transformer added to each platform being electrified. As the power demands are relatively low, this can be achieved in a containerised solution to minimise space and modifications required.

See Section 6.1.4 for a Case Study detailing this level of modification.

13.2.8 Other Considerations

The following additional equipment is likely to be required on all platforms:

- Topsides Umbilical/Cable Termination Unit (TUTU) – submarine umbilical containing power and communications will be terminated here
- High Voltage cable run from TUTU to Main Switchroom where HV Switchboard is located
- Fibre cable run from TUTU to Main Switchroom where HV Switchboard is located

The following modifications are likely to be required on all platforms:

- Modifications to platform PMS to reflect the change in use and incorporate new equipment and controls
- Modifications to ICSS/DCS etc to reflect the change in use and incorporate new equipment and controls

13.3 Maximising Use of Subsea Power

13.3.1 Direct Drive Replacement

Electrification of existing gas turbine driven, large rotating machinery from a technical perspective is not a challenge. The technology exists and is widely used across the industry. Depending on the compressor or pump technology being driven by the gas turbine the replacement of the mechanical drive and gearbox with an electric motor and revised high-speed gearbox (required to increase the rotational speed from the electrical motor) would enable the majority of direct drive rotating machinery to be electrified.

The electrification of these items would enable significant efficiency savings and typical operational uptime improvements versus use of direct drives. The typical availability for a fixed speed electrical motor is 97%, and 95% for an electric motor with Variable Speed Drive (VSD). In the North Sea, the typical reliability for a gas turbine is approximately 85 to 90%.

13.3.1.1 Mechanical Drive Removal

The challenge for this electrification comes with the constructability of this solution. Gas turbines are typically mounted on large baseplates and built into the structure of oil and gas installations which can make their removal particularly challenging without significant platform destruct, or removal of the gas turbines in small pieces.

Refer to Section 13.5.2 for a case study example.

When this is the case, the potential best way to electrify these equipment items could be to leave the existing gas turbine in situ and either remove the compressor casing and gearbox to relocate elsewhere or simply to fit a completely new unit.

As the North Sea is a mature basin, it is likely that a substantial number of platform gas compressors are oversized for their current duty. Replacement of the full compressor would allow for a more efficient compressor selection to be made, reducing the platform power demand and reliance on compression recycles.

Replacement of these core systems is not considered to be an easy modification, particularly due to the challenges associated with lifting large equipment items off and onto platforms (lack of laydown areas, access routing, hatches etc.). Therefore, this will have to be carefully considered during the design of these new facilities. From the work carried out as part of the study, it is considered approximately 35% of all emissions in the North Sea are from gas turbine driven mechanical equipment.

13.3.1.2 Evaluation of Compressor Sparing

Opportunities exist to potentially reduce the size of the compression equipment to reduce the impact to the electrical distribution system and reduce the size of VSD equipment. Potentially installing 2 x 10 MW (2 x 50%) gas compressors is a better solution than installing 1 x 20 MW (1 x 100%) or 2 x 20 MW (2 x 100%). Utilising electrical driven compressors has allowed a substantial number of new developments to install an un-spared compression system, whilst still offering similar operational availability as 2 x 100% of mechanically driven compressors.

Assets such as Western Isles, Martin Linge and Gjoa operate with either fully or partially un-spared compression systems.

Western Isles operates with:

- 2 x 100% LP compressors for VRU
- 1 x 100% HP compressor (3 stage machine)

Martin Linge operates with:

- 1 x 100% recompression compressor (3 stage machine)
- 2 x 100% gas export compressors

Gjoa operates with:

- 1 x 100% 1st Stage compressor
- 1 x 67% 2nd Stage compressor
- 1 x 33% 2nd Stage compressor
- 1 x 100% reinjection compressor

It is recommended that the determination of compressor sparing will be by evaluation of the Reliability, Availability and Maintenance (RAM) of the entire system. The RAM analysis takes into consideration two key parameters to calculate the Production Efficiency, the Actual Production, and Potential Production.

$$\text{Production Efficiency} = \frac{\text{Actual Production}}{\text{Potential Production}} \times 100\%$$

RAM analysis is typically performed using an event driven simulator which allows for a total reliability of production system to be calculated using life cycle behaviour patterns. RAM analysis can be used to provide the following information:

- Predicted production losses due to system downtime, expressed as total oil and gas volume reduction
- Predicted gas flaring throughout life cycle
- Predicted revenue loss for each year and total life cycle
- Predicted forced outages throughout life cycle
- Average system annual unavailability
- Predicted reliability for a defined life period
- Operational cost expressed as a nominal yearly basis

To be able to calculate the anticipated production efficiency for the whole asset, the individual systems availability is interrogated. Typically, two sets of availability numbers are evaluated, the first of which is Inherent Availability. Inherent Availability is calculated using two key parameters these are: Mean Time to Failure (MTTF) and Mean Time to Repair (MTTR).

This gives the following equation:

$$\text{Inherent Availability} = \frac{MTTF}{(MTTF + MTTR)}$$

The inherent availability is described as the probability that a system or equipment will operate satisfactorily at any point in time, under design conditions. This definition excludes preventive maintenance actions and excludes any logistical issues with rectification work. It is simply the measure of if an item is operating, how long does it take for a failure, and when it does fail, assuming the spares are available, how long does rectification take.

In order to account for the overall effect of all influences in production efficiency, the relevant operational availability needs to be considered. This parameter considers, besides unscheduled events, all the scheduled preventative maintenance activities, logistical and administrative delay times.

$$\text{Operational Availability} = \frac{\text{Operational Time}}{(\text{Operational Time} + \text{Maintenance Time})}$$

Where:

Operational Time = the amount of time the equipment operates uninterrupted

Maintenance Time = the amount of time the equipment is not operating due to a failure, scheduled and unscheduled maintenance including all logistical and administrative delays.

Where equipment performs to expectations and only scheduled maintenance is performed with replacement of parts already defined, the Inherent Availability and Operational Availability will be equal.

Offshore Reliability Data (OREDA) is an organization which provides a database of reliability data which allows for the RAM calculations to be carried out. Based on the data in this database a baseline of equipment performance can be made to be able to benchmark actual operability against the norms. It also allows for typical Inherent Availability and Operation Availability to be calculated.

This methodology is key to enabling an evaluation and assessment of sparing requirements for different systems.

For undertaking large scale modifications such as installing electrically driven compressors it is critical this assessment is performed rather than replacement of like for like equipment.

13.3.2 Electrical Requirements

To electrify these systems, the GTs must be replaced with an electric drive train. This includes the following key capital equipment:

- Electrical motor, usually suitable for an Explosive Atmosphere
- High Speed Gear Box
- VSD, often incorporating:
 - o Input Transformer
 - o Output Filter
- New cable runs and auxiliary supplies
- New utilities hook-ups, e.g. air for purge and pressurisation units

In addition the compressor unit control systems will require upgrade or replacement.

Electrical Supply Modifications

A majority of assets studied do not have sufficient capacity in their electrical distribution to accommodate large increases in electrical power required to support these large rotating machinery applications.

In order to supply sufficient power to a large rotating machine it is anticipated that a completely separate high voltage supply and switchboard will need to be provided which will feed the new VSDs.

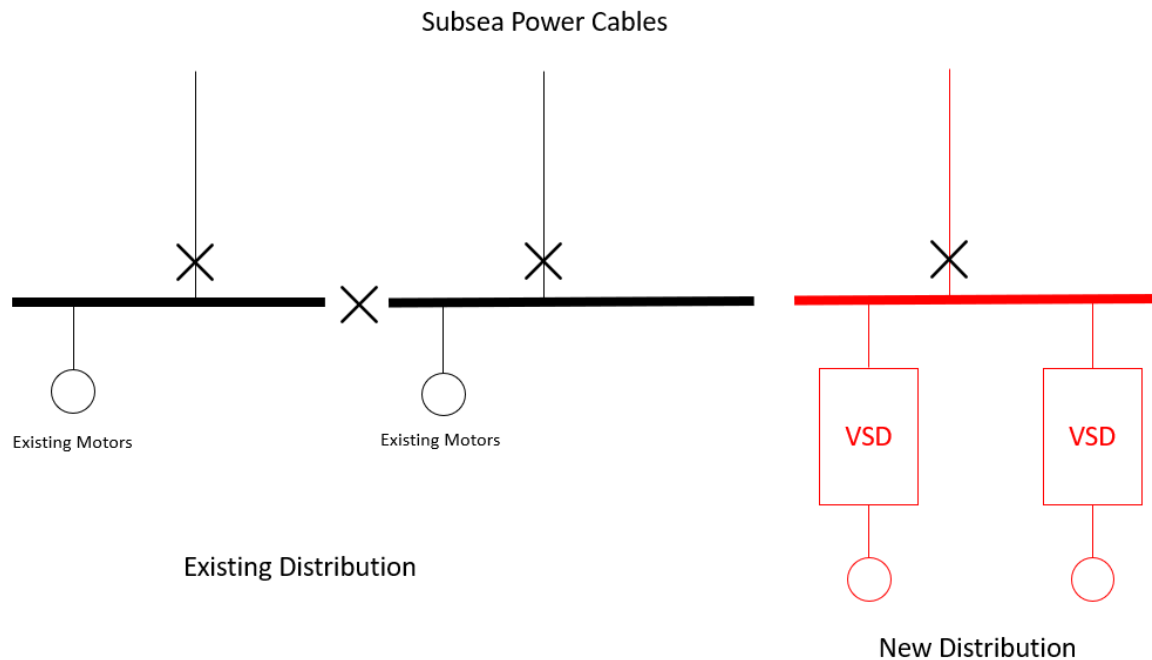


Figure 13-2: Existing and New Distribution for Large Rotating Equipment

This has the following implications:

- Additional topsides cable runs
- Additional E-House located on the topsides if insufficient space in existing switchrooms

Space for this equipment may be obtained through destruct of existing direct drive turbine MCCs which will no longer be required, along with destruct of the gas turbine and its auxiliaries.

Benefits

The power required by the direct driven equipment can make up a significant proportion of a platform's total power requirement and so electrifying this energy consumption can significantly reduce emissions and fuel gas costs.

Other potential benefits of replacing GTs with an electric drive train are:

- Increased overall efficiency
- Increased variable speed range
- Reduced maintenance burden (GTs have compulsory parts replacement)
- Quicker start-up time
- Reduced noise levels

13.4 Emissions Reduction and Process Optimisation

13.4.1 Excess Gas

Providing an external supply of electricity to the electrical power users of a platform will reduce or eliminate the load requirements of the on-platform GTs, resulting in a reduction or elimination of fuel gas consumption. The gas that was previously used for fuel must now be dealt with and there are several options for this:

1. Export the gas to other users or to a pipeline for sales
2. Reinject the gas into a disposal well
3. Flare the gas

13.4.1.1 Gas Export

Where there is sufficient produced gas to meet the required fuel gas consumption rate of the on-platform GTs it is likely that gas export facilities exist and are sufficiently designed to handle the additional gas flow. However, in the case where a platform is gas-deficient (i.e., produced gas rates are not large enough to meet fuel gas demands and fuel gas must be imported from an external source) the export gas facilities may require modification, however the design premise in the North Sea is typically bi-directional systems, i.e. systems acting as an import and export.

The length of time a platform has been gas-deficient could impact the required modifications. In some cases, the export system may not have been used for years and may be mothballed or completely redundant.

In cases where a gas export system has never been available and operational flaring has taken place, consideration of proximity to suitable export pipeline system, life remaining of field and monetary value of the gas all impact on the decision of what to do with the excess gas.

There are only a few major platforms in the North Sea which do not have tie ins to gas export systems. These platforms historically utilise any associated gas as fuel for main power generation, direct drive rotating machinery and gas lift. If full electrification of these assets occurred, then the economic case to export gas may then exist.

13.4.1.1.1 Gas Export Technology

Gas export would require the installation of a high-pressure compression system matched to the export pipeline pressure.

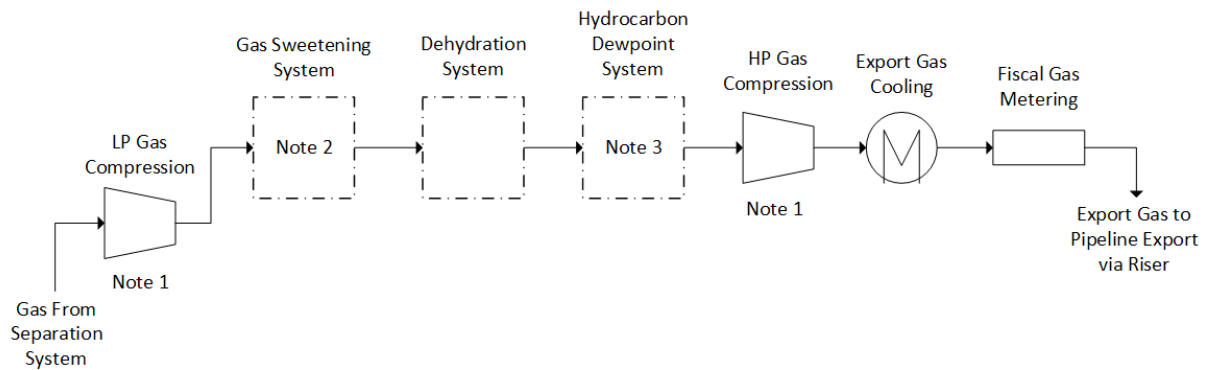
Based on most export gas pipeline specifications which facilitate gas export in the UKCS a 3-stage centrifugal compression system would be required. This would compress gas from the 1st Stage of separation pressure, considered to be between 10 barg and 20 barg, to an export pressure of between 100 barg and 140 barg.

The majority of assets in the North Sea will already have compression facilities to be able to compress gas, either to facilitate gas lift or to currently serve gas export. As a minimum, platforms will typically have low-pressure (25-30 barg) compression for their fuel gas systems.

13.4.1.1.2 Required Modifications – Existing Gas Export in Use

To facilitate gas export, or increased gas export rates it is considered based on basin maturity and availability of gas export routes from most assets that the existing systems would have sufficient capacity to export gas with minor or potentially no modifications. The systems required are:

- Existing – High pressure compression system
- Existing – Gas dehydration system
- Existing – Gas treatment / conditioning system
- Existing – Chemical injection system
- Existing – Gas export manifold
- Existing – Gas export / fiscal metering
- Existing – Gas export riser and flowline



Notes

Note 1 – Compression systems include interstage cooling, aftercoolers, and knock-out drums

Note 2 – Requirement for gas sweetening depends on gas composition

Note 3 – Requirement for hydrocarbon dewpoint system depends on export pipeline specification

Key

LP = Low Pressure

HP = High Pressure

--- Packaged System

Figure 13-3: Typical Gas Export System Sketch

Figure 13-3 shows a sketch of a typical gas export system. This is just one of many possible configurations.

Modifications to the compressor profile may be required due to the increase in flowrate.

13.4.1.1.3 Required Modifications – Out of Service Gas Export Route

To facilitate gas export on facilities which once had a serviceable gas export route but which is no longer in use due to either gas deficiency, out of specification gas or utilisation of export route as an import route, more significant modifications may be required.

The modifications required will primarily depend on the condition of the equipment / pipework that was previously in service, if this was maintained, and if the capacity of the system is sufficient for required export duty.

13.4.1.1.4 Required Modifications – Existing Gas Lift

To facilitate gas export on facilities which currently have a gas lift system, more significant modifications may be required; however, it is anticipated that a dehydration system will be operational, and the gas lift pressure is similar or exceeds required export pressure. Hydrocarbon dew point may prove to be the largest challenge, or potentially gas sweetening, to meet stricter export specifications compared with gas lift specifications.

13.4.1.1.5 Required Modifications – New Gas Export Route

In the instance that limited compression facilities are available on assets, to enable gas export additional equipment would be required.

The equipment which would typically be required to facilitate this injection is:

- New – Medium and high pressure compression stage
- New – Gas dehydration system
- New – Chemical injection system
- New – Gas reinjection manifold

13.4.1.2 Gas Reinjection

Some assets in the North Sea currently utilise gas reinjection to dispose of excess gas to reduce operational flaring.

On these assets, due to certain factors, gas is considered uneconomic to export and therefore high-pressure reinjection of the gas is carried out into the reservoir for reservoir pressure maintenance, or into disposal wells. Utilising this technique is considered to be acceptable for electrification opportunities, as although there is power associated with compression and disposal, the emissions associated with this method of disposal is substantially less than flaring of gas.

Increasing the amount of available gas on these assets by removal of on platform power generation and direct driven rotating machinery may change the economics of this activity leading to an acceptable volume of gas to export which was previously not available.

Other reasons why gas may be disposed of rather than exported is due to gas specification. Certain components present in gas composition may prove to be a challenge to treat to meet an acceptable export pipeline specification, and rather than treating the gas it is considered more economical to reinject gas rather than treat and export. These specifications are typically related to:

- H₂S content
- CO₂ content
- Mercury content
- NGL / Condensate fraction (hydrocarbon dewpoint)

Water content is not typically something which is considered prohibitive for gas export as most gas reinjection and or gas lift systems still operate with gas dehydration to prevent hydrates forming.

The most common reason to utilise gas reinjection rather than export is due to geographical proximity to subsea gas pipeline infrastructure.

In the CNS and SNS regions this is not typically considered an issue. The majority of assets would be considered as within acceptable proximity of existing infrastructure.

Gas reinjection into the reservoir is a common EOR technique which can boost oil production significantly. Each reservoir will react differently to this stimulation, however historically there has not be

the appetite to do this in the North Sea due to the established infrastructure present and the demand for gas onshore. Electrification of assets may provide operators with the opportunity to study this in more detail and determine positive impacts of this EOR technique for their fields. It has been reported that since a significant increase in gas reinjection projects since 1999, that recoverable oil reserves have increased by 33% /115/.

13.4.1.2.1 Gas Reinjection Technology

Gas reinjection would comprise installation of a high-pressure compression system matched to reservoir pressure. The gas would be compressed and cooled and routed to an injection point in the reservoir.

Based on most reservoir pressures in the UKCS a 3 stage compression system would be required, to compress gas from the 1st Stage of separation pressure, considered to be between 10 barg and 20 barg, to a reservoir injection pressure of between 120 barg and 160 barg.

The majority of assets in the North Sea will already have compression facilities to be able to compress gas to a higher pressure, either to facilitate gas lift or to provide high pressure fuel gas to gas turbines.

13.4.1.2.2 Required Modifications – Gas Lifted Wells

In the instance that wells are currently gas lifted, it would be considered that at least some of the equipment to facilitate gas reinjection is already available on the topsides, however capacity could be exceeded with additional gas volumes. The equipment which would typically be required to facilitate this injection is:

- Existing - High pressure compression stage
- Existing - Gas dehydration system
- Potentially new - Chemical injection system
- New - Gas reinjection manifold

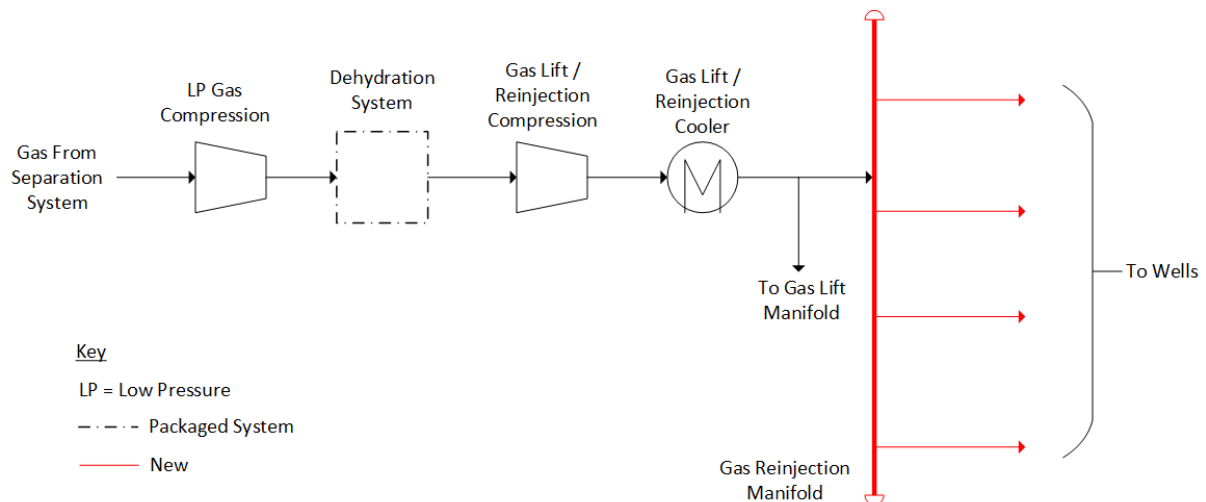


Figure 13-4: Gas Reinjection Modifications Sketch - Gas Lifted Wells

Potential modifications to the compressor profile may be required if the injection pressure is higher than the gas lift pressure, which may be the case depending on the injection point of the reservoir.

A new gas reinjection manifold would likely be required to meter the gas being reinjected and control the flow into the injection point.

To facilitate gas reinjection there may be a few options each with varying costs:

- Drilling of a new gas injection well
- Repurposing of an old production well if the completion is acceptable

- Repurposing of an existing or disused water injector

A new riser may be required depending on the infrastructure available to the platform.

13.4.1.2.3 Required Modifications – Fuel Gas Compression or Limited Compression

In the instance that limited compression facilities are available on assets, to enable gas reinjection additional equipment would be required. The equipment which would typically be required to facilitate this injection is:

- New – Medium and high-pressure compression stage
- New – Gas dehydration system – may exist for fuel gas treatment
- New – Chemical injection system
- New – Gas reinjection manifold

It is common for stranded assets (remote, standalone etc.) which currently use operational flaring as a means for dealing with excess gas production to have a single compression stage without gas dehydration to facilitate operation of gas turbines on produced gas. If that compression system has sufficient capacity, it could be reused as the first stage of compression, alternatively a new multi-stage compressor would potentially be more economical to install.

Like Section 13.4.1.2.2, the requirements for the injection points are the same, and the requirement for a new riser is more likely for this scenario than facilitates with existing gas lifted wells.

Additionally, the flare system may be impacted by the increase in high pressure gas inventory. The flare system may not have capacity for the increased inventory. Blowdown of the high-pressure gas will also result in cold temperatures which the existing flare system may not be designed for. A separate low temperature flare system may be required to prevent comingling with wet gas causing the formation of hydrates.

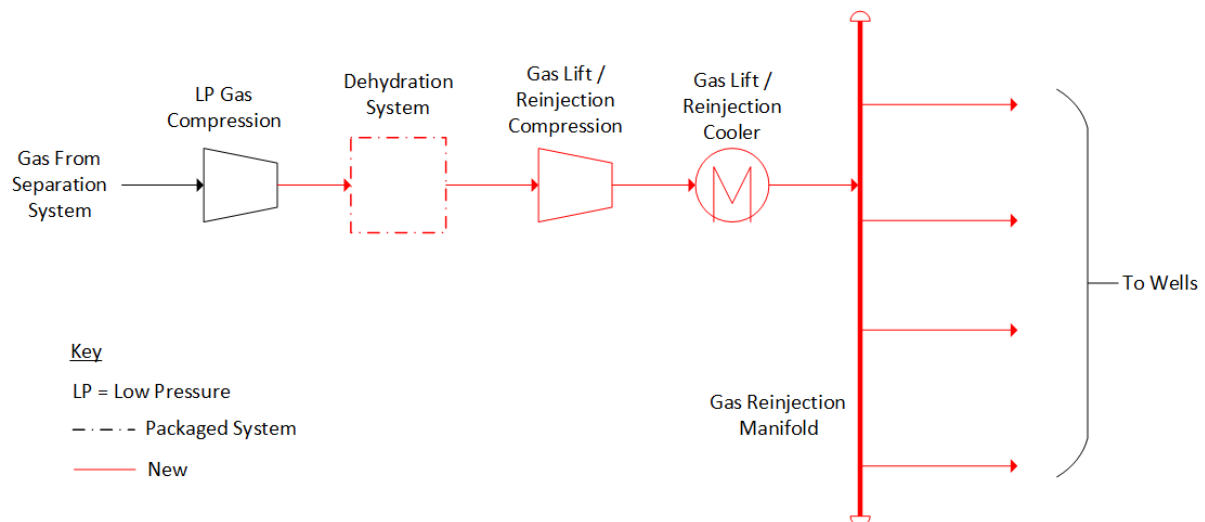


Figure 13-5: Gas Reinjection Modifications Sketch - Limited Compression

13.4.1.3 Gas Flaring

Flaring in the North Sea according to OGA accounts for approximately 25% of all CO₂ emissions from the upstream oil and gas industry. Approximately 60% of these emissions are from Base Load Flaring /113/.

Base Load Flaring is used for a variety of reasons, typically it is used to dispose of natural gas liquids (NGLs) which end up in LP Flare systems, stripping gas from TEG systems, or acid gas from sweetening systems. These heavier gaseous hydrocarbons typically flash off in secondary separation stages and do not contribute to export gas or will not stay in the liquid phase.

Naturally these NGLs will be removed in LP vents in various areas of plants and end up in LP / Utility flare systems. Some more modern assets have Vapour Recovery Units (VRU) to recover these, however in the North Sea these systems are typically uncommon.

For assets with VRU systems they typically do or can operate with a closed flare design. This design means that the flare is typically unlit, and only when a high-pressure event occurs will the flare system route gas to the stack and at this point the flare will be ignited. These closed flare systems are especially common in Norway where their use has been required since 1971. Operational flaring reduction decreased 8-fold from 1975 to 1979 based on application of the zero flaring requirements /116/.

While the legislative requirement for enforced zero flaring has not completely reduced operational flaring, it has made a significant impact on emissions.

It is considered for an asset to benefit from electrification then all operational flaring would be removed from normal operating procedures.

An exception to removal of operational flaring would be for either periodic discharge from regeneration of solid desiccant sweetening packages which typically have extremely concentrated sour gas, operational flaring from gas sweetening packages or permeate from gas treatment membranes. A detailed analysis of these off-gas streams and the impact to operations if these are not flared is required, however based on existing technology, flaring is typically the best solution for these systems.

13.4.1.3.1 Flare Gas Recovery

Recovery of flare gas on offshore installations is recommended. Flare gas recovery systems comprise typically of a compressor, main flare quick opening ESDV and a bursting disk in the event of ESDV failure. The ESDV remains closed during normal operation enabling the compressor to take its suction from the Flare KO drum. Depending on the method of pressure increase, additional ancillaries are required for the system. These include but are not limited to:

- Suction Scrubbers
- Suction Coolers
- Discharge Coolers
- Pumps – lube oil transfer pumps or condensate return pumps
- Noise Enclosures and Vibration Monitoring
- Ejectors / eductors

The main technology selection that is required for the Flare Gas Recovery Systems is the choice of the compression technology. There are several different solutions which will offer varying degrees of effectiveness and operating envelopes. The main compression technologies are:

- Dry Screw Compressors
- Oil Injected Screw Compressors
- Sliding Vane Compressors
- Reciprocating Compressors
- Liquid Ring Compressors
- Ejectors / eductors

Careful consideration is required for the suction pressure of the Flare Gas Recovery System. If the suction pressure is too high it can affect the operating pressure of flared gas such as Glycol Reboiler off gas and cargo tank blanket systems. Without boosters, the backpressure of the flare needs to be kept as low as possible to ensure the return is possible.

The other consideration that needs to be taken into account is the return pressure of the gas which has been recovered. Typically the gas will be returned into the main compression system, which depending on 1st stage operating pressure can typically range between 10 barg and 20 barg, or even higher on high Gas Oil Ratio (GOR) / condensate fields.

13.4.1.3.2 Compression Technology Evaluation

Each compression technology has its own unique operating envelope, developing the pros and cons of each technology will help make an informed decision about what is the best type of technology to select.

13.4.1.3.3 Sliding Vane Compressors

Sliding Vane Compressors work best in low pressure clean gas applications. The vanes can be prevented from sliding to their variable positions by fouling caused by waxes, solids and liquids. Oil lubrication is used as well as jacket cooling to maintain a temperature to stop the vanes from expanding too much.

The advantages of Sliding Vane Compressors are:

- Units are generally small and use a small amount of floor space
- The units are low cost
- Due to the nature of sliding vanes the turndown is very good

The disadvantages of sliding vane compressors are:

- Single stage and designed for low pressures, typically limited to 10 barg discharge pressure
- Continuously consumes oil
- Material availability of the technology can be poor

13.4.1.3.4 Liquid Ring Compressors

Liquid ring compressors are well suited for wet gas, dirty applications and are very common in Flare Gas Recovery Units. The liquid used for the sealing ring, which is typically water, absorbs heat through the compressor ensuring a higher discharge pressure with a lower temperature. The compressor however is not very efficient in comparison with other options. The liquid from the liquid seal needs to be treated to remove hydrocarbons which will have been dispersed and dissolved creating a new waste stream.

The advantages of liquid ring compressors are:

- Proven technology
- The units are low cost
- Liquid slugs typical in flare systems can be handled
- No upstream scrubbing is required
- Low noise and vibration
- Low discharge temperature
- Less sensitive to variations in gas molecular weight
- Low sensitivity to solids

The disadvantages of liquid ring compressors are:

- Single stage and designed for low pressures, typically limited to 10 barg discharge pressure
- Fresh water source required
- Additional waste stream (dirty water)
- Single speed means limited turndown

13.4.1.3.5 Reciprocating Piston Compressors

Reciprocating Piston Compressors are the most common compressor type used worldwide. These machines can handle high compression ratios and high discharge pressures. The compressor is sensitive to liquids and solids as they can foul the intake and exhaust valves, and the piston rings.

The advantages of using reciprocating compressors are:

- High discharge pressures are available
- High volumetric flows can be handled
- Multiple stages can easily be incorporated

The disadvantages of using reciprocating compressors are:

- Large footprint requirements
- High noise and vibration requirements
- High discharge temperatures
- Frequent maintenance is required
- Significant amount of ancillaries required

13.4.1.3.6 Oil Flooded Screw Compressors

Oil flooded screw compressors are simple machines which under the correct operating conditions are highly reliable. High compression ratios can be reached in a single stage due to the cooling effect of the oil on the gas. The compressors also have good efficiency, not as high as reciprocating compressors. The biggest issue with oil flooded screw compressors are the challenged that oil can react with some of the components in the gas causing acidification or a breakdown in the oil properties. This can lead to increase maintenance changing the oils and seals of the compressor.

The advantages of using oil flooded screw compressors are:

- High discharge pressures are available
- Internal slide valve arrangements allow for internal recirculating allowing good turndown performance
- The compressor is moderately priced
- Reasonable gas discharge pressure

The disadvantages of using oil flooded screw compressors are:

- Lube oil contamination and by the flare gas
- Cost to replace oil
- High noise and vibration potential of the compressor
- Ancillaries required, e.g. oil recovery scrubber, oil cooler, oil circulation pumps
- Liquids which are non-lubricating can cause damage to the bearings

13.4.1.3.7 Dry Screw Compressors

Dry Screw Compressors are the most expensive choice of compressors for this application. The compressor type can however handle wide variations of gas composition, has good efficiency levels and has no risk of oil contamination as it used dry gas seals.

The advantages of using dry screw compressors are:

- High discharge compressor pressures are achievable
- Multiple stages can be set on a single machine with multiple casings and a single shaft
- More flexible with regards to liquid contamination
- Good turndown can be afforded with a variable frequency drive

- Full turndown with full recycle operation

The disadvantages of using dry screw compressors are:

- High noise and vibration potential for the compressor
- Requirement for intercooling to reach high discharge pressures
- High costs

13.4.1.3.8 Costings of compressors

An economic analysis of flare gas recovery compression systems was carried out by NTNU for an internal study project /114/. This data is shown in Figure 13-6. While this data is not exhaustive it gives an easy to understand reflective evaluation of the relative prices of the different technology. The costings are relative to the most expensive dry screw compressor being valued at 100, and the other technologies being a ratio to 100.

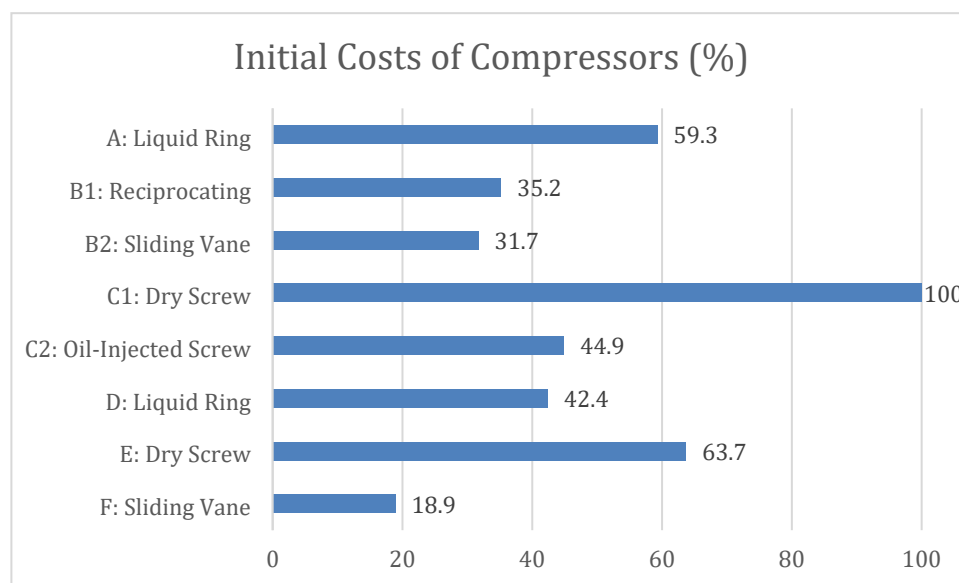


Figure 13-6: Initial Costs of Compressors (NTNU)

Where there are multiple entries for the same technology this shows variation between vendor costings.

13.4.1.3.9 Operational Envelopes for Compressors

Figure 13-7 demonstrates the operating envelopes of different compressor technologies.

The full low pressure gas system could be routed to the LP flare where all low-pressure tie ins are brought together and compressed by a single compressor to higher pressure. This will mean however that the LP Flare system on most platforms would need to increase in size as will the LP Flare knockout. This will however simplify the compressor arrangement, allowing 1 large dry gas compressor to be selected.

The alternative is installing the VRU recovery system fed from the 2nd stage separator and selecting a smaller compressor type for the flare gas recovery system, such as a liquid ring compressor. This is what is most commonly done in Norway based on the reference lists for these compressor manufacturers. Vendors such as GD Nash, Zeeco and Hamworthy all describe liquid ring compressors as the standard in flare gas recovery.

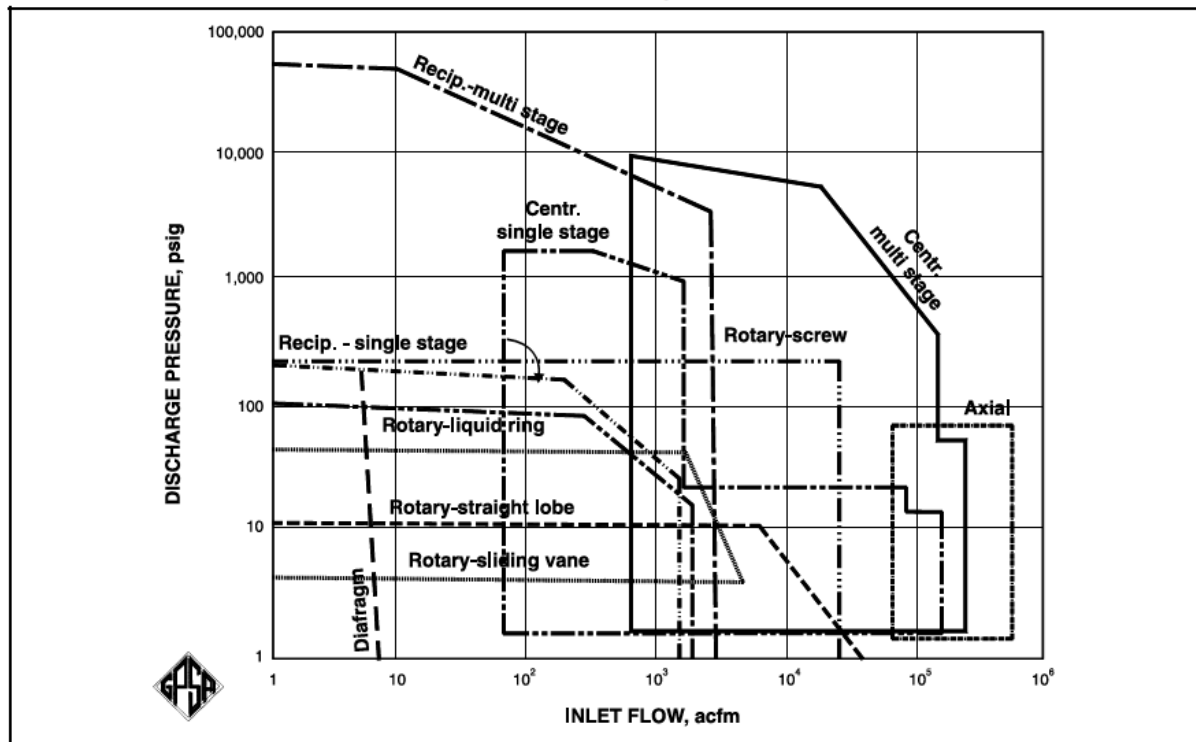


Figure 13-7: Compressor Operational Envelope (GPSA)

13.4.2 Gas Treatment for Export Specification

For assets which currently do not have a gas export route, it may be required to further treat gas produced from the respective reservoir prior to export.

The typical specifications which are required for pipeline export are:

- H₂S content
- CO₂ content
- Mercury content
- NGL / Condensate fraction
- Cricondenbar
- Water Content

Gas export pipeline entry specifications can vary significantly depending on pipeline and as a result based on geographical region this can affect the conditioning required for gas.

Two illustrative export gas specifications, for SAGE and the Fulmar Gas Line, are shown in Table 13-1.

Table 13-1: SAGE and Fulmar Gas Line Entry Specifications

Specification	Units	SAGE	Fulmar Gas Line
H ₂ S	ppm	500	2.5
CO ₂	mol%	22	1.6
O ₂	ppm	7	10
C ₂ -C ₁₂ Fraction	min mol%	10.67 - 21.82	-
C ₃ +	min mol%	-	5.5
Cricondenbar	bara	106	105
Mercury	µg/m3	0	0.01
Water Content	ppm	63	35

13.4.2.1 H₂S and CO₂ Removal

Treatment of the sour gas stream can present difficulties. Depending on the volume of gas present it can rule out specific technologies as the combination of low gas flowrate and high H₂S concentration can result in a sub-optimal feed stream for most common sweetening technologies.

The technologies considered for the treatment of sour gas are:

- Solid desiccant / molecular sieve adsorption with and without regeneration
- Membranes
- Chemical scavenger
- Liquid redox treatment
- Amine absorption

13.4.2.1.1 Amine Absorption

The most common method applied for gas sweetening is utilising amines to remove sour components from gas.

Amine systems work by using an amine based liquid absorbent to selectively absorb sour gas, H₂S & CO₂, from the gas stream, creating a sweetened gas product and a sour gas rich flue gas by-product. The absorbent is regenerated and continuously circulated. Whilst flue gas is typically flared.

The optimum operating point for amine systems is high volumetric flowrates of gas. Low gas flowrates typically result in a high capital cost per MMSCF of gas when using this technology.

The benefits of this technology are lower operating costs compared to chemical scavengers, no solid by-products are created, no regeneration gas stream is required, and it is a proven technology with a strong track record in the offshore oil and gas industry.

13.4.2.1.2 Solid Desiccant / Molecular Sieve Adsorption with and without Regeneration

Solid Desiccants and Molecular Sieve work by selectively adsorbing CO₂ and H₂S onto the surface of the solid media. The media can typically be regenerated by passing a hot side stream of the feed gas through it whilst offline. Non-regenerative options also exist but require regular replacement of the solid material and typically are impractical for offshore applications.

Regeneration rate for molecular sieves depends on bed size, and the regeneration temperature is typically between 150 and 200°C. These short regeneration cycles are typically flared due to the high concentrations of corrosive gas. The off-gas from the regeneration cycle is a by-product of oil production, and whilst there are methods to strip H₂S from this flue gas typically these are not employed offshore.

Due to the high operating temperatures associated with the regeneration system for the desiccant beds, these vessels are typically lined with concrete to act as an insulator. In addition to the high operating pressures of the system this typically makes the operating mass of the vessels very significant.

13.4.2.1.3 Membranes

Membrane systems work by using a synthetic membrane that selectively prevents sour gas from permeating the membrane, creating a sweetened gas product.

Membranes are typically only capable of around ~75% bulk removal H_2S from a gas stream but can operate as high as ~95%. Membranes typically do not offer the performance required to meet export specification where finer removal is required.

13.4.2.1.4 Chemical Scavenger

Chemical scavengers are typically liquid chemicals that selectively react with H_2S to remove it from the gas stream.

Typically for low flows of gas, chemical scavenger can be an effective way to mitigate H_2S , however with larger gas flows, or high concentrations then the anticipated chemical usage and replacement rate will make this technology economically unviable.

Additionally, chemical scavenging results in solid by-products which can cause operational issues if not adequately removed from the system using filter coalescers.

13.4.2.1.5 Liquid Redox Treatment

Liquid redox systems are based on a reduction-oxidation reaction carried out in the liquid phase which converts H_2S in the sour gas stream to sulphur and water.

This is a lesser utilised technology; however, it is considered a potentially good alternative for gas streams with high H_2S concentrations.

The process creates a solid sulphur by-product which is considered easier to handle and remove than the solids (typically salts) created by scavenger chemicals.

13.4.2.2 Mercury Removal

Mercury is typically removed from gas streams by utilising molecular sieves as described in Section 13.4.2.1.2.

Unlike gas sweetening however the desiccants are typically not regenerated offshore. Once the media is spent it is removed from the vessel and sent onshore for processing, whilst a regenerated supply of desiccant is sent back offshore for replacement.

13.4.2.3 NGL / Condensate Fraction

Typically, gas produced through oil and gas activities and compressed to normal export pressures will contain adequate quantities of NGLs. Even with high throughputs of gas lift, which is typically lower in these components, there is a stripping effect which will result in the gas being produced from the 1st stage separator being saturated in these components.

It is unusual for any technology to be applied to adjust this component fraction; it is typically the opposite where there is too much of these components in the system.

13.4.2.4 Cricondenbar Control

To control the cricondenbar of export gas the most common methods are Joule-Thomson expansion or refrigeration. By sub-cooling gas using either of these methods additional liquids can be made to condense from the gas thereby controlling the hydrocarbon dew point. The cricondenbar pressure is the maximum pressure at which liquids can form, i.e. as long as the gas is maintained above this pressure no liquids can form.

13.4.2.4.1 Joule-Thomson Expansion

The simplest method, when excess pressure is available from the compression system, is using a Joule-Thomson expansion of the gas. This involves using a valve to decrease the pressure of the gas leading to expansion. As this is a constant enthalpy process the amount of temperature reduction will depend on the initial pressure of the gas as well as the composition. Typically to meet pipeline specification a Joule-Thomson expansion of around 15 to 25 bar is required to achieve the cricondenbar required.

The only equipment required for this process is typically a valve and scrubber vessel in addition to the additional compression capacity required to counteract this differential pressure across the system. If the available compression capacity is not available then an additional compression step could be required.

13.4.2.4.2 Refrigeration

An alternative method to the Joule-Thomson Expansion technique is to use refrigeration. This operates on the same principal by cooling the gas to condense additional liquids at temperatures less than would typically be experienced through the gas compression system.

A refrigeration system is required to facilitate this process, this will be linked into the process via a cooler which will cool the gas to a pre-determined temperature. The liquids formed in this heat exchanger will be removed in a scrubber vessel.

Using a refrigeration process is typically substantially more costly than using Joule-Thomson, but depending on the operating conditions of the system a refrigeration system can be more economical than the addition of an additional compression step if there is no additional pressure available in the system based on the compression ratio and separator operating pressures.

Refrigeration is more efficient from an energy perspective as the power required to operate the refrigeration system is less than the power required to recompress the gas.

The downside to refrigeration is that it requires another piece of rotating machinery, as well as introducing a closed loop, typically hydrocarbon system, that has to be maintained in addition to the main compression system.

13.4.2.5 Water Content Control

The two most common techniques for water content control on oil and gas platforms are Tri-Ethylene Glycol (TEG) absorption systems and solid desiccant removal systems.

13.4.2.5.1 Dehydration - Solid Desiccant / Molecular Sieve Adsorption with and without Regeneration

The method outlined in Section 13.4.2.1.2 is the same method applied for water removal. Different molecular sieves are utilised, however a regenerative approach is still utilised for this system.

13.4.2.5.2 TEG Dehydration

The most common method applied to gas dehydration is utilising glycols, most commonly TEG, to remove water from gas.

TEG systems work by using a glycol based liquid absorbent to selectively absorb water from the gas stream in a contactor column. This results in a dehydrated gas leaving the contactor and a rich TEG stream (saturated with water) leaving as a liquid. The TEG is regenerated in a glycol reboiler and continuously circulated. Flue gas generated from the reboiler can either be flared or routed to a VRU.

Unlike amine systems, the circulation rates of TEG are typically very low, therefore TEG has a wide application base, and the costs of a system (for design and operation) are not particularly prohibitive. Additionally, operating pressures are relatively low.

Other glycols such as diethylene glycol and ethylene glycol can be utilised for this process, however TEG is the most common due to its chemical stability and higher vapour pressure which minimises losses during regeneration.

Vapour recovery is generally recommended due to potential H₂S and BTEX in flue gas.

13.4.3 NGL Use / Reduction

Use of VRUs can increase the quantity of NGLs in compression systems due to reductions in flaring. As NGLs build up in compression systems the power draw can increase, the gas molecular weight increases and compressors operate less efficiently due to continuous recycles around the system. To combat this there are technologies available which can remove these components and convert them into shorter chain hydrocarbons.

One such technology is the Wärtsilä Gas Reformer.

The condensate from the HP compression system could potentially be routed to a Wärtsilä Gas Reformer, as shown in Figure 13-8. Depending on the location of the condensate take-off, a combination of pressure let-down, heating and water removal may be required prior to entering the Gas Reformer.

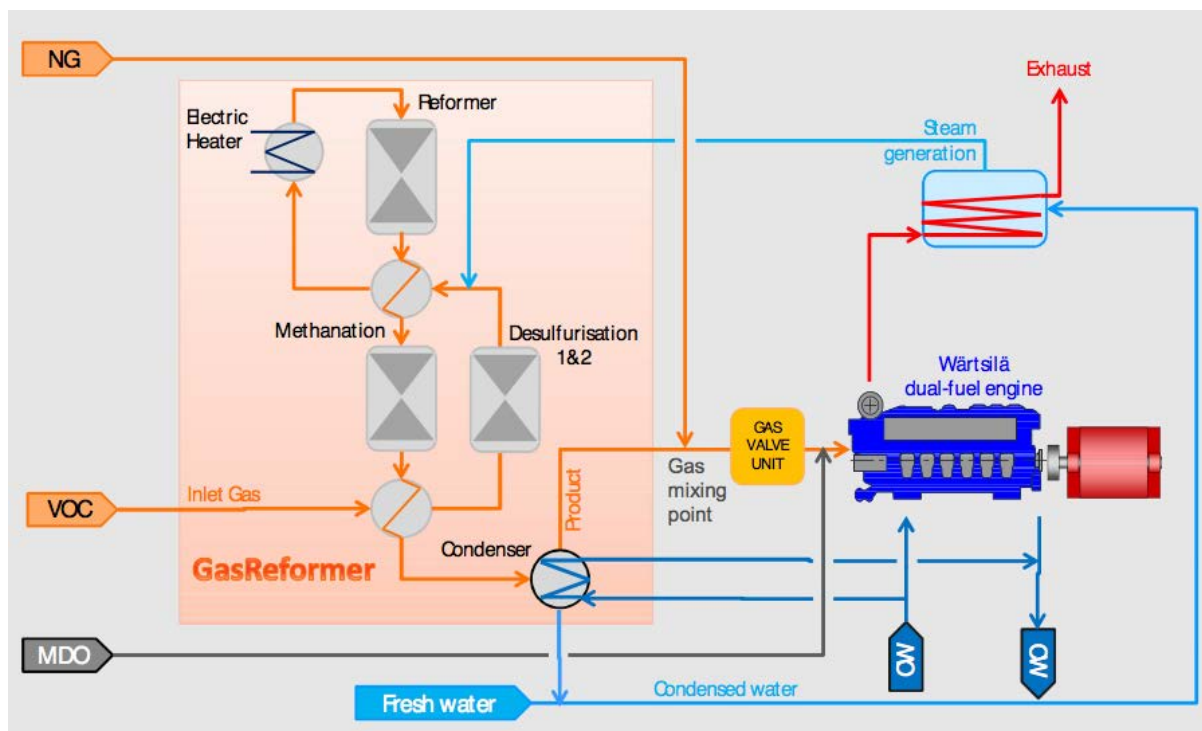


Figure 13-8: Gas Reformer schematic³

The Wärtsilä Gas Reformer takes the gas feed and ‘polishes’ it. It removes any sulphur from the gas and then injects steam into the gas stream before feeding it into a nickel based catalytic reactor. On the catalyst surface, all the heavier hydrocarbons are split into smaller components, mainly methane and other constituents with only one carbon atom. The gas is then cooled down, condensing all excess steam in the system, prior to utilising for fuel.

Whilst Figure 13-8 demonstrates the gas being routed into a reciprocating engine as fuel, this gas could be recycled back into the process at the 1st Stage of the compression system to be compressed for export. This could turn a detrimental by-product of oil and gas production into a valuable export.

13.4.3.1 Condensate Removal Simulation

A HYSYS simulation has been performed based on utilisation of a Gas Reformer on a typical oil and gas installation with a crude API of around 35. The simulation was adapted where condensate at three separate locations was removed from the process as feedstock for the Gas Reformer. The results, shown in Table 13-2, are averaged over a range of 50-100% condensate removal to provide a rough value for power reduction, heating and cooling load reduction and impact on oil production export. The simulation used a crude flowrate of 19,000 bpd with an associated GOR of 300.

Take-off location	Power reduction kW, (%) Note1	Heating reduction kW, (%)	Cooling reduction kW, (%)	Oil production loss bpd, (%)	Condensate removed (Sbpd) Note2
Upstream Contactor	900, (9%)	2,707, (38%)	3,630, (26%)	679, (4%)	1,079
Downstream Contactor	904, (9%)	2,611, (36%)	3,546, (25%)	565, (3%)	921
Downstream JT valve	880, (9%)	2,630, (37%)	3,563, (25%)	550, (3%)	1,179

Table 13-2: Condensate take-off to Gas Reformer

³ <https://www.wartsila.com/insights/article/a-gas-reforming-solution>

Notes for Table 13-2:

1. Power reduction percentage is based on a value of 9,955kW from the base HYSYS model which only includes fluid duty for the LP & HP Compressor and the various pumps.
2. 28.5–29 MMSCFD available for lift gas after condensate removal.

For all three condensate take-off locations, a power reduction of 0.9MW is observed (0.7-0.75MW attributed to the HP Compressor). An additional benefit is the reduced cooling requirement as a direct result of less throughput for the HP Compressor system coolers and reduced heating requirement as a result of less condensate recycled upstream of Inlet Heaters prior to entering 1st Stage Separator.

The small loss in oil productivity could partly be compensated for by reduced interstage heating before the final separation stage and/or higher pressure in the final separation stage within TVP target. This could be addressed with further work in the next stage. Additionally, blending of the condensate take-off streams could also be reviewed.

When gas is recycled back into the process the power reduction noted in Table 13-2 will decrease as a result of the reformed gas being compressed, however as this gas has been reformed from the condensate into primarily methane, hydrogen and carbon dioxide it is considered that very little of this will combine back into a condensate recycle.

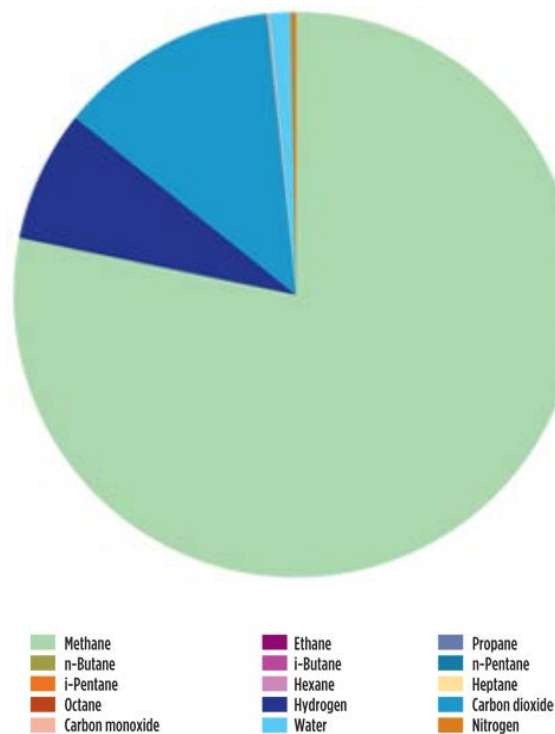


Figure 13-9: Reformer Product Specification (Typical)

Based on Figure 13-9, the simulation performed has determined that the composition of the reformed gas would be 80% methane, 12% CO₂, 6% hydrogen and 2% water. This composition of gas has a Methane Number of 104.

Simulations for maximum gas throughput and maximum water throughput have been carried out with the maximum resulting amount of gas generated by the reformer of 4.2 MMSCFD to 5.5 MMSCFD respectively. Based on a product stream LHV of 35.4 MJ/kg, there is potentially 38 MW to 52 MW worth of energy available from this stream.

Recycling of this gas back into the process will ultimately change the composition of the gas in the system dramatically reducing the amount of C₂ to C₆ components but increasing the amount of inert gas in the process. When production rates are lower, the build-up of inert components is larger. The maximum water case simulation shows the process reaches equilibrium with a nitrogen content of 1%

and CO₂ content of 5% taken at the gas lift point. NGL recycle reduction and inert components generated could be optimised to ensure gas still meets export specification.

With recycling of all the condensate removed and reformed, the load on the HP compressor will increase from 6000 kW to 6600 kW. This is still a potential 300 kW net reduction.

13.4.3.2 Modifications and Technical Challenges

At a high level, modifications to condensate pipework would be required with a suitable laydown area identified for the Gas Reformer skid.

Literature provided by Wartsila suggest that an “8 MW” Gas Reformer built for a pilot project is 9m x 2.5m x 3.5m (L x W x H) and weighs 22 tonnes. The 8 MW unit is designed to treat enough gas to produce a shaft power of 8 MW from a reciprocating engine, therefore the actual capacity of the unit is approximately 20 MW of available gas (based on a reciprocating engine efficiency of 40%).

The main opportunity with utilising the Gas Reformer technology is that an existing recycled loop stream can be converted for export thus reducing the overall platform power requirement and heating and cooling loads.

A trial was conducted in July 2016 using the Pilot Gas Reformer in combination with a Wärtsilä 6L20DF engine. The Gas Reformer was noted as successfully demonstrating its capability to reform Liquefied Volatile Organic Compounds (LVOC) into a high-quality gas used in the Wärtsilä 20DF engine. Nitrogen oxide (NOx) emissions were also confirmed to follow International Maritime Organization (IMO) Tier III limits when operating the engine on reformed LVOC. Furthermore, successful mixing tests were completed on the engine using ratios of non-reformed LVOC mixed directly into LNG ⁴.

The technology appears to have been readily adopted for the new e-tanker shuttle design due to tightening VOC emission limits with the following tankers built in 2020-21 and operating in the Norwegian and UK North Sea:

- Aurora Spirit, Rainbow Spirit, Tide Spirit, Current Spirit, Altera Wave, Altera Wind (Altera)
- Eagle Blane & Eagle Balder (AET)

⁴ <https://www.wartsila.com/insights/article/turning-waste-gases-into-power-saving-money-and-the-environment>

13.4.4 Utilities Use

13.4.4.1 Waste Heat Recovery

Waste Heat Recovery is a key benefit of local generation on the asset which increases the overall efficiency of the generating system.

There are additional power supply challenges associated with replacing the heat provided by a GT's WHRU. If the power provided by an on-platform GT with a WHRU is replaced by an external electrical supply then the process heating provided by the WHRU must also be replaced, requiring additional external electrical power or other means of replacing the WHRU.

For example, an on-platform GT may provide 30MW of power to electrical power users and an additional 10MW of process heating via the WHRU. If the external electrical power supply replaced the power supplied to the electrical power users, then 10MW of process heating has been lost. 40 MW of external electrical power would then be required, instead of 30 MW, for a full electrification solution.

Where enough electrical power can be supplied externally the WHRU can effectively be replaced by electrical heaters; however, in some cases the additional energy required for process heating results in an exceedance of the maximum power that can practically be supplied to the platform.

In this scenario a partial electrification option may be necessary, with the WHRU replaced by a fired heating solution such as a boiler or hot water system, depending on the existing heating medium.

13.4.4.1.1 Electrical Heating Solutions

Typically if a heating medium system is provided with heat from a WHRU the simplest modification would be to install a large electrical heater into the system to utilise the same system, replacing the exhaust heat with electric heating elements.

Figure 13-10 outlines a typical method for electrification of a heating medium system. This limits the number of modifications which must be performed by linking into the existing heating medium system.

Other concepts exist such as installing electric heaters into the process. There are a number of challenges which could arise from undertaking this type of modification.

- Process Safety concerns
 - o Electric heaters are typically complex to control
 - o Can superheat fluid to unlimited temperatures unlike heating medium
 - o Can damage vessels from localised overheating
 - o Can foul and be difficult to clean
- Number of electrical connections required in HV switchboard
- Additional transformers required meaning more equipment
- Equipment failures and overall impact on system reliability

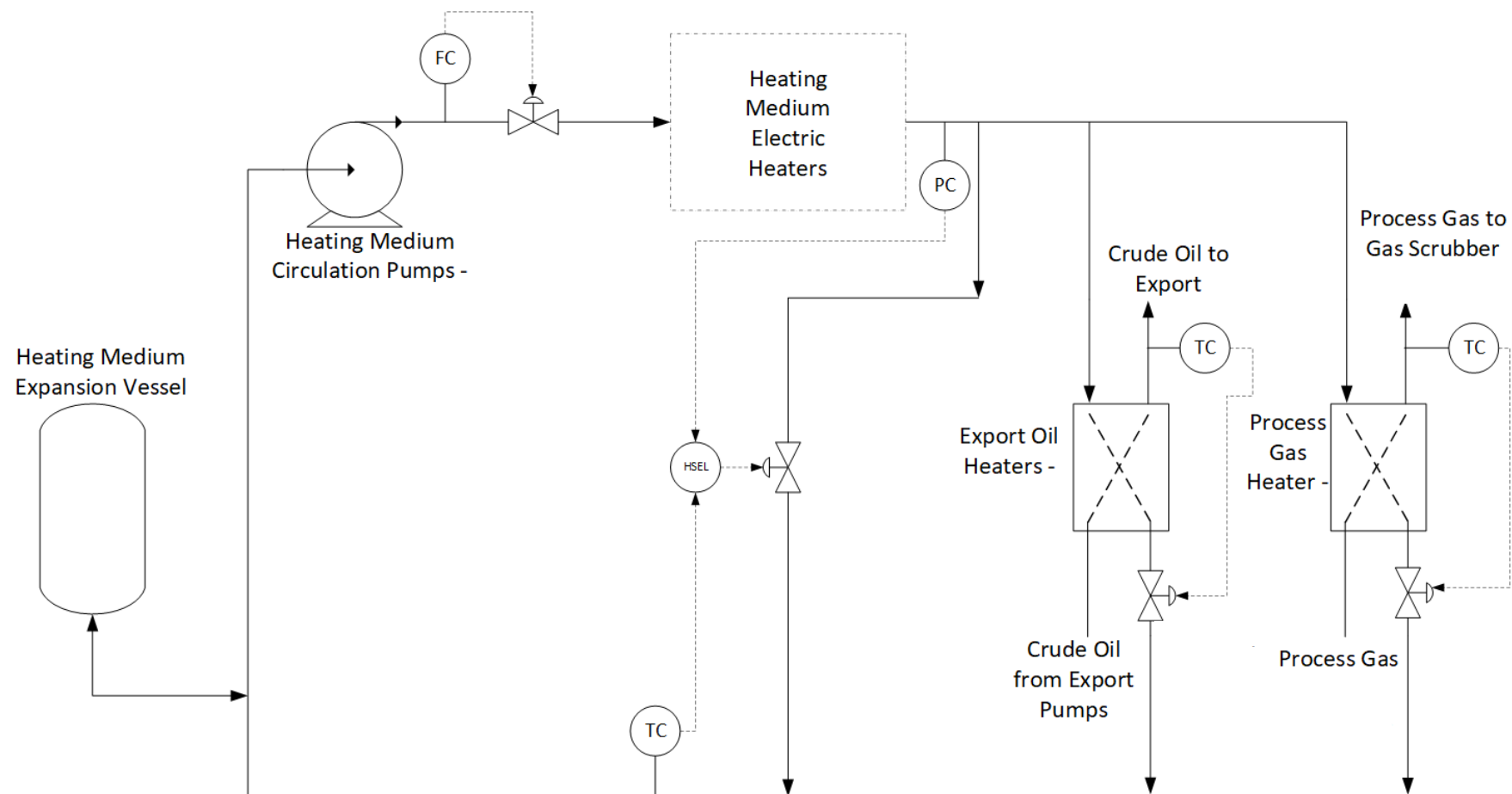


Figure 13-10: Heating Medium System Sketch

13.4.4.1.2 Electrical Supply Modifications

As with the direct drive equipment, process heating involves large quantities of power which may equal or exceed the platform's typical electrical demand. This means that the addition of process heating in sufficient quantities is likely to require new switchgear and transformers. One of the challenges associated with hazardous area electric heaters is that in general process heaters are low voltage, operating at 415 to 690V and controlled via Thyristor Control Panels (Heater CP). This requires step down transformers from a high voltage source of power which will likely necessitate a new switchboard.

A potential electrical distribution is shown in Figure 13-11.

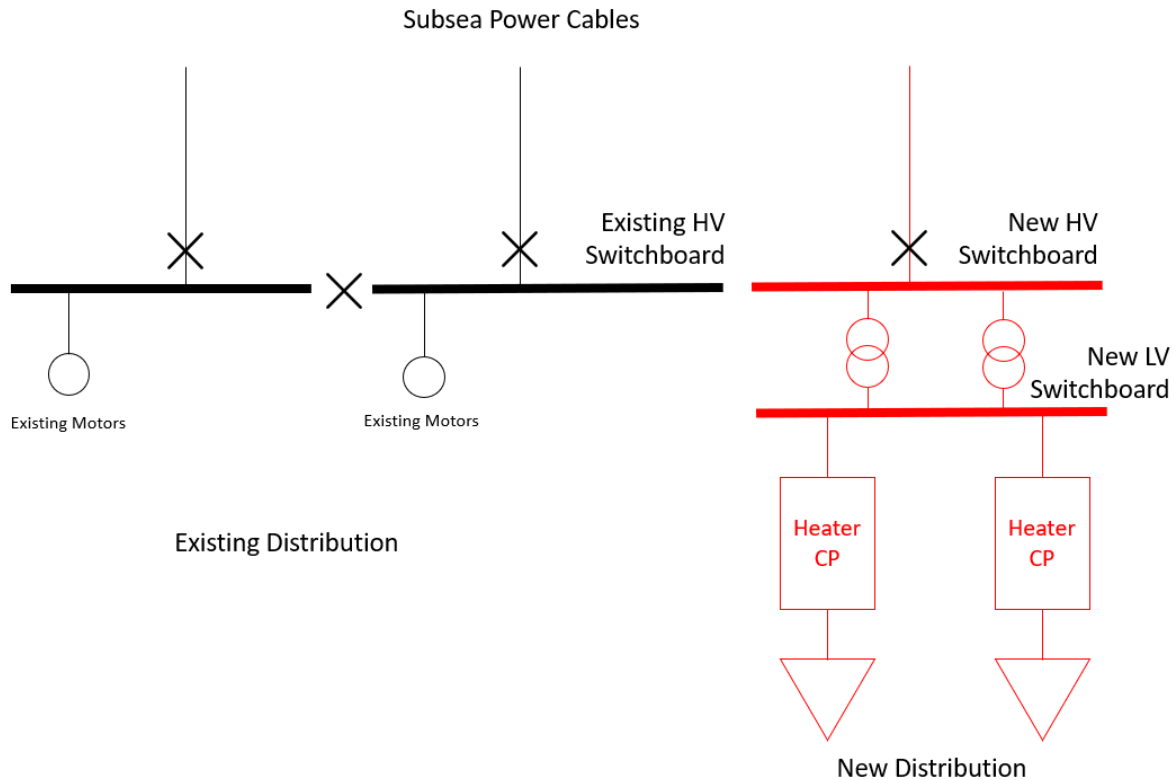


Figure 13-11: Existing and New Distribution for Electrical Heaters

13.4.4.1.3 Fired Boiler

An alternative to electric heaters is a fired boiler system. Fired boiler systems are relatively uncommon in the North Sea with a handful of platforms still using these for generation of heating medium.

The boiler will utilise a fuel; either diesel or gas which will be combusted and used to generate heat. The exhaust gases from the combustion are used to heat a heating medium, either water to steam, oil or hot water to be used for process heating.

Fired boilers can offer extremely high levels of efficiency reportedly up to 97%. This is advantageous when considering heating medium generation as this will mean a majority of hydrocarbons combusted will be utilised for the required heating on the asset, with very little additional emissions generated.

Like an electric heating system, incorporation of a fired heater into an existing heating medium system should be relatively straightforward. The largest challenge with installation of a fired heater is finding a suitable location for this to be sited on the platform. It will require an exhaust stack, however due to the open nature of the combustion taking place typically in the boiler it will need to be located in a carefully selected area so that Major Accident Hazards (MAH) are not introduced into the facility which did not exist previously.

A new generation of fired boilers are being developed to run on hydrogen, this could be an option for oil and gas installations in the future to further reduce emissions, however it is considered at present that neither a reliable source of offshore hydrogen or an industrialised hydrogen boiler system is available.

It is anticipated that the fired boiler would slot into the example schematic outlined in Figure 13-10 in place of the electric heaters.

No electrical modifications are required, only control and piping integration of the system is considered required.

Fuel type would typically be considered as gas due to the lower associated emissions with burning this, however diesel options are also considered feasible depending on platform requirements.

13.5 Case Studies

13.5.1 Electrical Integration

13.5.1.1 Platform A: Integration with HV Switchgear

In the case where there are a number of existing generators feeding into the main HV switchboard which is adequately rated, then integration of subsea electrical power is reasonably straightforward.

Platform A is a typical example of an aging North Sea asset. Historically it had a high electrical demand, with Main Oil Line and Water Injection Pumps making up the majority of the load. Originally provisioned with a single large GTG rated at around 40MW, it was later fitted with a supplementary GTG rated at 10MW to allow for more flexible operations. The main HV switchboard operates at 11kV and is rated for 2460A continuous, allowing for 42MW of power at an assumed power factor of 0.9. In addition to the main generation, the platform also has an essential services GTG of a much lower rating.

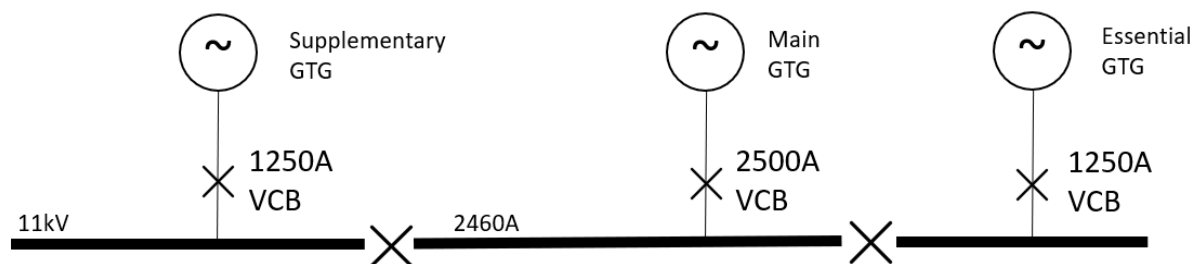


Figure 13-12: Platform A HV Switchboard Simplified SLD

Electrification of such an asset is relatively straightforward. The Main GTG incomer is modified to suit the cable incomer duty. The Main GTG can then be disconnected and can be mothballed, whilst the subsea power cable(s) are terminated at the switchboard. The Supplementary and Essential GTGs may be retained for redundancy/back-up purposes if required, though ongoing costs of maintenance should be considered.

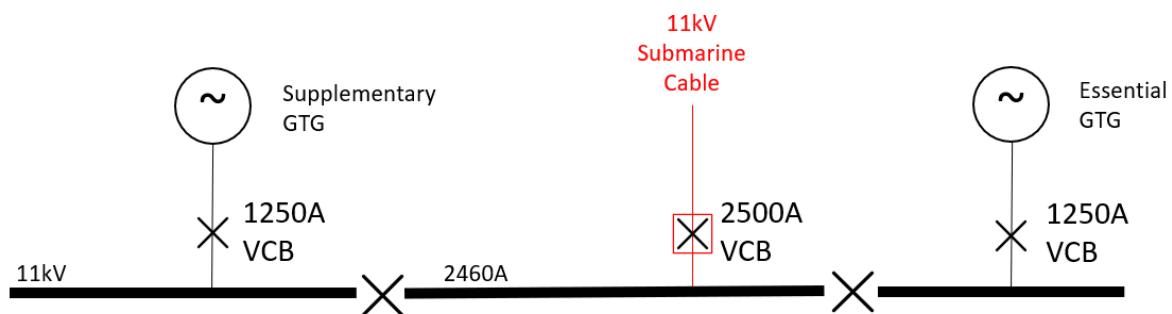


Figure 13-13: Platform A HV Switchboard after Subsea Power Modifications

Platform A has spare capacity within an existing riser (installed for a field extension that has not since progressed) and so the overall modifications identified are:

- Installation of Topsides Cable Termination Unit (TCTU) for the Submarine 11kV Cable
- Installation of new 11kV Cable between the TCTU and the HV Switchboard utilising existing racks and transits where practical
- Modifications to 11kV Switchboard Incomer Protection and Control (e.g. supply and fit of new relays)
- Modifications to Platform PMS
- Disconnection and mothballing of the Main GTG (costs not studied)

A high level study determined that the above scope of work would cost in the region of £340,000 including onshore engineering, procurement, construction and materials and could be implemented whilst minimising disruption offshore.

13.5.1.2 Platform B: Integration Via HV Switchgear Extension

Platform B is an example of an asset with an existing High Voltage distribution network, but without any suitable incomers to repurpose for subsea power import.

As shown in the simplified Single Line Diagram this asset already has a Higher Voltage distribution on the asset to facilitate sharing of power between it and its close neighbours. This is ideal for electrification due to the higher operating voltage which means that more substantial quantities of power can be transmitted to the asset at greater efficiency. The 33kV switchboard is rated for a continuous current of 1500A and therefore can support around 77MW of power assuming a Power Factor of 0.9.

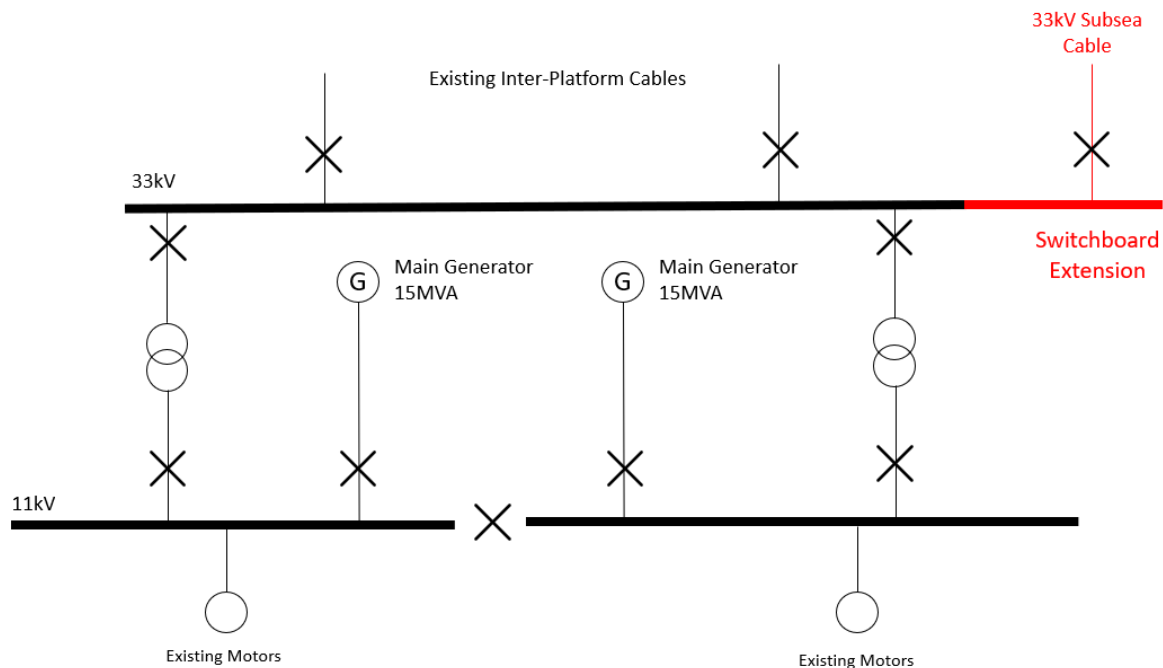


Figure 13-14: Extension of HV Switchboard to accommodate Subsea Power Import

As shown in Figure 13-14 the existing 33kV switchboard does not have spare incomers, or incomers which can be repurposed. In this case it will be necessary to add an additional incomer to allow subsea power import. This will entail extending the existing bus bars and installing an extension tier. An interface cubicle is not required in this case. The existing 33kV switchroom has little room for expansion and initial work has shown that it is necessary to relocate to auxiliary items of equipment (with associated cable re-routing) to allow enough space for the extension tier.

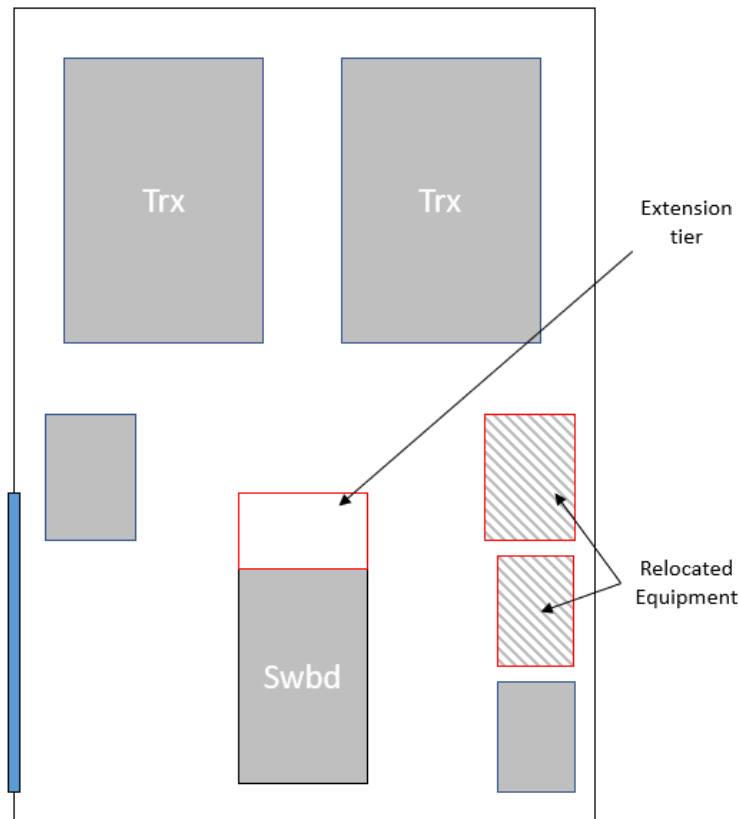


Figure 13-15: 33kV Switchroom showing Extension Tier and Relocated Equipment

The platform's main generators operate at 11kV and may remain in place. Alternatively, these cubicles may be repurposed to feed direct driven equipment that is to be electrified. This will require a review of the 33/11kV transformer capabilities as well as the 11kV switchboard ratings to understand any limitations on electrical loading.

As this platform already has subsea cabling to/from it, the existing cable facilities shall be utilised if they have sufficient space, along with established topsides cable routes to the 33kV switchroom.

13.5.1.3 Platform C: Integration with MV Switchgear

Platform C is an example of a more challenging electrification case. This platform has main generation and distribution at 6.6kV. The main MV switchboard is rated for 2500A current continuous which means it is capable of supporting around 26MW of power assuming a Power Factor of 0.9. It has 3-off GTGs each rated at 11MW and typically relies on two of these operating at around 60% to meet the relatively low electrical demand. The large energy consumers on Platform C are 3-off Export Gas Compressors driven directly by gas turbines.

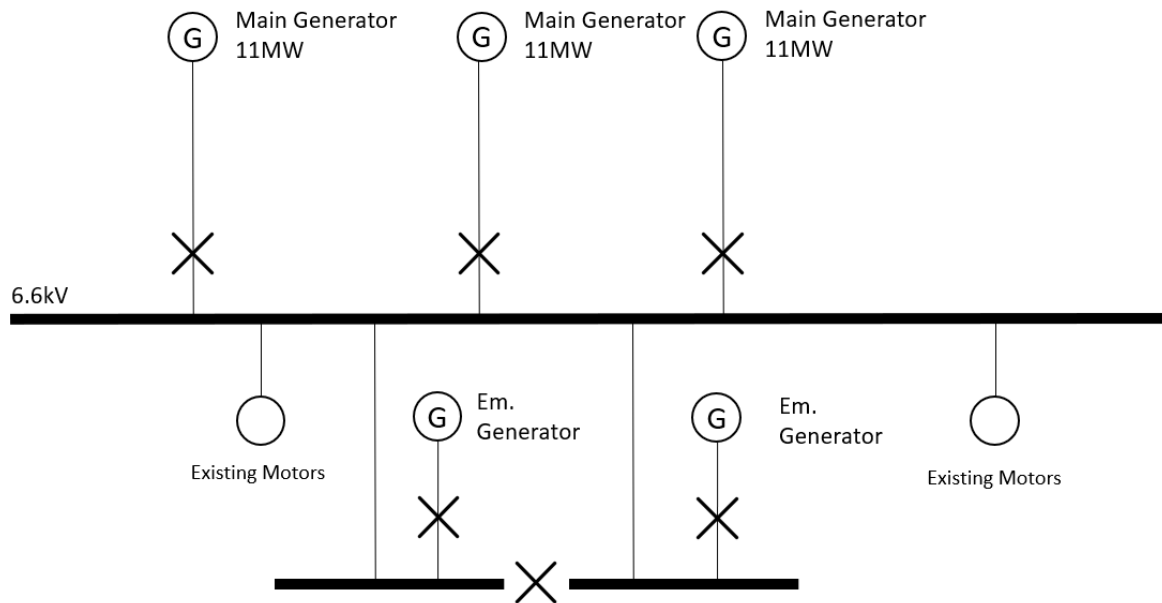


Figure 13-16: Platform C Simplified Medium Voltage Single Line Diagram

Direct electrification of **only** the electrical demand is relatively straightforward with 2 of the Main GTG incomers modified to accept Subsea Cable connections.

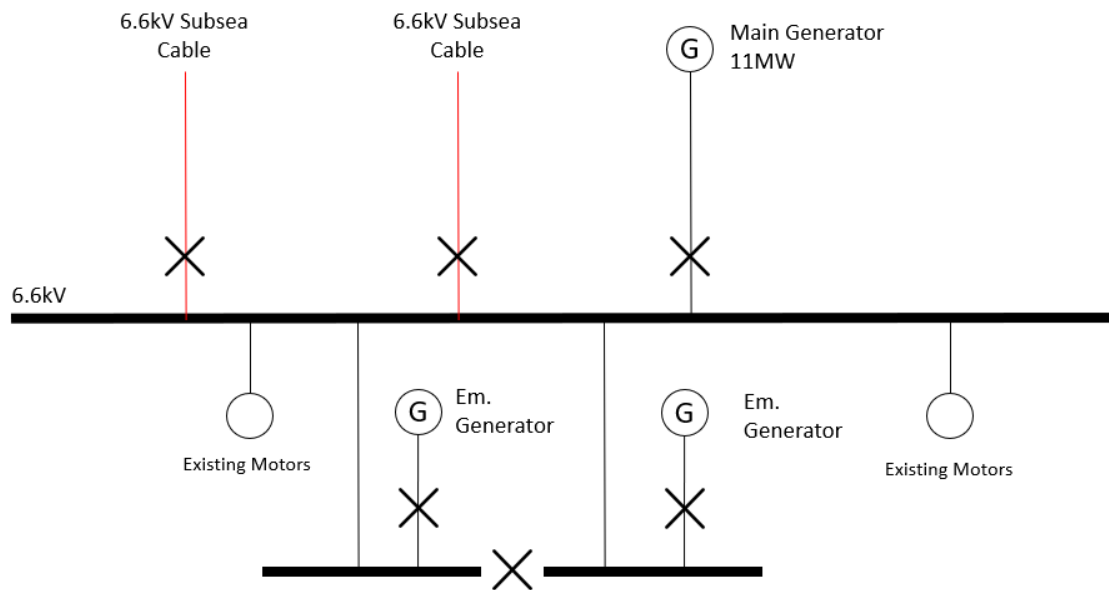


Figure 13-17: Replacement of Generators with Subsea Power Import

However, this approach is limited in terms of the quantity of subsea power that can be imported to the platform. It is not possible using 6.6kV cables and the existing switchgear to electrify the direct driven consumers, which require substantially more power than 6.6kV can deliver.

The status of spare risers is unknown in this case, but it is anticipated that topsides modification scope and costs would be similar to those in Section 13.5.1.1

To overcome the issue of restricted power at Medium Voltage it will be necessary to make more substantial topsides modifications. It is deemed impractical to either uprate the existing switchgear to

carry higher current, or replace it with switchgear rated for a higher voltage. Such works would be expensive and highly offshore work intensive, causing substantial disruption to the platform.

As an alternative it is proposed in this situation that a separate High Voltage switchboard be installed to receive imported subsea power at a higher operating voltage. This would allow the requirements of both electrical platform demand, and electrified Export Gas compressors, to be met.

A proposed distribution scheme for Platform C is shown below in Figure 13-18. A 33kV Switchboard would be installed along with 3-off transformers to provide feeds to the existing 6.6kV distribution, and a new 11kV switchboard used to feed the Export Gas compressors. This would ultimately provide greater operational flexibility and capacity, meeting the requirements of a fully electrified topsides.

Based on preliminary equipment weights and dimensions, including the switchgear, transformers and VSDs, a new E-House would be required

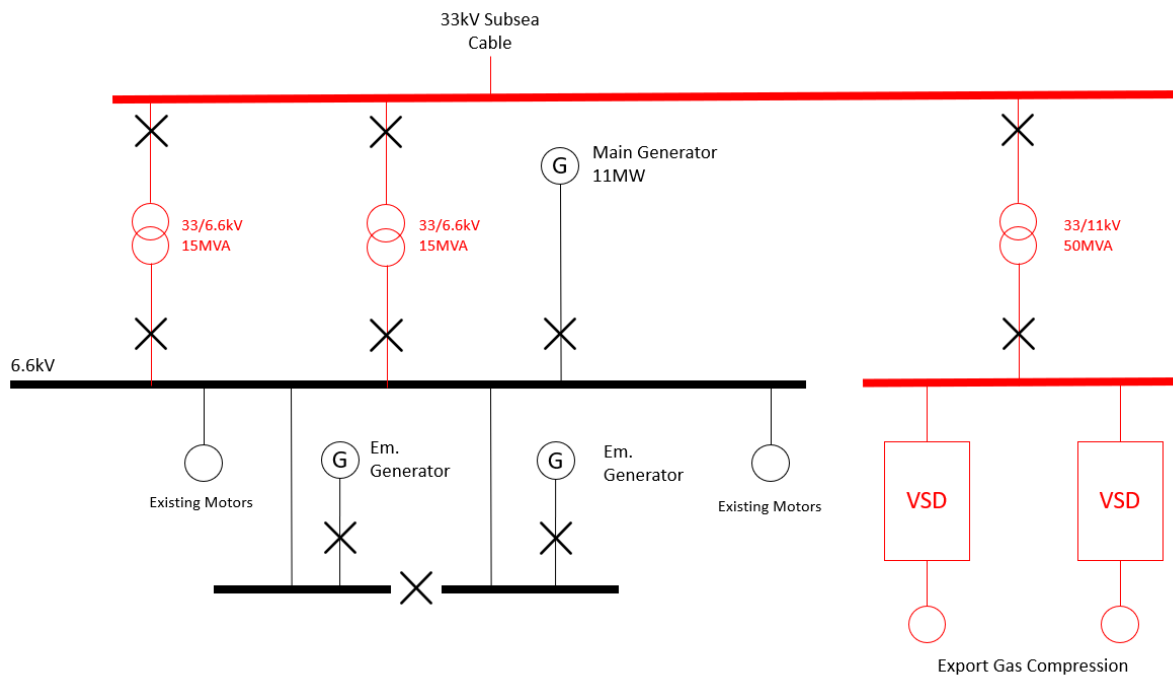


Figure 13-18: Platform C Integrated HV and MV Solution Single Line Diagram

There is an opportunity to supply this as a complete module, able to be installed in a single piece which would minimise offshore scope. The modifications to the existing system are minimised, although systems like PMS will need to be modified/upgraded.

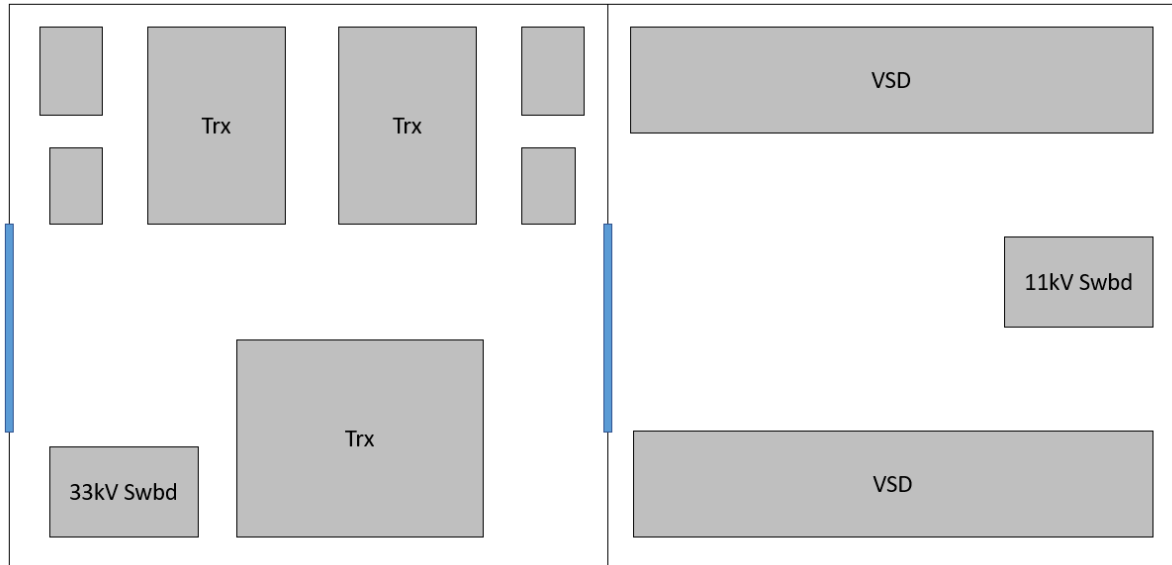


Figure 13-19: Integrated Transformer and VSD Module Layout

A proposed module, on a single level, would be approximately 22mx11m with a layout shown in Figure 13-19.

13.5.1.4 Platform D: Integration with LV Distribution

Platform D is an example of typical Southern North Sea asset where generation and distribution is limited to Low Voltage, in this case 0.415V. Platform D has a main 0.415V switchboard comprising three sections. Each section has a feed from a generator. The Non-Essential Bus receives power from the platform's Main Generator whilst the Essential and Utility buses also have feeds.

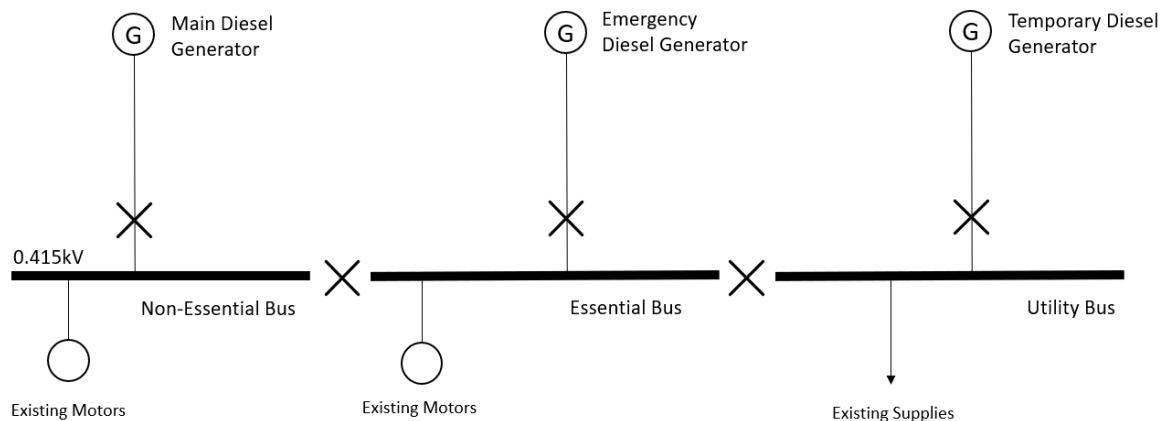


Figure 13-20: Platform D Main LV Switchboard Simplified Single Line Diagram

As with the MV platform discussed in 13.5.1.3, the lower operating voltage makes it impractical to import subsea power at the platform's operating voltage. However, for the majority of LV assets, the electrical demand is also low. This allows the modifications to be minimised. As shown in Figure 13-21 the modifications are to provide a containerised HV to LV reception package consisting of HV switchgear and a stepdown transformer rated to meet the platform power demand; for Platform D and 6.6/0.415V transformer rated for 500kVA is sufficient. This is then tied-in to the existing platform distribution in place of the existing main LV generator. The existing emergency and back-up generation can be retained.

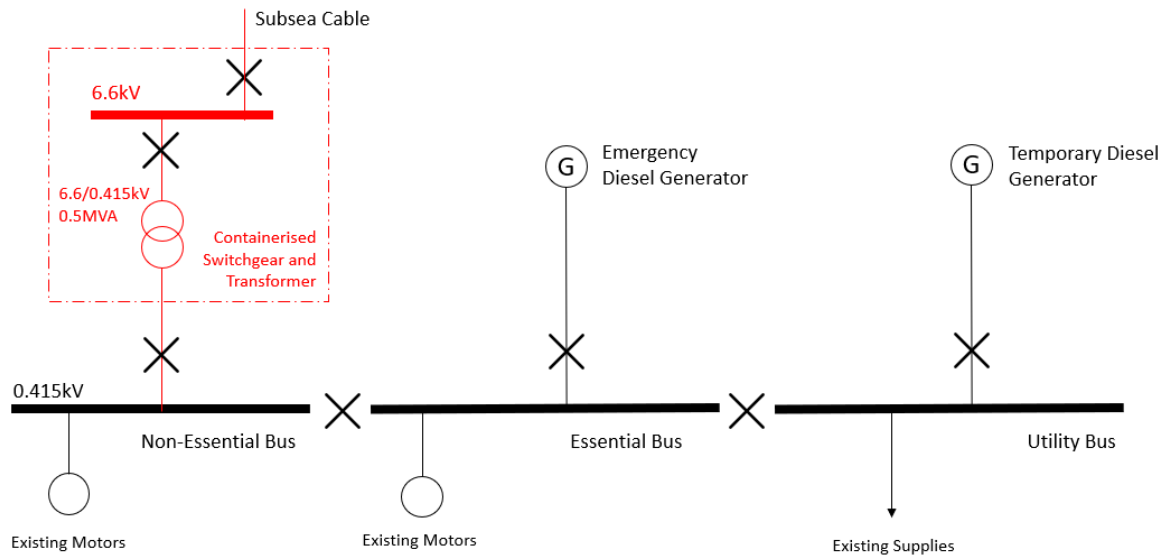


Figure 13-21: Illustration of LV Platform Electrical Modifications

The incomer would need modifications to simplify its control/protection scheme with most of the subsea cable protection achieved at the containerised equipment.

It is anticipated that the containerised switchgear and transformer would fit into a 10ft ISO container. The location of this container would depend on deck space and cable routes. Platform D has space on its Weather Deck close to existing containerised power generation where the containerised reception facilities could be placed.

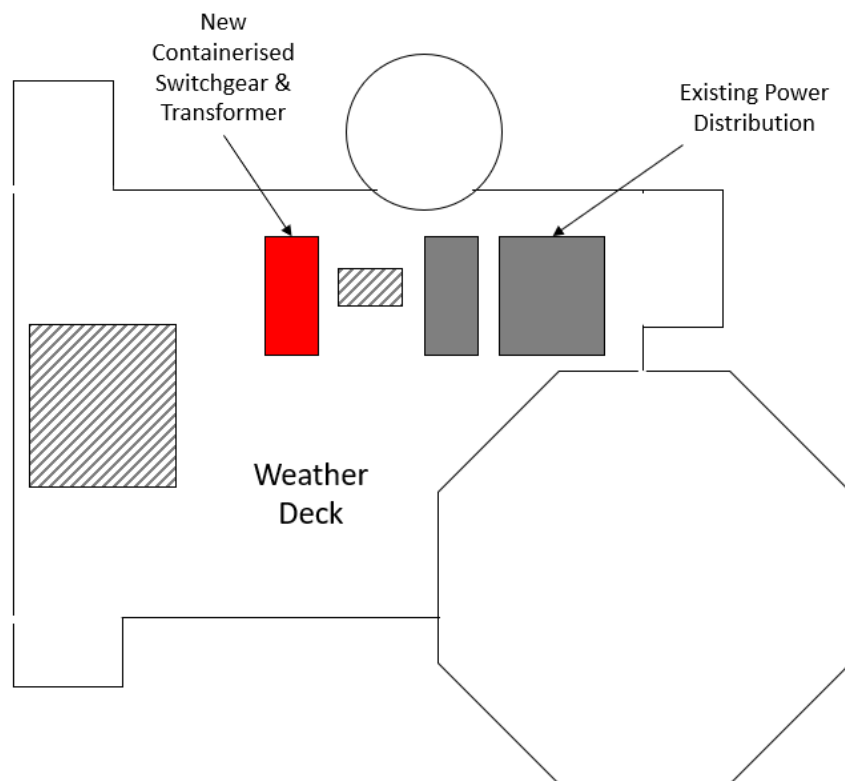


Figure 13-22: Platform D Containerised Reception Facilities on Weather Deck

13.5.2 Direct Drive Replacement

Electrification of direct drive equipment represents a significant opportunity with regards to potential emissions reduction associated with power generation for offshore platforms. As can be seen from Figure 13-1, direct drive power requirements make up a significant amount of the total energy usage of offshore platforms.

As discussed in Section 13.3.1, converting direct driven equipment to mechanical drive is not technically complex from an equipment perspective; however, there can be complications regarding the actual removal of the existing gas turbine generator.

13.5.2.1 Gas Turbine Removal Case Study

13.5.2.2 Background

The existing Gas Turbine Generators installed on an offshore platform were designed to run on produced fuel gas. The GTGs operate to produced power for the asset, and are designed to operate on fuel gas and liquid fuel. A study has been performed by Katoni to evaluate the impact and complexity at removing one or more of these GTGs to increase available area on the platform. The complexity in achieving this is documented in the following sections.

13.5.2.3 GTG-C Removal

GTG-C is located directly under the pedestal of the Starboard deck crane. The minimum reach radius from the crane's centre line was 8.9m with the boom at an angle of 82.7°. This was the maximum boom angle achievable by the starboard crane and as such the lift radius could not be further reduced. To fully implement the removal of GTG-C a bespoke lift plan/procedure would need to be created.

The existing GTG was sized at approximately 11.9m length x 2.7m width x 4.0m height with an approximate weight of 60 tonnes. This would have to be broken down into component pieces to reduce the weight of the largest single lift to use platform facilities.

A provisional study of the structural steelwork under the GTGs shows the whole module was designed as a complete unit to mount the three gas turbine generators. To remove just one GTG would take significant structural modifications – refer to the 3D model images in Figure 13-23, Figure 13-24, Figure 13-25 and Figure 13-26 showing the GTG area and the structural steel underneath.

Even with reduction of the GTG into components which can be handled using the platform crane, the destruct of the structural supports in themselves would be a major scope which likely would be not feasible to actually carry out offshore using on asset personnel and equipment.

13.5.2.4 GTG-A Removal

GTG-A is located next to the starboard crane to the (platform) South. Unlike GTG-C, GTG-A is within the reach of the lift radius of the main hoist. The overall weight of the GTG is in excess of what the platform crane can handle in a single lift, hence the GTG will have to be broken down to allow it to be removed from the platform.

The same structural issues apply to the removal of GTG-A as are described for GTG-C.

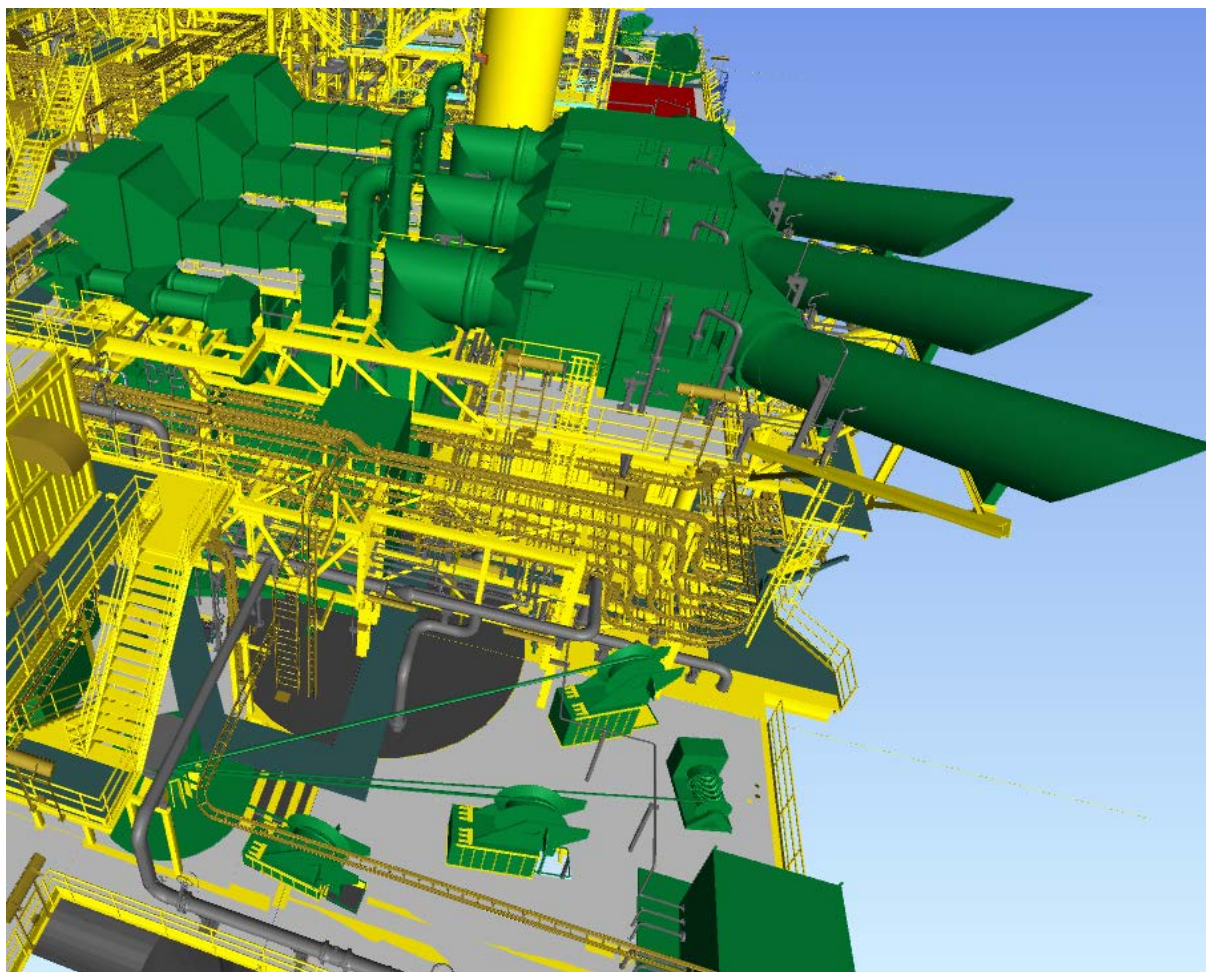


Figure 13-23: GTG Area

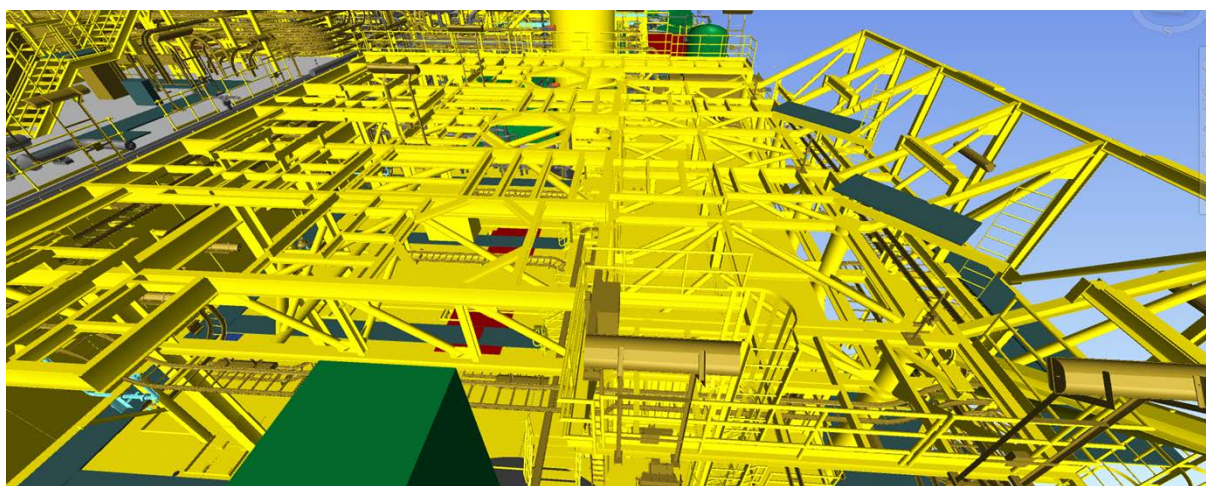


Figure 13-24: GTG Area Structural Steel 1

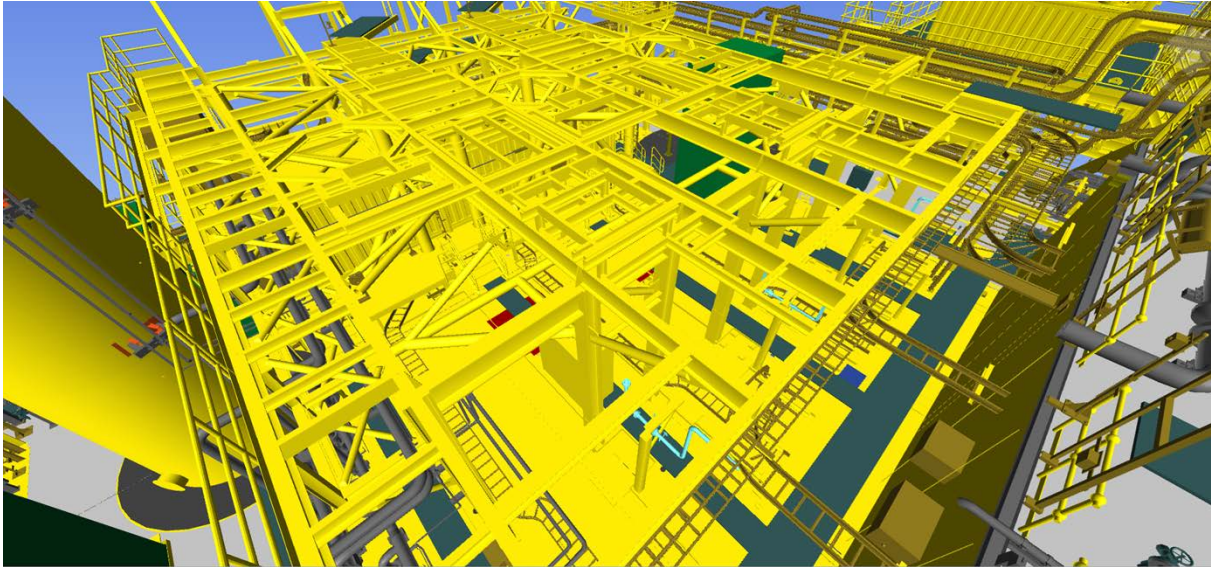


Figure 13-25: GTG Area Structural Steel 2

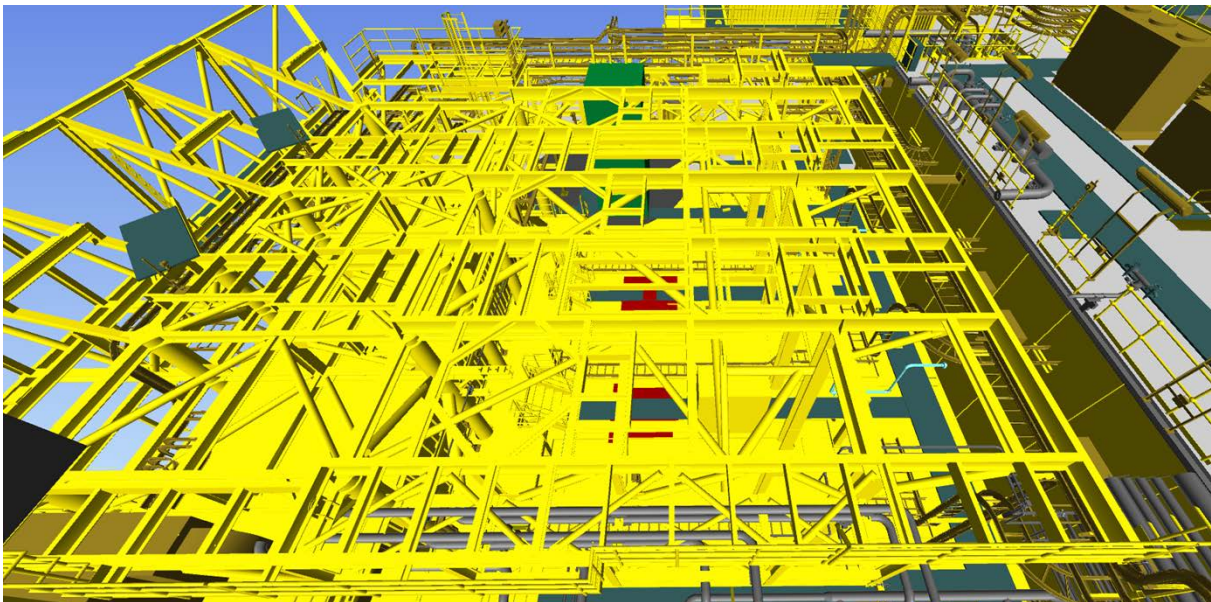


Figure 13-26: GTG Area Structural Steel 3

13.5.2.5 Electrification of Asset

If the asset described above is to be electrified the area where the existing GTGs are currently located would be the preferred location for installation of a new E-House to house the new electrical equipment required for the asset.

The study conducted has demonstrated that utilisation of on-platform infrastructure would not be possible to facilitate removal of the module. Therefore removal of this in a single lift using a heavy lift vessel is the most practical approach to remove this equipment.

The complexity involved in this operation is significant, and although the lift itself may be able to occur in 1 to 3 days, the preparation work required to facilitate this cannot be understated. It is estimated a 4 week outage to allow the system to be prepared for removal prior to lift would be required, in addition to then 3 to 6 weeks for integration of the new E-House module.

In total, disruption to production is estimated to be up to 10 weeks to achieve this upgrade of the facility.

The costs for a project of this scale would be estimated to be in the £50 to £100m range including new equipment, heavy lift vessel hire and subsea cable costs.

13.5.3 Electrical Implications of Direct Drive Conversion

13.5.3.1 Supply from existing distribution

On a platform with existing HV distribution and where the direct drive demand is within the rating of existing switchgear, it will be possible to support replacement electrical driven equipment from the existing distribution. Figure 13-27 shows the proposal for Platform C where a spare cubicle on the 11kV switchboard is used to feed a new VSD supplying gas compression equipment. The ratings of the 11kV switchgear, cables and transformers would need reviewing to ensure no adverse impact.

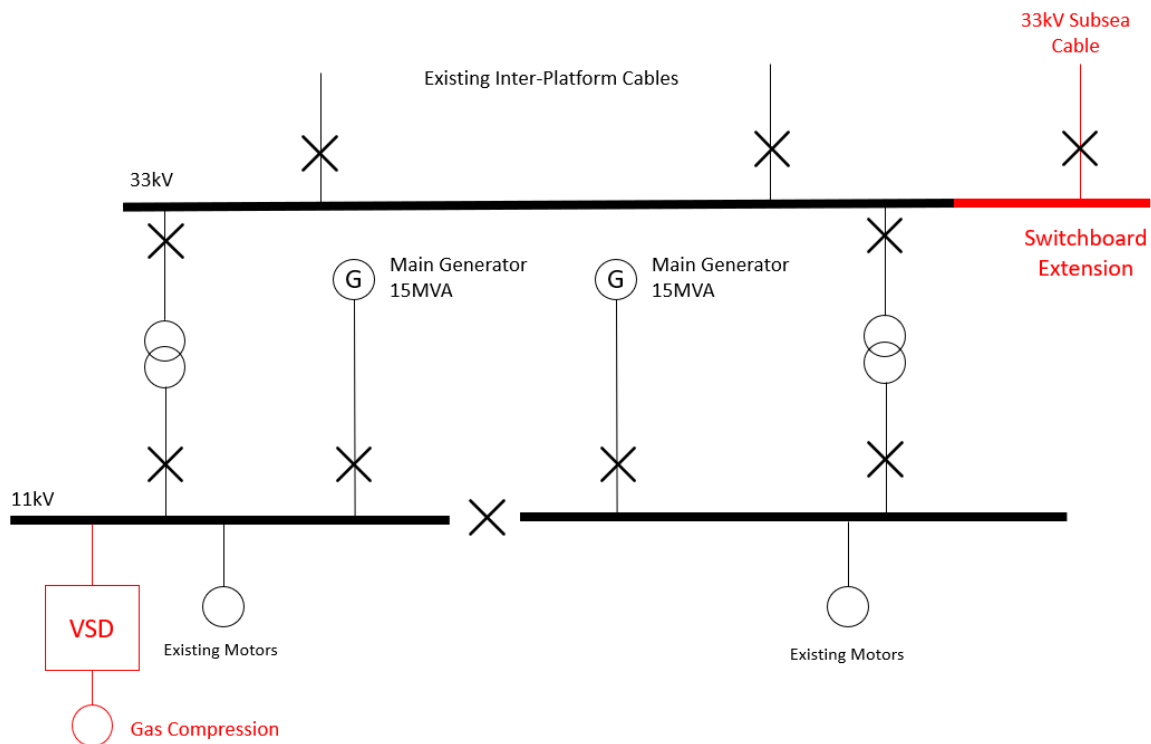


Figure 13-27: Platform C with Electrified Compression Equipment

13.5.3.2 Supply from new distribution

If the direct drive electrification scope is completed some time after the initial electrification scope, then an arrangement as shown in Figure 13-28 would be most suitable. In the illustrated example, the existing distribution has limited ability to support additional load, so a further subsea power cable is run to the platform which is then solely used to support the new compression equipment. There is no interface between the existing electrical distribution system and the system supporting the direct drive equipment.

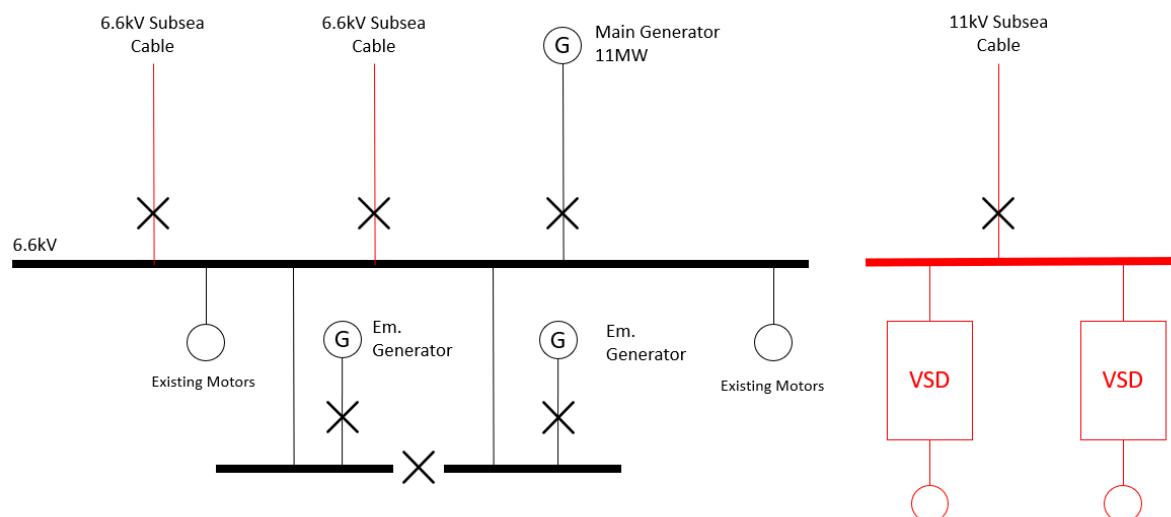


Figure 13-28: Powering Direct Drive Replacement Equipment

Alternatively, a holistic approach could be adopted if direct drive electrification was planned in from the start. This has already been discussed and shown in Section 13.5.1.2.

13.6 Other Modifications

13.6.1 Platform Gas Export

13.6.1.1 Background

Katoni carried out a feasibility study for an oil and gas operator in the CNS into the electrification of one of their platforms, referred to here as “Asset 1”.

Asset 1 produces heavy crude with a low GOR. It is now gas deficient and operates with gas import from a neighbouring platform via a 6” pipeline.

Full electrification of the asset would result in the need to use the surplus produced gas that was previously used for fuel gas. The simplest solution was to assume the import pipeline from the neighbouring platform would be used for export of the produced gas and so the necessary modifications to prepare Asset 1 for gas export were studied.

The asset has existing gas export equipment consisting of export compressors, export heater, filter coalescer and a TEG dehydration system. All but the export compressors, which are used for fuel gas compression, have been mothballed and out of service for approximately 10 years.

The Asset 1 produced gas flowrate and composition has also changed significantly since the export system was in use. In particular, the gas now has a very high concentration of H₂S which must be reduced to meet export pipeline specifications.

13.6.1.2 Asset Gas and Export Specifications

13.6.1.2.1 Asset 1 Gas Composition and Flowrate

The Asset 1 gas flowrates and composition has changed significantly from initial design conditions. The export equipment was initially designed for 18 MMSCFD and current production rates will peak at 4.5 MMSCFD, only a quarter of the design rates.

Additionally, the H₂S concentration was <100 ppmv and could be treated using H₂S scavenger chemicals to meet export pipeline specifications. The concentration is now >1000 ppmv and expected to reach up to 2700 ppmv by 2027, and treatment using scavenger chemicals would not be sufficient to meet export pipeline specifications. Export Specification to Neighbouring Platform

The key export specifications are as follows:

- H₂S concentration = 8 ppmv
- H₂O concentration = 21 ppmv
- Arrival pressure = 30 barg
- Arrival Temperature = 30 °C

The gas would be further treated on the neighbouring platform to meet hydrocarbon dewpoint specifications and pressures to meet the requirements of the export pipeline system.

13.6.1.3 Mothballed Equipment

There were two options for the mothballed export equipment:

1. Assess the condition of existing equipment and ensure it is appropriately designed for current gas flowrates and composition, and make the necessary modifications to bring it back to full service
2. Replace the existing system with new equipment designed for the current produced gas

Option 2 was selected as the most appropriate solution for the following reasons:

- The gas flowrate had reduced to a maximum of 25% of the initial design flowrate. This existing equipment was therefore significantly oversized for current production rates and significant modifications were anticipated to achieve efficient operation. A full assessment of the equipment and instrument sizing was not carried out in this early stage but is something that could be considered as a future scope of work if full replacement was not feasible.
- Katoni were informed by the operator that much of the instrumentation and equipment had been scavenged for spares and repairs.
- The equipment was located on a platform module that could be removed with relative ease and replaced by a similar module containing new gas export equipment.

13.6.1.4 Gas Sweetening Technology Review

Treatment of the Asset 1 gas stream presents difficulties, as the combination of low gas flowrate and high H₂S concentration results in a sub-optimal feed stream for most common sweetening technologies.

The technologies considered for the treatment of the Asset 1 gas were as follows:

- Solid desiccant / molecular sieve adsorption with and without regeneration
- Membranes
- Chemical scavenger
- Liquid redox treatment
- Amine absorption

13.6.1.4.1 Solid Desiccant / Molecular Sieve Adsorption with and without Regeneration

Molecular Sieve technology was assessed as there is potential for combined removal of H₂S and dehydration using a single system. However, the high concentration of H₂S presents difficulties for solids adsorption technology as it results in high regeneration rate requirements or large material requirements for non-regenerative systems.

This was confirmed by (Honeywell / UOP) who showed that regeneration rates of up to 50% of the total gas stream were required for a regenerative molecular sieve system and their analysis of a non-regenerative solid desiccant system resulted in unfeasibly high solids material usage rates.

Additionally, for regenerative systems, the very sour gas used for regeneration is typically sent for reinjection but in the absence of reinjection facilities would require further treatment / equipment to meet the export specification.

13.6.1.4.2 Membranes

Membranes are typically only capable of around ~75% bulk removal H₂S from a gas stream but can operate as high as ~95%; however, the Asset 1 gas requires ~99% H₂S removal and so the use of membrane technology by itself was not viable, in this case.

Additionally, we anticipate due to the membrane regeneration requirements that similar regeneration gas issues described for solid desiccants / molecular sieves will be encountered with membrane technology.

13.6.1.4.3 Chemical Scavenger

Chemical scavenger was previously used to treat the Asset 1 gas, when concentrations of H₂S were a factor of 10 lower than they currently are.

It is possible to treat the current stream to meet the export specification using chemical scavengers; however, at current concentrations the anticipated chemical usage and replacement rate will make this technology economically unviable.

Additionally, chemical scavenging results in solid by-products which are expected to be significant for the Asset 1 stream and can cause operational issues.

13.6.1.4.4 Liquid Redox Treatment

This is a lesser utilised technology; however, this may be a promising option for treating the Asset 1 gas as it is considered a potentially good alternative for gas streams with high H₂S concentrations.

The process creates a solid sulphur by-product which is considered easier to handle and remove than the solids (typically salts) created by scavenger chemicals.

13.6.1.4.5 Amine Absorption

An amine system was viable for treating the Asset 1 gas; however, the low gas flowrates are expected to result in a high capital cost per MMSCF of gas.

The benefits of this technology for use on Asset 1 are lower operating costs compared to chemical scavengers, no solid by-products are created, no regeneration gas stream is required, and it is a proven technology with a strong track record in the offshore oil and gas industry.

13.6.1.4.6 Conclusion of Technology Review

The following technologies were ruled out as viable options for the reasons discussed in the individual sections above:

- Solid desiccant / molecular sieve adsorption with and without regeneration
- Membranes
- Chemical scavenger

The following are considered potentially viable options:

- Liquid redox treatment
- Amine absorption

An Amine system was reviewed and received and all further analysis including cost estimation, system sketch and space and weight analysis was based on the use of an Amine system for sweetening of the Asset 1 gas. The potential high capital costs per MMSCF of gas were accepted as a compromise as other systems were incapable of treating the gas due to the very high H₂S concentrations.

In addition to the gas sweetening system, a dehydration system, filter coalescer and export gas cooler were required to complete the gas export system.

A TEG system was proposed for gas dehydration purposes, to replace the existing system, and a shell and tube heat exchanger was selected for the gas export cooling requirements. A TEG system was selected due to being a proven technology with many operational hours in the offshore oil and gas industry, and potential operator familiarity.

13.6.1.5 Required Modifications and Implementation

13.6.1.5.1 Process Modifications

The new gas treatment equipment would be tied into the existing system at the discharge of the Produced Gas Compressors, where the existing mothballed equipment currently ties in, as shown in the sketch below:

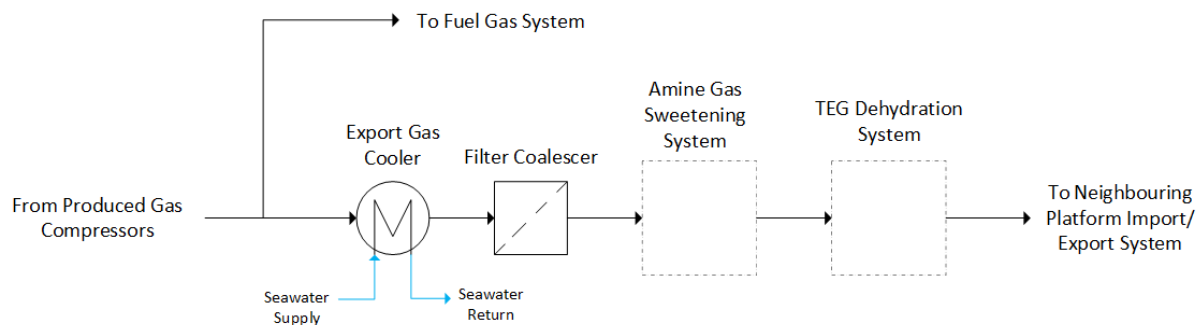


Figure 13-29: Platform Gas Export System Sketch

13.6.1.5.2 Impact on Electrical System

The proposed Gas Export system does not include significant electrical driven pumps or heating loads. It was expected that any small pumps or heaters could be accommodated within the existing Asset 1 low voltage distribution with minor modifications required to refit starter cubicles etc.

Where possible, if equipment was being destructured and replaced (e.g. the TEG system) then these electrical supplies would be reused. Any additional supplies would be sourced from the same switchboards and distribution as far as possible.

The new module may also have required alterations to lighting as well as the provision of trace heating which would have needed to be studied in more detail.

13.6.1.5.3 Location and Layouts

The existing Gas Export and TEG Equipment which was mostly self-contained within a specific module could be removed and this area then used for a new Gas Export module which would incorporate the system shown in Figure 13-29.

One possible approach would be to remove the existing module from the platform and then retrofit a module of similar dimensions containing the new Gas Export equipment. Both removal and installation would be completed using a Heavy Lift Vessel as the location does not suit the reach or capacity of the platform crane.

It was proposed that this module be installed as single lift, similar to other recent examples in the UKCS, for example, the addition of the Alder module to Britannia Satellite Platform.

13.6.1.5.4 Weight

Equipment	Weight (tons)	Source
Prefabricated Steel Module	300 Te	Estimate
Process Equipment	220 Te	Quote
Total	520 Te	

Table 13-3: Key Equipment Weights

13.6.1.6 Constructability

It was proposed that the Replacement Export Gas Module be fabricated onshore with as much pre-works and pre-commissioning completed based on the single lift installation strategy. Prior to this, the existing Module would need destructing, tie-in points installed and any structural modifications completed.

The module would be installed as a single lift utilising a Heavy Lift Vessel.

Once the module was in place, hook up works would take place with integration work including cable installation (re-routing existing cables), gas pipework and cooling medium pipework. It was recommended that tie-in points be installed during a TAR prior to the main construction phase.

Identified areas for further study were:

- Requirements for preparing the area to receive the new module – structural works, integrity work etc
- Review of the existing analysis models
- Review of module attachment points
- Detailed offshore dimensional survey
- Review of Access/Egress routes
- Determine new module integration works
- Verification of location from a Technical Safety aspect including proximity to flare and other process equipment as well as the requirement for passive and active fire protection on this side of the platform
- Existing primary steel girders require to be checked for capacity and probable strengthening due to additional loads from the new module
- Requirement to provide dropped object protection over flowlines below the platform in the area of the new module

Challenges to this scope included:

- Manoeuvring equipment into the area using the heavy lift vessel with other supporting scopes completed using the platform crane
- Potential for other equipment in the area blocking access/egress – requiring temporary removal and reinstatement
- Capacity of the jacket overall, and the deck in this area, to accept additional weight
- Potential inaccuracy of platform reference drawings, weights etc to complete structural analysis
- Changes in weight and CoG of the platform
- Weather window required for the lift – likely to be a short window during the summer
- Additional manpower and impact on bedding to complete module installation and integration works
- Potential for damage to the platform during the lift – requirement for bumper bars etc to be added to the platform

13.6.1.7 Project Cost and Schedule

Description	Gas Export
Estimated Project Cost	£30,000,000
Estimated Project Timescale	2-3 years
Topsides impact	Replacement of existing Gas Export module with a newly fabricated module. Utilise existing tie-ins, utility supplies etc where possible but there may be some additional Topsides scope identified to suit the new equipment.
Key Risks	Substantial destruct and construct scope with interfaces to existing platform systems to consider. Heavy lift installation. Reintroducing active gas processing equipment and export to Asset 1.

Table 13-4: Gas Export Modification Project Summary

13.6.2 Gas Export – Minimal Export Facilities

13.6.2.1 Background

There are several offshore platforms and platform clusters that present a specific challenge with regard to electrification due to a lack of gas treatment and export facilities. All the produced gas on these platforms is typically either used as fuel gas and/or for gas lift.

Electrification of these platforms would result in excess gas, previously used for fuel gas, which would need to be handled to prevent flaring.

This case study assesses a specific example of a platform cluster that produce from a shared oil field – henceforth known as Cluster 1.

Cluster 1 has minimal gas treatment facilities and no existing export route. Most of the platforms in the cluster share a very similar topsides design. A sketch of the existing gas system is shown in Figure 13-31.

13.6.2.2 Gas Export Route

Gas export was identified as a potential solution that could provide the most value while reducing modifications required to the platforms.

The overall concept would be to connect the Cluster 1 gas systems via a pipeline ring main / manifold, with a single export pipeline to a local platform with an export route to a transmission system.

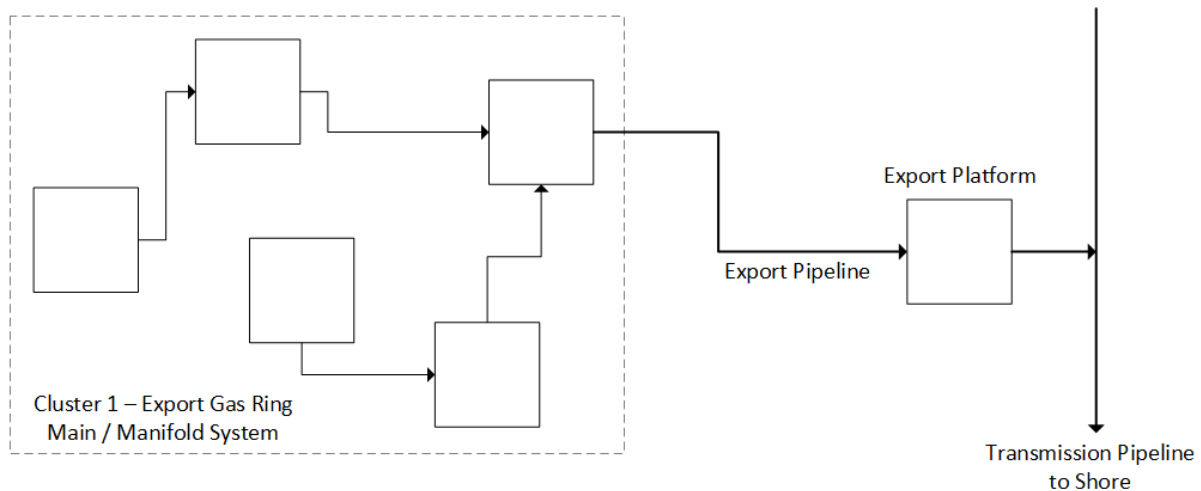


Figure 13-30: Gas Export Concept Sketch

This was identified as a potentially optimal solution for the following reasons:

- The close clustering of the platforms ensures that the ring main system length is relatively short
- The platforms have existing gas treatment for the fuel gas and gas lift systems which include much of the equipment required to meet gas export specifications, including dehydration, compression, and cooling
- The export gas would provide an additional valuable product stream

13.6.2.3 Export Route

The most likely export routes for the gas would be via one of two platforms located near to Cluster 1. These platforms have operational gas treatment and export facilities. The platforms are henceforth known as Platform 1 and Platform 2.

Platform 1 exports gas to the SAGE pipeline and Platform 2 to the Fulmar pipeline. As per Section 13.4.2 of this report, the SAGE pipeline specifications are less strict than the Fulmar specifications, which may prove beneficial for exporting the Cluster 1 gas.

This assessment assumes that Platform 1 and Platform 2 have capacity to facilitate the additional gas from the Cluster 1 platforms.

13.6.2.4 Required Modifications

13.6.2.4.1 Gas Treatment

There is no hydrocarbon dewpoint treatment on the Cluster 1 platforms, therefore use of the Platform 1 or Platform 2 facilities is the simplest option available to meet appropriate export specifications. Refer to Figure 13-31 for a sketch of the existing Cluster 1 gas treatment system. In this option the export gas from Cluster 1 to Platform 1 or Platform 2 does not need to meet the full pipeline specifications but must meet appropriate specification to tie into the Platform 1 or Platform 2 gas treatment system upstream of the dewpoint control system. This is assumed to require at a minimum:

- Gas dehydration to export pipeline specification
- Gas compression up to a minimum of 30 barg
- Gas cooling to $<50^{\circ}\text{C}$

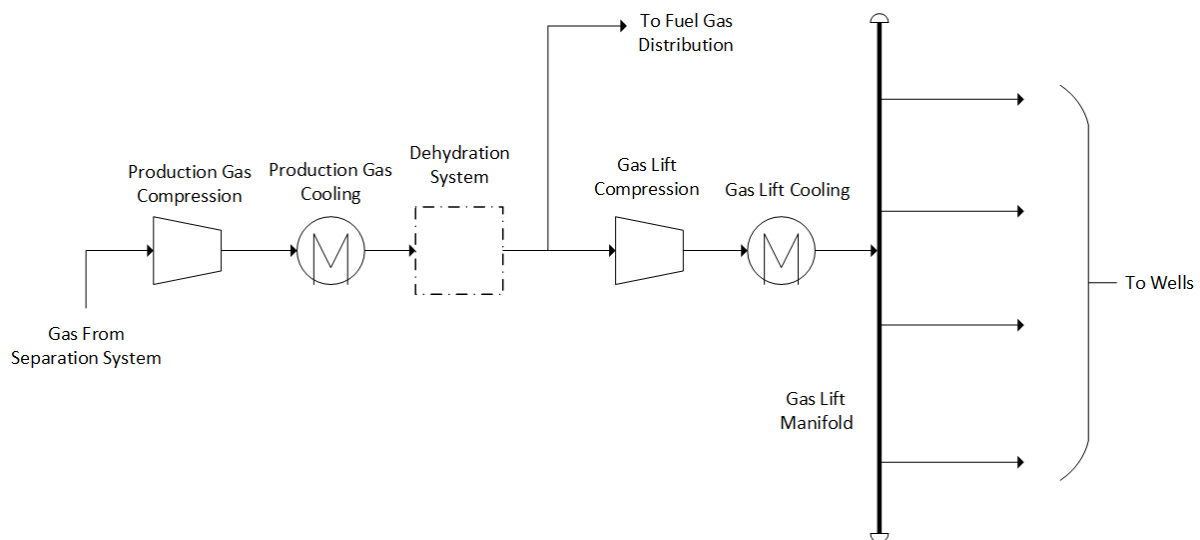


Figure 13-31: Cluster 1 Gas System Sketch

Gas compression is provided on the Cluster 1 platforms via the production gas compressors which compress the gas to approximately 30-40 barg and the gas lift compressors which compress the gas to approximately 125 barg.

The assumed export pressure to Platform 1 or Platform 2 can be achieved by the production gas compressors; however, if pressures above approximately 40 barg are required then other options would have to be considered.

This represents the option with the potential for the least modifications. A sketch of the system is shown in Figure 13-32.

If the option of tying into the gas treatment system on Platform 1 or Platform 2 is not possible and the full export pipeline specification must be met, then a new hydrocarbon dewpoint system would be required. This could be a Joule-Thomson cooling system or a refrigeration system. Given the potential lack of available compression capacity and the aim to reduce emissions, a refrigeration system would likely be the most suitable option.

The gas compression and cooling requirements could potentially be met by a combination of the production gas compression / cooling and the gas lift compression / cooling; however, the gas lift system may not have capacity for the combined gas production and gas lift requirements and in that scenario additional gas compression and cooling would be required to meet the export specification.

If hydrocarbon dewpointing and additional gas compression and cooling were required, then there are two options:

1. Provide the hydrocarbon dewpointing and additional compression on each of the platforms and operate the ring main at export pressures
2. Provide the hydrocarbon dewpointing and additional compression on the export platform only (platform with export pipeline to Platform 1/Platform 2) and operate the ring main at intermediate pressure, tying in upstream of the export compression system.

In the event where hydrocarbon dewpoint control was required on the platforms then condensate / NGL treatment, storage and export facilities could also be used. The product could be exported by tanker. Otherwise, the condensate / NGLs could be recycled back to the separation system but may cause the type of operational issues addressed in Section 13.4.2.3.

This option would require the most platform modifications. A sketch of the system, assuming the use of additional gas compression option 2, is shown in Figure 13-33.

If the pipeline specifications could be relaxed for receipt of Cluster 1 gas, most likely in the case of export to Platform 1 due to export to SAGE pipeline, then a hydrocarbon dew pointing system may not be required, reducing the required modifications significantly.

In addition to the potential modifications already addressed, the production gas compressors on Cluster 1 are direct drive and would require conversion to mechanical drive if Cluster 1 was fully electrified.

Gas dehydration could be provided fully by the existing TEG systems used on the Cluster 1 platforms.

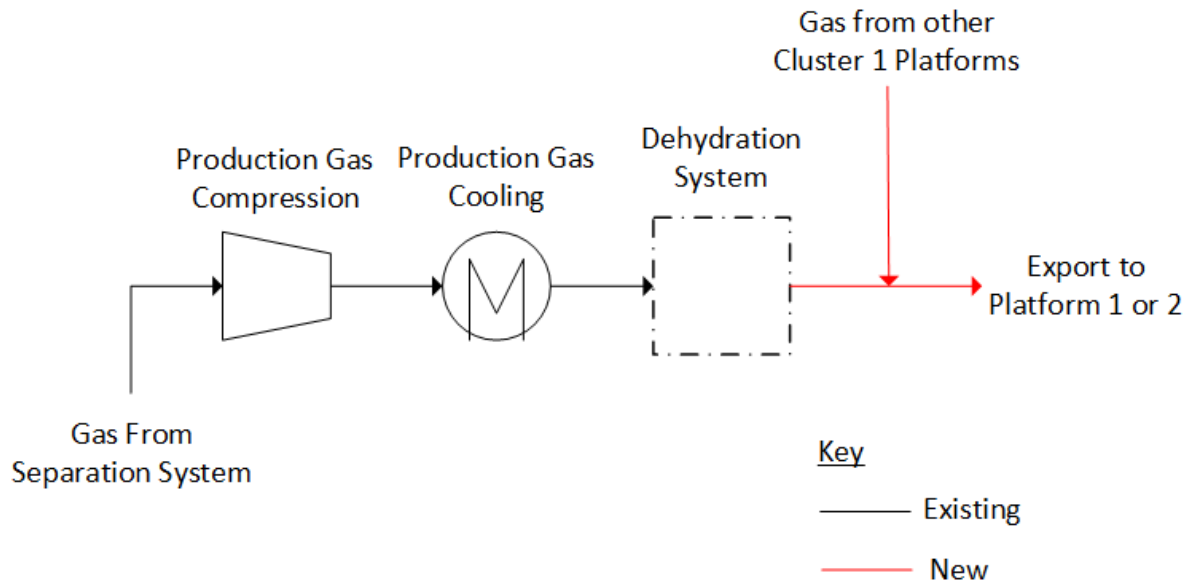


Figure 13-32: Sketch of Cluster 1 Gas System (minimum modifications)

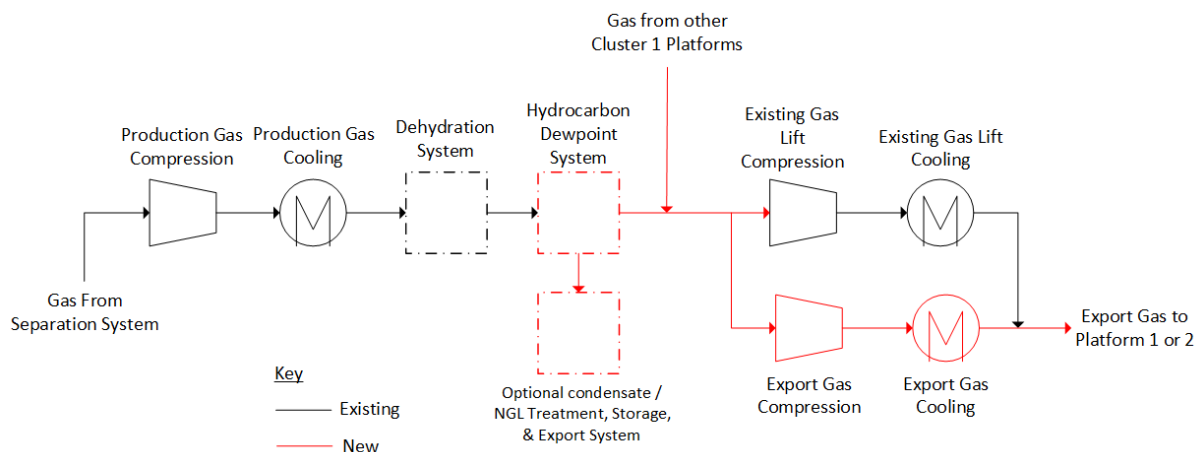


Figure 13-33: Sketch of Cluster 1 Gas System (significant modifications)

13.6.2.4.2 Distribution and Export

Depending on the selected gas treatment modifications, minor piping modifications may be required to connect and bypass parts of the gas treatment system.

The ring main system and export pipeline will require significant subsea pipeline lengths as well as risers between the platforms.

Fiscal metering will be required upstream of the export pipeline to Platform 2.

Platform 1 and Platform 2 will require a new riser and piping modifications to connect the import gas to the platforms gas treatment system.

13.6.2.5 Project Cost and Schedule

The project cost is estimated to be approximately £50m with an estimated duration of 2-3 years.

13.6.3 Pipeline Specifications

For many platforms, the excess gas that will be generated by electrification of the power generation system is best exported for sale. However, for platforms without full export gas treatment facilities, significant modifications are required to meet export pipeline specifications.

The implications of excess gas are discussed in Section 13.4.1, export pipeline specifications are discussed in Section 13.4.2, and a relevant case study is analysed in Section 13.6.2.

Relaxation of certain pipeline specification requirements could allow for greater electrification of offshore platforms by reducing the modifications required for platforms with minimal export gas treatment facilities.

13.6.3.1 Analysis of Pipeline Specifications

The typical pipeline specifications are discussed in detail in section 13.4.2. This section will discuss the pipeline specifications that are and are not candidates for relaxation, the implications of relaxation of certain specifications and the practicality of doing so.

The following are considered not to be candidates for specification relaxation:

- Water content – the water content specifications are not a good candidate for relaxation as they are important to prevent hydrate formation in the export system. Additionally, there may be little benefit in reducing this specification as even platforms with limited export gas treatment facilities may have a gas dehydration system for treating produced gas for use as fuel.
- H₂S and CO₂ – this is not considered a good candidate for relaxation as these aspects ensure the export pipeline is not corroded and that toxic levels of H₂S cannot reach end users.
- Mercury – Mercury content is also a poor candidate due to limited benefits and to ensure it does not impact the integrity of the pipeline.

The following are considered to be good candidates for specification relaxation:

- NGL / Condensate Fraction
- Cricondenbar Control / Hydrocarbon Dewpoint Control

Both specifications are linked, in that longer chain hydrocarbons seen in NGLs / condensate have lower boiling points and contribute to higher hydrocarbon dew points.

These specifications exist to prevent hydrocarbon liquid dropout in the gas export pipeline which can cause operational issues such as increased pipeline pressure drop / reduced capacity and equipment issues such as compressor damage.

Reducing these specifications could have a major benefit since the removal of heavy hydrocarbons from the gas stream requires the use of both a hydrocarbon dewpoint control system (typically refrigeration system) and the treatment, storage and export of the NGLs and condensate products of the hydrocarbon dewpoint system. This additional equipment required may make the electrification of platforms with minimal existing export gas treatment facilities unfeasible or impossible.

There is some research that suggests the hydrocarbon dewpoint specification in pipelines could be relaxed with minimal impact on pipeline and equipment operation /112/.

The composition of gas in an export gas pipeline consists of an aggregate of all the gas from many different sources; however, all imports to the pipeline are expected to meet the same specification. Allowing selected platforms to import into the pipeline at a reduced specification, at a certain cost or reduced sale value, could allow more platforms to export their gas with minimal impact on the aggregate pipeline specification. There are examples of this type of agreement being used already, such as with South Arne in Denmark.

A more extreme solution could be to provide an export pipeline route with significantly reduced NGL / condensate and cricondenbar / hydrocarbon dewpoint specifications that could be used by these types of platforms. This could also be operated at lower pressures, which could allow platforms with minimal compression equipment to export their gas with further reduced modifications burden.

13.6.4 Heating System Replacement

13.6.4.1 Background

Katoni carried out a feasibility study for an operator in the CNS into the electrification of one of their platforms – henceforth known as Asset A.

The Asset A facilities are made up of a three interconnected production assets. Asset A crude is exported and gas can be exported and imported via subsea pipeline.

The two of the three assets have separate power generation and heating medium systems. The Facility A uses WHRUs to provide heat to the heating medium system whereas the Facility B uses gas fired heaters. All three Facilities are electrically interconnected.

13.6.4.2 Electrification Options

13.6.4.2.1 Partial Electrification

In the Partial Electrification scenario Asset A could be partially electrified without requiring any process modifications by supplying additional electrical power at 11kV and 60Hz. In this scenario electrical power could be supplied to Asset A to reduce the reliance on the gas turbines on the Facility A and to remove the need for any power generation on Facility B. One GT would remain in service to deliver both base load and heat input to the process via the WHRU to Facility A and the fired heaters on Facility B would remain in service.

13.6.4.2.2 Full Electrification

In the Full Electrification scenario further electrification of Asset A could be achieved but would require additional modifications to replace the WHRUs and fired heaters and to provide enough electrical power to make up the additional electrical demand created by the complete removal of the Facility A GTs and WHRUs, and Facility B fired heaters. In this scenario the WHRU and fired heaters are replaced by electric heaters and additional electrical power is supplied at 66kV and 60Hz.

13.6.4.3 Process Heating

Figure 13-34 and Figure 13-35 show the system sketches for Facility A and Facility B heating medium systems after replacement by electric heaters. The electric heaters would tie into the existing system at the inlet and outlet of the WHRU, effectively bypassing the redundant WHRU, through a simple piping modification.

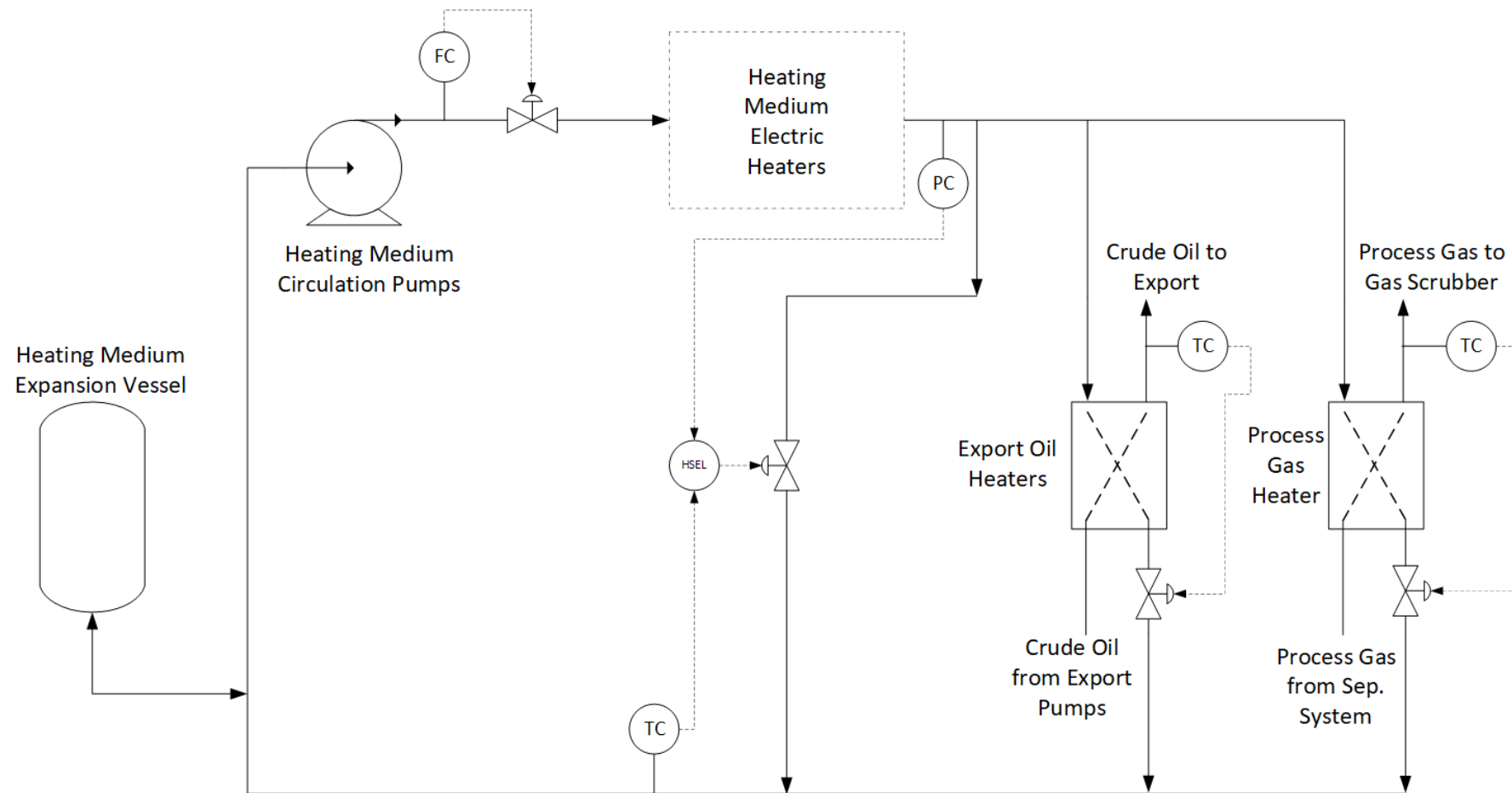


Figure 13-34: Facility A Modified Heating Medium System Sketch

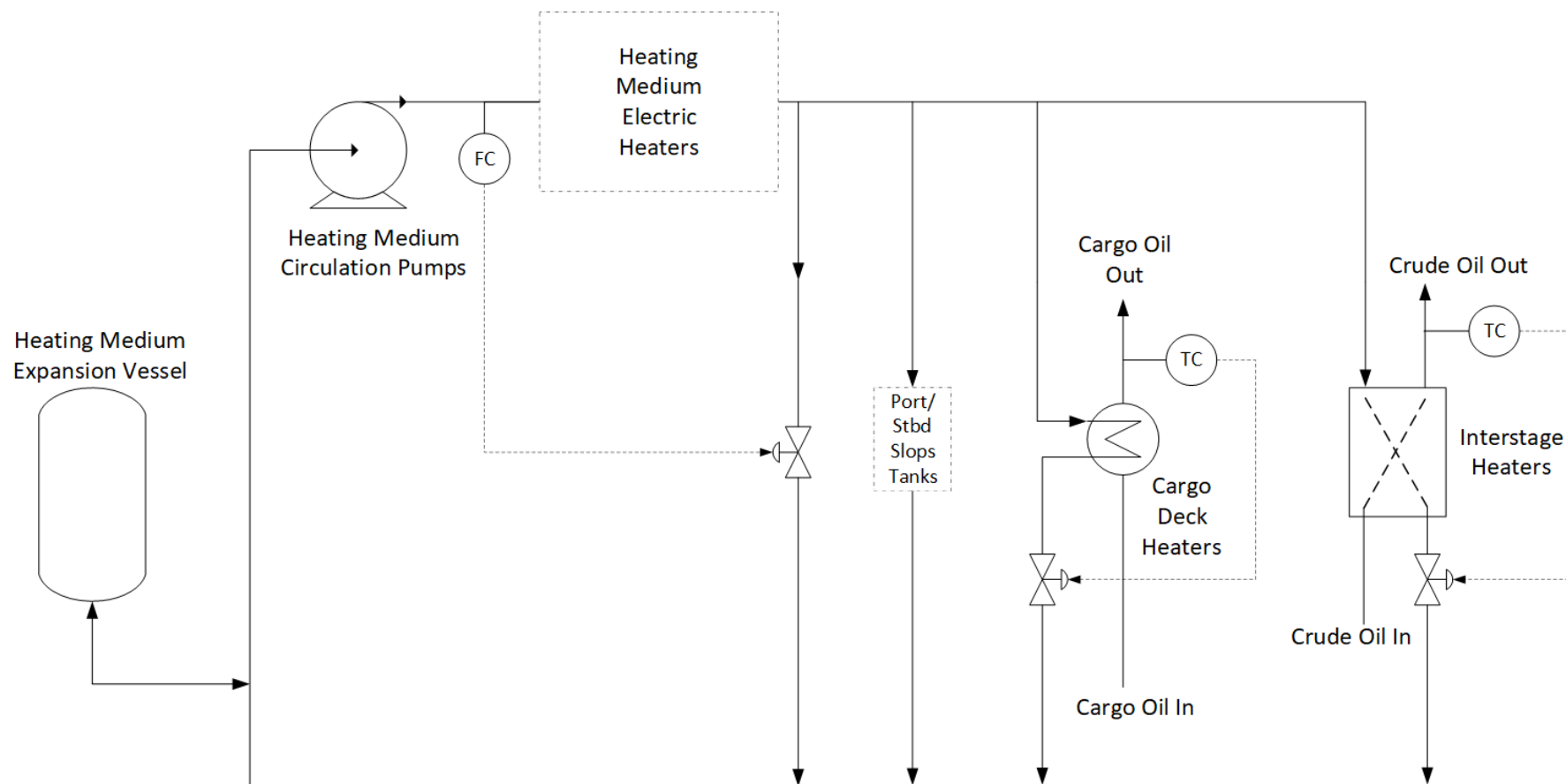


Figure 13-35: Facility B Modified Heating Medium System Sketch

13.6.5 Process Heating Duty Estimate

To properly size the electric heaters and determine the total electrical power requirements, an estimate of Facility A and Facility B current and future process heating requirements was made.

Using production profiles supplied by the operator, the current and future heating requirements were estimated using the Asset A HYSYS simulation model. The results are summarised below:

Platform	Current Operating Duty (MW)	Maximum Future Operating Duty (MW)
Facility A	10.5	24.1
Facility B	17	22.6

Table 13-5: Asset A Facility A and Facility B Current and Future Process Heat Duty

13.6.5.1.1 Electric Heaters

Electric heaters were provided, based on an initially estimated 9MW load for Facility A.

The 9MW load was based on latest operating conditions; Maximum heating demand was determined to be 24 MW. Electric heaters are modular and can be scaled to the load using multiple heaters in parallel operation.

The first electric heater configuration was based on a maximum current rating from the 11kV switchboard of 1250A. The offered line heaters for this quotation can provide a heat load of 1130kW each, with each heater supplied with a dedicated control panel.

However, a 690V supply was offered by the vendor, as opposed to an 11kV supply, as the vendor were unable to offer a high voltage (HV) supply heater. It is understood that properly certified HV heaters pose a significant technical challenge in terms of physical size (e.g. of the resistive element) and weight, making them not well suited to offshore applications. A stepdown from the 11kV supply to 690V was therefore required.

A second set of electric heaters were requested with the current 1250A limitations excluded. The heaters offered for this duty could provide a total heat load of 9MW and would be supplied with 2 x 4.5MW control panels which link into a single 9 MW resistive element heater..

13.6.5.2 Full Electrification

It was identified, based on Facility B process heat demand that full electrification of Facility B could not be met. The existing subsea cable with a maximum capacity of 13.9 MW which is approximately half of the total power and heat required.

To meet the full heating demand an additional 11kV subsea power cable would be needed which would require modifications at both the on Facility C and Facility B. At Facility C the capacity of the 11kV switchgear was likely to be exceeded requiring a complete upgrade, along with a new J-tube. At Facility B there would be the need to replace or modify the subsea infrastructure to accept a second cable. Additional deck space on Facility B would be required to accommodate the required transformers, control panels and the second process heater.

13.6.5.3 Electrification Scenario Summary and Comparison

The following table evaluates the two scenarios against the study drivers:

	Base Scenario	Sensitivity Scenario
Project Cost	£0.5 million ¹	£30 million
Project Timescale	9-12 months	24-36 months
Achieves full electrification of existing electrical load		
Minimal switchboard modifications		
Retain existing infrastructure		
Can support future maximum process heat demand on Facility A		
Can support future maximum process heat demand on Facility B		
Can support future maximum process heat demand on Facility C		
Topsides impact	Minor impact. Utilises existing switchroom space and cabling where possible.	Major impact. Requires new module to be installed on Facility A incorporating 66kV and heating equipment.
Electrical systems impact	Minor impact. Ability to start largest DOL motors may be impacted.	Additional 66kV equipment
Control and Safety systems impact	Minor impact. Modifications to PMS required.	Modifications to PMS and existing switchgear to incorporate 66kV equipment. Reliance on subsea cable power means changes to PMS control and philosophy.
Operations impact	Generally improves reliability and availability as subsea power becomes another option alongside existing generation. This gives more flexibility and uptime.	Fundamental change in normal power with no reliance on local generation. Potential for higher uptime but subsea cable is a single point of failure.

Table 13-6: Electrification Scenario Summary

¹ This value assumes that power is arriving on the topsides at 11 kV and is appropriately conditioned for the asset as provided by the Sub Hub.

13.7 Conclusion

The study describes the general considerations and modifications required for differing levels of platform electrification based on existing platform infrastructure and highlights solutions and technologies that can be applied in specific scenarios.

The Case Studies described provide further details of the types of technical and commercial challenges that can arise from modifying a platform for electrification.

14. Emissions Reduction Analysis Study

14.1 Objective

The purpose of this study is to determine the emissions reduction potential of the proposed solution versus current platform operations.

14.2 Methodology / Background

Using an analytical tool created for the Renewables Generation Modelling (Section 8), the proposed power generation and distribution system can be modelled against the existing platform power generation system(s) to determine the potential emissions reduction achieved by the proposed system.

14.2.1 Proposed Power Generation and Distribution System

The power generation and distribution system proposed by Katoni is a centralised system where power is generated by a combination of wind power and combined cycle gas turbines (CCGTs).

The electricity is distributed from a central floating main hub to several floating Sub Hubs which are located close to oil and gas platforms and transmit power to platforms at the correct voltage.

A simplified diagram of the system is shown in Figure 14-1.

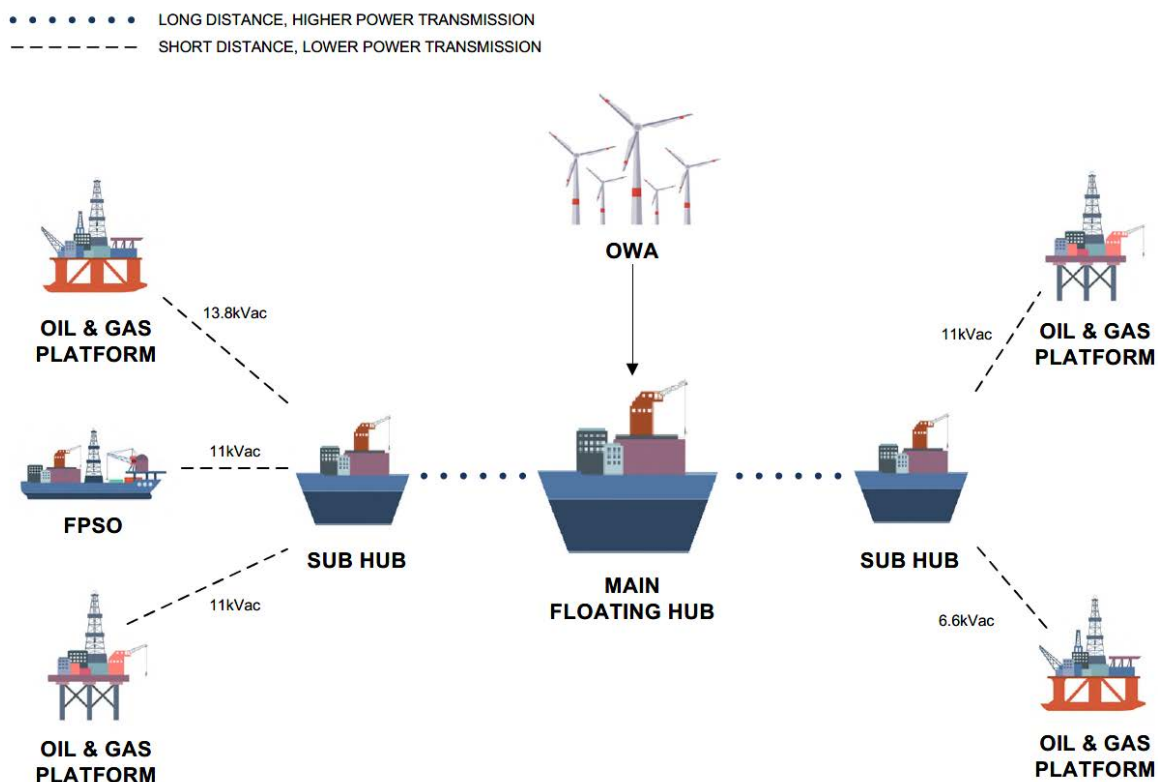


Figure 14-1 - Diagram of Proposed Power Generation and Distribution System

The Renewables Generation and Modelling Report concluded that a wind provision of approximately 105% of the base load requirement was optimal. This is referred to as the P_{95} case and will form the basis for the comparison of the two systems in this study. For completeness an additional case has been included to evaluate the overprovision of wind and its impact to emissions reduction. This is referred to as the $P_{Optimised}$ case.

The Hydrogen Technology Study (Section 23) concluded that hydrogen energy storage was not part of the base design and so no energy storage is built into the model.

The proposed power generation and distribution system was therefore modelled using the following summarised basis:

- Wind provision ~105% of base load requirements (P_{95})
- Wind provision ~155% of base load requirements ($P_{Optimised}$)
- Local generation using LM6000 PF+ CCGTs
- No energy storage

14.2.2 Existing Platform Power Generation System

Existing platform generation systems typically use on platform aeroderivative gas turbines in simple cycle operation (SCGTs) for power generation.

These SCGTs can be used for both electricity production for electric power users or used in direct drive operation, usually for powering large rotating machinery such as compressors and pumps. Depending on the process heat requirements, the SCGTs can be used with Waste Heat Recovery Units (WHRUs) to provide the heat to a platform heating medium distribution system.

The fuel gas for the GTs is either provided directly from the produced gas (treated to fuel gas specification) or is imported from an outside source via an import/export pipeline if the platform is gas deficient.

It is common for platforms operating in the North Sea to be operating significantly below the optimum efficiency of their power generation technology due to decreasing production rates and less power demand required vs peak generation.

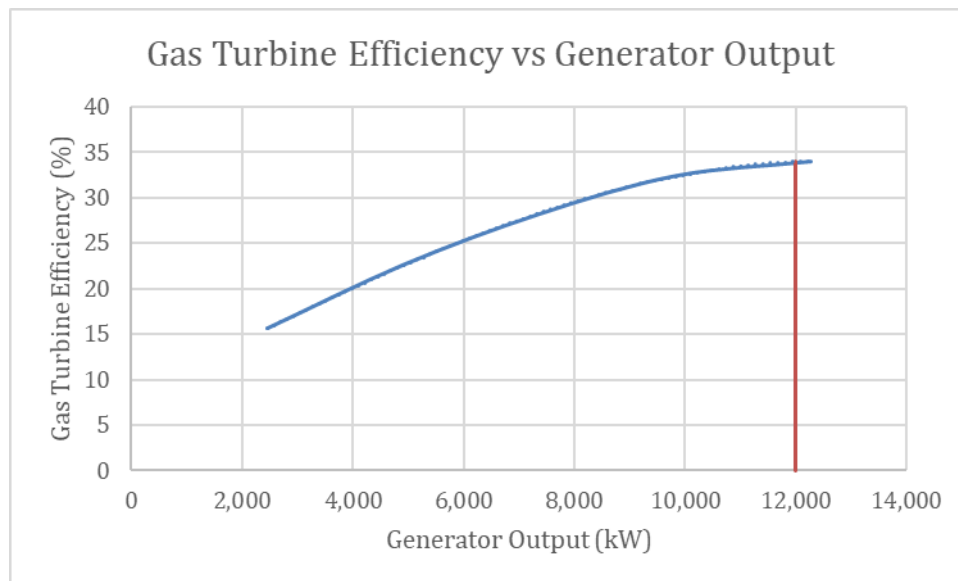


Figure 14-2 Latest Generation Gas Turbine (DLE)

Figure 14-2 details the efficiency curve for a latest generation gas turbine operating in the North Sea. This gas turbine is described as being one of the highest efficiency gas turbine generators on the market. It is installed with Dry Low Emissions (DLE) technology to reduce emissions.

The asset which this gas turbine is installed on is typically operating this gas turbine with an output of 5.5 MW to 6 MW. This results in an efficiency of approximately 25%.

From review of other platforms during this project this is a common trend where platforms are operating with power demands of between 40 to 60% of the installed capacity of their gas generators.

14.3 System Modelling

14.3.1 Wind Power

The two power generation systems, proposed and existing, were modelled using the analytical tool developed for the Renewables Generation Modelling to determine and compare their total emissions for a specified energy load.

The tool uses energy production data for the Dudgeon wind farm between Feb-21 and Feb-22 in 30-minute time steps to extract load factors which can then be used to model the wind energy production profile.

Where there is a shortfall in wind energy to meet the required load demand, GTs are used to make up the deficit. The tool is set up to model the number of GTs required at a particular time step, their efficiency and total fuel requirements based on the demand, the GT capacity and the GT performance curves. This can then be used to estimate fuel gas consumption rates at each time step and the cumulative fuel gas consumption can be totalled to give a yearly fuel gas consumption figure.

Figure 14-3 shows a graph of wind power vs base demand. The areas shaded in grey show when GTs are required to meet the load demand.

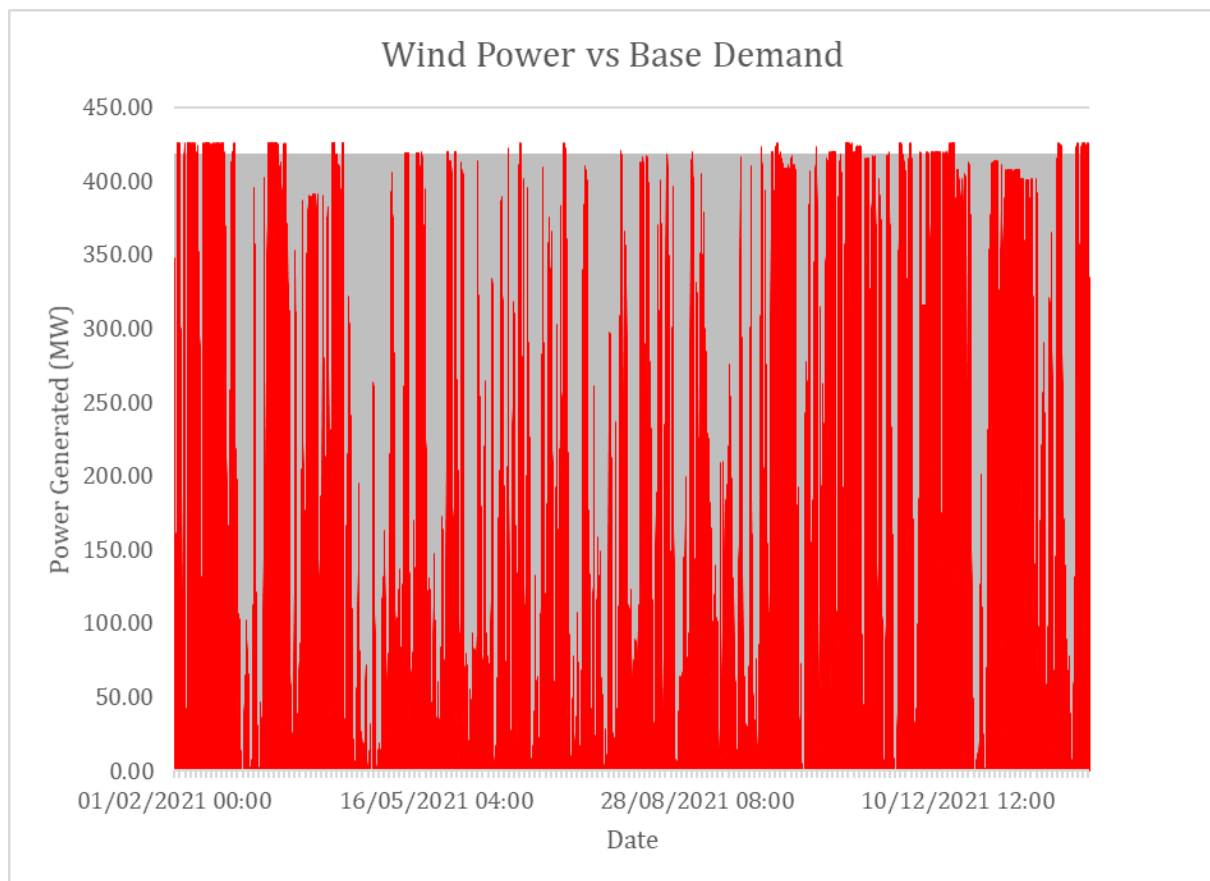


Figure 14-3 - Graph of Wind Power vs Base Demand (P_{95})

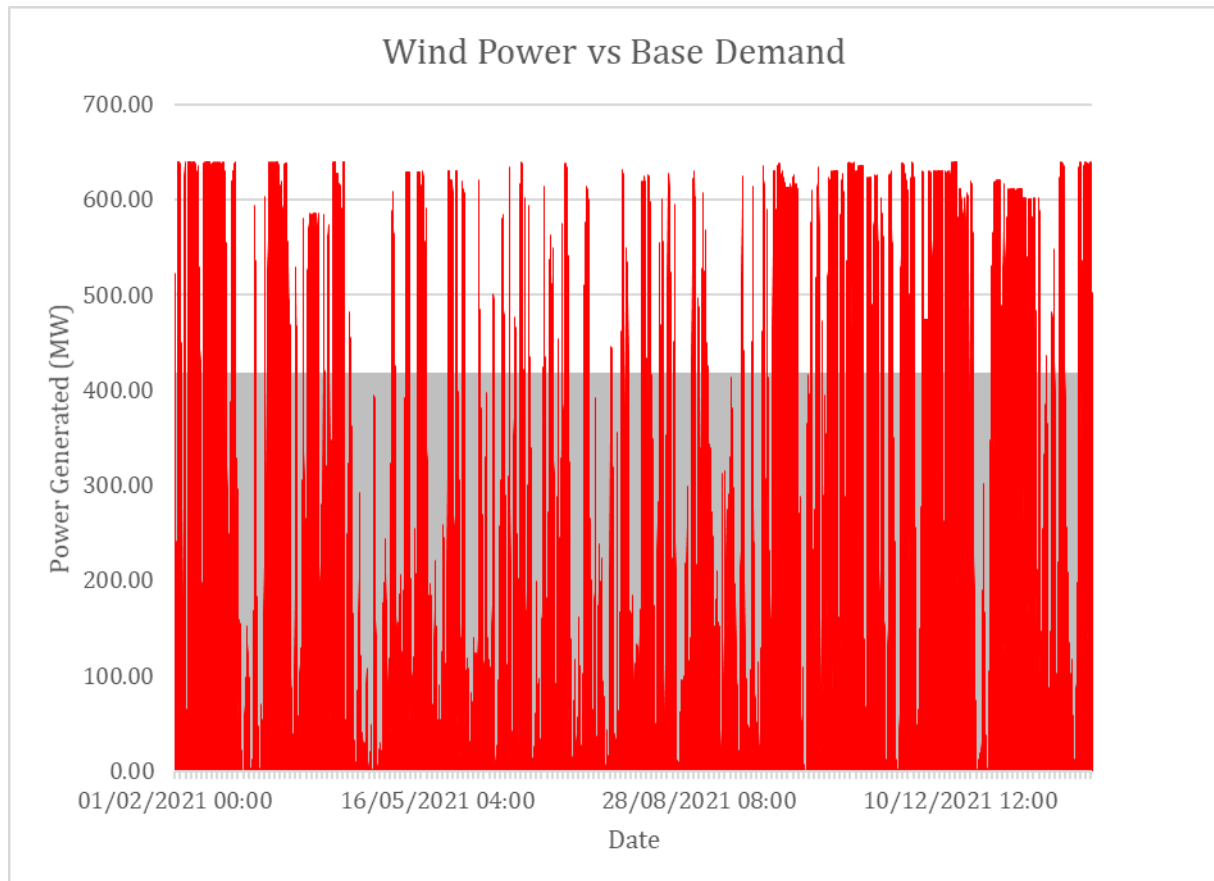


Figure 14-4 Graph of Wind Power vs Base Demand ($P_{Optimised}$)

Figure 14-4 similarly to Figure 14-3 demonstrates the base load in grey and the wind generation in red. Compared to the P_{95} case the $P_{Optimised}$ case appears to have more significant operation in excess power generation.

14.3.2 Platform Power Generation

To simplify the platform power generation, and to allow for an average to be utilised for the generation, to predict an across asset basis a flat 25% efficiency has been applied to all platform thermal power generation systems.

It is anticipated that this efficiency is reflective of the average platform generation efficiency across the North Sea.

The LM6000 gas turbines performance curves which have been utilised for the modelling have been modified with the new efficiency curves. Figure 14-5 details the flat efficiency curve, and Figure 14-6 demonstrates the associated linear fuel curve which is the resulting output of the modified efficiency curve.

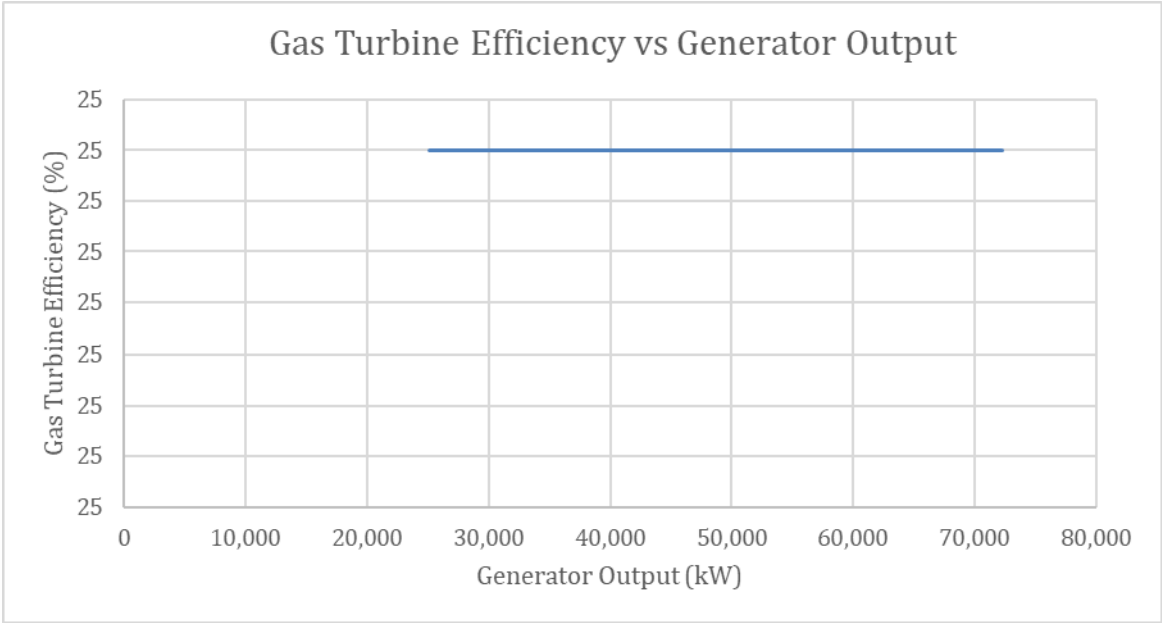


Figure 14-5 Modified Gas Turbine Efficiency Curve

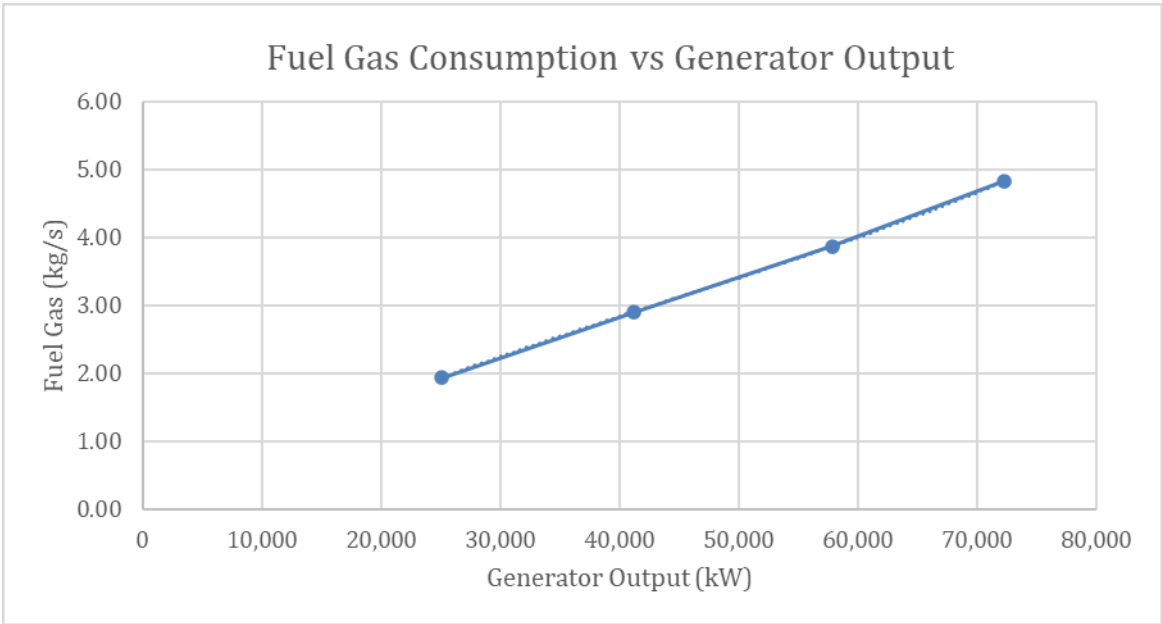


Figure 14-6 Modified Gas Turbine Fuel Consumption Curve

14.3.3 Case Descriptions

Three cases were modelled – a P_{95} , $P_{Optimised}$ and an “Existing System”.

The Main Hub system was modelled using the P_{95} and $P_{Optimised}$ wind provision and using the fuel and efficiency curves for LM6000 PF+ CCGTs.

The P_{95} case represents wind provision based on the 95th percentile load factor for the Dudgeon wind farm data set and results in wind provision only slightly higher than the base power demand, which was concluded to be within the optimal wind provision range by the Renewables Generation Modelling Study.

The $P_{Optimised}$ case represents wind provision based on the 65th percentile load factor for the Dudgeon wind farm data set and results in wind provision only significantly higher than the base power demand. This is viewed as a sensitivity which based on fuel gas price and ETS could be cost neutral to install.

Both systems are compared against a total power demand of 418.5 MW which is based on the target CNS zone identified from the Platform Clustering Study (Section 6).

The cases are summarised in Table 14-1.

Case	Required Load (MW)	Gas Turbine Type	GT Efficiency (%)	Installed Wind Capacity (MW)
Platform Generation	418.5	Simple Cycle	25	0
P_{95}	418.5	Combined Cycle (LM6000)	Up to 54.7	425
$P_{Optimised}$	418.5	Combined Cycle (LM6000)	Up to 54.7	648

Table 14-1 - Modelled Cases Summary

A sensitivity case with CCGTs only and no wind energy was also analysed for comparison.

14.4 Results

The results of modelling the three systems are summarised in Table 14-2.

Case	Fuel Gas Consumption (ktonnes per year)	CO ₂ Emissions (ktonnes per year)	Emissions Reduction Relative to Existing System
Existing System	1,157	2,893	-
P_{95}	297	741	74%
$P_{Optimised}$	239	598	79%
Sensitivity	529	1,323	55%

Table 14-2 - Case Modelling Results

Table 14-2 outlines the estimated emissions reduction associated with displacing 418.5 MW of power from the assets identified. This results from a mix of partial and full electrification of each asset and is a like for like displacement based on total amount of power transmitted. This should be considered as the maximum emissions reduction able to be achieved from the concept developed.

Case	Power Requirements (MW)	Fuel Gas Consumption (ktonnes per year)	CO ₂ Emissions (ktonnes per year)	Emissions Reduction Relative to Full OMF + CNS
Full OMF + CNS	640	1,768	4,419	-
P ₉₅	640	1,006	2,514	43.11 %
P _{Optimised}	640	931	2,327	47.33 %
Sensitivity	640	1,140	2,850	35.51 %

Table 14-3 Basin Emissions Reduction

Reviewing all of the assets in the OMF and CNS regions in totality the above basin emission reduction could be achieved based on the platforms being targeted in this region. Of the 640 MW identified as required power demand in this region this solution could offset approximately 420 MW of this demand.

By centralising thermal power generation and applying combined cycle technology to boost efficiency and distributing the power centrally significant reduction in emissions can be achieved. This is based on the base case clustering to minimise infrastructure, i.e. 1 Main Hub and 4 off Sub Hubs.

Similar analysis has been carried out on the SNS. Based on the platform infrastructure in this region and with the volumes of power which can be distributed it is possible to reduce basin emissions by 75% utilising this concept as all of the high emissions platforms are tied into this concept. Using the P₉₅ design case, the same emissions reduction as outlined in Table 14-2 will be achieved.

14.5 Discussion

The results of modelling the three systems shows that there is a potential for an approximate 74% reduction in emissions associated with platform power generation by using the proposed system compared to the existing system.

The sensitivity case shows that with no wind there is potential for an approximate 54% reduction in emissions associated with platform power generation. This means that using wind power reduces the total emissions by a further 44% compared to using CCGTs alone.

When considering basin emissions, targeting key assets can help the oil and gas industry reduce emissions at a scale that is required for climate change targets. The concept developed by Katoni can be better developed to tie in three large platforms for which no reduction in emissions have been allowed for: Buzzard, Captain and Golden Eagle.

In combination with optimally designed wind farms better tailored for the oil and gas industry requirements it is considered greater efficiencies can also be achieved.

14.6 Conclusion

The proposed system, with optimal wind provision based on the Renewables Generation Modelling, results in potential emissions reduction of 74% compared to the existing power generation system used by offshore Oil and Gas platforms in the North Sea for assets tied into the system, with a total reduction in basin emissions of 43% for CNS and OMF.

14.7 Opportunities / Risks / Assumptions

- The emissions estimated in this study are based specifically on emissions directly associated with providing power to offshore oil and gas platforms. As these platforms direct emissions are reduced this will lead to an increase in gas export or gas reinjection associated with each platform.
- The wind energy production profile was modelled on Dudgeon wind farm data for a particular year (Feb-21 to Feb-22). This represents a possible risk as wind generation can vary from year to year. In fact, Europe experienced milder wind speeds than usual in 2021 /65/. This may result in a wind generation profile that is too conservative, and greater emissions reductions than those modelled may be possible.

- The model assumes instantaneous ramp rates for the GTs which may result in an overestimation of the overall efficiency associated with the CCGTs.

15. Main Hub Design Report

15.1 Objective

The report records the considerations for the design and specification of the Main Hub infrastructure required to support the North Sea electrification.

The report details how the proposed modular hub design can be scaled up or down to suit regional infrastructure clusters and outlines:

- The methodology of the selected marine solution
- The considerations made in the design of the Main Hub
- The specification of the Main Hub
- Potential limitations of the systems

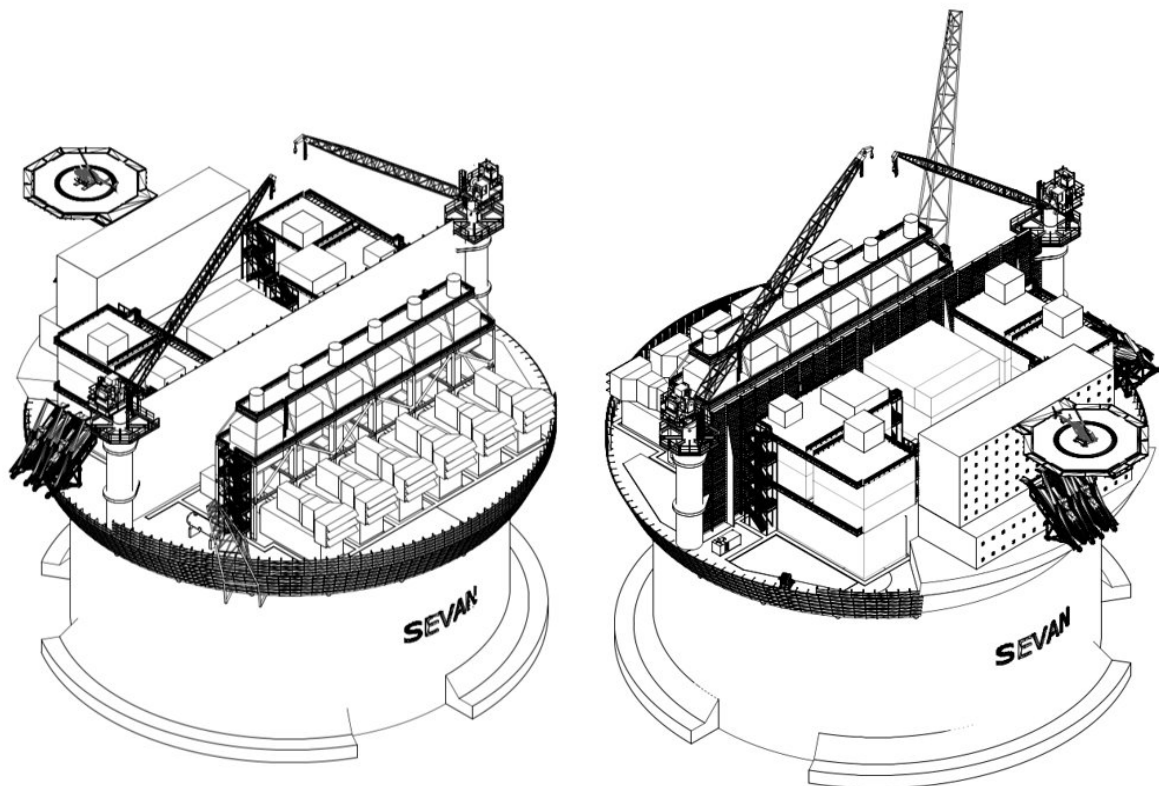


Figure 15-1: Overview of concept developed

15.2 Main Hub Solution

15.2.1 Marine Solutions

The purpose of the complete electrical supply system is the provision of essential power service for all oil production installations connected to it. As such, the potential economic penalty of lost or deferred production from between 15 and 30 platforms following an extended outage of the Main Hub is substantial. The requirement therefore is for the Main Hub to be suitable to remain on station for the duration of electrification project life, without dry-docking for inspection, maintenance or repair.

In addition to the outage of platforms, potential difficulties in riser and mooring disconnection and reconnection in the harsh environment, as well as significant costs for docking are additional drivers for ensuring the marine solution selected is robust, reliable and suitable for the required design life, located in the UKCS.

The project analysed different marine solutions to determine the optimum approach. The analysis conducted was on the following solutions:

- Fixed Jacket
- Ship Shaped FPSO
- Sevan Circular Shaped FPSO
- Jack-up Platform
- Semi-Submersible Platform
- Subsea Equipment

15.2.2 Marine Options Analysis

A concept level analysis was carried out to determine the most suitable marine solution for facilitating the required Main Hub topsides. The key drivers for the decision making process are:

- Initial capital costs
- Topsides weight capacity and operation
- Decommissioning
- Redeployment of infrastructure
- Motion performance, if floating

Initial capital costs are considered to ensure that the selection is considerate of the economic impacts from initial CAPEX costs. This is a key driver for technology selection, however is not the primary driver.

Topsides weight capacity is important to consider as the weight density of the equipment located on the topsides of the Main Hub is significantly higher than in typical oil and gas installations. Use of multiple large gas turbines and steam turbines, in combination to the large, heavy electrical distribution equipment is uncommon in conventional platform designs. In addition, consideration for complexity of maintenance is required.

Decommissioning and lasting environmental impact is important to consider for this design.

Investment in this type of infrastructure is considerable. Oil and gas assets in existing locations may not be in production throughout the life time of the electrification system. Therefore, it is considered important that the system can be redeployed and used for the full duration of the system's lifecycle to maximise the initial investment.

If floating, motion performance is important to ensure that minimal system outages are experienced due to sea states, and that vessel motions imposed on electrical or mechanical equipment does not lead to increased failure rates or maintenance costs.

15.2.2.1 Fixed Jacket

A fixed steel jacket installed in a suitable location in the North Sea:

Driver	Advantages	Disadvantages
Initial capital costs	- Initial jacket costs are less than a new build floating solution - More compact modular design can be utilised potentially reducing construction costs	- Offshore construction and commissioning costs can be high compared to other options - Cost of jacket can be significantly affected by water depth
Topsides weight capacity and operation	- Structure can be designed to accommodate any topsides weight capacity required	- Due to construction of platforms it is a challenge to maintain and remove heavy components located on lower deck levels
Decommissioning	-	- Complex decommissioning of asset, required to be destructed offshore and moved to shore. - Recovery of jacket is complex, and regulations may change which requires this to be removed
Redeployment of infrastructure	-	- Not possible to redeploy without new jacket structure
If floating, motion performance	- Not floating, therefore motions are insignificant.	-

Table 15-1 Fixed Jacket Comparison

15.2.2.2 Ship Shaped FPSO

A converted VLCC or new build VLCC hull installed in a suitable location in the North Sea is considered as one of the marine options for the Main Hub.

Driver	Advantages	Disadvantages
Initial capital costs	- Conversion of ships can significantly reduce capital costs	- If new build selected, on no requirement for liquid storage ship shaped is inefficient
Topsides weight capacity and operation	- Significant deck space available - Accessibility for equipment maintenance good	- Turret required, limited number of slots, complex piece of equipment and very expensive - With no crude storage stability performance can be affected without significant ballast
Decommissioning	- Can be removed from station by abandoning cables and moorings and moving to dock	-
Redeployment of infrastructure	- Can be redeployed in a different area providing adequate water depth	-
If floating, motion performance	-	- Motion performance is acceptable, however may impact large electrical equipment which utilises liquid insulators.

Table 15-2 Ship Shaped FPSO Comparison

15.2.2.3 Sevan Circular Shaped FPSO

A new build Sevan Circular Shaped FPSO installed in a suitable location in the North Sea is considered as one of the marine options for the Main Hub.

Driver	Advantages	Disadvantages
Initial capital costs	- New hull can be specified and designed for specific requirements - Comparative costs to new build jacket	- Cost of Hull in comparison to conversion more expensive
Topsides weight and capacity and operation	- Significant deck space available - Accessibility for equipment maintenance good - No turret, therefore opportunity for unlimited connections constrained by subsea infrastructure, not topsides / hull infrastructure.	- With no crude storage stability performance can be affected without change to ballast design - Minimum water depth of approximately 70m required
Decommissioning	- Can be removed from station by abandoning cables and moorings and moving to dock	-
Redeployment of infrastructure	- Can be redeployed in a different area providing adequate water depth	- May limit redeployment opportunities based on water depth.
If floating, motion performance	- Motion performance is excellent	-

Table 15-3 Sevan Circular Shaped FPSO Comparison

15.2.2.4 Jack-up Platform

A conversion or new build jack-up installed in a suitable location in the North Sea is considered as one of the marine options for the Main Hub.

Driver	Advantages	Disadvantages
Initial capital costs	- New jack-up can be specified and designed for specific requirements - Conversion offers a reduction in CAPEX opportunity	-
Topsides weight and capacity and operation	- Significant deck space available - Accessibility for equipment maintenance good - No turret, therefore opportunity for unlimited connections constrained by subsea infrastructure, not topsides / hull infrastructure.	- Maximum water depth of approximately 100m to 150m
Decommissioning	- Can be removed from station by abandoning cables and moving to dock	-
Redeployment of infrastructure	- Can be redeployed in a different area providing adequate water depth	- May limit redeployment opportunities based on water depth.
If floating, motion performance	- Not floating, therefore motions are insignificant.	-

Table 15-4 Jack-Up Platform Comparison

15.2.2.5 Semi-Submersible Platform

A conversion or new build semi sub installed in a suitable location in the North Sea is considered as one of the marine options for the Main Hub.

Driver	Advantages	Disadvantages
Initial capital costs	- If conversion is available initial capital outlay can be significantly reduced	- Limited standardised designs available - Costs can be more than comparative ship shaped or Sevan type design
Topsides weight and capacity and operation	- Significant deck space available - Accessibility for equipment maintenance good - No turret, therefore opportunity for unlimited connections constrained by subsea infrastructure, not topsides / hull infrastructure.	- With no crude storage stability performance can be affected without change to ballast design - Minimum water depth of approximately 100m required - Motion in harsh environments can lead to structural fatigue due to design
Decommissioning	- Can be removed from station by abandoning cables and moorings and moving to dock	-
Redeployment of infrastructure	- Can be redeployed in a different area providing adequate water depth	- May limit redeployment opportunities based on water depth.
If floating, motion performance	-	- In particularly rough seas, very high dynamic loads on mooring and risers

Table 15-5 Semi-Submersible Platform Comparison

15.2.2.6 Subsea Equipment

As an alternative to using a marine option, use of all subsea equipment was evaluated.

Driver	Advantages	Disadvantages
Initial capital costs	- No marine solution required	- Subsea equipment electrical equipment is substantially more expensive than topsides based equipment.
Topsides weight and capacity and operation	- No marine solution required, all equipment located subsea therefore unlimited weights and space available - No manning is required	- If equipment fails, it will have to be recovered and replaced. This is not a quick operation. - Track record of equipment on this scale does not exist
Decommissioning	- Equipment would be recovered from the sea bed	-
Redeployment of infrastructure	-	- Unlikely any redeployment of infrastructure would be afforded
If floating, motion performance	- N/A, not floating therefore no impact.	-

Table 15-6 Subsea Equipment Comparison

15.2.2.7 Assessment Summary

From the assessment of each option, the options which scored highly were:

- Sevan shaped solution
- Jack-up
- Semi-sub

15.2.3 Recommended Solution

The Sevan shaped solution was selected based on track record of performance in the North Sea from use with the Hummingbird and Voyager FPSOs as well as the Goliat FPSO in the Barents Sea.

In water depths which are too shallow for both a Sevan or semi-sub solution, a Jack-up is recommended.

15.2.3.1 Sevan Description

The recommended solution is to make use of a Sevan circular hull vessel. The design utilised for the Goliat FPSO is the basis for study. The justification of the use of this design is:

- Geo-Stationary Hull Double bottom / sides
- Scalable Concept
- Excellent Motions
- Conventional Spread Mooring
- Insignificant Bending Stress for risers
- Unlimited number of riser connections
- Track record in power cable integration as power from shore already integrated into Goliat design.

Instead of turret, in a cylindrical design vessel, mooring is used in fixed orientation, this eliminates problem with rapid change of wind direction and vessel heading corrections. This also makes this design highly tolerant to storms and more stable than ship-shaped vessels. Due to the hull form profile vs a semi-sub this give superior harsh environment performance.

For this conventional hull form, a marine gas riser and all incoming and outgoing electrical connections have been run through the hull through the ballast tanks in I tubes and passing through watertight glands on the main deck where they are terminated in the TUTU units. The same arrangement will be utilised for incoming and outgoing cables for this design.

A modification to the ballast system is required due to not using the cargo tanks for liquid storage. A high level of ballast is required to be run to reach the required Ballast Draft and is a feature of this design which can be investigated in further phases to reduce costs. An opportunity to address this is contained in Section 15.6.

The Sevan design offers incredible flexibility to enable expansion of the number of Sub Hub connections even if all I-tube capacity has been utilised, as the number of cable interfaces can be increased through use of outboard cable routing.

15.2.3.2 Jack-Up Description

Even for smaller units, the use of a Sevan design is not practical for shallower water depths. Typically, at water depths of less than 70m the required length of mooring lines becomes impractical. A jack-up platform is proposed to be utilised in those locations.

No locations have been identified for the reviewed areas that requires a jack-up for a main hub due to water depths, however this remains an option for the future if the location identified requires it.

The main justification for use of a jack-up vs a fixed installation for this premise is in the event that redeployment is required. If no redeployment of the infrastructure is identified, i.e. there will be a power to shore connection from the Main Hub, then a fixed jacket may be warranted. This is not considered as part of the base design at present.

15.2.4 Marine Design

15.2.4.1 Expected Operational Life

The design life has been set at 25 years. Some assets may be able to exceed this and be redeployed or reused elsewhere as required.

15.2.4.2 Hull

Sevan have a range of standard hull sizes available, based on the installed topsides equipment anticipated for the Main Hub a Sevan 1000 unit was determined to initial hull size to be evaluated. The Goliat FPSO used as the base case for marine systems and concept layout.



Figure 15-2 Goliat FPSO on Station

The Goliat FPSO Sevan 1000 is a cylindrical, geostationary FPSO with a hull diameter of 93m flaring out to 110m at the process deck, 25 riser slots and 15 mooring lines. Weighing 22,500t, the FPSO topsides include the process plant and utilities. The bilge box sits at the base of the hull with a diameter of 109m.

The main deck sits at 20m above the waterline, with the process deck a further 6.5m above this. A bulwark offers weather protection to the main deck.

The provisional deck loading capacity is approximately 30,000 tonnes of equipment.

Item	Value	Units
Diameter main hull (at wl)	93	m
Diameter main deck	104	m
Diameter process deck	110.5	m
Diameter bilge box	109	m
Height of bilge box	3.25	m
Elevation Main Deck	42	m
Elevation Process Deck	48.5	m
Ballast Draft	22	m
Loaded Draft	22	m
Scantling Draft	25	m
Maximum Displacement	162,000	Tons
POB	140	persons

Table 15-7 Key Data for Sevan 1000 Unit

15.2.4.3 Main Deck

The Main Deck is located at EL. +44,000 and forms the top surface of the hull. The Main Deck area is primarily utilised for routing of utility connections, cabling, drains and structural supports for the Process Deck and the Bulwark. Some primary process equipment is located on the Main Deck such as the Sea Water Lift Filters, Condensers for the Power Generation System. There is space currently allocated on the Main Deck level for Standby and Emergency Diesel Generators to support the Main Hub. The design of the Main Deck includes a radial primary support structure which is used to interface with the pillar/stooling arrangement to support the Process Deck and to transfer the loads on to the strong points of the hull. The arrangement is detailed in Section 15.3.7.1.1 of the report.

The Main Deck also acts as a key means of access for equipment, and as the primary escape route to the temporary refuge. The weight of the Main deck is estimated at 4000 Tons and diameter 104m

15.2.4.4 Process Deck

The Process Deck is located at EL. +50,000 and has a diameter of 110m which is 6m above the Main Deck level.

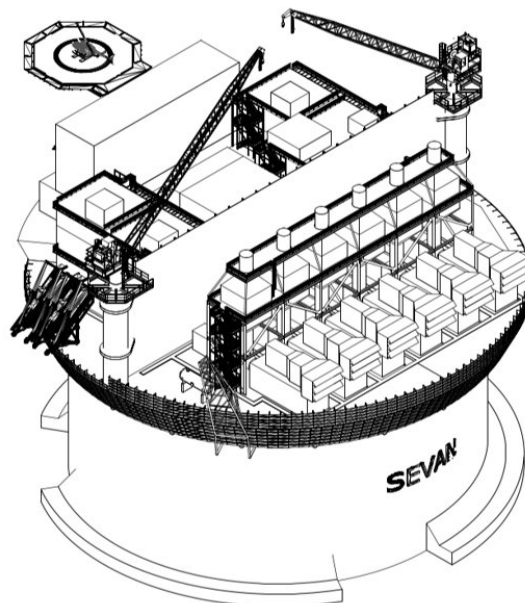


Figure 15-3 Main Hub Overview

The topsides takes the form of a series of modules laid out to provide the functions required. These have been standardised where possible to allow common designs and philosophy to be used between the main and sub hubs.

The arrangement of the Process deck modules are described in greater detail in Section 15.3.7 of this report.

Components that are supported on the Process Deck are :-

- 6 x Combined Cycle Gas Turbines (CCGT) for the power generation system comprising of :
 1. 6 off LM6000 PF+ Gas Turbines
 2. 6 off WHRU units, including closed loop system
 3. 6 off Steam Turbines
- Blast Wall
- Living Quarters
- Lifeboat Davits
- Two Crane pedestals
- Flare Stack
- Transformer Housing
- 200MW Conversion Module (PAU)
- 3 x 100MW Conversion Modules (PAUs)
- Switchroom Module – incorporating HV, MV & LV switchgear (PAU)

The blast wall separates the hazardous areas from non-hazardous areas. The hazardous side of the blast wall contains the CCGT and flare equipment while the non-hazardous side contains the equipment covering electrical, control and accommodation. Located on the east and west side of the blast wall are pedestals for the main platform cranes.

The Process Deck level is 6m above the Main Deck Level. This height has been selected to facilitate the installation of diesel generators on the Main Deck.

15.2.4.5 Mooring

The Sevan circular hullform used for the Main Hub is moored using a passive mooring system with no use of thrusters for dynamic position keeping. Overboard chains are located at three points around the Hull. One set of chains are directed towards the prevailing direction of the most severe wave conditions.

The proposed number and size of chains have been calculated by Sevan during their mooring and motion study. The results of this study were that mooring design for the main hub was optimised with the use of 15 chains in three groups of 5 orientated at 30, 150 and 270°. The diameter of the chains used in this mooring design are 165mm.

The chains are kept tensioned using fairlead and winches with a chain-stopper included and this is mounted to the deck of the Sevan unit.

Polyester mooring line is used in between the top and bottom chain sections. The mooring system is tightened during installation of the unit and retightening of the system during field life is expected due to polyester creep.

Sufficient safety factors are maintained in the mooring design even under extreme loading.

Main Hub Mooring system :-

Item	Value	Units
No of mooring lines	15	item
Bottom chain length	160	m
Bottom chain diameter	170	mm
Polyester line length	1025	m
Polyester line diameter	290	mm
Top chain length	50	m
Top chain diameter	170	mm

Table 15-8 Main Hub Mooring Design

Mooring anchors – Since the Main Hub is assumed to be in the field for 25 years the mooring on the seabed will be provided by way of suction piles for all lines connected to bottom chains. An assumption has made that the soil conditions on the sea bed will be suitable for this method of mooring securement is suitable.

All analysis of mooring design has been carried out using the Shelley, Chestnut and Huntington field locations.

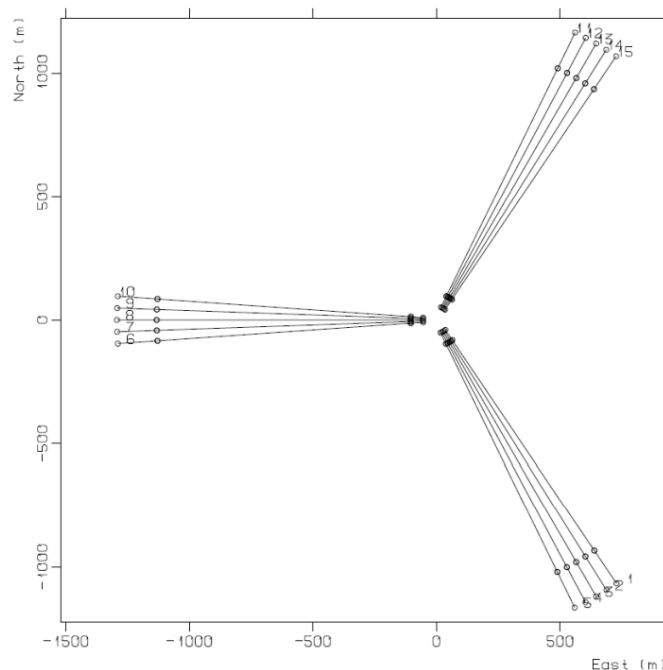


Figure 15-4 Main Hub Mooring Configuration

Analysis of the mooring system has consisted of generating models using DNVs WADAM hydrodynamic analysis program. Input to these models is the hull geometry and hydrodynamic coefficients based on scaling values from comparable hulls using data from model tests. The mooring system is designed using DNVs MIMOSA (mooring system and individual mooring line analysis software) with a ULS 100-year directional condition and a governing safety factor of 2.0 for the mooring line tension.

15.2.4.5.1 Prevailing Wind Direction

Metoccean data covering the monthly, annual, 10, 50 and 100 year return periods have been used for this wind and wave data as data for the exact location was not available to Sevan they have made use of data for the nearby Shelley field. The Shelley field is located very near to Britannia and Andrew.

This is included in the Sevan Study Report located in Appendix 28.20.

15.2.4.6 Marine Motion Evaluation

For the main hub design the marine motion evaluation was carried out for the relevant hullform by Sevan. This was using wave data relevant for the areas proposed for the main hub locations. Sevan utilised NAPA software to conduct the motion analysis.

The results of this study gave a maximum heave of 8.42m and a max roll angle of 12.19 degrees.

The motion data provided has been used to provide the input to the design of structure and equipment within the design.

The Sevan study showed that an acceptable level of reserve buoyancy and stability remained at all times.

Loading on the fuel gas import flexible line was also determined to be within acceptable limits.

It also highlighted that due to the lack of use of the cargo tanks a large amount of water ballast was required to utilise the conventional hullform of the Sevan 1000.

For full details of the Sevan study see Appendix 28.20.

15.2.4.6.1 Motion effect on Risers and Flexibles

From the modelling work completed by Sevan the findings of their study are the dynamic loads of the hull form are well within the requirements for using flexible cables and risers.

15.2.4.6.2 Motion effect on equipment

Consideration of the effect of motion on specific equipment items have been made, with items being assessed to determine what effect motions would have on operation.

The effect on the gas turbines are expected to be minimal. As gas turbines operate at very high rotational speeds the effect of vessel motions are typically mitigated by the centrifugal force of the turbine. Issues however can arise in ancillary and seal systems. All ancillaries such as reservoirs for lube oil, seal oil and hydraulic oil should be checked to ensure that excessive sloshing of fluids, which might lead to damage to internal baffles or loss of pump suction, does not take place. Bedplates and holding down bolts should be designed accordingly. In addition areas such as bearings on the gas turbine, depending on type may experience accelerated wear.

There are no anticipated effects on electrical equipment selected based on the motion profiles of the Sevan 1000.

The Flare KO vessel and Gas Import Scrubber should not have substantial quantities of liquids present, however they will be designed in accordance to best practice to ensure motion has limited effect on their operation. Due to the prevalence of FPSOs in the oil and gas industry general design rules for equipment are well understood

15.2.4.6.3 Motion effect on Operations

Due to the motion performance of the Sevan Hull, the operability time for the helideck based on sea states is considerably higher than conventional ship shaped FPSOs. This motion performance is also applicable to crane operations ensuring that supply boats can be serviced in more severe sea states.

15.2.4.7 Material Handling / Crane Selection

An offshore material handling philosophy has been developed in line with the expected day to day operation and long term maintenance requirements of the Main Hub. 2 pedestal cranes have been located and sized to ensure the following:

- Majority of topsides is within crane reach
- Major equipment/components that require crane assistance for maintenance are within crane radius capabilities
- Common laydown areas to enable the transfer of materials/equipment between cranes
- Ability to unload supply vessel from two locations
- Redundancy during crane downtime/maintenance

The crane capacities have been based on operation requirements and therefore differ.

15.2.4.7.1 West Crane – 200t

The west crane has been sized to lift a transformer with a shipping weight of approximately 100t, this has been identified as the largest single component that may require removal for replacement as a complete item. As this would be lifted off the platform onto a supply vessel, a Dynamic Amplification Factor (DAF) of 2 has been used to size the crane, resulting in a specified crane capacity of 200t.

The largest transformers on the Main Hub weigh approximately 250t. These are considered to be too large to handle in a single lift. During the development of this concept it could be required to resize the crane capacity to suit this lifting requirement. It is considered unlikely a full transformer replacement would be required. There are two off the largest transformer on the Main Hub, with the rest of the transformers weighing approximately 100t.

15.2.4.7.2 East Crane – 40t

The East crane has been allocated a 40t capacity. The East crane can be utilised for unloading supply vessels and general platform maintenance. Additionally, the reach of the East Crane will be such that materials and equipment can be transferred between the East and West crane via a common laydown area.

On the North side of the platform, the Gas turbines have been spaced to allow for maintenance and removal of specific components. The likelihood of the gas turbine structure requiring removal is low and would require the use of a specialist heavy lift vessel. Instead, both cranes provide laydown areas to allow the transfer of spares for routine and unplanned maintenance activities. This also allows for the maintenance of the WHRU and the steam turbines.

15.2.4.8 Helideck

The helideck has been designed in accordance with CAP437 Standards for offshore helicopter landing areas and CAA Paper 2008/03: “Helideck Design Considerations – Environmental Effects”. The design considers the location of the installation systems and equipment relative to the helideck ensuring that environmental effects that may be present do not impact on the safety of helicopter operations from the deck.

The helideck on the main hub will be approx. 22m in diameter which is consistent with the design of the Goliat FPSO. The helideck shall be suitable for a Eurocopter (Aerospatiale) AS332-Super Puma (19 pass +2 crew) or a Sikorsky S-92 (19-24 pass + 2 crew) helicopter as a minimum.

Turbulence and thermal effects caused by hot gas plumes from the flare or gas turbine exhausts, are mitigated by locating the helideck at the southern edge of the vessel, away from the exhaust stacks and flare tip. The current arrangement is designed to negate any turbulence or vertical wind velocity. The

positioning of the helideck takes account of the wind environment around the Main Hub. The height of the helideck and the air gap between it and the living quarters will ensure as clean a flow of air as possible, mitigating structure-induced turbulence.

Whilst the design of the installation and location of the helideck minimises environmental effects, it will be necessary to complete Computational Fluid Dynamics (CFD) modelling in detailed design to identify if operational restrictions to the helideck are required in specific circumstances e.g. wind direction and gas turbine operating load.

Helideck markings and side identification panels shall be installed visible from directions of approach and in all light conditions. As per convention, the helideck shall be dark green and the perimeter of the landing area identified with a white line. Lighting shall be provided to ensure the markings and helideck landing area are visible for day and night operations.

Provision of equipment for the response to a helicopter accident occurring at the helideck shall be provided. A helicopter accident resulting in fuel spillage and fire / smoke has the capacity to injure personnel and impair passenger escape routes. The equipment shall be designed to respond to a fire event quickly to allow personnel to escape from the area. To provide the quickest response time a fixed foam application system (FFAS) will be installed. A deck integrated fire-fighting system (DIFFS) is included subject to detailed review.

The helideck will be provided with facilities for refuelling helicopters. Storage, handling and quality control of fuel is vital for ensuring the safety of helicopters in flight with the key goal of providing of clean fuel free of contamination. The fuelling system shall consist of storage and distribution method for the fuel, including provision for fuel quality sampling.

15.2.4.9 Escape and Evacuation

15.2.4.9.1 Escape

Escape, evacuation and rescue facilities are included in the main hub design to ensure personnel are able to escape from the immediate effects of a hazardous scenario, muster in a temporary refuge and evacuate from the vessel.

The Main Hub has been designed with a minimum of two escape routes from all areas of the asset transiting to the living quarters which forms the temporary refuge (TR). The primary escape route is via main deck. Due to the design of the main hub, this area is relatively clear as there are limited utility services on it and cable routing. There are no cargo tanks on this facility therefore there is no cargo offloading pipework which typically can congest main deck layout.

Each module has been designed with diverse escape routes to ensure that a minimum of one route to the TR remains uncompromised in an emergency event. This allows personnel to muster at the TR from any part of the vessel.

All escape routes are designed in accordance with the Prevention of Fire and Explosion and Emergency Response (PFEER) regulations.

15.2.4.9.2 Evacuation

The main evacuation methods from the Main Hub will be via helicopter. Secondary evacuation method is provided via TEMPSC. Evacuation routes will be available from the muster area within the TR to the embarkation areas for the TEMPSC and helideck. Separate TEMPSC platforms are located on the south and east edges of the platform to provide diversity and minimise likelihood of both launch directions being compromised.

15.2.4.10 Hazardous Area Classification

Ignition control is implemented in the design to prevent the likelihood that a release of flammable hydrocarbon gas will come into contact with a source of ignition.

In addition to ATEX certification of mechanical, electrical and instrument equipment; all structures, equipment and piping shall be electrically bonded to eliminate sparking. Potential hot surfaces (e.g. exhaust piping) shall be identified and flame arrestors used where appropriate.

The Hazardous Area Classification will be determined according to DNV-OS-A101 Safety Principles and Arrangements, Section 3. This will be the subject of a detailed study taking into account sources of release and dispersal modelling and is typically done in accordance with the Energy Institute: Model Code of Safe Practice - Part 15 Area Classification Code for Installations Handling Flammable Fluids [IP 15].

The hydrocarbon inventory of the main hub is limited to the gas supply for the gas turbines and a limited volume of diesel fuel.

The Main Hub layout has been arranged to segregate the power generation area from the electrical/utilities/accommodation area. A blast wall separates these two key areas of the vessel. The majority of explosive hazards will be located on the power generation side of the blast wall, including the CCGT turbines and associated fuel gas systems, the fuel gas import, the flare tower and associated knock-out drum.

The electrical/utilities/accommodation area has minimal sources of explosive substances, being limited to diesel fuel and venting from batteries. Battery room shall be classified as non-hazardous area due to dilution. In addition, the electrical equipment will be housed within pressurised modules which will have protective systems to avoid gas ingress.

Electrical equipment located external to pressurised modules shall be selected in accordance with the Hazardous Area Classification and the requirements of DNV-OS-D201 Chapter 2 Section 11. It is recognised that mechanical equipment must also be Hazardous Area compliant and this should be considered as part of equipment specification.

On confirmation of gas detection, electrical equipment not required for use during an emergency shall be automatically isolated as per the ESD hierarchy.

15.2.4.11 Emergency Power

Emergency Power shall be provided in compliance with DNV-OS-D201 Offshore Standards for Electrical Installations.

To meet this requirement a self-contained source of electrical power shall be provided and shall be located above the worst damage waterline and be readily accessible.

In the case of the Main Hub it is proposed that the source of emergency power be a self-contained diesel generator (or multiple generators) and dedicated switchboard capable of supporting all identified emergency power supplies.

15.2.4.12 Blast Wall Design

A large Blast wall divides the process deck into a hazardous area north of the wall and a safe area south of the wall. The large gas driven turbines with their gas fuel import and metering station are placed on the hazardous side, while on the safe side the electrical equipment for power transformation, switchboards, utilities for power export to the sub hubs and accommodation/office block are located. The fire and blast wall will protect the accommodation and other utility areas in the event of a fire or blast caused by the gas turbines or gas import systems, minimising the spread of fire and smoke and preventing direct jet fire impingement on the accommodation block.. The layout is arranged to position the most hazardous equipment as far from the accommodation module, which forms the TR, as practical.

This wall will be high enough to fully protect the accommodation block or any of the electrical equipment that may extend above the height of the accommodation block.

The blast wall must retain its integrity after the blast event. The Blast Wall has been secured to the two crane pedestals at either end. Detailed calculations have not been carried out, but they will be required before the design is finalised. These calculations will be conducted to a regulated industry code such as ISO 13702 or DNV-RP-C204.

Penetrations for piping or cabling through the blast wall from the utility and gas turbine side shall be minimised and any transits that are introduced shall maintain the rating of the wall.

Material handling or emergency escape routes through the wall shall be provided with self-closing blast and fire rated doors.

15.2.4.13 PFP

PFP will be provided in accordance with DNV standards with the aim to protect against the effects of fire and the damage caused by fire. The purpose is to protect personnel and safety critical equipment against hydrocarbon jet fires and explosions.

The PFP shall be rated to minimise fire escalation, prevent structural collapse and enable Emergency Response (ER) activity to function as designed.

Formal safety studies and fire and explosion modelling shall be undertaken to develop the Fire and Blast Philosophy and Basis of Design for fire protection including optimisation of PFP installation. However it is anticipated that the main structures and bulkheads requiring PFP shall include.

- J-60 bulkhead at riser hang off area
- A-60 or H-60 bulkhead for fire pump room perimeter walls
- H-60 bulkhead for crane pedestals
- A-60 accommodation and office block
- A-60 emergency switch room
- H-60 support structures for modules on the process deck

Gas import riser piping, supports and ESDV shall be protected from jet fire impingement by insulation jacket rated as J-60.

Segregation of internal areas will vary depending on the fire hazards and required survival times.

15.2.4.14 HVAC

Air ventilation systems will be installed on specific modules control the working environment for personnel and equipment within the modules. The systems shall prevent ingress of hazardous gases and fumes, prevent build-up of hazardous gases/fumes, maintain essential ventilation to equipment, rooms and areas required to operate or be available during an emergency event and prevent excessive temperatures in critical areas.

The HVAC for the TR shall provide isolation in the case of smoke or gas detection thereby preventing ingress into the TR and compromising support to life. The TR shall maintain a positively pressure over atmospheric.

HVAC ducting has been shown between the modules to represent where these services will need to run. Supply air is taken from non-hazardous areas and inlets are equipped with fire and gas detection, and dampers.

It is anticipated two segregated HVAC systems will be required for the Main Hub. The first will be for the E-House and the second for the TR.

Detail design of the HVAC systems has not been conducted but in addition to setting temperature, humidity and noise levels and the number of air changes per hour for each room or space, the HVAC design will need to address major topics such as:

- Provision of smoke and gas detection
- Prevention of smoke ingress into accommodation and control areas
- Smoke clearance, especially in accommodation and control areas and in escape routes
- Interaction with the Hubs main fire and gas system
- Ventilation of the Temporary Refuge and main control areas in emergencies and shutdown of non-essential users
- Provision of minimum life support in upset conditions
- Implications of hazardous area classification
- Dispersion of gas in areas where gas escapes may occur and use of supplementary mechanical devices
- Fire protection and rating of dampers and ductwork
- Controls, control stations and control system configuration
- Position of inlets and exhausts relative to hazardous areas
- Testing of fire and gas and shutdown dampers
- Sparing of fans
- Pressurisation of spaces and airlocks

15.2.4.15 Greenwater

Green water i.e. unbroken wave crests inundating the deck of the Main Hub, is a major consideration because of the equipment mounted on the Main Deck.

Most of the equipment on the Main Hub is mounted on the raised process deck (located above main deck), which minimises the effect of green water.

There have been several reported instances in the industry of damage and personnel injury from greenwater events. Damage such as broken cable trays, damaged walkways and stairs been sustained to Main Deck equipment.

The Sevan 1000 hull design defines a sufficiently high freeboard with the Main Deck being 20m above waterline at ballast draft, and the addition of a bulwark above the main deck. The process deck is 26.5m above the waterline to further reduce greenwater on equipment located here.

Based on the Shelley metocean data the 200 year maximum wave height is considered to be 25.4m, with the significant wave height in 200 year conditions as 13.7m.

15.2.4.16 Ballast System Design

The ballast system has been provided as part of the Sevan Hull solution and is based on the standard arrangement for the Sevan 1000 hull.

The current concept Sevan considered utilises the conventional Sevan hullform and this requires a significant amount of water ballast to be added to allow the vessel to operate at suitable trim due to the lack of cargo fluid in the storage tanks. This presents a potential to optimise how the hull is designed to reduce the buoyancy of the vessel to improve stability and reduce the ballast requirements. Based on the modelling presented the ship stability performance is still acceptable. The full stability analysis is presented in Appendix 28.20, Chapter 7.

A ballast water treatment system is required to comply with the International Convention for the Control and Management of Ships' Ballast Water and Sediments, 2004 to ensure no transfer of contaminants from one region to another.

15.2.4.17 Fire suppression system

The active fire protection systems shall protect against fire hazards on the vessel by aiming to extinguish a fire that develops, limit escalation of a fire and minimise the consequence of a fire.

15.2.4.17.1 Firewater System Overview

The proposed fire water system design shall be to the requirements of DNVGL-OS-D301 and consist of the key components.

- Seawater inlet,
- Main fire pumps (Seawater lift pumps) (3x100% or 4x50%)
- Jockey pumps (2x100%)
- Ring main
- Deluge Systems
- Sprinkler Systems
- Fine Water Mist Systems
- Hydrants
- Hose Reels
- Foam skid / proportioners and tanks.

The firewater pumps and ring main system provides a reliable source of firewater supply to firewater systems. The sizing of the system shall be developed based on firewater demand scenarios and appropriate contingency.

15.2.4.17.2 Gaseous Fire Protection

For other areas of the vessel an extensive gas detection, fire and smoke detection and extinguishing system covering all modules and compartments will be installed. Fire extinguishing systems will include water mist system, foam system and inergen system adapted to the equipment in each room and module.

15.2.4.18 Cable pull in

Subsea cables are routed onto the vessel via penetrations in the base of the hull in one sector midway between two sets of the mooring chains. This prevents the cables snagging in the mooring chains. They pass through the ballast tanks in I tubes up to the weather deck where they are made watertight using glands and are terminated in the TUTU.

In order to get the cables on-board a pull in winch is provided to allow handling of the subsea cables onto the Main Deck. This will allow any damaged flexible cables to be changed without the requirement for a specialist cable pulling or laying vessel. The available free space on the Main Deck will enable this area to be reserved for this activity.

The size of the pull-in winch has been taken to be similar to that commonly used for riser pull in and is expected to have a capacity in the region of 150-200 tonnes.

15.2.4.19 Collision Damage

Sevan have assessed damage stability of the Hull with the proposed topsides loading according to HSE RR387 (covered MODU Code and DNV). This covers typical damage scenarios that may be experienced while the Main hub is on station.

This has been found to be acceptable to all requirements with the use of watertight hatches between compartments.

This is covered in greater detail in the Sevan report in section 7.2.10 which is included in Appendix 28.20.

15.2.4.20 Workshop and Stores

Provision for workshops and stores has been made by using a single storey block on either side of the accommodation block. This should provide sufficient storage and workshop space for any of the routine maintenance tasks anticipated.

15.2.5 Marine Utilities

The Main Hub will have integrated utilities to provide essential utilities to the electrical, power generation and accommodation facilities.

15.2.5.1 Sea water lift

The water system incorporates main seawater lift pumps, located in the Hull, delivering to the sea water supply manifold for distribution to three inter-related subsystems, namely: seawater, cooling water, and firewater.

The main seawater lift pumps supply the firewater ring main with water at a minimum pressure of 8.5 barg. A pressure control valve in the common header, will maintain the upstream firewater pressure to ensure that it is the preferential route for water ahead of cooling and seawater utility supply.

A pressure relief valve, dumping back to the sea, protects the seawater lift system.

15.2.5.1.1 Air Systems

Two air compressors with associated air dryers are located in the machinery space in the hull and supply dried air at 10 barg to the Air Receivers located on the Main Deck. The compressors automatically load and unload taking signals from the pressure from the receivers, and in addition pressure switches on the instrument air header system.

Should the air pressure in the air receiver fall to 8 barg, the a diesel standby compressor will start automatically, and will run until the pressure is again at 10 barg.

The air from the compressors divides to supply both instrument and plant air. There is one instrument air receiver, one plant air receiver and two air accumulators located in the system. It is critical to have this back-up as in the event of air compressor failure. Loss of instrument air will cause an outage of the HVAC system which could result in the deluge system operating and resulting in a significant power outage.

15.2.5.1.2 Instrument Air

Dry air for instrumentation purposes will be supplied from the Instrument Air Header.

15.2.5.1.3 Plant Air

Plant Air is supplied to the Plant Air Receiver after the Dryers. Plant Air is supplied to the users at 7.5 barg as controlled by a pressure control valve. In the event of low instrument air pressure, the PCV will close to isolate plant air to protect the instrument air header.

15.2.5.2 Diesel Supply and Treatment

Diesel oil is shipped to the Platform and pumped from supply boat to the bunkering system via reel. Diesel is routed to the diesel storage tanks.

The main diesel distribution pumps discharge to the following users:

- Fire Pumps Reserve Fuel Tanks
- Emergency Generator Day Tank
- Standby Diesel Generator Day Tank

It is not considered that the power generation system will operate on a dual fuel basis as the volume of diesel required is well in excess of bunkering and storage capacity.

15.2.5.3 Fresh Water

A single Reverse Osmosis (RO) unit generates and delivers adequate volumes of potable water directly to two potable water storage tanks in the hull. The RO unit is fed from the sea water header. Treated water enters the potable water storage tanks and reject saline liquid is dumped overboard. Water generated by the RO unit is dosed with a suitable dosing system, to help prevent bacteria developing in the potable water system.

A secondary option is to offload potable water from a supply boat, via bunkering is provided in the event that the primary method for generation is unavailable.

Two distribution pumps located near the tank take suction from the storage tanks and feed the fresh water distribution system from where the water is distributed to consumers.

Samples of water from various parts of the system including the galley will be obtained on a quarterly basis. These samples are forwarded to a Public Health Laboratory for chemical and bacteriological analysis. In addition samples will be taken annually from various accommodation-washing facilities, particularly showerheads, and tested for Legionella.

15.2.6 Manning Requirements

It has been determined that the Main Hub will require a crewing requirement of approximately 140-200 POB. The Main Hub is viewed as being permanently manned. This will allow rectification of supply issues and maintenance of the power generation system which is viewed to be a continuous programme to maintain all 6 gas turbines, WHRUs and Steam Turbines and associated ancillaries and marine systems.

It is anticipated all maintenance on the Sub Hubs will be facilitated from the Main Hub using it as a base of operations to dispatch teams to the Sub Hubs. Having permanent manning of the facility will allow operational issues to be resolved quickly to minimise the potential impact from an outage. Based on the criticality of supplying constant power to interlinked oil and gas installations ensuring quick resolving of outages is important to prevent a near full outage.

The required manning level has been catered for using an accommodation block sized to suit this crew level and providing all required utilities and amenities.

For the concept of the Sub Hubs being unmanned it is critical for the following to be well planned and coordinated during the initial system design to ensure that sufficient capacity is available.

- Short and long term maintenance
- Integrity inspection programmes
- Duration and frequency of planned shutdowns
- Extent of ongoing support from specialist technicians and engineers
- Need for ongoing support for subsea operations
- Possibility of unplanned shutdowns and resources to deal with them

The accommodation facilities have been designed to include:

- The temporary refuge along with fire fighting equipment provisions
- Emergency control and response room, control rooms, radio room, offices and meeting rooms
- Cabins
- Helicopter reception facilities
- Dining, recreation and leisure facilities, locker rooms, galley, laundry facilities and stores
- HVAC plant rooms and battery rooms
- Sick bay and medical rooms

15.3 Topsides design

15.3.1 Layout Concept

The layout philosophy applied looks to adhere to general principles for safe, operable and maintainable facilities while aligning with relative industry recommended practices and guidelines mentioned later in this report.

The Main Hub layout utilises the preferred marine solution providing a scalable, pre-assembled modular approach with a repeatable design and allows for future expansion.

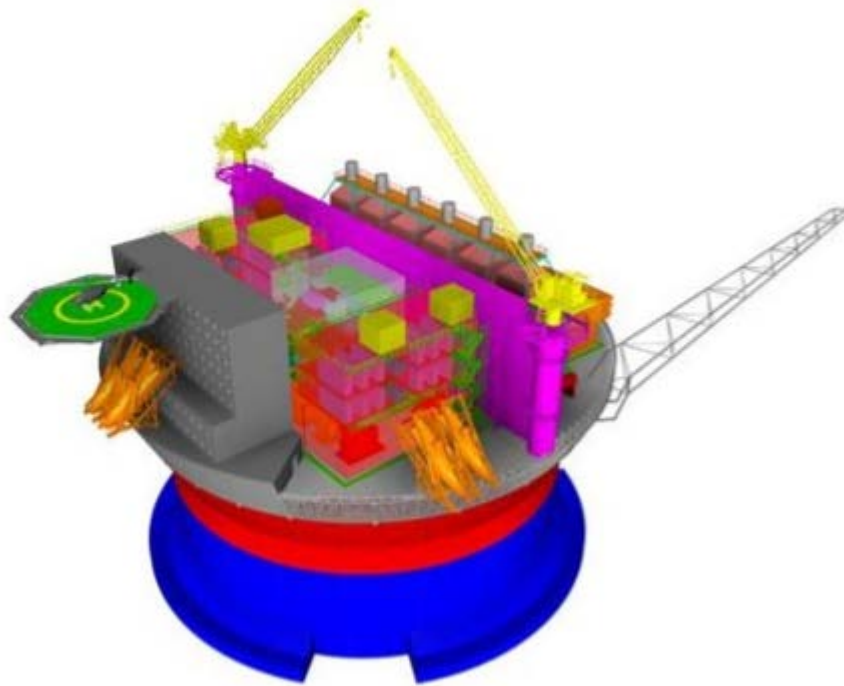


Figure 15-5 - Main Hub Layout Concept

Primary layout considerations have included:

- Safety
- Operability
- Maintainability
- Constructability
- Weight Control
- Centre of Gravity
- Cost-Effective

15.3.2 Modularity (PAU)

Modular design refers to designing products by organising sub-assemblies as distinct building blocks (i.e. modules/PAUs) that could be integrated into the overall Main Hub concept. The main advantages of modular design include flexibility and augmentation; additionally, modular systems simplify overall shipyard construction and reduce integration costs and schedule. Modules can be independently fabricated, tested and delivered to the shipyard as complete packages ready for integration, commissioning and start-up. In addition, the system can be upgraded or modified by the removal/addition of new modules in future.

For the Main Hub, equipment was identified and grouped within modules based on system. This allowed for modules to be designed independently of the whole asset. The following modules were identified as being required:

- 200MW Conversion Module.
- 100MW Conversion Modules.
- Switchroom Module – incorporating HV, MV & LV switchgear.

15.3.3 Pancake Structure

Where possible PAU's have been utilised to construct the Hub modules, these structures can be repeated across the Main and Sub Hub design. Two of the systems required for the Main hub topsides did not lend themselves to a PAU. The transformer housing and power generation package are significant structures and are only required on the Main Hub.

The combined weight and overall size of the CCGT's, WHRU's and Steam Turbines are too large to be designed as a pre-assembled unit/module and instead are installed on a pancake structure which is integrated into the Process deck. The pancake structure provides the foundation for the Power Generation equipment to be sited and allows load transfer and load distribution into the main hull structure.

A similar philosophy will be used for constructing the Transformers Housing. The pancake structure, integrated with the process deck will provide the support arrangement for transformers units. A clad structure will be constructed around the transformers to create a 'housing' that will protect the transformers from weather, the housing will be designed such that PAU's can be installed on the roof of the structure.

15.3.4 Standardisation

For the design of the modular PAUs on the Main Hub, consideration was given to standardising the modules such that the design could be repeated across subsequent Main Hubs and Sub Hubs. The following design parameters were adhered to:

- A standard overall footprint of modules to ensure they are repeatable, stackable and an allowance for access walkways incorporated.
- Standard heights of modules and integrated mezzanine levels to ensure stair towers and access points are common across the design.
- Standard components (i.e. structural sections sizes and cladding profile) were used throughout the design.

15.3.5 E-House

On the Main Hub it is proposed structures housing electrical power systems equipment will be contained within an E-Houses environment. This will extend to the following structures:

- 200MW Conversion Module.
- 100MW Conversion Modules.
- Switchroom Module – incorporating HV, MV & LV switchgear
- Transformer Housing

E-houses allow all electrical equipment and instrument panels to be pre-installed and pre-commissioned in a "controlled" environment before mobilisation. They can be designed for either safe or hazardous area environments and for protection against extreme climatic weather conditions. The Main Hub E-houses consist of several pressurised climate-controlled environments and they create a safe environment for personnel to operate in. They typically have fire protection rated to A60 level and contain a full range of HVAC and sensors.

All cable and pipe penetrations will transit through a single area in the E-house to allow a common transit design. From this input / output location, all cables and pipework can be run within the E-house to minimise the impact on the operators. Examples of this include routing cables under a false floor or around the perimeter of the E-house.

15.3.6 Topsides Layout

The layout of the Main Hub topsides is split into the zones as indicated below:

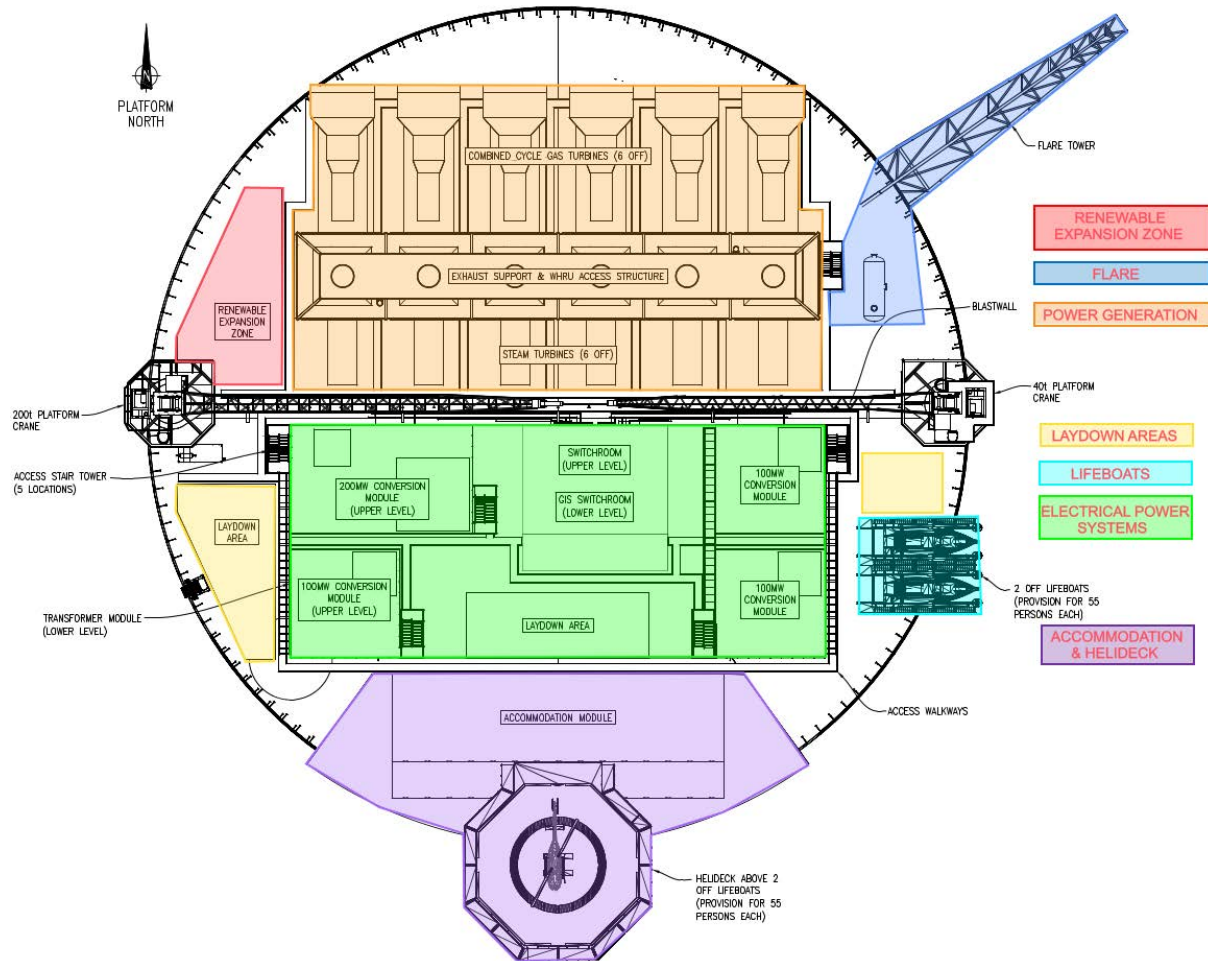


Figure 15-6: Topsides layout overview

15.3.6.1 Power Generation

The equipment used for power generation is located on the opposing side of the blastwall to the accommodation block. The Power generation system is required due to the potential irregularity of supply from renewable generation sources.

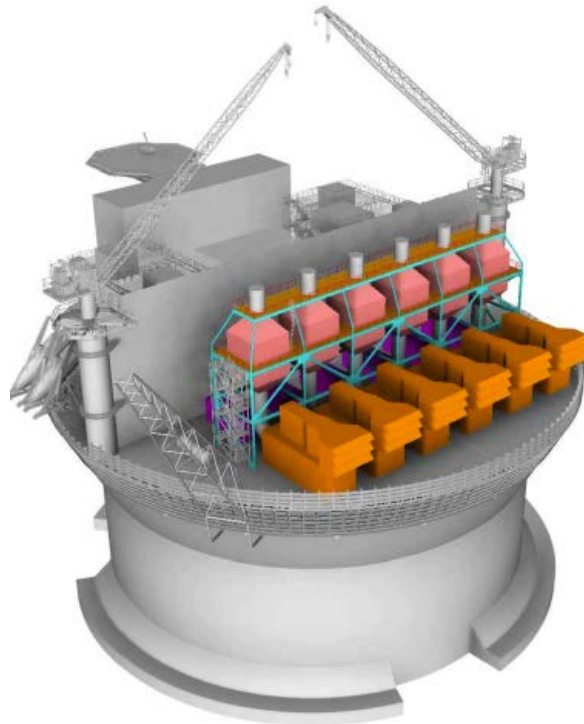


Figure 15-7 - Power Generation Layout

A list of the key components that make up the 6 x Combined Cycle Gas Turbines (CCGT) for the power generation system are:

- 6 off LM6000 PF+ Gas Turbines
- 6 off WHRU units, including closed loop system
- 6 off Steam Turbines

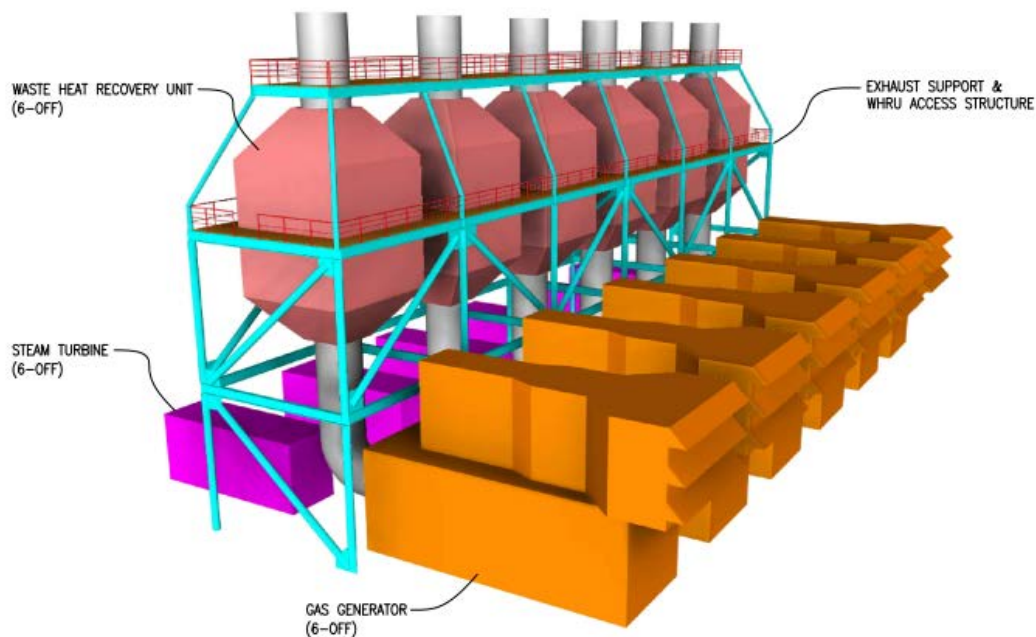


Figure 15-8 - Power Generation Components

The footprint and total weight of each CCGT system is (approx. 600t), this dictates that a modular system is not feasible. To support the weight of the CCGTs a pancaked structure will be incorporated into the

design of the Process deck. Each component of the CCGT will be mounted on the pancake structure via bolted connections incorporating Anti-Vibration Mounts.

The gas turbines have been positioned & orientated as far outboard to ensure clean air intake via the intake plenum on the top of the gas turbine. The gas turbines have been spaced with sufficient gaps between them to allow maintenance of individual components via the provided service doors on their modules. The Platform cranes are positioned such that they can reach and remove the individual components as required, adequate laydown areas are provided to facilitate the laydown of equipment.

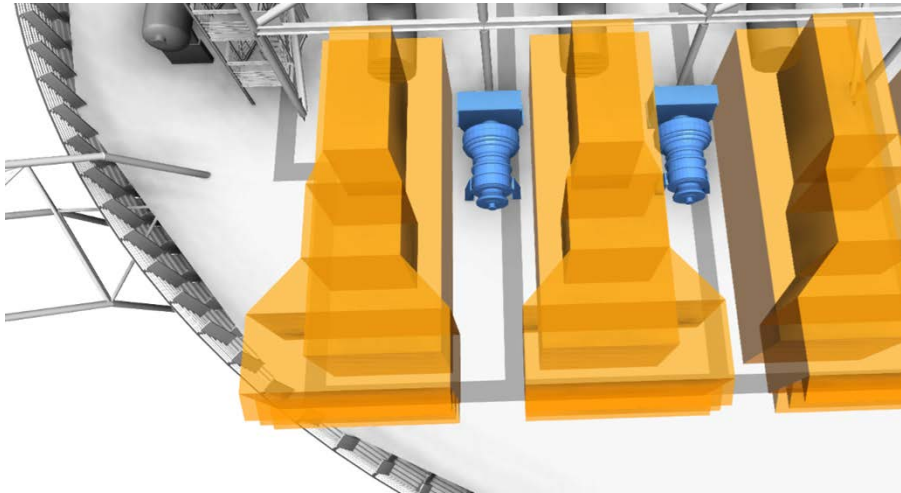


Figure 15-9 - Gas Turbine Component Removal

The spacing between the turbines and the arrangement of the WHRU support structure is designed to ensure there is sufficient space that, in the unlikely event of a total failure, they can be removed from the Main Hub via lift-off from a heavy lift vessel. Access to the WHRU is provided via stair towers onto a platform provided as part of the supporting structure. This platform is located at a suitable height to access and maintain the WHRU throughout their service lives.

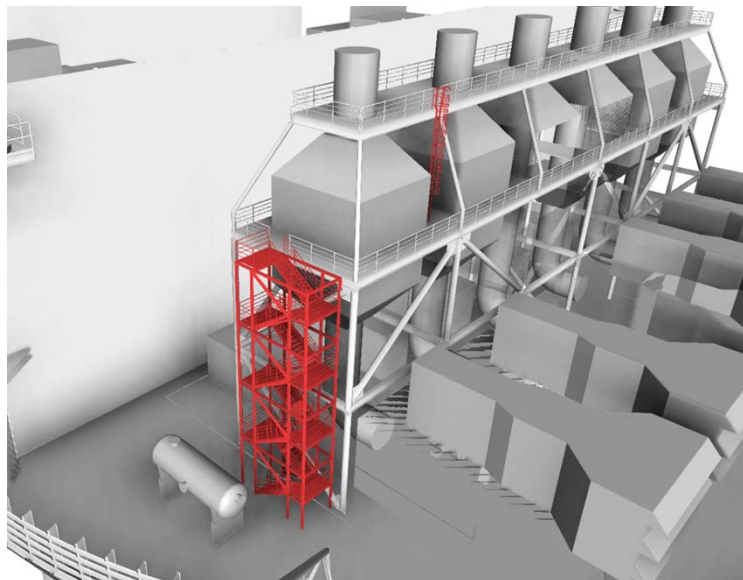


Figure 15-10: Access to WHRU

As part of the WHRU there are two heat exchangers and one steam condenser per WHRU that have been located directly below on the main deck.

The design of gas turbine exhausts is considered to route exhaust gas to an area that will not impede operations from emissions, impacting helicopter operation, impacting the safe area plant, the air intakes for the HVAC systems, or the air intakes for the generators themselves. These are routed at a high point

on the Main Hub. Detailed analysis and emission modelling are required to confirm the exhausts' correct height based on all wind conditions for the facility.

Access to the steam turbines is from the process deck through the maintenance doors provided in the steam turbine units.

Piping access for the gas import line and water from the seawater lift system has been routed in the gap between the main deck and process deck.

Similarly, control and communication cabling can be efficiently run through the service area between decks to the control and communication centre.

Alternative arrangements for the layout of the CCGT were reviewed, such as 2 banks of 3 turbines in parallel, but the overall footprint, access & operation requirements of the package dictated it was not feasible on the Sevan hull design.

15.3.6.2 Electrical Power Systems

The Electrical Power systems are located between the accommodation block and the blastwall, the electrical power system contains the following systems:

- Transformer Housing
- 200MW Conversion Module (PAU)
- 3 x 100MW Conversion Modules (PAUs)
- Switchroom Module – incorporating HV, MV & LV switchgear (PAU)

15.3.6.3 Transformer Housing

The Transformer Housing is a pancaked structure integrated into the Process Deck steelwork with the associated structural frame and equipment mounted above; due to the overall size and weight of the housing, it is not feasible to construct the housing as a dedicated Module (PAU). Consideration was given to the use of several Transformer Modules (PAUs) but this was ruled out due to the requirement of a gantry crane for the potential removal of transformer equipment.

The pancaked structure and associated weights of equipment dictated that the Transformer House would be located on the Process Deck Level. Additionally, it helps maintain as low a C.O.G as possible and improves motions for the overall Main Hub.

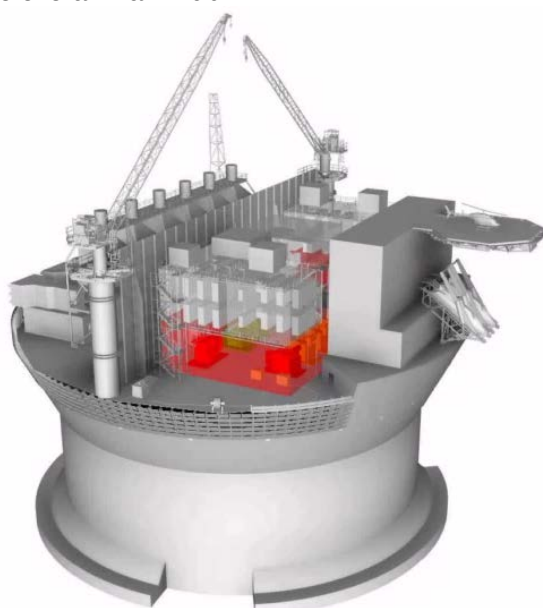


Figure 15-11: Location of the Transformer Housing

For the sizing of the transformer housing and equipment layout out within the housing, consideration was given to:

- Maintenance envelopes
- Withdrawal spaces
- Potential removal/replacement of transformers
- Handling Aids
- Access and Safety Routes

To allow for removal/replacement, a central access corridor and gantry crane running the length of the housing is provided. A maintenance door at the west end of the housing allows the transformers to be transferred to the main laydown area local to the 200t crane for offloading onto a supply vessel. To incorporate a gantry crane the overall height of the transformer module has been suitable sized to account for hook heights and rigging arrangements etc.

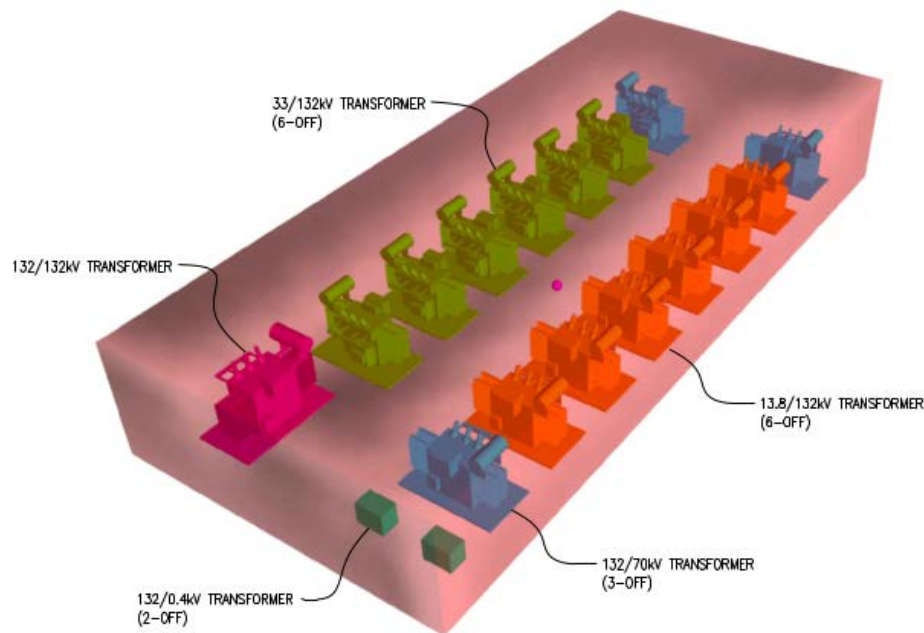


Figure 15-12 - Transformer Housing – showing central access corridor

Located on top of the Transformer housing is the 200MW Conversion module, 3 x 100MW Conversion Modules, Switchroom module and central laydown area. The following criteria were considered when positioning the modules:

- Symmetry of module layout to aid C.O.G and vessel motions
- A common Laydown Area
- A common module height to aid safety routes and access/egress
- Reducing cables runs as far as practical
- Access and Safety Routes
- Repeatability in layout of modules

To aid the installation and removal of modules, a standardised bolted connection with guide arrangement would be integrated into the transformer housing structure.

15.3.6.4 200MW Conversion Module

The 132/132kV transformer connects to the 200MW conversion module. To reduce cable routes, the 200MW Conversion module has been positioned directly above in the N/W corner, maintenance doors opening towards the central laydown area provide a transfer route for electrical components requiring repair or replacement.

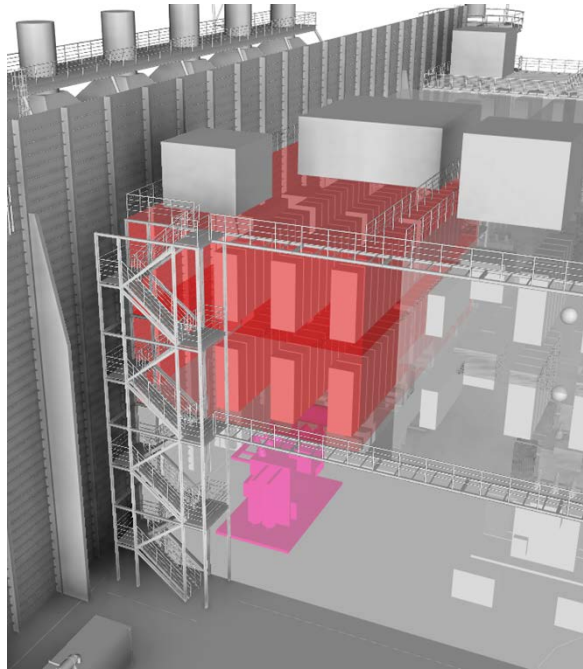


Figure 15-13 - 200MW Conversion module located over 132/132kV Transformer

15.3.6.5 100MW Conversion Module

The three 100MW Conversion modules are located in the remaining corners above the Transformer Housing. Similar to the 200MW conversion module, maintenance doors opening towards the central laydown area provide a transfer route for electrical components requiring repair or replacement.

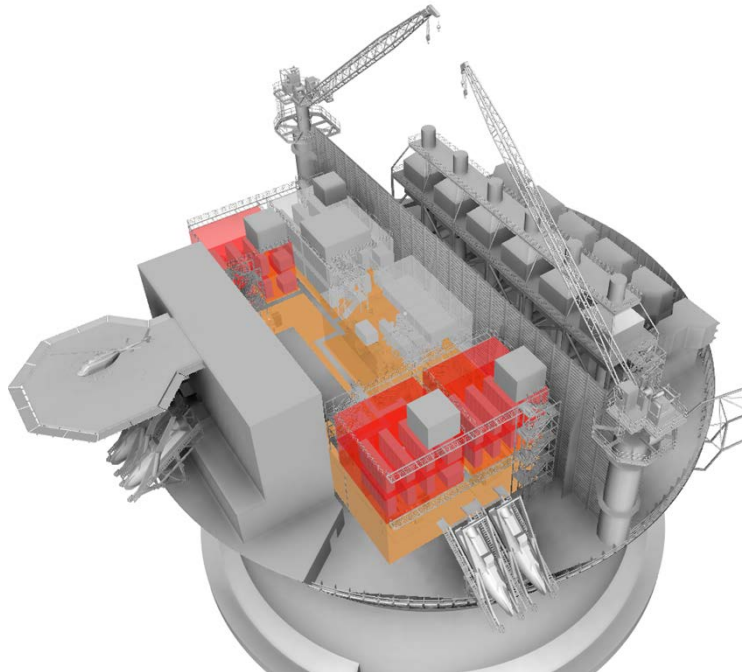


Figure 15-14: Location of 3 x 100MW Conversion Module

15.3.6.6 Switchgear Module

The Switchgear module is located between the N/E and N/W conversion modules, running parallel to the blastwall. Similar to the conversion modules, maintenance doors that open towards the central laydown area are incorporated into the module.

The switchgear module contains the HV switchgear located on the lower level reducing the cable run of the larger HV cable. The MV and LV switchgear is located on the upper level. Cable routes to and from adjacent modules and the transformer housing can be run along the blastwall and enter the switchgear module via the north side face, keeping walkways and handling areas clear of cable runs.

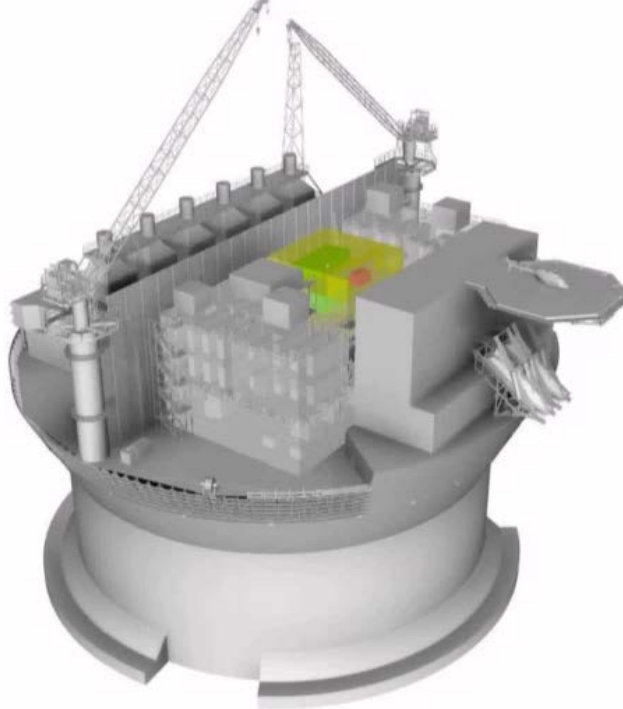
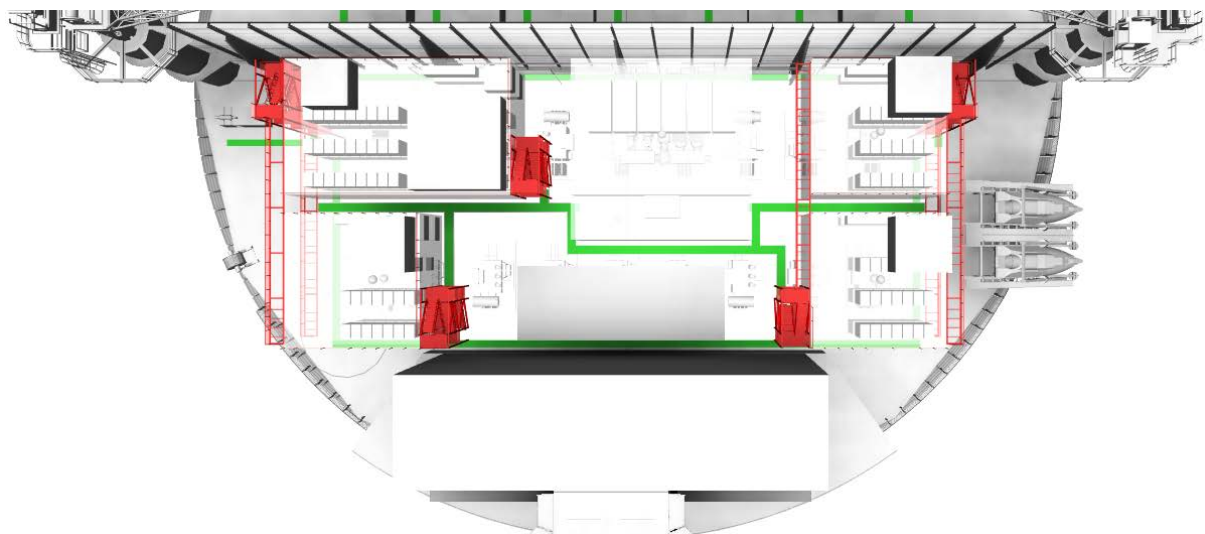


Figure 15-15- Switchgear Module

15.3.6.7 Walkway and Stair Towers

The layout of the electrical power system has been developed to maximise safety, efficiency, handling, and maintenance operations. The transformer housing and electrical system modules have been sized and positioned to allow routing of main walkways and common use Stair towers.

The transformer housing has been sized to allow for a perimeter walkway around the outside; two main stair towers at the East and West side of the housing provide access to the modules above. Module heights and integrated mezzanine levels have been duplicated across all Modules to ensure commonality on stair tower design. A minimum of two means of access/egress has been provided to all areas, including accommodation, lifeboats and temporary refuge.



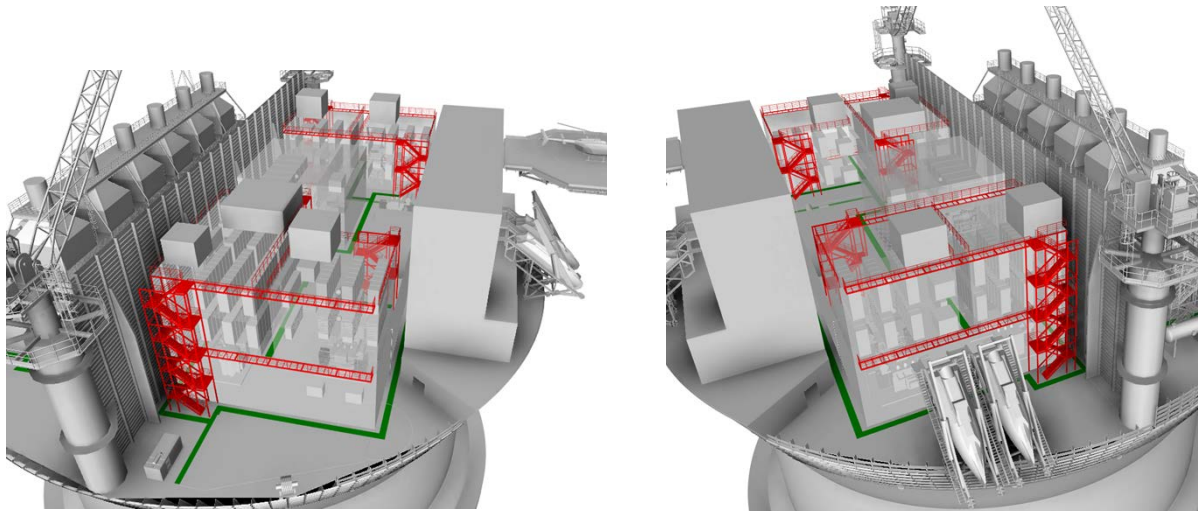


Figure 15-16 - Electrical Power System - Stair Towers and Walkways

15.3.6.8 Flare System and Stack

As the Main Hub has a gas import connection to operate the thermal generation equipment, a flare is required to ensure that gas can be disposed of safely from the plant in emergency conditions. The gas import system will be fully rated to the pipeline design conditions with the main HP/LP interface between the gas turbines and gas import superheater. This volume of section of pipework will be kept to a minimum to minimise the scale of any potential release.

An HP Flare Header will be provided which will be used to receive gas from either PSVs located on the HP/LP interface or from blowdown valves located on the gas import heater.

The flare header will be routed at a high point running parallel to the blast wall to allow connections from the fuel gas feeds to the gas turbines, and connections from the steam system for fire case or thermal PSVs. The header will slope from a high point into the Flare Knockout Vessel located on the utility area at the base of the Flare Stack.

The anticipated maximum relief sizing will be based on the maximum gas import rate which is approximately 25 MMSCFD.

The flare tower is located in the Hazardous Area of the Main Hub, on the north side of the blast wall.

All associated flare equipment such as the Flare KO Vessel, liquid seal and ignition system will be located at the base of the tower in the hazardous area on the process deck level. All components of the flare system will be designed in accordance with API RP 521.

A closed flare design will be selected to minimise emissions from the Main Hub from operational Flaring. This will involve utilisation an electronic ignition system located in the flare tip to ignite the flare on detected gas. This system will avoid running a HP flare pilot unnecessarily.

The flare stack height will be determined based on isopleths generated based on the maximum relieving rate and the selected flare tip, and prevailing wind direction. The location of the Flare Stack is designed to be as far downwind from the prevailing wind direction to ensure heat and or gas is not blown back to the main hub. The flare stack elevation will be determined based on the API RP 521 radiation levels. Typically the design will be for the base of the flare tower to experience 4.73 kW/m^2 radiation to allow an operator to move to a safe location.

For the purposes of this study the Flare Stack has been considered as being 30m and angled overboard.

The flare will also have a low pressure cold vent to allow limited venting of gas without flare ignition. This will be required for maintenance of the system. The alternative would be a utility flare, however this

is not considered due to requiring a pilot supply to increase emissions vs limited low volume cold venting. Determination of whether a vapour recovery unit is required will be carried out during FEED. There is no intended continuous utility routing to flare identified in the current design, however some ancillaries for the gas turbines may require a connection of this type.

15.3.6.9 Renewable Expansion Zone

Space has been identified next to the CCGT and marked on the model to allow the Green Hydrogen unit to be deck mounted. Further details on the hydrogen strategy can be found in Section 23.

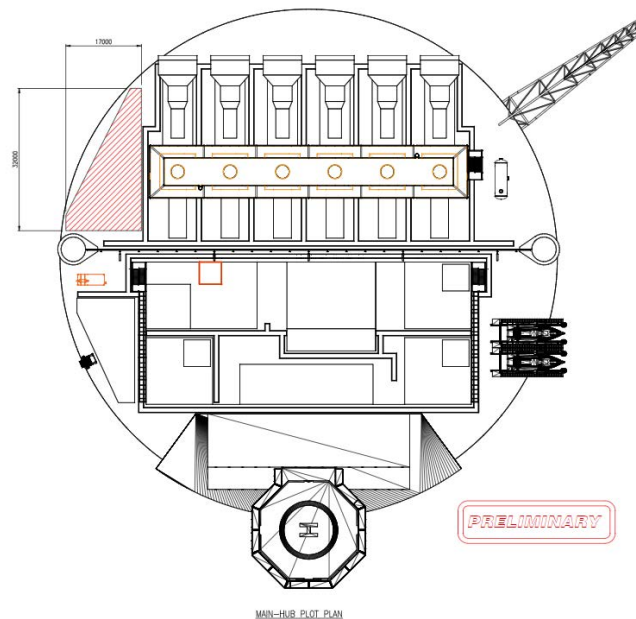


Figure 15-17: Area set aside for future Green Hydrogen unit

This area will primarily be utilised as a laydown area for the power generation system maintenance in the base design. Large components will be able to be stored here for periodic maintenance such as turbine changeout.

A future use of this space considered is installation of a hydrogen generation system. This system is required to be located in a hazardous area due to the risks associated with hydrogen. The area is designed as a laydown area therefore the deck capacity of this area will exceed the rest of the main deck.

Current hydrogen generation technology is based on utilising containerised equipment, however as the technology matures it is considered that modularised designs will become available.

The equipment required to be located in this area is primarily the electrolyzers for hydrogen generation and special hydrogen compressors. The hydrogen will then be routed to the Main Deck to a new riser for subsea hydrogen storage.

This system has not been designed yet, however this area is 32m x 17m with approximately 20m of available height before potential impact on the Hub crane.

15.3.6.10 Laydown areas

Three main laydown areas have been provided on the Main Hub, other locations can be utilised for general-purpose laydown, but these have not been defined at this stage.

The main laydown area at the foot of the West Crane on the accommodation side of the blastwall will be utilised for platform operational requirements, supply vessel operations and equipment laydown. The

capacity of the laydown is to be based on the heaviest single component that may require to be removed or replaced; this has been identified as a transformer (approx. weight = 100t).

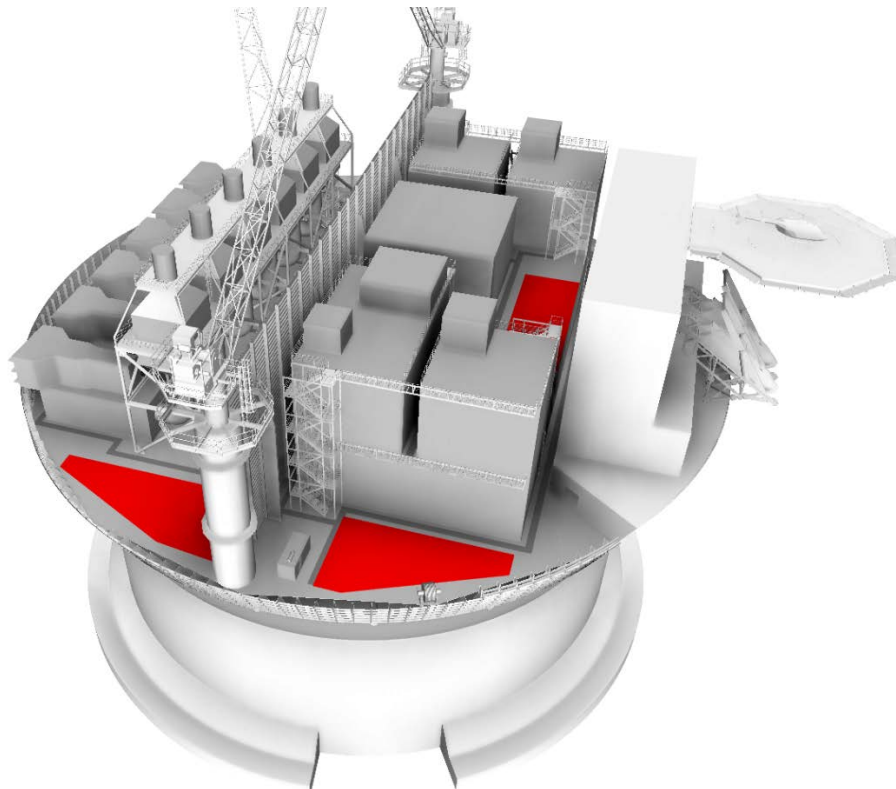


Figure 15-18 - Laydown Areas

The central laydown area is provided on top of the transformer module; the laydown is local to the conversion modules and switchroom modules to aid operation requirements. Both the East and West Cranes can reach the central laydown area allowing transfer of materials across the platform. The central laydown area is parallel to the accommodation block, allowing the unloading of containers for galley use, etc. Due to the proximity of the accommodation block to the central laydown area, a suitable bumper bar structure is required.

The third laydown area is located at the base of the west crane on the power generation side of the blastwall. This area will primarily be used as a laydown area but maybe re-purposed to accommodate a hydrogen generation system. The capacity & design of the deck steelwork in this area will be arranged to allow the future installation of the hydrogen generation system.

15.3.6.11 Lifeboats

Free fall lifeboats (TEMPSC) are provided on the vessel and held in two banks containing two lifeboats. For the purpose of this study a 60 Person lifeboat has been shown and included in the costing.

One bank is shown outboard of the accommodation block in the safe zone away from IP code hazardous areas with the other at on the east side of the Main Hub to the south of the blastwall.

The lifeboats have been placed at two opposing locations to allow access from either side of the electrical module stack in the centre of the accommodation block. This provides redundancy of escape route if there is an incident restricting access to one of the banks of lifeboats.

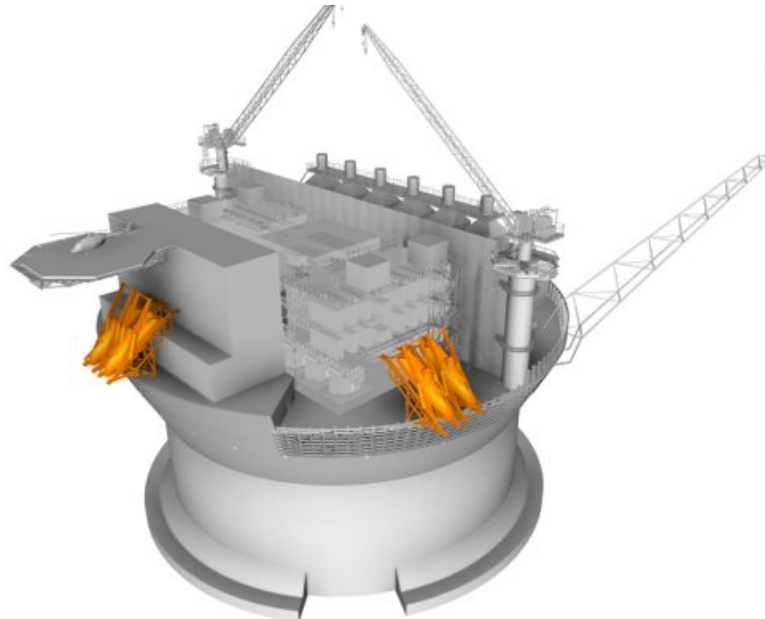


Figure 15-19: Location of lifeboats

15.3.6.12 Accommodation and Helideck

The concept and layout for the accommodation block and integrated helideck has been taken from the Sevan 1000 Goliat arrangement. The position of the accommodation block allows for routine access to the electrical power generation package and lifeboat stations. Additionally, the location of the blastwall maximises the separation between the accommodation and hazardous areas associated with the power generation system.

A laydown area on top of the transformer housing provides a suitable location for, temporary storage, the laydown and unloading of containers related to daily operations, for maintenance or the assembly of construction equipment or other supplies.

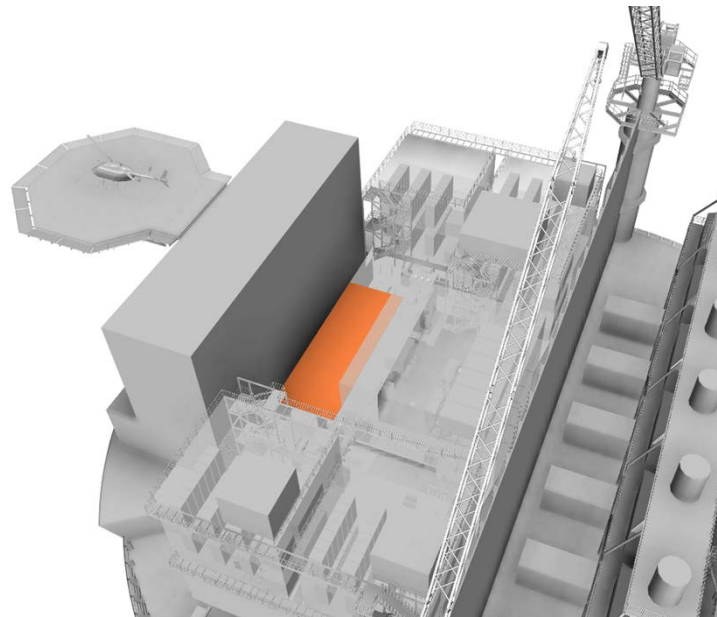


Figure 15-20 - Accommodation Module – Laydown

15.3.7 Topsides structure

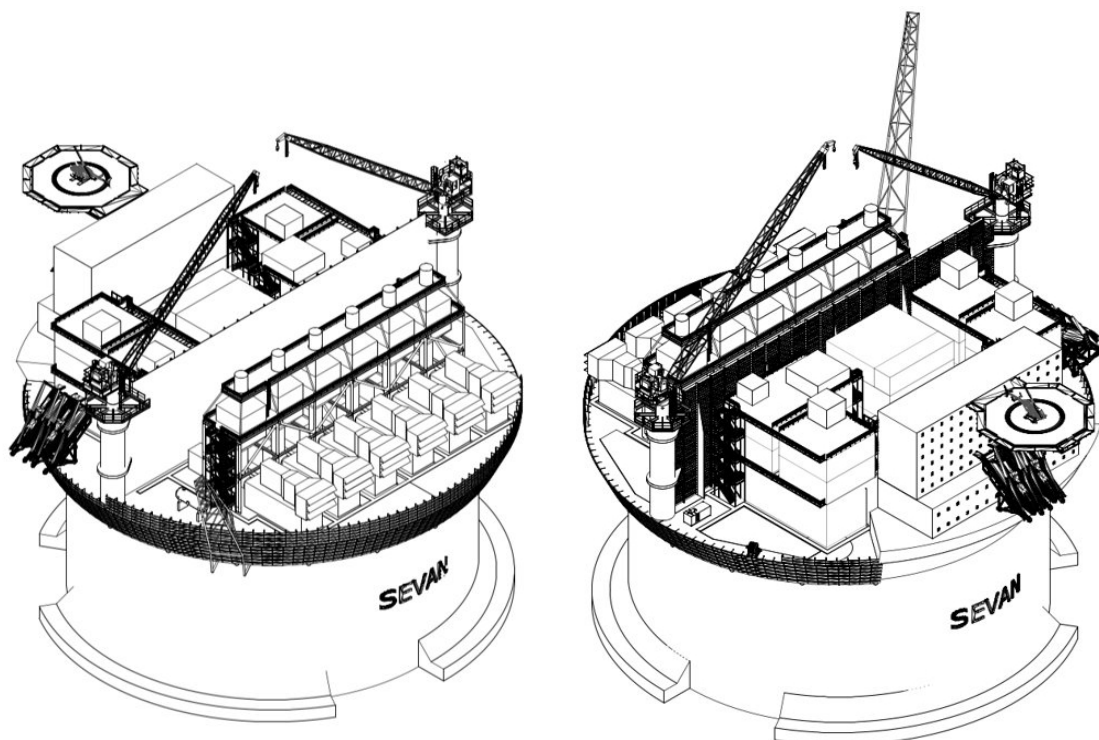


Figure 15-21: Topsides overview

The large deck area on the Main Hub has facilitated the use of PAUs from cost and safety points of view. With the view of standardisation, the structural section sizes & cladding profiles were designed as standard components. Large 'module' structures impose high point loads on the vessel and transferring the loads on to the relevant strong point is vital. Large rigid modules, spanning a significant length of deck, need to have some flexibility built into their supports to prevent high hull stress levels being transmitted into the module. For all support arrangements, fatigue due to hull flexure and inertia loads on PAU/modules in the design of supports will also be considered during the design.

The Process deck supports the following :-

- Living Quarters including Lifeboat davits, Helideck & Stair tower
- Blast Wall
- Gas Turbines
- Transformers & coolers
- Switchboards & Distribution boards
- Diesel Generators
- Flare stack

The Process deck structural steel arrangement will be designed to support the items above.

The elevation of the Main deck is EL +44,000 and the elevation of the Process deck is EL +50,000. The supporting steelwork ToS for the Process deck is EL +50,000.

The topsides structures have been designed as concepts only at this stage but the intention is that they would be developed during detail design with the following considerations.

15.3.7.1 Primary Structural Steel Sizing Basis / Methodology

15.3.7.1.1 Pillar/Stool arrangement for transfer of loads

To transfer the loads and to support 6-off Gas generator and the Steam Turbine units on the process deck, 'Pillars/stools' will be added at engineered distances to distribute the loads from the equipment to the main ship hull structure. Provision to be made for misalignment of the pillar relative to the deck support. Attachment weld some distance above the deck is required to avoid damaging internal tank coatings. Fatigue damage may arise due to either longitudinal hull bending being transmitted through the supports to the PAU or bending from transverse loads on topsides from roll motions hence this needs to be reviewed at the design phase.

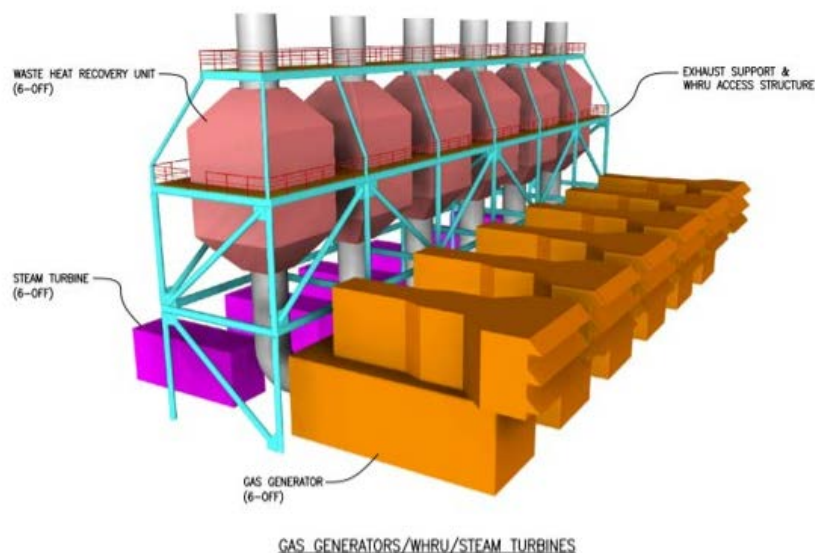


Figure 15-22: Gas generators & Steam turbines

The weight of 60MW Generator combined cycle (weight control sheet /68/) is estimated at 600 Tons. The beams supporting the Generator units to transfer the loads to the ship hull via stools will be made of fabricated plate girders and will be located under either end of the equipment.

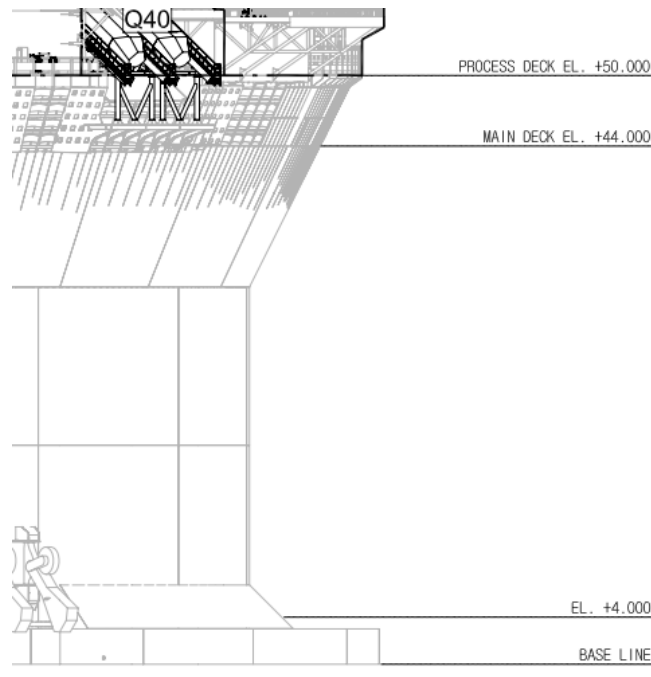


Figure 15-23: Elevation of Main/Process deck of Goliat

For this study the plate girder beams supporting the Generator unit/Blast wall is estimated to be 1m depth. The Process deck is estimated at an El +50,000 (TOS). This gives a clear height of 5m between the Main deck and the Process deck. There will be a need for cable trays that may reduce the clear height (depending on the layout/routings of the cable trays) between the levels. This will be reviewed during the detailed FEED study of the project.

The Plate Girders supporting the Generator units will be mounted on pillars/stools to transfer the load into the strong points on the vessel. These intermediate supports stools will be added at locations where the support beam of the Generator unit is in line with the hard points of the main deck and the hull of the vessel. This will provide adequate support for the process deck in these highly loaded areas. The beams will be fabricated at the shipyard. The topside loads are spread more evenly into the ship's structure and allow local flexing to reduce the hull bending stresses transmitted into the PAU structure.

A typical arrangement of stooling of the process deck is shown below :-

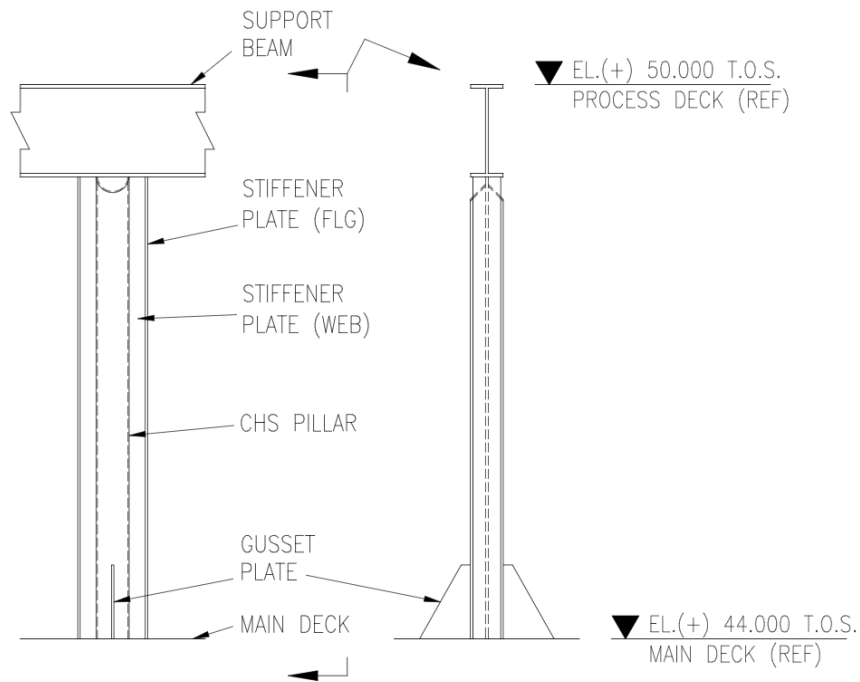


Figure 15-24 Example Pillar/stooling arrangement

A total of 33 such 'Pillars/Stools' are identified as required at this stage which will be reviewed during the detail design phase of the project for confirmation on total numbers.

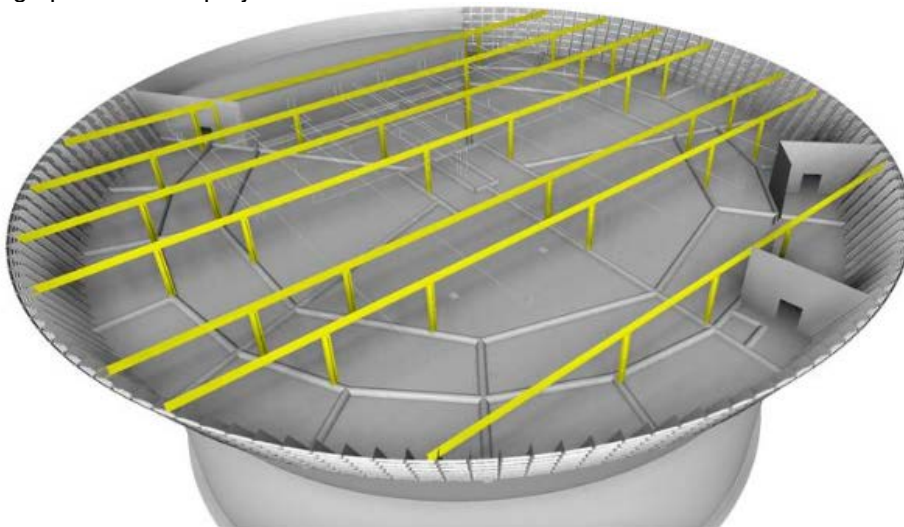


Figure 15-25 Pillar/stooling arrangement



Figure 15.4-15-26: Example Pillar/stooling arrangement

Another area where there is a requirement of these Plate Girder beams & stools will be support for the Steam Turbines. At this stage four numbers of such beams are estimated and the number of stools will be engineered to suit the design.

The entire process deck is therefore supported using a regular pattern of stools between the main deck and the process deck. These are spaced to transfer the radial framing system of the Sevan hull to the rectangular framing required for the process deck. It is acknowledged that this use of fixed only stools adds to the fatigue loading on the main deck which supports this but this is a common feature of the Sevan hullform.

These stools are manufactured to reduce the fatigue impact on the main deck connection by creating a bracketed transition between the stool and the deck. This is important to consider due to the effect of fatigue in the offshore environment.

The stools are placed at as regular intervals as possible with consideration of the structure below and the high load areas of the process deck requiring a greater frequency of stools to provide adequate support of the process deck.

Primary steelwork for the additional decks and modules that make up the topsides will be designed and produced according to the AISC ASD methodology consistent with existing platform topsides design methodology.

15.3.7.2 Regulations Codes and Standards :-

The design shall be in accordance with the latest international legislation, codes and standards.

Good engineering practice shall be applied to facilitate a safe operating design and minimise the risks to personnel as low as reasonably practical (ALARP).

Typical codes and standards are :-

- DNV rules for classification of ships – January 2015
- AISC specification of Structural steel
- BSEN 10025-02 -Hot Rolled products of Structural steel
- DNVGL-ST-N001 Marine Operations and Marine Warranty – Jan2020
- DNVGL-ST-0378 – Offshore and platform lifting appliances, July 2019

15.3.7.3 Secondary Structural Steel Design Basis / Methodology

Secondary Structures are as follows :-

- Exhaust Support & WHRU access structure
- Stair Towers

Secondary steelwork for the additional decks and modules that form the topsides will be designed and produced according to the AISC ASD methodology consistent with existing platform topsides.

Secondary steelwork will be attached to the primary steelwork and provide bracing for out of plane loading and prevent unnecessary vibration.

Secondary steelwork will consist of S355 grade and will take the form of beams / girders commonly available and sized to ensure code compliance.

15.3.7.4 Tertiary Structural Steel Design Basis / Methodology

Tertiary steelwork will be designed in a similar manner to the secondary steelwork with the exception of using sound engineering design rather than prescribed rule checks given in the AISC ASD.

Should the design requirement suit the Grade of Steel for the tertiary members can be lower than that of the primary/secondary steel.

15.3.7.5 Lifting & Handling

Lifting & handling of pre-assembled PAU/Pancakes/Equipment will be performed with certified lift rigging. Pad eyes to be welded to facilitate the lifts. Lift analysis and the design of rigging/installation aids shall be carried out in compliance with procedures.

It will be ensured that the Structural deflections during lifting shall be minimised to prevent damage to the structure/cladding/coatings.

Temporary structural framing and weatherproofing will be provided for the transit/installation condition where necessary to ensure Structural integrity and weather-tightness. Any temporary strengthening or bracing shall have bolted connections to permit easy removal offshore.

15.3.7.6 Gas Import

This concept considers that gas will be imported from a pipeline in the North Sea. This will either be the Fulmar Gas Line or the SAGE Pipeline based on location of infrastructure.

Gas at pipeline specification will be imported to the Main Hub via a submerged flowline connected to a flexible which will route through an I-tube to a TUTU connection on the Main Deck.

From the TUTU point gas will be routed to an import heater which will heat the incoming gas prior to a pressure let down system. A pressure control valve will decrease the pressure of the gas to the required fuel gas supply pressure and gas will be routed to a scrubber / accumulator vessel. This vessel will be sized appropriately to act as a buffer for the rundown of gas turbines in the event of a system outage.

From the scrubber gas will be heated in a super heater and routed into the fuel gas manifold.

The gas import skid is located on the Flare equipment zone on the Main Deck.

15.3.8 Electrical Power Systems

15.3.8.1 Transformer Housing

Transformers shall be specified for a minimum design life of 25 years. Transformers are considered unlikely to fail and need complete replacement, however, maintenance access shall be considered to conduct testing and repairs, as well as liquid replacement if this becomes necessary.

The transformers shall utilise synthetic ester (e.g. Midel) as the insulation fluid. This has a lower flammability risk and pollution risk in the event of a loss of containment compared to more traditional mineral oil.

In offshore transformer design earthing units are often built within the same main tank. This option should be explored as a way to minimise equipment layout requirements.

Transformer cooling shall be considered in greater detail during future study phases. Typically ONAN (cooling with radiators but without fans) offers the lowest maintenance burden, but the impact on the transformer module HVAC must also be considered.

As the Main Hub electrical loading evolves, there may be a requirement to replace transformers with units of a more suitable rating. Therefore, it is envisaged that the transformers will be placed to allow for complete withdrawal down the module's centre to an external laydown area for removal.

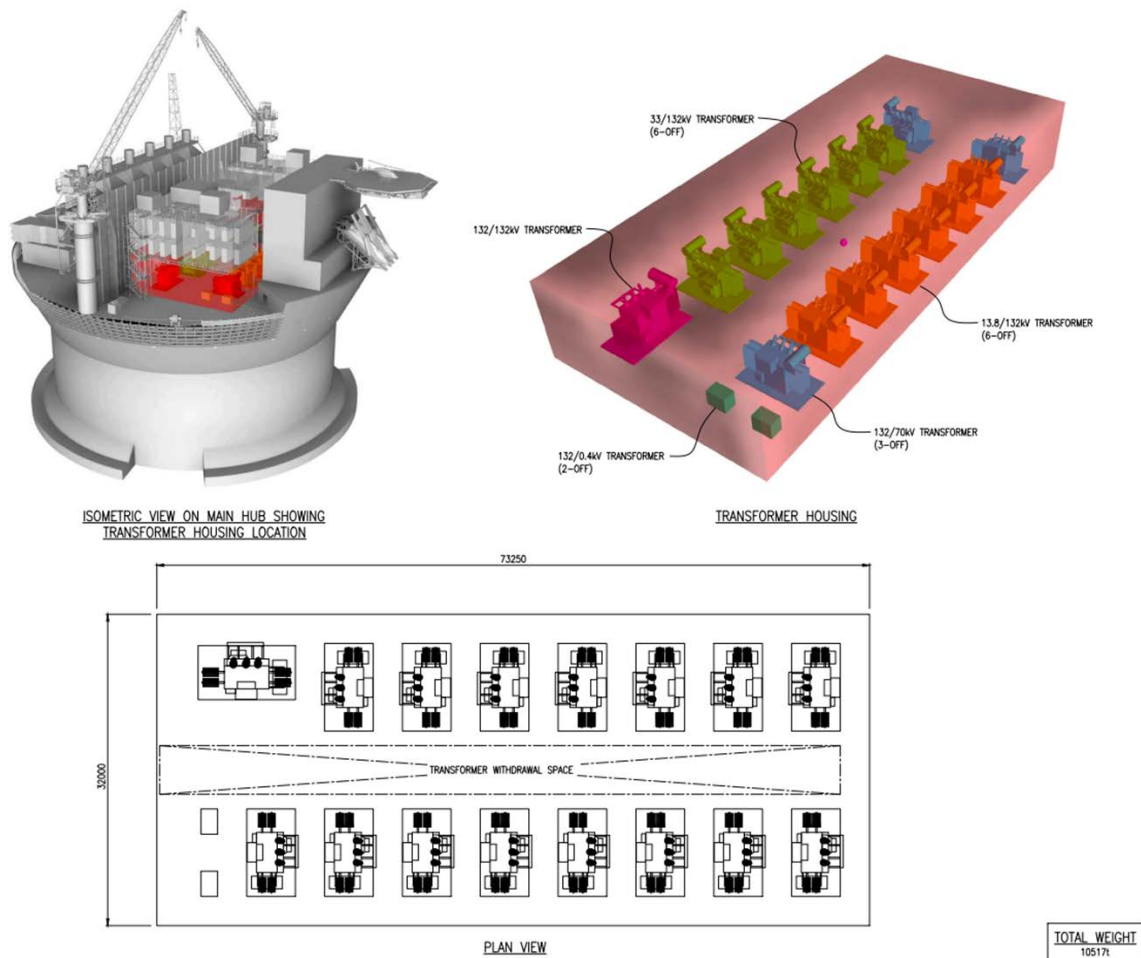


Figure 15-27: Overview of the Transformer Housing Layout

15.3.8.2 Conversion Modules

Each Conversion Module contains all the Medium Voltage Direct Current equipment (MVDC) required for transmitting bulk electrical power from the Main Hub to the Sub Hubs. There shall be 4 separate Converter Modules on the Main Hub corresponding to the 4 Sub Hubs intended to be supplied. 3 of these modules are rated for an output of 100MW, with the 4th being rated for 200MW.

The sensitive nature of the power electronics means that the Converter Modules shall be pressurised and environmentally controlled to ensure temperature and humidity are kept within acceptable limits.

The MVDC equipment proposed by GE consists of multiple Half Bridge converters arranged on open racks. These employ power semiconductor switches and capacitors as part of the conversion technology. The racks are arranged to be accessible for component inspection and replacement.

Each converter also has an associated Control Unit as well as ancillary equipment such as an AC reactor. These components have been located within the Conversion Module to minimise control cabling and allow for operators to monitor and control equipment locally if required. There will be interfaces between local Unit Control Panels and the Main Hub's ICSS for overall monitoring and control from a Central Control Room.

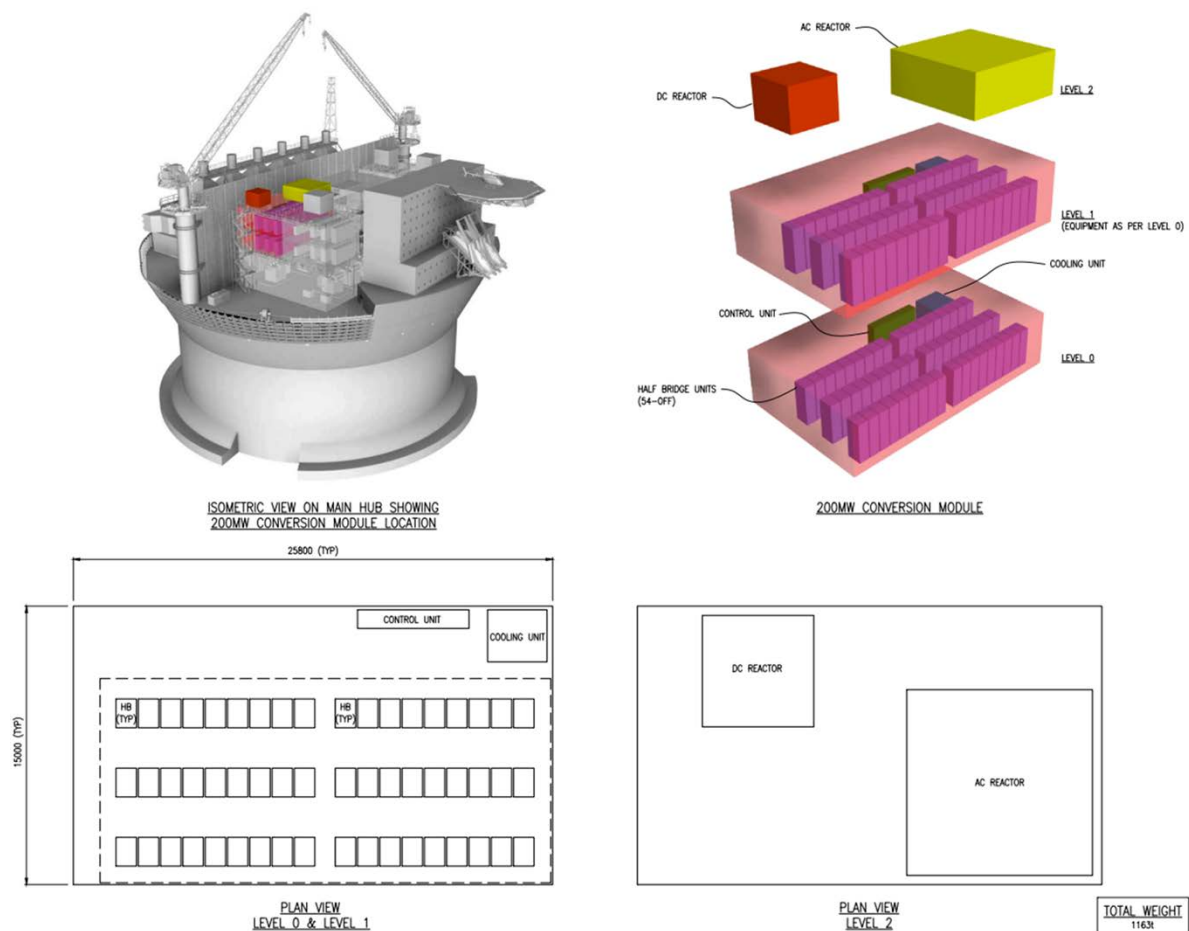


Figure 15-28: Overview of 200MW conversion module

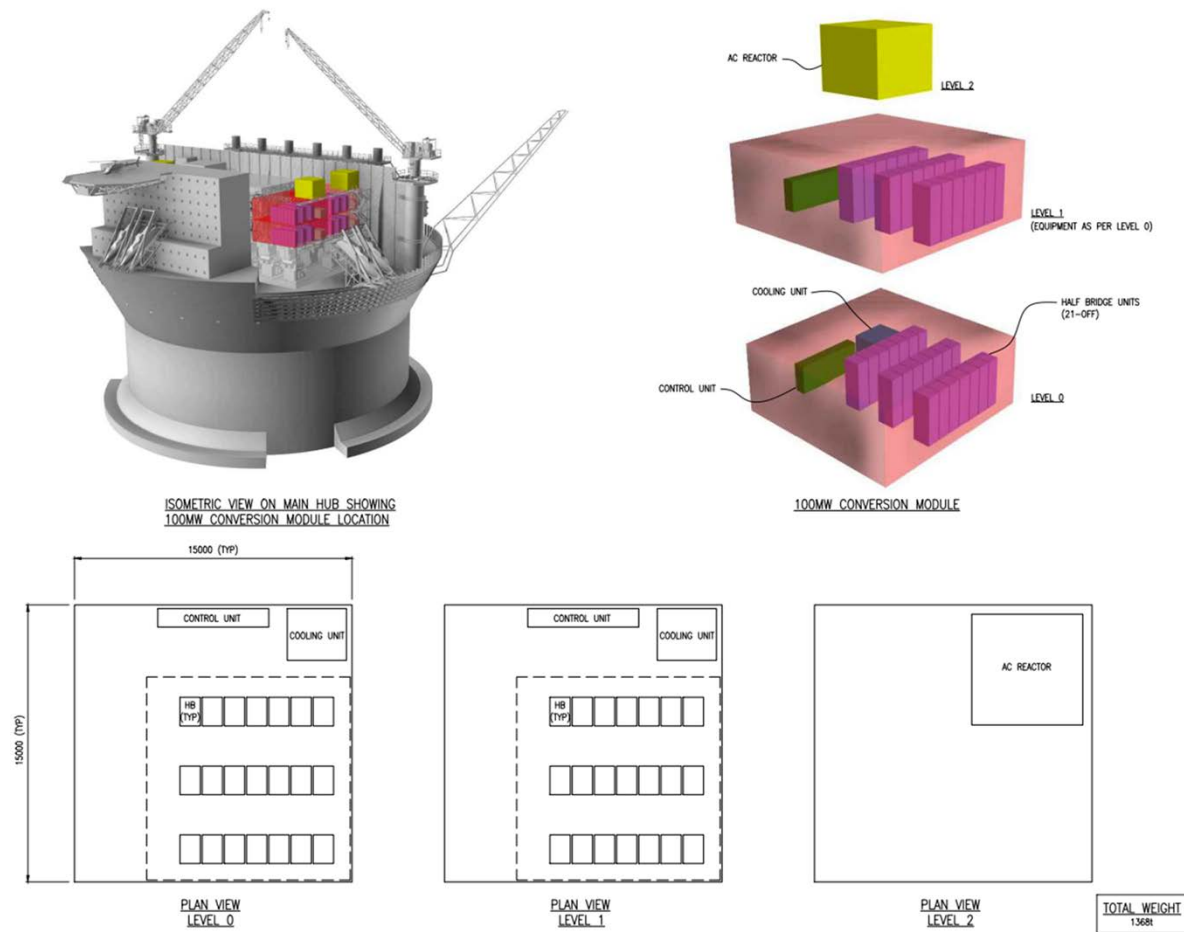


Figure 15-29: Overview of 100MW conversion module

15.3.8.3 Switchgear Modules

In order to segregate the electrical switchgear there shall be a Switchgear Module provided for each voltage category: High Voltage (above 52.5kV), Medium Voltage (between 3.3kV and 52.5kV) and Low Voltage (0.4kV).

HV Switchgear

Metal-enclosed gas insulated switchgear (GIS) shall be used for voltages above 52.5kV.

Gas Insulated Switchgear utilises Sulphur Hexafluoride (SF₆) under pressure (generally a few bars) as the insulating medium. This allows for relatively compact equipment suitable for installations indoors offshore where space is limited.

High voltage interface connections will depend on the distance: cables shall be used for long runs (e.g. between modules) whilst gas insulated busbar (GIB) ducting shall be used for short runs (i.e. within a module). The connection type selected shall also take into account the current rating, turning radius, supports, proximity to heat sources, proximity to other electrical equipment and cables.

Any High Voltage GIS switchgear shall be located in its own room to allow controlled access and reduce hazard exposure. The SF₆ gas in particular shall be monitored and risk assessed due to its high global warming potential if released.

GIS switchgear is generally very low maintenance and can be remotely monitored to reduce the need for on site checks and inspections.⁵ Specialist personnel and equipment will be required for servicing and maintenance when working with SF6.

MV Switchgear

Switchgear at voltages between 3.3kV and 33kV shall be metal-enclosed Air Insulated Switchgear (AIS). This typically offers the most compact equipment for these medium voltages and is a well proven technology offshore utilised extensively for 3.3kV, 6.6kV, and 11kV equipment in the UKCS.

Switchboards are typically formed of incomers, feeders and bus ties with each tier incorporating the switching device and the associated controls and protections. Switchgear can be specified to be front access with cable entry either top or bottom to suit the cable routing.

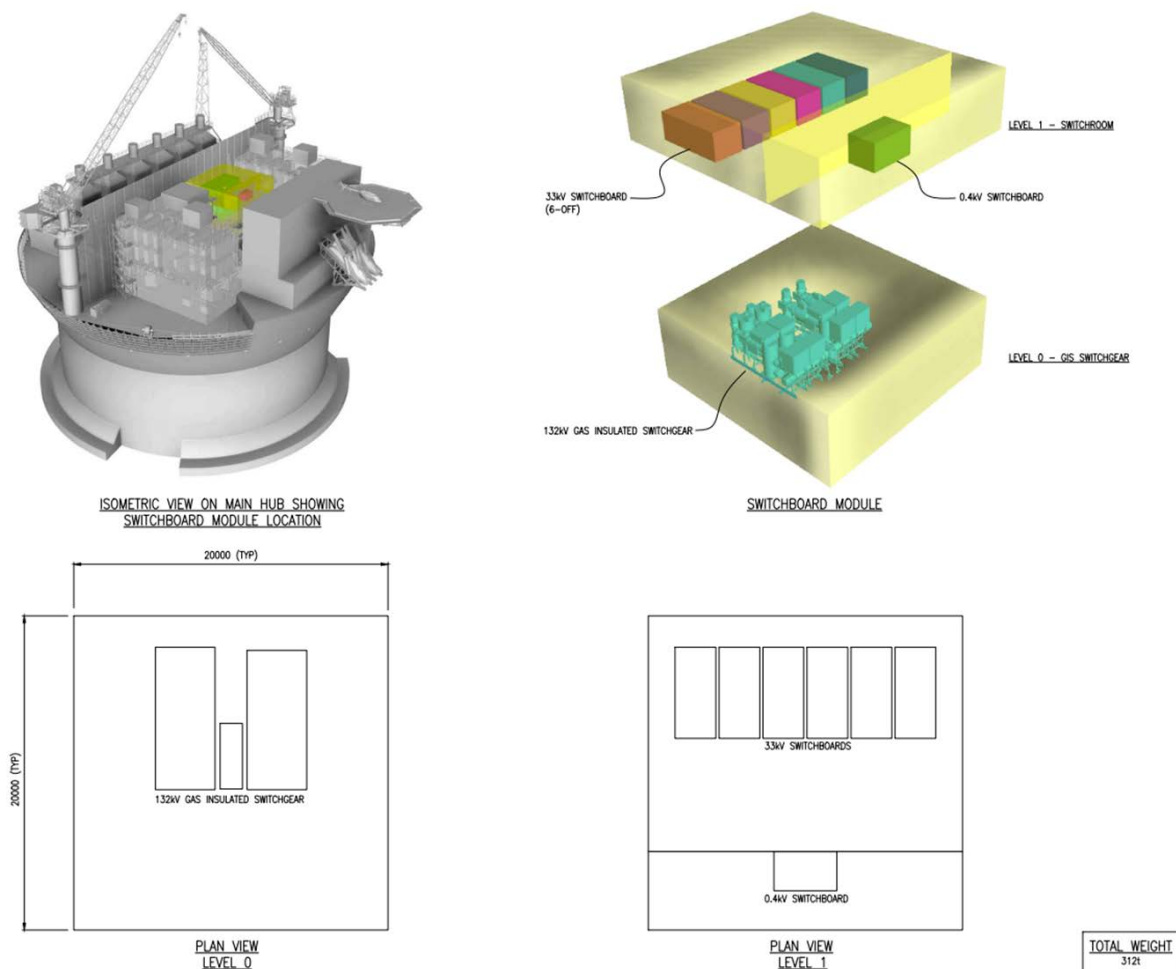


Figure 15-30: Overview of Switchboard module

LV Switchgear

Switchgear at voltages below 1kV shall be metal-enclosed Air Insulated Switchgear supplied in accordance with the IEC 61439 standard. LV switchgear shall typically consist of an incomer and bus tie section utilising large power circuit breakers. The outgoing MCC sections consist of multiple small outgoing feeders employing fused contactors or motor starters. The exact makeup of the LV switchgear will be informed by the number and type of supplies required to feed, for example the turbine auxiliaries.

⁵ <https://www.nationalgrideso.com/document/47036/download>

15.3.9 Additional Areas

15.3.9.1 Cable Racks

Due to the large diameter, and hence weight, of the cables, heavy duty bespoke designed cable trays have been required to transmit cables of the same voltage on the topsides between the different modules as required.

This cable rack will run along the edge of the blast wall between the blast wall and the modules. This is planned to take the majority of the cable runs. The cable rack concept is presented below.

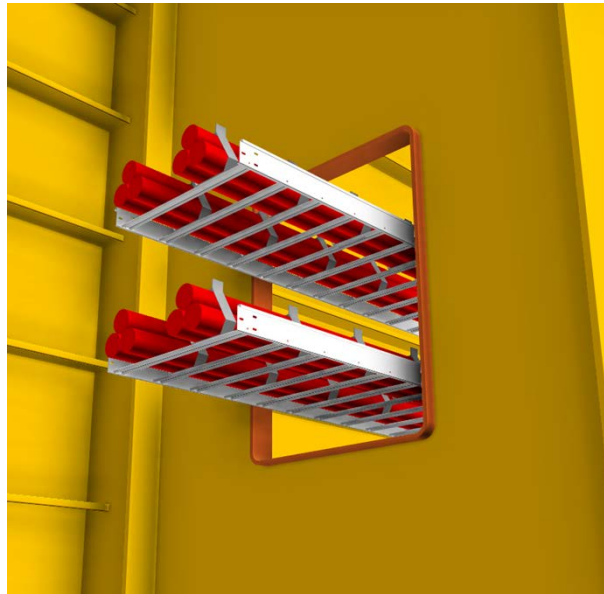


Figure 15-31: Blastwall Cable Penetration

Where practical equipment has been located in the modules and on deck space in close proximity to minimise cable runs and help reduce voltage drop due to cable resistance/reactance.

The transformers and switchgear are all bottom entry cabling and therefore the cables can be routed from this main cable tray beneath the process deck in the space between the main and process decks.

15.3.9.1.1 Cable Segregation

Different voltage cables, such as the import cables and those going to the Sub Hubs will be required to be supported on different trays with minimum offsets interference maintained at all times to prevent electromagnetic interference.

In all instances the design of the cables trays has taken account of the weight of the cables and the motions of the vessel increasing the loading.

15.3.9.2 Pipe Racks

Pipe racks have been provided on the main deck to support piping for the various topsides systems.

Several pipework systems are inherent in the Sevan concept such as ballast water, fire systems, water (potable and technical). These have been routed in hull void spaces.

In all cases the piping has been supported in such a way as to take account of thermal expansion / contraction and any loading that may occur during pressurised operation. This will be confirmed through piping analysis where required in further detailed design stages.

15.3.9.3 Hose reels

Hoses are required for bunkering of fluids to facilitate the ongoing operations of the Main Hub. A double hose reel will be utilised. One hose will be provided for bunkering of diesel (Marine Fuel Oil) and the second as a secondary potable water supply. These are located on the Process Deck level next to the primary laydown area as shown in Figure 15-32.

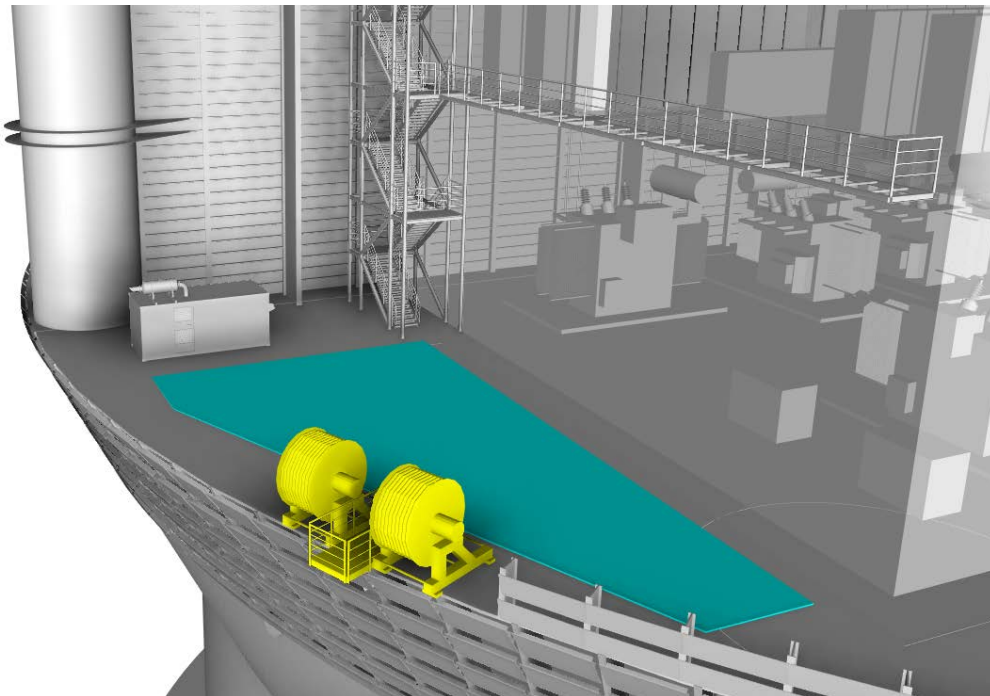


Figure 15-32: Layout location of the hose reel

The basis for these bunkering hoses are the reels located on the Goliat FPSO. This is an electrically driven reel powered from the existing Main Hub supply. Lifting of the hose for connection would be via the crane.

Specification of the hoses for diesel and water have been made largely in line with an existing hose specification for a North Sea FPSO.

15.3.9.3.1 Diesel Hose Specification

The diesel hose selected is a 4" x 60m hose with a design pressure of 15 barg. The weak link coupling for safe breakage of the hose based on elevated tension is valved to ensure no leakage of diesel to the sea occurs. The supply boat fitting is a 4" dry break hose unit in 316 stainless steel to minimise deck spillage on the supply boat.

The diesel hose is a single skinned hose complete with strap on floatation aids. The hose material is carbon steel. A lifting hook is fitted for crane operations for handling of the hose. The reel fitting end of the hose is a 150# carbon steel ASME B16.5 flange.

The hose is rubber lined with cord reinforcement and anti-static configuration.

15.3.9.3.2 Potable Water Hose Specification

The potable water hose selected is a 3" x 60m hose with a design pressure of 15 barg. The weak link coupling for safe breakage of the hose based on elevated tension is un-valved as there is no safety / environmental consequence associated with loss of potable water to sea. The supply boat fitting is a 3" hammer lug union in carbon steel.

The potable water hose is a single skinned hose complete with strap on floatation aids. The hose material is carbon steel. A lifting hook is fitted for crane operations for handling of the hose. The reel fitting end of the hose is a 150# carbon steel ASME B16.5 flange.

15.3.9.4 Helifuel Package

A Helifuel package will be installed on the Main Hub for refuelling allowing the Main Hub to be a more flexible base for transportation to the Sub Hubs, none of which will have any re-fuelling capability.

The helifuel package will consist of 3 skids as follows:

- Portable Aviation Re-fuelling Tanks (complete with laydown skid)
- Dispensing Unit
- Pump Skid

These skids will be located in close proximity to the Helideck with consideration given to the ergonomics and working environment.

Fuel will be supplied via regular Platform supply vessels and offloaded in certified transportable fuel tanks using the platform crane. Depending on the final location of the Heli-fuel package it is likely only one of the platform cranes will be capable of reaching the Helifuel package. This is mitigated by having a central laydown area where equipment can be transferred between cranes.

15.3.9.5 Bridge Link Area

The use of Bridge links has not been considered during this study. It is assumed that personnel will stay on the Main Hub and arrive and leave via helicopter. Therefore a flotel would not be required.

15.3.9.6 Removal of Equipment / Decommissioning of Assets / Future Expansion

No consideration has been made with regards to removing redundant modules if an operating installation is removed from a cluster group e.g. by decommissioning. In the event this happens and it affects the output requirements of the Main Hub the associated equipment would be retained on the main hub and could be re-utilised either for spares or if additional new assets could replace those that have been decommissioned.

15.3.10 Topsides Weight and Centre of Gravity Report

A topsides weight and centre of gravity report has been produced to aid with the calculation of vessel motions and track the amount of weight added to the Hull as part of this design. This was provided to Sevan for their use in the Motion and mooring study.

Equipment weights that form each of the modules (Switchgear module, Conversion Module, Power Generation Module and Transformer Housing) and their positions have been used to generate module weights and centre of gravity locations.

Cable runs were modelled and mass properties assigned to the various cables to produce overall mass and COG locations for the electrical cabling.

Process equipment was calculated in the same way with the Heat exchanger sets and Flare Knock-out drum used to generate the overall mass and COG location of process equipment.

Main Structural components including the Blastwall and main and secondary crane formed the structural weight calculation. Further large structures including the Flare tower, Accommodation module with Helideck, Lifeboats and supporting structure and the Deck structures for the main and process decks are included in the Sevan design calculations.

Where exact data for the equipment used could not be sourced this has been estimated. Most notable for this was on the topsides supporting structural elements where the module weight was factored to calculate the structural weight required. This would be refined as the design was progressed further.

The individual data were combined to generate the overall mass estimate and location of the COG. Sevan advised the Datums to be used. The centre of the vessel to be North = 0, East = 0 and the baseline of the hull = 0. The combined data provided the below Topsides C.O.G /68/.

Total Topsides Weight = 28000t		
North (m)	East (m)	Vertical (m)
-7354	-1367	55395

Table 15-9 CoG Information

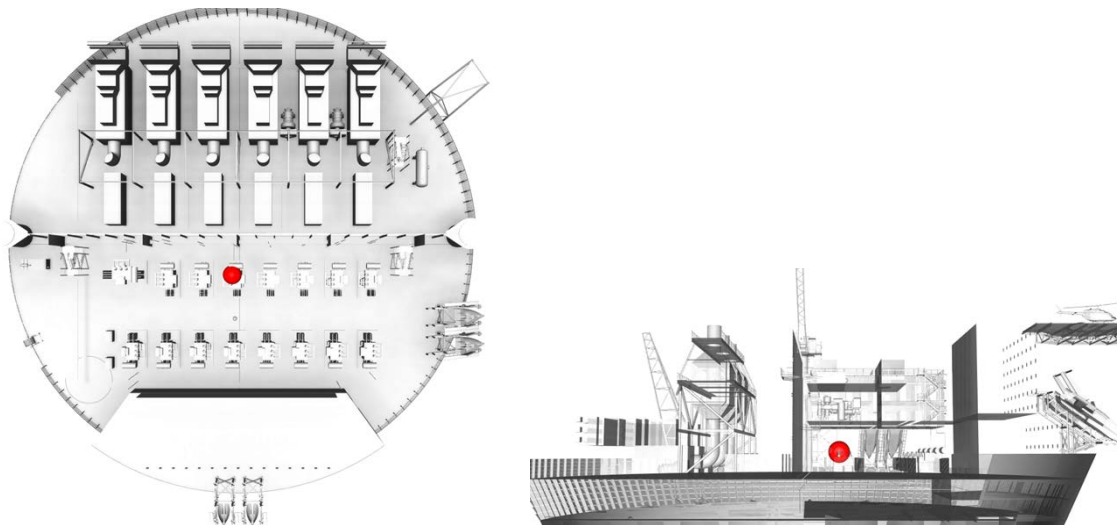


Figure 15-33 - Plan & Elevation showing C.O.G.

15.3.11 Design Safety Case

Whilst consultation with the regulator will need to be undertaken to confirm application, the design of the main hub design proposal is based on the premise that the operation will come under the Offshore Installations (Offshore Safety Directive) (Safety Case etc) Regulations 2015 and require the operator to reduce the risks from major accident hazards to the health and safety of the workforce employed on the hub, increase the protection of the marine environment and coast against pollution and ensure incident response provisions are available.

Dry hydrocarbon gas will be imported via pipeline for fuel to supply the gas turbines which will be used to supply power to production installations via Sub Hubs. The main hubs and sub hubs are associated with the secure and reliable supply of power to production assets and loss of ability for the main hub to supply power will have a detrimental impact on the connected operating installations.

Hazard Management Philosophy and Risk Management are key areas to be defined to establish the main hub operators overall aims and arrangements for managing and controlling MAHs and how those aims are to be achieved.

15.3.12 Relocation/Redeployment/Decommissioning Options

The Main Hub has to be taken off-station when it reaches end of its service life. A Comparative Assessment will be carried out in line with the recommendations of the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) Guidance Notes in the Department for Business, Energy and Industrial Strategy (BEIS) to study options to Relocate/Redeploy/decommissioning the Main Hub.

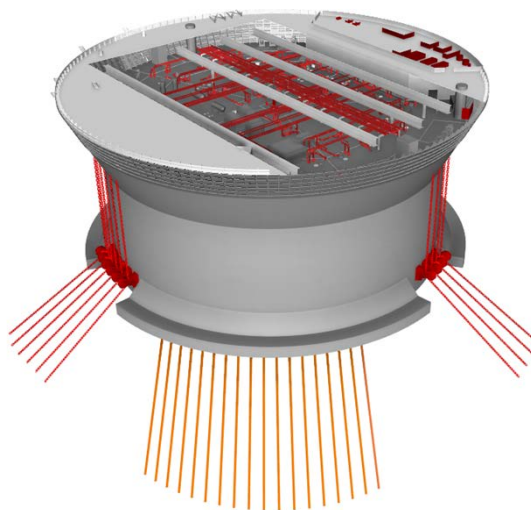


Figure 15-34 Main Hub Hull

The Main Hub will be utilised for the initial decommissioning activities, preparation for sail away including hazardous waste assessment and removal options which could include:

- Planning for removal from location prior to moving off station.
- Assessment of Subsea infrastructure, riser/I-tubes and mooring chains, options including cleaning, removal, retrenching
- Identification of additional cleaning required at quayside prior to redeployment/disposal or cross frontier shipment
- Inventory estimates and waste management planning and associated hierarchy

Activities associated with the subsequent decommissioning stages of the mooring systems, risers and dynamic umbilical's will require the services provided by other specialist vessels. The Subsea cables/I-tubes and risers may be wet stored and managed through a risk-based inspection and maintenance programme to ensure future safe recovery. Main Hub mooring lines, risers and umbilical's to be

disconnected from the Main Hub and laid down on the seabed in order to allow the Main Hub to be towed from the field. Mooring lines and I-Tubes will subsequently be recovered from the seabed.

Following cleaning of the vessel, disconnection of risers, I-Tubes and mooring lines, vessel will be towed from field to a nominated redelivery port. The vessel will then be redelivered to its owner who will re-assume full control of and responsibility for the Main Hub (including any ship recycling which will be carried out at an approved shipyard in compliance with all relevant UK legislation, including retained EU ship recycling regulations).

With respect to recovered subsea infrastructure, any infrastructure which cannot be reused will be provided to an appropriately licensed waste management company and yard. This location will be identified through a selection process that will ensure that the chosen facility demonstrates a proven record of waste stream management throughout the deconstruction process, the ability to deliver appropriate reuse / recycling options, and ensure the aims of the waste hierarchy are achieved. The waste management provider's / disposal yards shall follow the waste management hierarchy in the handling of materials from the Main Hub decommissioning project to maximize the amount of material from the project which is reused or recovered/recycled. The selected removal contractor(s) will, monitor and review the disposal route of all materials and waste to the point of final reuse, recycling or disposal. Early engagement with the relevant waste regulatory authorities will ensure that any issues with Trans Frontier Shipment of Waste (TFSW) are addressed.

As the main hub is a floating unit it can be redeployed to different areas, assuming satisfactory results from a motion and mooring study for the new location. The Main hub is not powered so would require to be towed to the new location after disconnection and termination of import gas pipeline and subsea cables.

15.3.12.1 Environmental Appraisal management

During disconnection of risers and dynamic umbilical's any discharges to sea associated with the decommissioning of the Main Hub and riser/umbilical flushing and disconnections will be subject to the relevant permitting requirements.

The selected removal contractor(s) will, monitor and review the disposal route of all materials and waste to the point of final reuse, recycling or disposal. Early engagement with the relevant waste regulatory authorities will ensure that any issues with Trans Frontier Shipment of Waste (TFSW) are addressed. Work procedures will be in place to minimise the duration of activities and therefore optimising vessel use.

The lifting activity during cut and laying down of risers, J-Tubes and vessel mooring lines will be undertaken while vessel is on dynamic positioning, thus will be undertaken through controlled, precise manoeuvring.

Post-Decommissioning Debris clearance - A full-scale post decommissioning environmental seabed survey of the Field will be carried out following full decommissioning of the Main Hub to identify debris and it's clearance

The Project is expected to promote the 'Circular Economy', driving waste management up the waste hierarchy and adopt the Duty of Care framework for managing all material from decommissioning.

15.3.13 Expected Decommissioning/ABEX Strategy

The drivers for the disposal of Main hub are largely economic and commercial but all options must be safe and environmentally acceptable whilst complying with local, regional and/or international regulations.

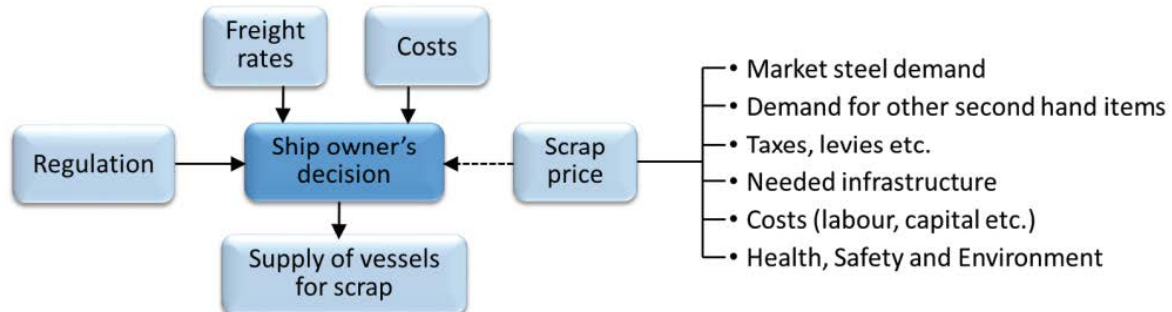


Figure 15-35 Decommissioning Decision Drivers

Options for Decommissioning can be as follows :-

1. Re-sale
2. Repurpose/Re-deploy to a different location
3. Dismantle
4. Dispose

15.3.13.1 Resale / Reuse / Repurpose

The primary intent for the Main Hub is for it to be relocated for further use after the first deployment to decarbonise the North Sea Oil and Gas Industry.

Several options are envisaged to exist for reuse:

- Redeployment in the same function as currently utilised in the UK or EU to facilitate further electrification.
- Redeployment in the UK or EU with the associated floating wind arrays to tie into the grid (if no shore connection is utilised)
- Potential international redeployment, however this will potentially be an issue based on standards regime utilised.

Should the Main Hub be sold to another operator for either re-use or re-purposing then transfer of custody will be deemed at the point of sale and any further modification upgrades will be completed by the new owner. The 'option' will depend on market conditions and Main Hub integrity at the time. The Main Hub will be cleaned prior to departing the field however further cleaning and conditioning may be required by the new owner as a condition of sale. Reuse would require the Main Hub to be used solely for oil and gas development purposes. Repurposing could see the vessel converted to a freight / cargo carrier, flotel or floating platform for other commercial uses

Dismantling

Dry docks around the world can accommodate vessels the size of the Main Hub. However their core purpose and revenue stream is for refurbishment whereby multi trades can be employed to refit and refurbish vessels. Therefore decommissioning which is essentially dismantlement and waste disposal may not be seen as an attractive proposition, However with the correct contracting strategy it may be of interest to sites where work is in short supply. To minimise the time spent in the dry dock, as much preparation (cleaning) and piece small removal would be completed on the quayside where berthing costs are lower. The final hull dismantlement would then be completed in the dry dock, cutting the hull

into size and weights of the dock side cranes for removal to an area where the sections can be further broken down for road/rail haulage to recycling centres.

Ship dismantling, also commonly referred to as ship "recycling", is an inherently sustainable activity, the benefits of which are felt at the global level. As the term ship "recycling" implies, value is derived from the materials and equipment comprising end-of-life ships: the scrap steel is melted down and is commonly used in the construction industries of ship recycling countries, and equipment (engines, mechanical parts or furniture) is refurbished and re-used in other industries.

Criteria for identifying ships likely to go for Dismantling

- **Legal Obligations** – Phasing-out under the International Convention for the Prevention of Pollution from Ships convention
- **Age & Type** - As the vessels age greatly influences it's probability of being scrapped because the earning potential declines and running cost increases with age
- **Flag of the vessel** – as it indicates the country's Port State Control performance of the fleets based on detention statistics and can determine the overall safety/ quality of a vessel.
- **Economic Factors** – Regarded as a very important driver for the ship owner's decision on when to send a ship for dismantling
- **Classification society** – Ranking of the classification society could indicate the ship is being surveyed by a high performing organisation or by an organisation with a history of low performance

15.3.13.2 Disposal - Green Ship Recycling

When recycling and re-using goods and products has become an important requirement, the shipbreaking method has also witnessed the recycling of the parts of the vessel. Moreover, with the rise in awareness towards the maritime environment, there have been several changes in the process, which have given rise to a new term – green ship recycling. International Maritime Organisation's Hong Kong International Convention for the Safe and Environmentally Sound Recycling of Ships, 2009 also strictly directed that vessels that are being recycled after their service lives should not pose any unnecessary risks to human health, safety and to the environment.

As a viable alternative to other methods of shipbreaking that makes negative effects on the environment, green ship recycling has been introduced across the world. As a way of responsible ship recycling, this method reduces the amount of waste and also keeps the waste materials from shipbreaking out of the beaches, reducing its impact on the environment. There are several reasons which have made the concept of green ship recycling popular and meaningful. But, the most relevant benefits among them are:

- Isolate those parts of the ship which are harmful and dangerous to both marine and human lives
- Conserve marine ecosystem by proper discarding of ship breaking waste
- Reusing those parts of the ship that are important and can be re-used successfully while making new ships, thus saving resources
- Help the ship owner benefit from the process by optimum utility of the ship's parts

The valuable components of a ship that are reused include steel, aluminium, silver and brass, among others. Since a major part of a ship's weight is in steel, the steel scrap from the vessel is being converted into bars and rods for several other uses. However, in addition to the metal that can be recycled, there are a number of the toxic components inside a vessel. These harmful substances include lead, asbestos, mercury and oil sludge etc. The inefficient shipbreaking methods, especially those carried out on beaches than the dry-dock ship recycling facilities, allow these toxic and hazardous waste to be disposed of unsafely. However, the green ship recycling, which carries great responsibility of saving the environment, offers a better recycling standard.

On the other hand, this environmentally sound and safe recycling of a ship also offers the owner optimum utility of the ship's parts. With the methodical dismantling of the vessel, the components that can be reused are saved with better care. The steel, along with other metal components, turns into rods for use in the construction industry and also corner castings and hinges. The generators and batteries

which were part of the scrapped vessel will be reused for several other purposes. The appropriate recycling of the hydrocarbons on board transformed into oil products, while light fittings also reused on another vessel or even on land.

Prior to leaving station the vessel must:

1. Be cleaned of hydrocarbons and production chemicals
2. Have full sea worthiness warranty assurance
3. Have a full inventory of materials including tonnage and location of each material type
4. Depending on the final disposal country it may be beneficial to re-flag the vessel

15.3.13.3 Comparative Assessment

The Main Hub disposal option will be arrived at by a 'Comparative Assessment' of the options available to Decommission the vessel. The UK comparative assessment process is a useful method to understand contributing factors to making an informed decision for the disposal of the Main hub. Through a Comparative Assessment process the Options for disposal are evaluated for the above criteria and the most suitable one is arrived at. The key criteria that are assessed are:

1. Safety
2. Environment
3. Technical
4. Societal
5. Economic

It is considered that in 25yrs when the main hub comes to be decommissioned, the criteria may be different.

15.4 Potential Hub Configurations

At present for the purposes of this study, both the CNS and SNS Main Hubs are considered to be identical. There are optimisations which can be made, specifically for the SNS region, to reduce the capital costs of the Main Hub

- 450 MW configuration is the maximum power output configuration for the Main Hub Sevan 1000 is considered to be the correct size marine solution.
- SNS output is 250 MW, smaller marine option is possible, same configuration of modules, power generation system would decrease to 4 of LM6000 units, potentially 3 off units is 210 MW is sufficient for powering the SNS.

15.5 Further Areas of Study

The following is brief description of the further areas of study that should be taken further and not already covered in this report.

A further development of the concept would need to include design of the supporting structures for the topside modules including primary and secondary steelwork. This would be expected to be carried out taking account of the motion data provided by Sevan and the loads identified in this document.

The design of a Jack-up platform for use as a Main Hub should be carried out to the same level of detail as with the Sevan FPSO concept if areas considered for locating the Main Hub require this due to motions or water depth.

Further consideration of alternative power generation using Molten Salt Nuclear Reactors. This would eliminate the need to have purpose deployed offshore wind farms and the associated subsea cabling to import low carbon electricity to the Main Hub. Additionally, the requirement for backup generation

through the CCGT's would no longer be required along with some of the electronics to manage the import of electricity. This has the potential to offer significant cost savings to the concepts.

The use of a SWACH hullform in place of the conventional Sevan 1000 hullform would offer significantly reduced cost of manufacture, lower amount of water ballast required and better utilisation of available space. Additionally the central moonpool this hullform offers provides greater flexibility in the subsea routing of cables offering another benefit of this design change. This design change has been estimate to result in a 30% reduction in the cost to build the Sevan Hull but exact figures cannot be confirmed until this design is developed further.

15.6 Opportunities / Risks / Assumptions

15.6.1 Use of SWACH design

For the initial motion and mooring study carried out by Sevan a conventional FPSO style hull has been used but an alternative Small Waterplane Area Circular Hull Design (SWACH) has been considered for concept generation as the lack of a moonpool and requirement to use a significant amount of water ballast from the Sevan 1000 presented problems. This use of a SWACH would generate significant cost savings.

Cost savings would be due to the reduction in water ballast requirement, steel weight for manufacture and costs of manufacture.

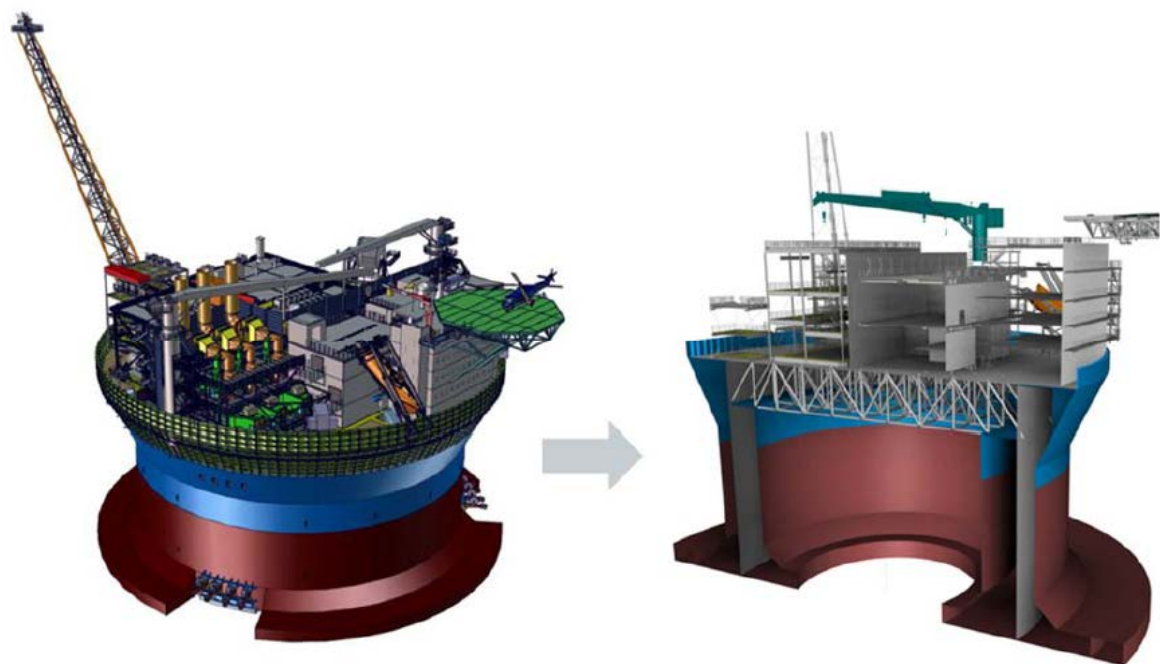


Figure 15-36: Example of the SWACH hull concept

This alternative hull form is suitable due to the lack of production fluid in the cargo holds, which reduces the operational weight and required ballast added to get to the design draft of 22m.

Ballast tanks are provided within the hull to allow the design draft to be obtained. A significant amount of ballast water is needed to obtain the required draft using the conventional hull form. This has meant that the ballast tank size has had to be increased from the conventional hull design with the remaining cargo tanks being able to be utilised for marine fuel storage and the remaining areas as sealed void spaces.

The Hull for the SWACH design contains a central moonpool that would contain the import gas pipeline and subsea cables, allowing for greater flexibility in cable routing subsea. As with the conventional hullform the cables must be routed through I tubes located through the centre of the hull and passing through the tanks and void spaces.

Machinery spaces for the marine systems are contained within the hull. Examples of this include:

- Marine power systems
- Firewater system
- Sewage system
- Ballast water system
- Fresh and technical water systems
- Utility cooling system.

At present, there is sufficient of available space for this. For the SWACH hullform available space will be reserved for these systems while sizing the hull.

16. Sub Hub Design Report

16.1 Objective

The report will provide an overview of the design and specification of the infrastructure required to support the electrification of the North Sea, and to define the requirements of the Sub Hubs.

The report details how the modular design can be scaled up or down to suit regional infrastructure clusters and outlines:

- The methodology of the selected marine solution
- The considerations made for the design of the Sub Hubs
- The specifications which they have been designed to fulfil,
- Potential limitations of the systems
- Description of how the equipment is configured on the marine solution

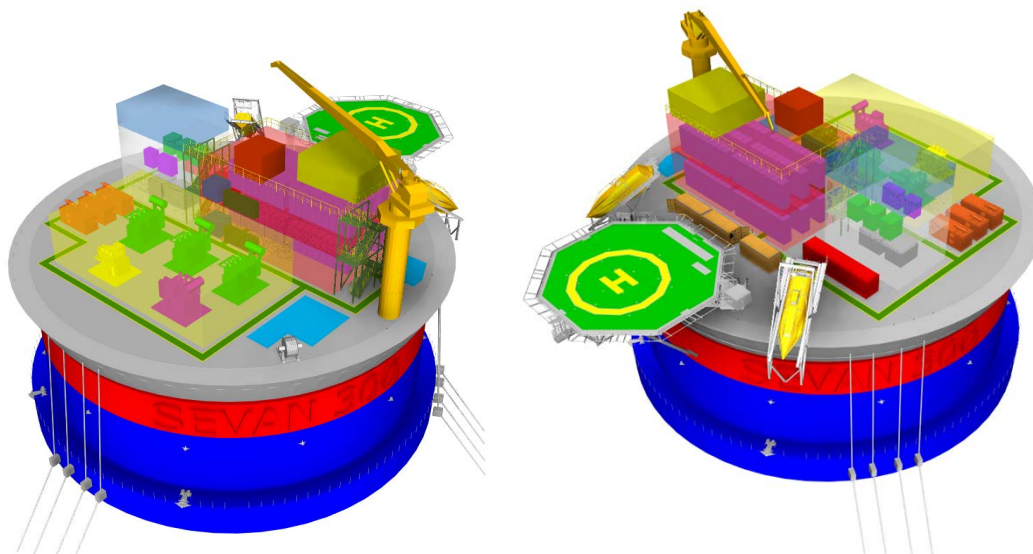


Figure 16-1: Overview of the concept developed

16.2 Sub Hub Solution

16.2.1 Marine Solutions

The requirement is for Sub Hub to remain on station for the duration of field life, without dry-docking for inspection, maintenance or repair. This is because of potential difficulties in cable and mooring disconnection and reconnection in the harsh environment. As the purpose of this system is essential power service for all platforms connected to it the economic penalty of lost or deferred production is substantial as up to five platforms production could be lost from an extended outage.

The project performed an analysis on different marine solutions to determine the preferred approach. The analysis conducted was on the following solutions:

- Fixed Jacket
- Ship Shaped FPSO
- Sevan Circular Shaped FPSO
- Jack-up Platform
- Semi-Submersible Platform
- Subsea Equipment

16.2.1.1 Marine Options Analysis

Analysis carried out in the Main Hub Section is valid for the Sub Hub where Sevan based marine designs and Jack-ups scored highest on the criteria being evaluated.

16.2.2 Recommended solution

16.2.2.1 Sevan Description

The recommended solution is to make use of a Sevan circular hull vessel. The design utilised for the Hummingbird FPSO is the basis for study. The justification of the use of this design is:

- Geo-Stationary Hull Double bottom / sides
- Scalable Concept
- Excellent Motions
- Conventional Spread Mooring
- Insignificant Bending Stress for risers
- Unlimited number of riser connections
- Track record in power cable integration as power from shore already integrated into Goliat design.

Instead of turret, in a cylindrical design vessel, mooring is used in fixed orientation, this eliminates problem with rapid change of wind direction and vessel heading corrections. This also makes this design highly tolerant to storms and more stable than ship-shaped vessels. Due to the hull form profile vs a semi-sub this give superior harsh environment performance.

For this conventional hull form, a marine gas riser and all incoming and outgoing electrical connections have been run through the hull through the ballast tanks in I tubes and passing through watertight glands on the main deck where they are terminated in the TUTU units. The same arrangement will be utilised for incoming and outgoing cables for this design.

A modification is required to the ballast is required due to not using the cargo tanks for liquid storage. A high level of ballast is required to be run to reach the required Ballast Draft is a feature of this design which can be investigated in further phases to reduce costs. An opportunity to address this is contained in Section 16.5.

The number of cable interfaces can be increased through outboard cable routing to allow further expansion even if all I-tube capacity has been utilised which offers incredible flexibility.

16.2.2.2 Jack-up Description

For shallower water depths the use of a Sevan unit is not possible. Typically, this occurs when the water depths less are less than 70m as the length of mooring lines required becomes impractical and the stress on the risers becomes too great.

For these locations it is proposed that the same equipment would be installed on a jack-up unit instead of the Sevan Hull. This has been highlighted as an issue for the proposed Sub Hub locations in the Southern North Sea where the water depth is between 15-45m.

The use of a converted Jack-up unit will provide better loading for the deck mounted equipment that forms the basis of the study, however the space considerations will be different due to the free deck space that must be maintained for the legs.

Jack-up rigs are better suited to these lower water depths and allow an air gap to be maintained over the water. This will aid in keeping green water from impacting the transformers and would reduce the need for a weather resistant enclosure on the jack-up solution.

16.2.3 Marine design

16.2.3.1 Expected Operational Life

The design life has been set at 25 years. Some assets may be able to exceed this and be redeployed or reused elsewhere as required.

16.2.3.2 Hull

For this study, a Sevan 300 unit was considered the primary hull form.



Figure 16-2 Western Isles FPSO Sevan 300 Unit

The vessel has main hull diameter of 60m flaring out to 72.5m at the process deck. The bilge box sits at the base of the hull with a diameter of 75m.

The main deck is 13.25m above the waterline with the process deck a further 6.5m above this. A bulwark is included to offer some weather protection to the main deck.

The Sevan 300-design has been installed at 3 locations in the central North Sea operating as FPSO's and have proven they are suitable for the harsh environmental conditions occurring in this area.

Item	Value	Units
Diameter main hull (at wl)	60	m
Diameter main deck	66	m
Diameter process deck	72.5	m
Diameter bilge box	75	m
Height of bilge box	2	m
Elevation Main Deck	27	m
Elevation Process Deck	33.5	m
Ballast Draft	13.75	m
Loaded Draft	13.75	m
Scantling Draft	15	m
Maximum Displacement	42,000	t
POB	0	persons

Table 16-1 Key Data for Sevan 300 Unit

16.2.3.3 Main Deck

The main deck has a diameter of 66m and is located at EL. 32,000. It forms the weatherproof top surface of the hull and allows a space for the layout of ancillary equipment including piping and cabling.

The Main Deck area is primarily utilised for routing of utility connections, cabling, drains and structural supports for the Process Deck and the Bulwark. All transformers have bottom entry cabling; incoming cables will be run via the available space between the main deck and process deck. The design of the Main Deck includes a radial primary support structure which is used to interface with the pillar/stooling arrangement to support the Process Deck to transfer the loads on to the strong points of the Hull. The arrangement is detailed in section 3.1.6.1.1 of the report.

16.2.3.4 Process Deck

The process deck has a diameter of 72.5m and located at EL 36,500.

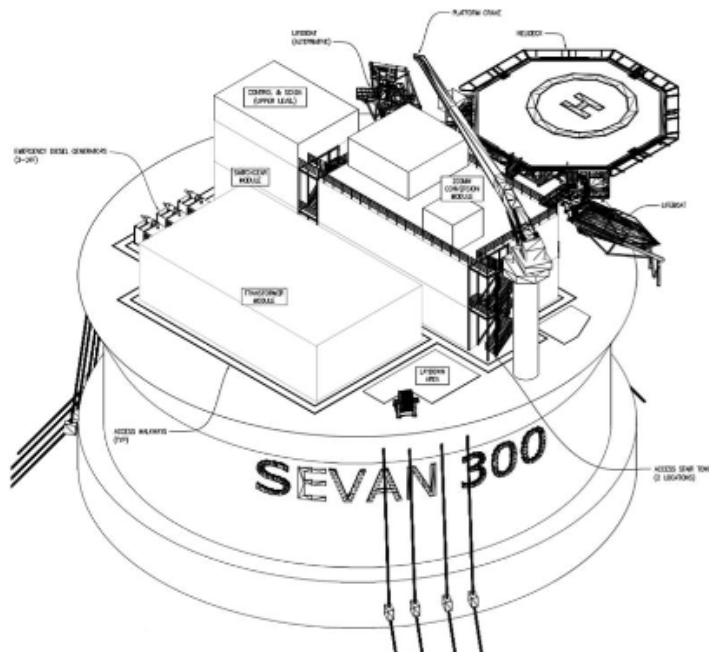


Figure 16-3 Main Hub Overview

A components that are supported on the Process Deck are :-

- 200MW Conversion Module.
- Switchroom Module – incorporating HV & MV switchgear.
- ICSS Module / SCADA
- Switchroom Module – incorporating HV, MV & LV switchgear
- Transformer Housing
- ICSS Module / SCADA
- Temporary refuge
- Lifeboat Davits
- Crane pedestal
- Bunkering Hose reel

The Process Deck level is 4.5m above the Main Deck Level.

The topsides takes the form of a series of modules laid out to provide the functions required. These have been standardised where possible to allow common designs and philosophy to be used between the main and sub hubs. The modules are described in greater detail in Section 16.3 of the report.

16.2.3.5 Mooring

The Sevan Circular hullform used for the Sub hub is moored using overboard chains located at three points around the hull. One set of chains are directed towards the prevailing direction of the most severe wave conditions. The exact number and size of chains have been calculated by Sevan during their mooring and motion study.

The results of this study were that mooring design for the Sub Hub was optimised with the use of 12 chains in three groups of 4. The diameter of the chains used in this mooring design was 140mm.

The chains are kept tensioned using fairlead and winches with a chain-stopper included and this is mounted to the deck of the Sevan unit. A further improvement could be the use of in line tensioners (ILT) which would offer a weight saving.

Polyester mooring line is used in between the top and bottom chain sections.

Sufficient safety factors were always maintained in the mooring design even under extreme loading.

Sub Hub Mooring Design :-

Item	Value	Units
No of mooring lines	12	item
Bottom chain length	150	m
Bottom chain diameter	140	mm
Polyester line length	900	m
Polyester line diameter	240	mm
Top chain length	50	m
Top chain diameter	140	mm

Table 16-2 Sub Hub Mooring Design

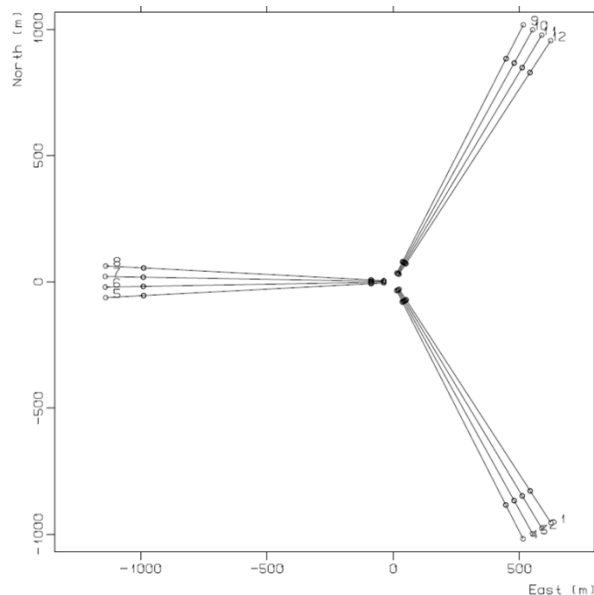


Figure 16-3 Sub Hub Mooring Configuration

Mooring anchors – Since the Sub Hub is assumed to be in the field for 25 years the mooring on the seabed will be provided by way of suction piles for all lines connected to bottom chains. An assumption has made that the soil conditions on the sea bed will be suitable for this method of mooring securement

is suitable. Size of suction anchors depends on seabed conditions. Available geotechnical data for the Shelly, Chestnut and Huntington show suitable soil conditions for use of suction anchors.

Prevailing Wind Direction

Metocean data covering the monthly, annual, 10, 50 and 100 year return periods have been used for this wind and wave data as data for the exact location was not available to Sevan they have made use of data for the nearby Shelley field.

This was attached within the Sevan report which is included in Appendix 28.20.

16.2.3.6 Marine Motion Evaluation

For the Sub hub design the marine motion evaluation was carried out for the relevant hullform by Sevan. This was using wave data relevant for the areas proposed for the sub hub locations. Sevan utilised NAPA to conduct the motion analysis.

The results of this study by Sevan gave a maximum heave of 11.76m and a max roll angle of 17.98 degrees.

The motion data provided has been used to provide the input to the design of structural components within the design.

The Sevan study showed that an acceptable level of reserve buoyancy and stability remained at all times. Sevan also highlighted that due to the lack of use of the cargo tanks a large amount of water ballast was required to utilise the conventional hullform of the Sevan 300. It was proposed that for future development the use of a Small Waterplane Area Circular Hull Design (SWACH) be investigated as a more efficient use of the hull and this is expected to offer a significant cost saving over the data presented to date.

For full details of the Sevan study see Appendix 28.20.

16.2.3.6.1 Motion effect on Risers and Flexibles

For the Sub hub design the marine motion evaluation was carried out for the relevant hullform by Sevan. This was using wave data relevant for the areas proposed for the main hub locations. Sevan utilised NAPA to conduct the motion analysis.

The results of this study gave a maximum heave of 11.76m and a max roll angle of 17.98 degrees.

The motion data provided has been used to provide the input to the design of structure and equipment within the design.

The Sevan study showed that an acceptable level of reserve buoyancy and stability remained at all times.

Loading on the fuel gas import flexible line was also determined to be within acceptable limits.

It also highlighted that due to the lack of use of the cargo tanks a large amount of water ballast was required to utilise the conventional hullform of the Sevan 1000.

For full details of the Sevan study see Appendix 28.20.

16.2.3.6.2 Motion effect on Operations

Due to the motion performance of the Sevan Hull the operability time for the helideck based on sea states is considerably higher than conventional ship shaped FPSOs. This motion performance is also applicable to crane operations ensuring that supply boats can be serviced in more severe sea states.

16.2.3.7 Crane Selection / Material Handling

A single pedestal crane is required for the Sub Hub and this a general-purpose crane and has been sized at 40 Tonnes.

This crane would be used in the event that routine maintenance is carried out and replacement parts are required. In the event that larger items such as the transformers are required to be swapped out, either through failure or changes in supply requirements, then a heavy lift vessel would be required.

Access walkways have been provided around the perimeter of each module to allow the transfer of materials & equipment by skidding additionally, davit cranes can be positioned where material handling is necessary but outwith crane reach.

16.2.3.8 Helideck

The helideck has been designed in accordance with CAP437 Standards for offshore helicopter landing areas and CAA Paper 2008/03: "Helideck Design Considerations – Environmental Effects". The design considers the location of the installation systems and equipment relative to the helideck ensuring that environmental effects that may be present do not impact on the safety of helicopter operations from the deck.

The helideck on the sub hub will be approx. 22m in diameter which is consistent with the design of the Western Isles FPSO. The helideck shall be suitable for a Eurocopter (Aerospatiale) AS332-Super Puma (19 pass +2 crew) or a Sikorsky S-92 (19-24 pass + 2 crew) helicopter as a minimum.

The current arrangement is design to negate any turbulence or vertical wind velocity. The positioning of the helideck takes account of the wind environment around the Sub Hub. The height of the helideck and the air gap between it and the structure will ensure as clean a flow of air as possible, mitigating structure-induced turbulence.

Whilst the design of the installation and location of the helideck minimises environmental effects, it will be necessary to complete Computational Fluid Dynamics (CFD) modelling will be required in detailed design to identify if operational restrictions to the helideck are required in specific wind direction.

Helideck markings and side identification panels shall be installed visible from directions of approach and in all light conditions. As per convention, the helideck shall be dark green and the perimeter of the landing area identified with a white line. Lighting shall be provided to ensure the markings and helideck landing area are visible for day and night operations.

Provision of equipment for the response to a helicopter accident occurring at the helideck shall be provided. A helicopter accident resulting in fuel spillage and fire / smoke has the capacity to injure personnel and impair passenger escape routes. The equipment shall be designed to respond to a fire event quickly to allow personnel to escape from the area. To provide the quickest response time a fixed foam application system (FFAS) will be installed. A deck integrated fire-fighting system (DIFFS) is included subject to detailed review.

As the Sub Hub is a NUI there is no storage of Helifuel as it is not intended that the helicopters will stay on the Sub Hub but only arrive for drop-off / pick up and then depart. It is intended that they refuel at the main hub locations when this is required.

16.2.3.9 Escape and Evacuation

16.2.3.9.1 Escape

Escape, evacuation and rescue facilities are included in the sub hub design to ensure personnel are able to escape from the immediate effects of a hazardous scenario, muster in a temporary refuge and evacuate from the vessel.

The Sub Hub has been designed with a minimum of two escape routes from all areas of the asset transiting to the temporary refuge (TR). The primary escape route is via Process deck.

Each module has been designed with diverse escape routes to ensure that a minimum of one route to the TR remains uncompromised in an emergency event. This allows personnel to muster at the TR from any part of the vessel.

All escape routes are designed in accordance with the Prevention of Fire and Explosion and Emergency Response (PFEER) regulations.

The TR has been provided shown as a 20ft converted container at the rear of the Conversion Module.

16.2.3.9.2 Evacuation

The main evacuation methods from the Main Hub will be via helicopter. Secondary evacuation method is provided via TEMPSC. Evacuation routes will be available from the muster area within the TR to the embarkation areas for the TEMPSC and helideck. Separate TEMPSC platforms are located on the south and east edges of the platform to provide diversity and minimise likelihood of both launch directions being compromised.

16.2.3.10 Emergency Power Generation

Emergency Power shall be provided in compliance with DNV-OS-D201 Offshore Standards for Electrical Installations.

To meet this requirement a self-contained source of electrical power shall be provided and shall be located above the worst damage waterline and be readily accessible.

In the case of the Sub Hub it is proposed that the source of emergency power be a self-contained diesel generator (or multiple generators) and dedicated switchboard capable of supporting all identified emergency power supplies.

16.2.3.11 PFP

PFP will be provided in accordance with DNV standards with the aim to protect against the effects of fire and the damage caused by fire. The purpose is to protect personnel and safety critical equipment against hydrocarbon (diesel) pool fires or electrical equipment fires.

The PFP shall be rated to minimise fire escalation, prevent structural collapse and enable Emergency Response (ER) activity to function as designed.

Formal safety studies and fire and explosion modelling shall be undertaken to develop the Fire and Blast Philosophy and Basis of Design for fire protection including optimisation of PFP installation. However it is anticipated that the main structures and bulkheads requiring PFP shall include.

- A-60 bulkhead for fire pump room perimeter walls.
- A-60 bulkhead for crane pedestals
- A-60 TR
- A-60 emergency switch room
- H-60 support structures for modules on the process deck.

Segregation of internal areas will vary depending on the fire hazards and required survival times.

16.2.3.12 HVAC

Air ventilation systems will be installed on specific modules control the working environment for personnel and equipment within the modules. The systems shall prevent ingress of hazardous gases and fumes, prevent build-up of hazardous gases/fumes, maintain essential ventilation to equipment, rooms and areas required to operate / be available during an emergency event and prevent excessive temperatures in critical areas.

The TR for the Sub Hub is a containerised unit located on the Main Deck. There is an alternative area in the Hull which can also be utilised.

The HVAC for the TR shall provide isolation in the case of smoke detection thereby preventing ingress into the TR and compromising support to life. The TR shall maintain a positively pressure over atmospheric.

HVAC ducting has been shown between the modules to represent where these services will need to run. Supply air is taken from non-hazardous areas and are equipped with fire and gas detection, and dampers.

It is anticipated two segregated HVAC systems will be required for the Sub Hub. The first will be for the E-House and the second for the TR.

Detail design of the HVAC systems has not been conducted but in addition to setting temperature, humidity and noise levels and the number of air changes per hour for each room or space, the HVAC design will need to address major topics such as:

- Provision of smoke detection
- Prevention of smoke ingress into muster areas
- Smoke clearance, especially in accommodation and control areas and in escape routes
- Interaction with the sub hubs main fire system
- Ventilation of the Temporary Refuge and main control areas in emergencies and shutdown of non-essential users
- Provision of minimum life support in upset conditions
- Fire protection and rating of dampers and ductwork
- Controls, control stations and control system configuration (avoiding undue complexity)
- Position of inlets and exhausts relative to hazardous areas
- Testing of fire and gas and shutdown dampers
- Sparing of fans
- Pressurisation of spaces and airlocks

16.2.3.13 Greenwater

Green water i.e. unbroken wave crests inundating the deck of the Sub Hub, is a major consideration because of the electrical equipment mounted on deck.

This equipment is mounted on the raised process deck (located above main deck) and this minimises the effect of green water.

However damage has been sustained to topsides equipment such as cable trays, walkways and stairs, and containers have been lost from the production deck. Items which are at most risk are those under the production deck e.g. drains vessels, and these must be designed for green water loading.

The hull design defines a sufficiently high freeboard, main deck is 13.25m above waterline at ballast draft, and the addition of a bulwark above the main deck. The process deck is 17.75m above the waterline to further reduce greenwater on equipment located here.

Based on the Shelley metocean data the 200 year maximum wave height is considered to be 25.4m, with the significant wave height in 200 year conditions as 13.7m.

16.2.3.14 Ballast System Design

The ballast system has been provided as part of the Sevan Hull solution.

The current concept Sevan considered utilises the conventional Sevan hullform and this requires a significant amount of water ballast to be added to allow the vessel to operate at suitable trim due to the lack of cargo fluid in the storage tanks.

Additionally a ballast water treatment system is required complying with the International Convention for the Control and Management of Ships' Ballast Water and Sediments, 2004 to ensure that there is no transfer of contaminants from one region to another.

16.2.3.15 Fire suppression system

Fire suppression system design should be conducted to recognised code where possible, an example of this is DNVGL-OS-D301.

For manned areas a fire main system should be used.

For areas containing switchgear etc housed within a E-House, a fixed gaseous fire extinguishing system is more appropriate.

For other areas of the vessel an extensive fire and smoke detection and extinguishing system covering all modules and compartments will be installed. Fire extinguishing systems will include water mist system, foam system and inergen system adapted to the equipment in each room and module.

16.2.3.16 Collision Damage

Sevan have assessed damage stability of the hull with the proposed topsides loading according to HSE RR387 (covered MODU Code and DNV). This covers typical damage scenarios that may be experienced while the Main hub is on station.

This has been found to be acceptable to all requirements with the use of watertight hatches between compartments.

This is covered in greater detail in the Sevan report in section 7.2.10 which is included in Appendix 28.20.

16.2.3.17 Workshop and Stores

Provision for workshop and stores has been made by using three deck mounted 20ft containers located on the process deck. This should provide sufficient storage and workshop space for any of the routine maintenance tasks anticipated.

16.2.4 Marine Utilities

The Sub Hub will have integrated utilities to provide essential utilities to the electrical, power generation and accommodation facilities.

16.2.4.1 Sea water lift

The water system incorporates main seawater lift pumps, located in the Hull, delivering to the sea water supply manifold for distribution to three inter-related subsystems, namely: seawater, cooling water, and firewater.

The main seawater lift pumps supply the firewater ring main with water at a minimum pressure of 8.5 barg. A pressure control valve in the common header, will maintain the upstream firewater pressure to ensure that it is the preferential route for water ahead of cooling and seawater utility supply.

A pressure relief valve, dumping back to the sea, protects the seawater lift system.

16.2.4.2 Air Systems

Two air compressors with associated air dryers are located in the machinery space in the hull and supply dried air at 10 barg to the Air Receivers located on the Main Deck. The compressors automatically load and unload taking signals from the pressure from the receivers, and in addition pressure switches on the instrument air system.

Should the air pressure in the air receiver fall to 8 barg, the a diesel standby compressor will start automatically, and will run until the pressure is again at 10 barg.

The air from the compressors divides to supply both instrument and plant air. There is one instrument air receiver, one plant air receiver and two air accumulators located in the system. It is critical to have this back-up as in the event of air compressor failure. Loss of instrument air will cause an outage of the HVAC system which could result in the deluge system operating and resulting in a significant power outage.

16.2.4.2.1 Instrument Air

Air for instrumentation purposes will be supplied from the Instrument Air Header.

16.2.4.2.2 Plant Air

Plant Air is supplied to the Plant Air Receiver after the Dryers. Plant Air is supplied to the users at 7.5 barg as controlled by a pressure control valve. In the event of low instrument air pressure, the PCV will close to isolate plant air to protect the instrument air header.

16.2.4.3 Diesel Supply and Treatment

Diesel oil is shipped to the Platform and pumped from supply boat to the bunkering system via reel. Diesel is routed to the diesel storage tanks.

The main diesel distribution pumps discharge to the following users:

- Fire Pumps Reserve Fuel Tanks
- Emergency Generator Day Tank
- Standby Diesel Generator Day Tank

It is not considered that the power generation system will operate on a dual fuel basis as the volume of diesel required is well in excess of bunkering and storage capacity.

16.2.4.4 Fresh Water

A single Reverse Osmosis (RO) unit generates and delivers adequate volumes of potable water directly to two potable water storage tanks in the hull. The RO unit is fed from the sea water header. Treated water enters the potable water storage tanks and reject saline liquid is dumped overboard. Water generated by the RO unit is dosed with a suitable dosing system, to help prevent bacteria developing in the potable water system.

It is considered that fresh water will primarily be utilised for equipment maintenance on the Sub Hub.

16.2.5 Manning Requirements

It has been determined that the Sub Hub will be a normally unmanned installation and as such doesn't have any accommodation block only a Minimal Accommodation Facilities including at TR.

The TR has been provided within a converted container shown on deck with suitable HVAC ducting to maintain the environment.

It is intended that personnel will only be onboard during planned and unplanned maintenance events and during this time and expected POB of 14-38 would be expected.

As the Main Hub is permanently manned, all maintenance on the Sub Hubs will be facilitated from the Main Hub using it as a base of operations to dispatch teams to the Sub Hubs.

For the concept of the Sub Hubs being unmanned it is critical for the following to be well planned and coordinated during the initial system design to ensure that sufficient capacity is available.

- Short and long term maintenance
- Integrity inspection programmes
- Duration and frequency of planned shutdowns
- Extent of ongoing support from specialist technicians and engineers
- Need for ongoing support for subsea operations
- Possibility of unplanned shutdowns and resources to deal with them

Additionally a workshop / stores container is also shown on deck for spares and tooling to be maintained on site.

16.3 Topsides design

16.3.1 Layout Concept

The layout philosophy applied looks to adhere to general principles for safe, operable and maintainable facilities while aligning with relative industry recommended practices and guidelines mentioned later in this report.

The Sub Hub layout utilises the preferred marine solution providing a scalable, pre-assembled modular approach with a repeatable design and allows for future expansion.

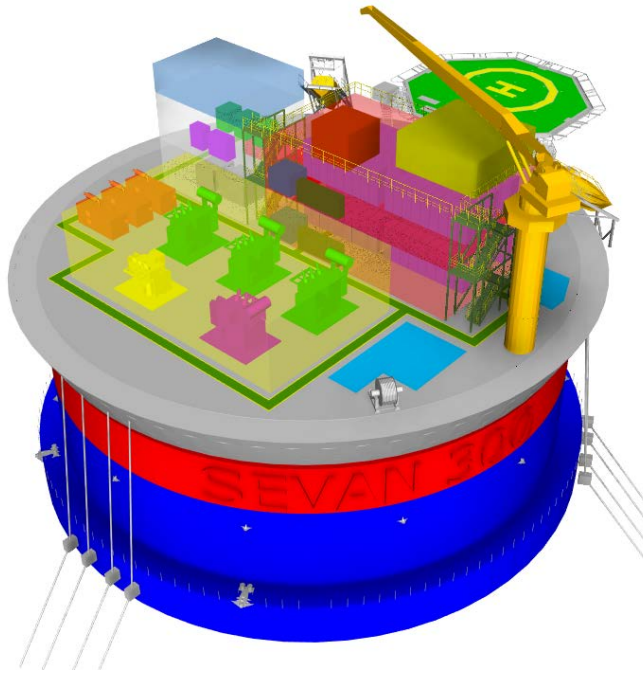


Figure 16-4 - Sub Hub Layout Concept

Primary layout considerations have included:

- Safety
- Operability
- Maintainability
- Constructability
- Weight Control
- Centre of Gravity
- Cost-Effective

16.3.2 Modularity (PAU)

The same modular design philosophy used on the Main Hub has been adopted on the Sub Hub.

For the Sub Hub, equipment was identified & grouped within modules based on system. This allowed for modules to be designed independently of the whole asset. The following modules were identified as being required:

- 200MW Conversion Module.
- Switchroom Module – incorporating HV & MV switchgear.
- ICSS Module / SCADA

16.3.3 Pancake Structure

Where possible PAU's have been utilised to construct the Hub modules, these structures can be repeated across the Main and Sub Hub design. The Transformer arrangement required for the Sub Hub topsides did not lend itself to a PAU.

The combined weight and overall size of the Transformers are too large to be designed as a pre-assembled unit/module and instead are installed on a pancake structure which is integrated into the Process deck. The pancake structure provides the foundation for the transformer equipment to be sited and allows load transfer and load distribution into the main hull structure. A clad structure will be constructed around the transformers to create a 'housing' that will protect the transformers from adverse weather conditions.

16.3.4 E-House

As described on the Main Hub report, the proposed structures housing electrical power systems equipment will be contained within an E-Houses environment. This will extend to the following structures:

- 200MW Conversion Module.
- Switchroom Module – incorporating HV, MV & LV switchgear
- Transformer Housing
- ICSS Module / SCADA

16.3.5 Topsides Layout

A combination of PAU modules, transformer housing, containerised equipment & containers are required on the Sub Hub.

To improve motions & maintain the lowest possible C.O.G of the Sub Hub the following criteria were considered when locating modules:

- Symmetry of module layout in terms of footprint & weight
- A common Laydown Area
- A common module height to aid safety routes and access/egress
- Reducing cables runs as far as practical
- Access and Safety Routes

The layout of the Sub Hub topsides is indicated below:

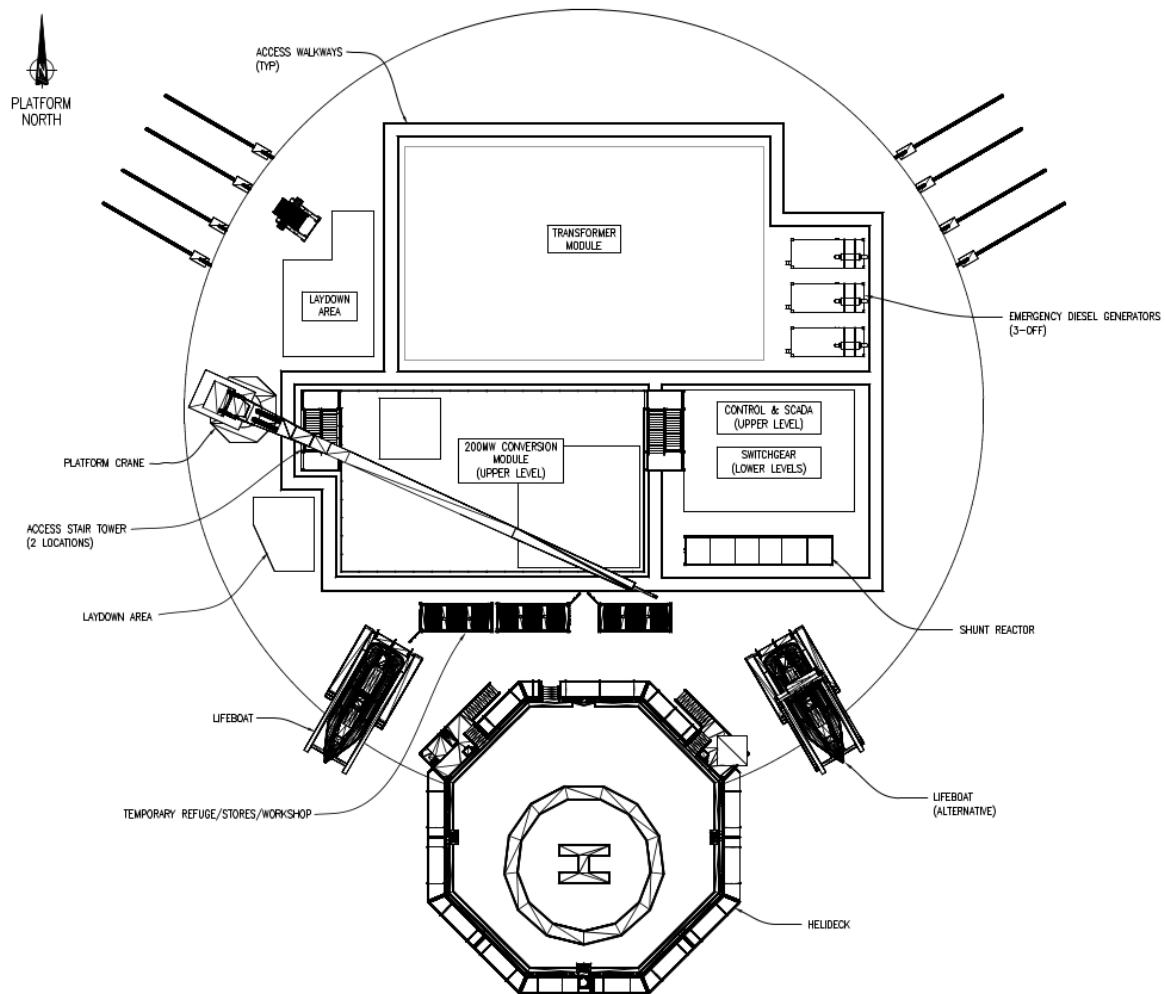


Figure 16-5: Topsides layout overview

16.3.5.1 200MW Conversion Module

The Sub Hub layout was based on the use of the 200MW Conversion module, this was identified as the worst case in terms of layout options as it is significantly larger than the 100MW Conversion module.

The 200MW conversion module runs parallel with the transformer housing on the process deck. Space for cable distribution has been provided by using a main cable rack between the Transformer housing, Conversion module and switchgear module.

Around the perimeter of the conversion modules are walkways that provide access to adjacent modules & laydown areas. Maintenance doors opening towards the south-west laydown area provide a transfer route for electrical components requiring repair or replacement. For crane access to equipment based on Level 1 of the conversion module a maintenance hatch will be incorporated into the roof of the module.

On Sub Hubs with lower demand requirements, the 200MW Conversion module will replace the 100MW Conversion module & the adjacent modules repositioned to suit.

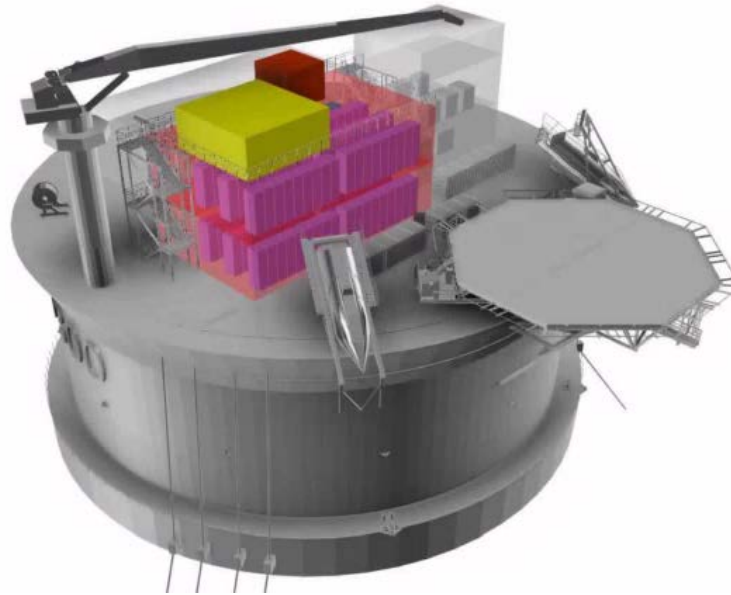


Figure 16-6: Location of 200MW Conversion Module

16.3.5.2 Transformer Housing

The Transformer Housing is a pancaked structure integrated into the Process Deck steelwork with the associated structural frame and equipment mounted above; due to the overall size and weight of the housing, it is not feasible to construct the housing as a dedicated Module (PAU).

For the sizing of the transformer housing and equipment layout out within the housing, consideration was given to:

- Sufficient footprint to ensure it is repeatability across multiple Sub Hub which require differing quantities & size of Transformers
- Maintenance envelopes
- Withdrawal spaces
- Potential removal/replacement of transformers
- Handling Aids
- Access and Safety Routes

All transformers have bottom entry cabling; incoming cables will be run via the available space between the main deck and process deck. The transformers will output to the associated switchgear and conversion modules. To minimise cable runs where possible equipment being fed by a transformer is located as close as possible to the relevant transformer.

The transformer housing has large double doors at the west end closest to the main crane laydown area to allow access maintenance. No allowance for a gantry crane within the transformer housing has been made to facilitate the removal of transformers. If an entire transformer requires replacement, a Heavy Lift Vessel will be required due to the reduced crane capacity; maintenance hatches above the transformers can be incorporated into the housing design to remove specific transformers.

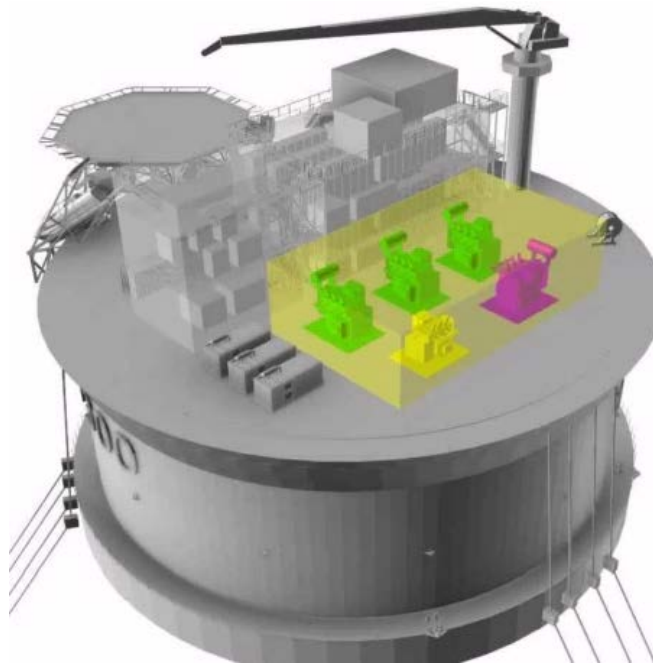


Figure 16-7: Location of Transformer Housing

16.3.5.3 Switchgear Module

The Switchgear module is located adjacent to the Conversion Module on the process deck opposite the Transformer Housing. It has maintenance doors that open towards free deck space at its outboard edge. Due to restricted crane reach, equipment requiring removal or replacement must be skidded from the maintenance door to a suitable laydown area.

Contained within the switchgear module is the HV switchgear located on the lower floor and the MV switchgear on the upper floor. This allows the larger diameter HV cable to have the minimum cable run, keeping costs to a minimum. Cable entry for these modules is via the side of the module closest the Transformer Module.

Additionally for the Sub Hub a Reactive Compensator Unit is required to support efficient power transfer via submarine cable. This is shown adjacent to the Switchgear Module in a converted 40ft container.

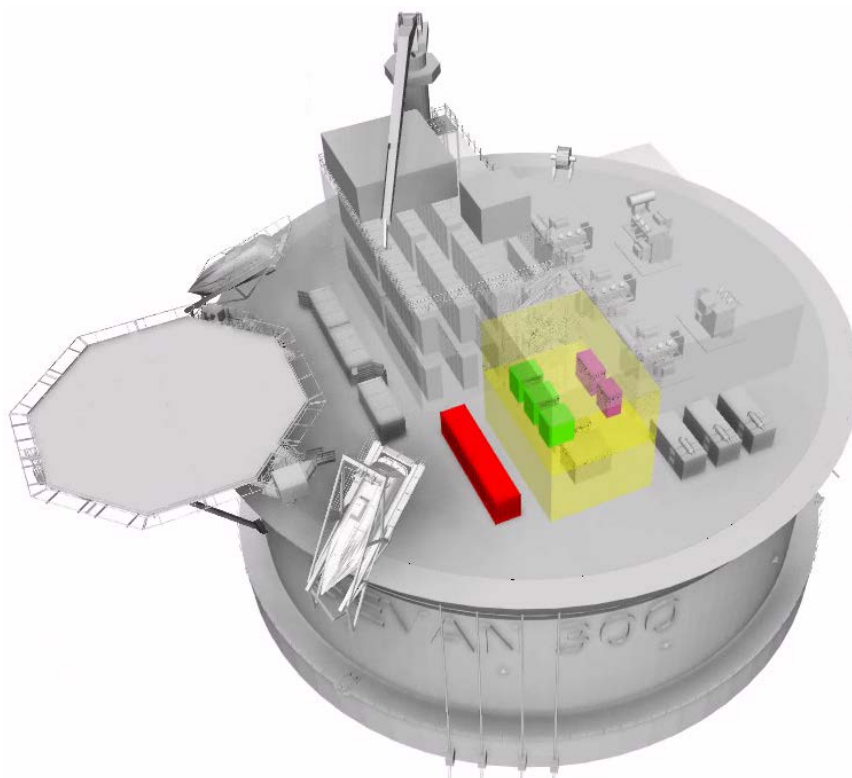


Figure 16-8: Location of Switchgear module & Reactive Compensator Unit

16.3.5.4 ICSS/SCADA

The ICSS module has been located on top of the switchroom. Access to the module is via the stairtower located between the Switchgear module & the Conversion module.

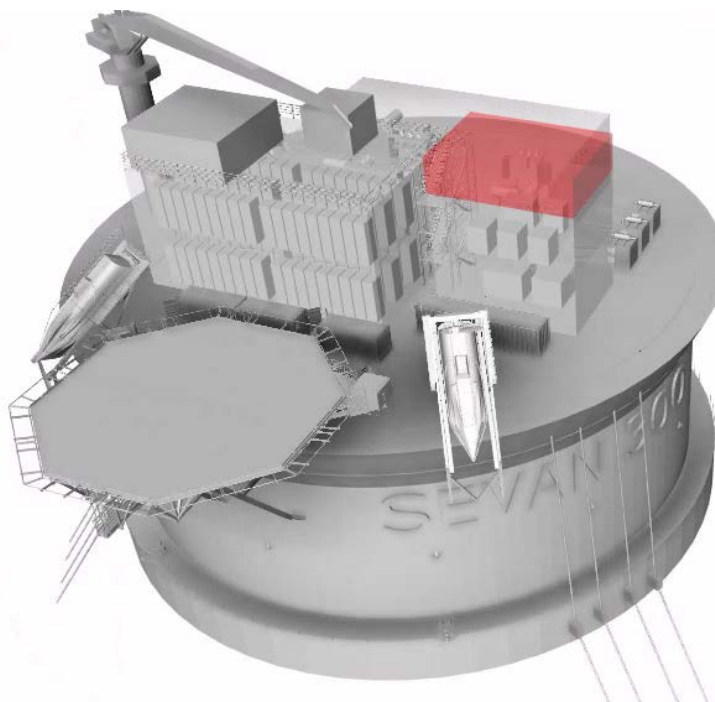


Figure 16-9 - ICSS Module

16.3.5.5 Laydown areas

Two main laydown areas have been provided on the Sub Hub, other locations can be utilised for general-purpose laydown, but these have not been defined at this stage.

Both areas are located on either side of the crane pedestal and will be utilised for platform operational requirements, supply vessel operations and equipment laydown.

The laydown area adjacent to the Transformer Housing will have the load capacity based on the heaviest single component that may require removal or replacement; this has been identified as a transformer (approx. weight = 70t). In the highly unlikely scenario that a transformer needs to be removed from the Sub Hub a heavy lift vessel will be required.

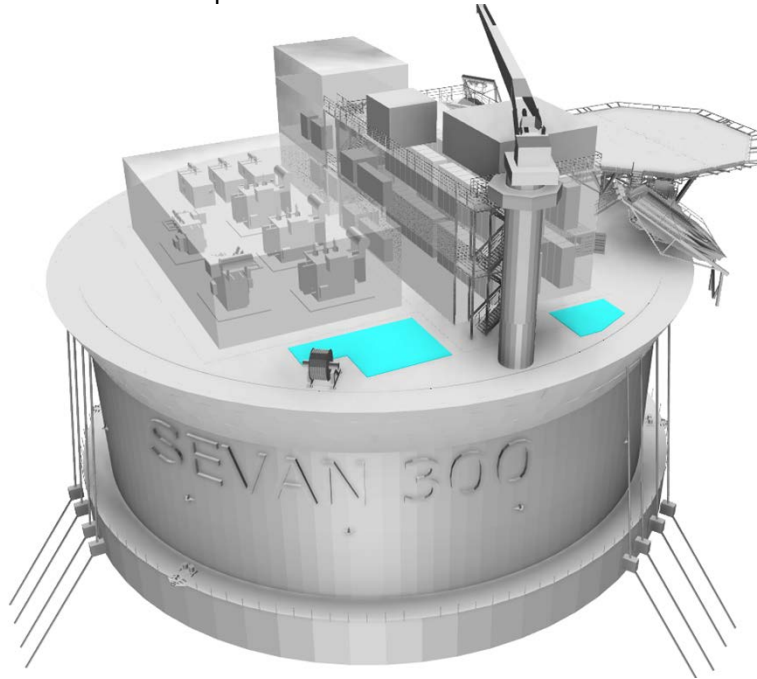


Figure 16-10: Location of Sub Hub laydown areas

16.3.5.6 Lifeboats

Lifeboats (TEMPSC) are provided on the vessel in two locations on either side of the helideck. For the purpose of this study a lifeboat has been shown and included in the costing. This has been shown a free fall lifeboat but given the NUI status of the sub hub and the lower expected personnel on board this may be changed to davit launched lifeboats.

The lifeboats have been placed at these two opposing locations to allow access from either side of the electrical module stack. This provides redundancy of escape route in case there is an incident restricting access to one of the banks of lifeboats.

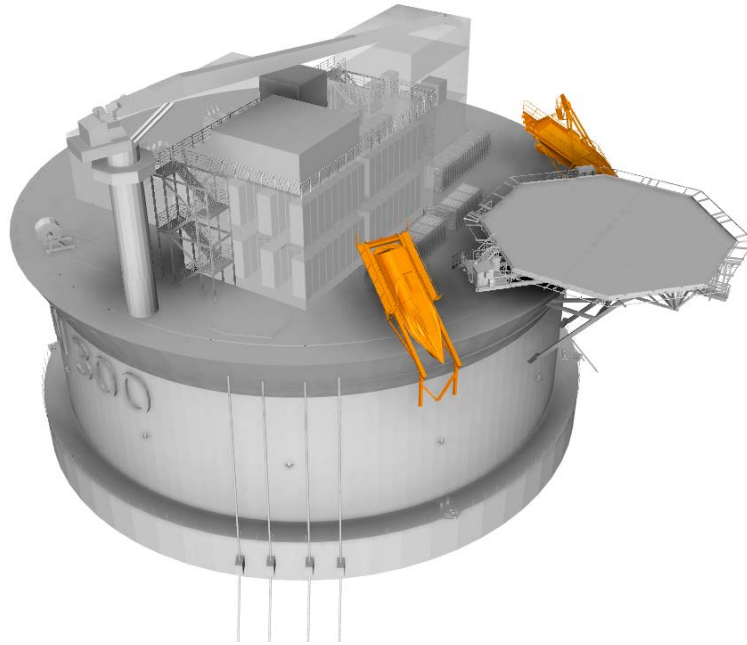


Figure 16-11: Location of lifeboats

16.3.5.7 Walkways & Stair Towers

Common walkways have been routed around the topsides to provide access to all modules, laydown areas, equipment, temporary refuge, helideck and lifeboats.

Module heights and integrated mezzanine levels have been duplicated across modules to ensure the commonality on stairtower design. The design used in the Main hub can be scaled in height and used in the Sub Hub as shown below.

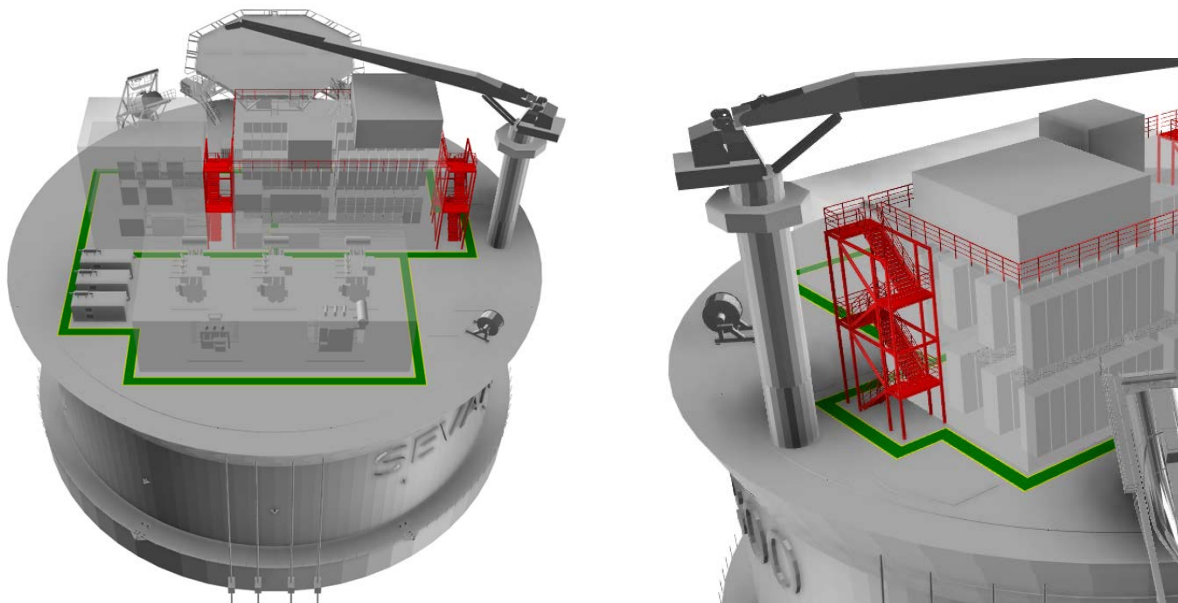


Figure 16-12 Walkways and Stair Towers

16.3.5.8 Minimal Accommodation Facilities & Helideck

The Minimal Accommodation Facilities are located as personnel exit the helideck stairs to the south of the 200MW Conversion module. The facilities are made up of a workshop / storage, a social area with lockers, workstation area and Temporary Refuge.

The helideck has been designed and positioned as mentioned in section 16.2.3.8, which takes in to account access/egress to the accommodation facilities, wind parameters and all safety factors.



Figure 16-13 Minimal Accommodation Facilities and Helideck location

16.3.5.9 Emergency Power Generation

Emergency power will be provided by two containerised generator sets located on the Main Deck of the Sub Hub. The maximum power provided will be approximately 3 MW with 3 off 1.7 MVA generator sets selected. This is considered as the maximum load required to ensure all essential services are online during system outages. During this time the emergency power generation will be supported by diesel from the diesel storage tanks.

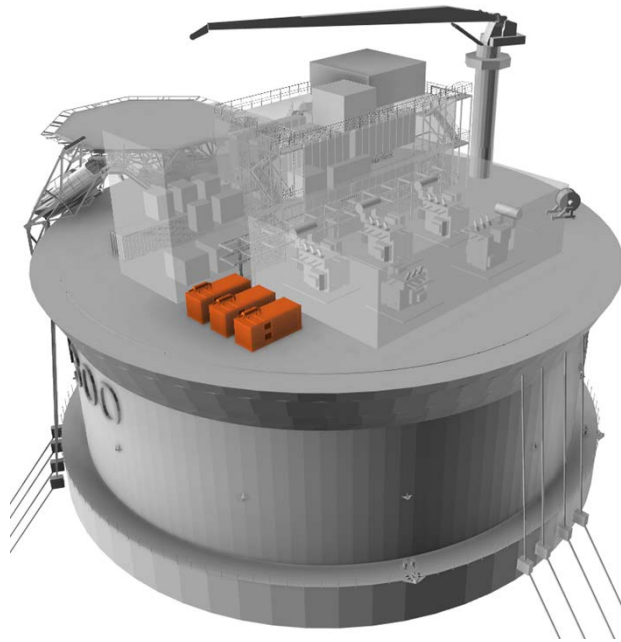


Figure 16-14 Emergency Diesel Generators Location

16.3.6 Topsides structure

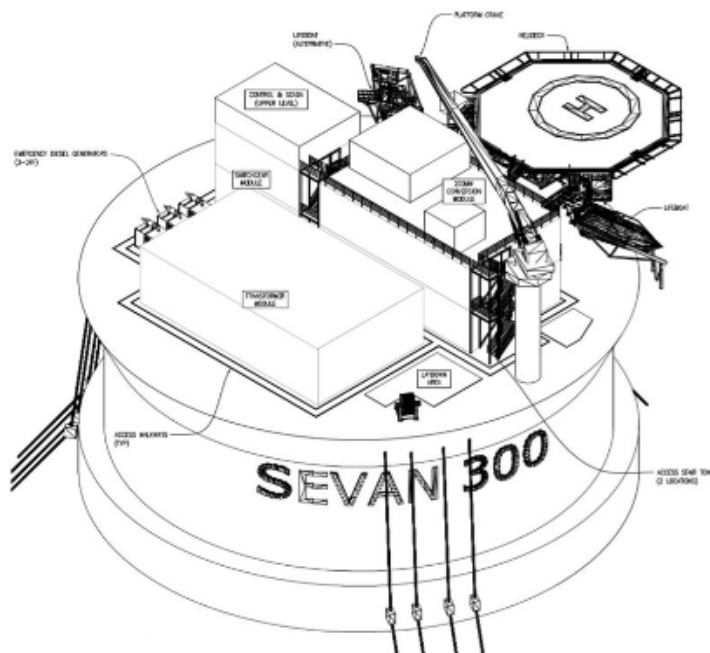


Figure 16-15: Topsides overview

The large deck area on the Sub Hub has facilitated the use of PAUs from cost and safety points of view. In addition to the PAU, a pancaked structure integrated into the Process Deck steelwork with the associated structural frame and equipment mounted above to support the Transformer Housing. Due to the large combined weight and overall size of the Transformers, they are installed on a pancake structure which is integrated into the Process deck. The pancake structure provides the foundation for the transformer equipment to be sited and allows load transfer and load distribution into the main hull structure. Large 'module' and 'Pancake' structures impose high point loads on the vessel and

transferring the loads on to the relevant strong point is vital. Large rigid modules and pancakes, spanning a significant length of deck, need to have some flexibility built into their supports to prevent high hull stress levels being transmitted into the module. For all support arrangements, Fatigue due to hull flexure and inertia loads on PAU/modules in the design of supports will also be considered during the design.

The Process deck supports the following :-

- Transformer Module
- Conversion Module
- Switchgear Module
- Lifeboat Davits
- Helideck
- Emergency Diesel Generators
- Temporary Refuge/stores/workshop
- Bunkering Hose Reel

The Process deck structural steel arrangement will be designed to support the items above. The elevation of the Main deck is EL +32,000 and the elevation of the Process deck at EL +36,500.

The topsides structures have been designed as concepts only at this stage but the intention is that they would be designed during detail design with the following considerations.

16.3.6.1 Primary Structural Steel Sizing Basis / Methodology

16.3.6.1.1 Pillar/Stool arrangement for transfer of loads

To transfer the loads and to support the Transformer module, Switchgear module, Conversion module, Crane foundations etc on the process deck a plate girder beam supported on 'Pillars/stools' will be added at Engineered distances to distribute the loads from the equipment to the main ship Hull structure. Provision to be made for misalignment of the pillar relative to the deck support. Attachment weld some distance above the deck is required to avoid damaging internal tank coatings. Fatigue damage may arise due to either longitudinal hull bending being transmitted through the supports to the PAU/Pancake or bending from transverse loads on topsides from roll motions hence this needs to be reviewed at the design phase.

The weight of Transformer module, Conversion module, Switchgear etc, the Beams supporting the modules transfers the loads to the ship hull via 'Stools' will be made of fabricated plate girders and will be located under either end of the equipment.

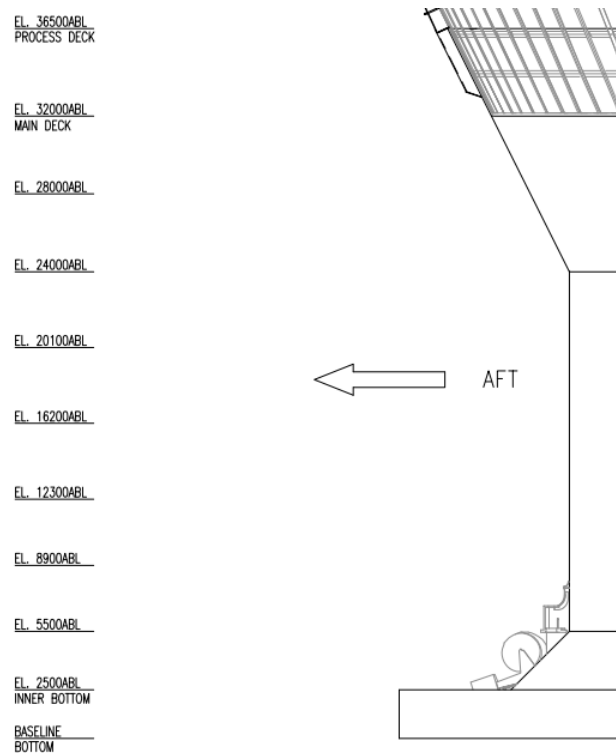


Figure 16-16 Elevation of Main/Process deck of Sevan 300

For this study the plate girder beams supporting the modules/pancake is estimated to be 0.8m depth. The Process deck is estimated at an El +36,500 (TOS). This gives a clear height of 3.7m between the Main deck and the Process deck. There will be a need for cable trays that may reduce the clear height (depending on the layout/routings of the cable trays) between the levels. This will be reviewed during the detailed FEED study of the project.

The Plate Girders supporting the units will be mounted on pillars/stools to transfer the load into the strong points on the vessel. These intermediate supports stools will be added at locations where the support beam of the unit is in line with the main deck's hard points and the vessel's hull. This will provide adequate support for the process deck in these highly loaded areas. The beams will be fabricated at the shipyard. The topside loads are spread more evenly into the ship's structure and allow local flexing to reduce the hull bending stresses transmitted into the PAU structure. A typical arrangement of stooling of the process deck is shown below :-

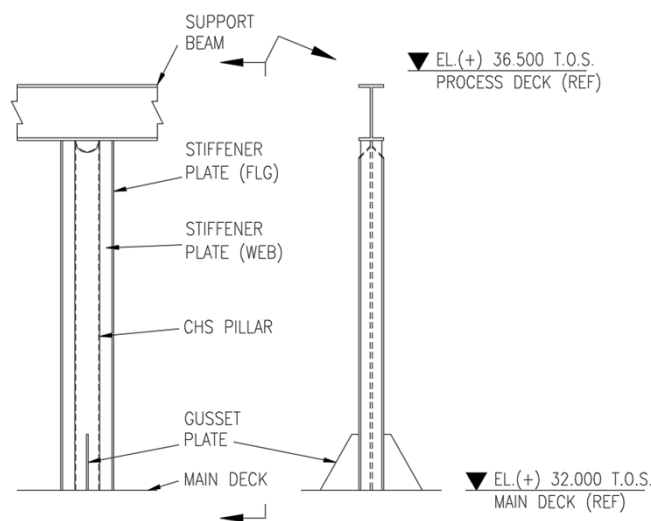


Figure 16-17 Example Pillar/stooling arrangement

A total of 21 such 'Pillars/Stools' are identified as required at this stage which will be reviewed during the detail design phase of the project for confirmation on total numbers.

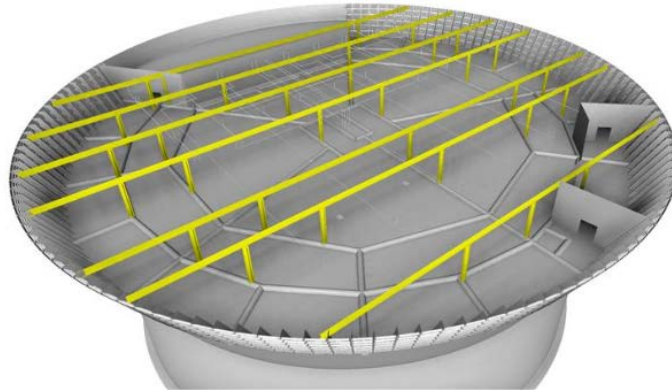


Figure 16-18 Pillar/stooling arrangement

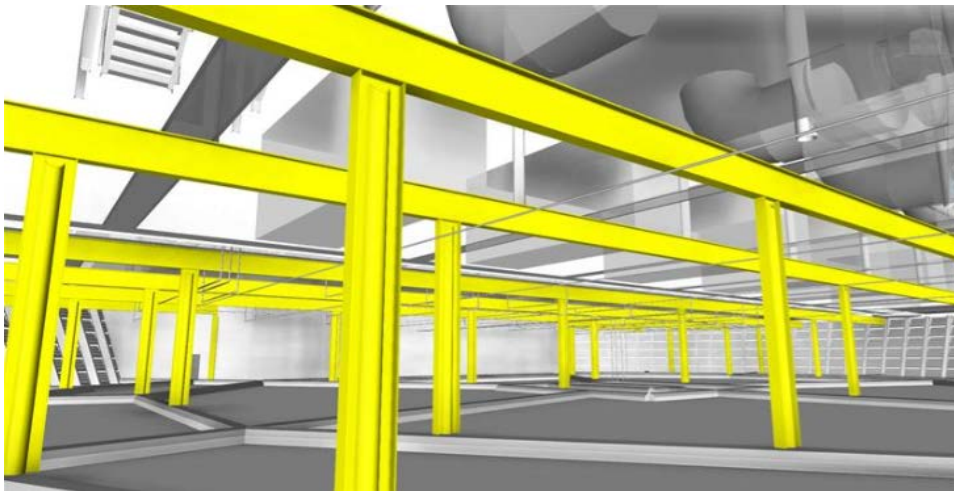


Figure 16-19 Example Pillar/stooling arrangement

The entire process deck is therefore supported using a regular pattern of stools between the main deck and the process deck. These are spaced to transfer the radial framing system of the Sevan hull to the rectangular framing required for the process deck. It is acknowledged that this use of fixed only stools adds to the fatigue loading on the main deck which supports this but this is a common feature of the Sevan hullform.

These stools are manufactured to reduce the fatigue impact on the main deck connection by creating a bracketed transition between the stool and the deck. This is important to consider due to the affect of fatigue in the offshore environment.

The stools are placed at as regular intervals as possible with consideration of the structure below and the high load areas of the process deck requiring a greater frequency of stools to provide adequate support of the process deck.

Primary steelwork for the additional decks and modules that make up the topsides will be designed and produced according to the AISC ASD methodology consistent with existing platform topsides design methodology

16.3.6.2 Regulations Codes & Standards:-

The design shall be in accordance with the latest international legislation, codes and standards.

Good engineering practice shall be applied to facilitate a safe operating design and minimise the risks to personnel as low as reasonably practical (ALARP).

Typical codes & standards are :-

- DNV rules for classification of ships – January 2015
- AISC specification of Structural steel
- BSEN 10025-02 -Hot Rolled products of Structural steel
- DNVGL-ST-N001 Marine Operations and Marine Warranty – Jan2020
- DNVGL-ST-0378 – Offshore & platform lifting appliances, July 2019

16.3.6.3 Secondary Structural Steel Design Basis / Methodology

Secondary steelwork for the additional decks and modules that form the topsides will be designed and produced according to the AISC ASD methodology consistent with existing platform topsides.

Secondary steelwork will be attached to the primary steelwork and provide bracing for out of plane loading and prevent unnecessary vibration.

Secondary steelwork will consist of S355 grade and will take the form of beams / girders commonly available and sized to ensure code compliance.

16.3.6.4 Tertiary Structural Steel Design Basis / Methodology

Tertiary steelwork will be designed in a similar manor to the secondary steelwork with the exception of using sound engineering design rather than prescribed rule checks given in the AISC ASD.

Should the design requirement suit the Grade of Steel for the tertiary members can be lower that that of the Primary/secondary steel.

16.3.6.5 Lifting and Handling

Lifting & handling of pre-assembled PAU/Pancakes/Equipment will be performed with certified lift rigging. Pad eyes to be welded to facilitate the lifts. Lift analysis and the design of rigging/installation aids shall be carried out in compliance with procedures.

It will be ensured that the Structural deflections during lifting shall be minimised to prevent damage to the structure/cladding/coatings

Temporary structural framing and weatherproofing will be provided for the transit/installation condition where necessary to ensure Structural integrity and weather-tightness. Any temporary strengthening or bracing shall have bolted connections to permit easy removal offshore.

16.3.7 Electrical Power Systems

16.3.7.1 Transformer Housing

Transformers shall be specified for a minimum design life of 25 years. Transformers are considered unlikely to fail and need complete replacement, however, maintenance access shall be considered to conduct testing and repairs, as well as liquid replacement if this becomes necessary.

The transformers shall utilise synthetic ester (e.g. Midel) as the insulation fluid as this has a lower flammability risk and pollution risk in the event of a loss of containment when compared to more traditional mineral oil.

In offshore transformer design earthing units are often built within the same main tank. This option should be explored as a way to minimise equipment layout requirements.

Transformer cooling shall be considered in greater detail during future study phases. Typically ONAN (cooling with radiators but without fans) offers the lowest maintenance burden, but the impact on the transformer module HVAC must also be considered.

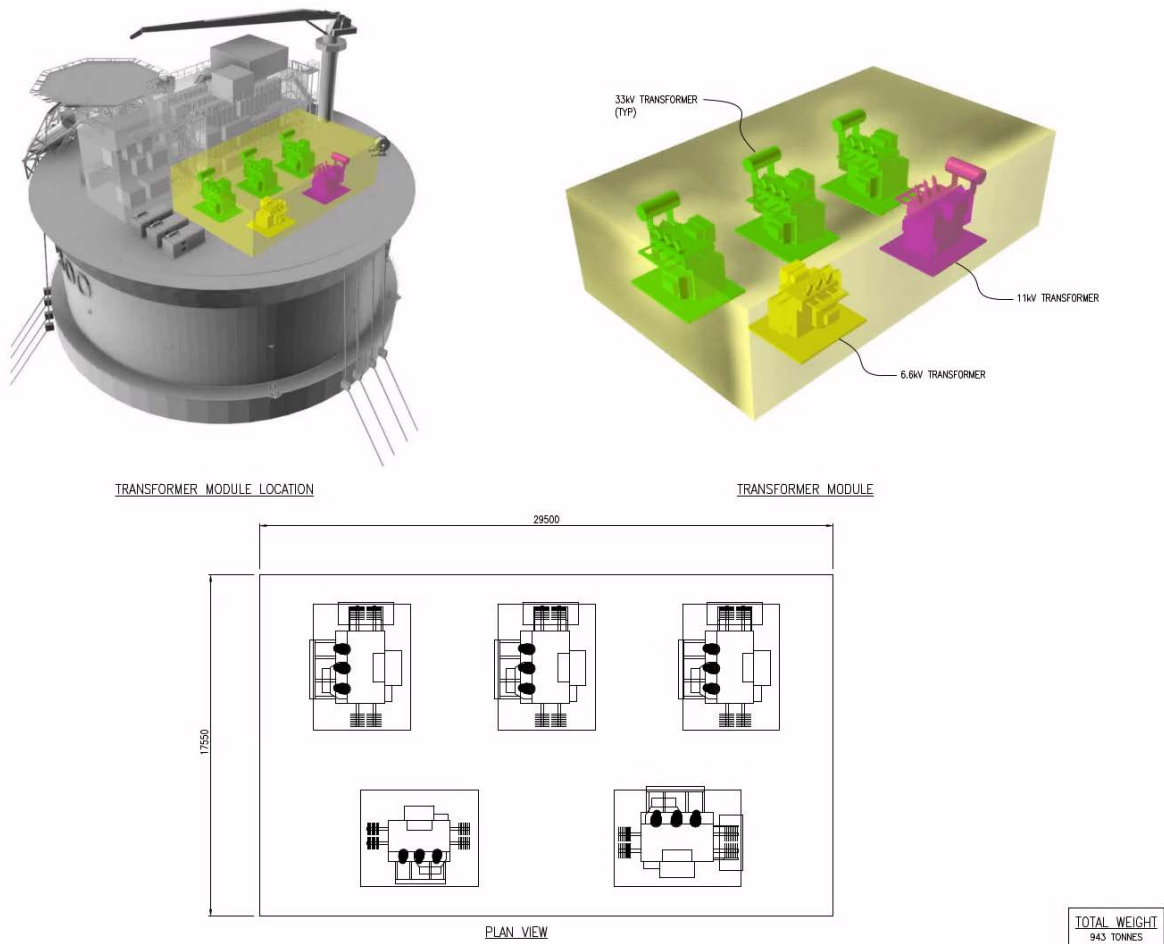


Figure 16-20 Overview of the Transformer Housing Layout

16.3.7.2 Conversion Modules

Each Conversion Module contains all the Medium Voltage Direct Current equipment (MVDC) required for receiving bulk electrical power from the Main Hub. Each Sub Hub shall have a single Converter Module rated either 100MW or 200MW depending on the electrical power demand of the connected assets.

The sensitive nature of the power electronics means that the Converter Modules shall be pressurised and environmentally controlled to ensure temperature and humidity are kept within acceptable limits.

The MVDC equipment proposed by GE consists of multiple Half Bridge converters arranged on open racks. These employ power semiconductor switches and capacitors as part of the conversion technology. The racks are arranged to be accessible for component inspection and replacement.

Each converter also has an associated Control Unit as well as ancillary equipment such as an AC reactor. These components have been located within the Conversion Module to minimise control cabling and allow for operators to monitor and control equipment locally if required. There will be interfaces between local Unit Control Panels and the Sub Hub's ICSS for overall monitoring and control from a Central Control Room located back on the Main Hub.

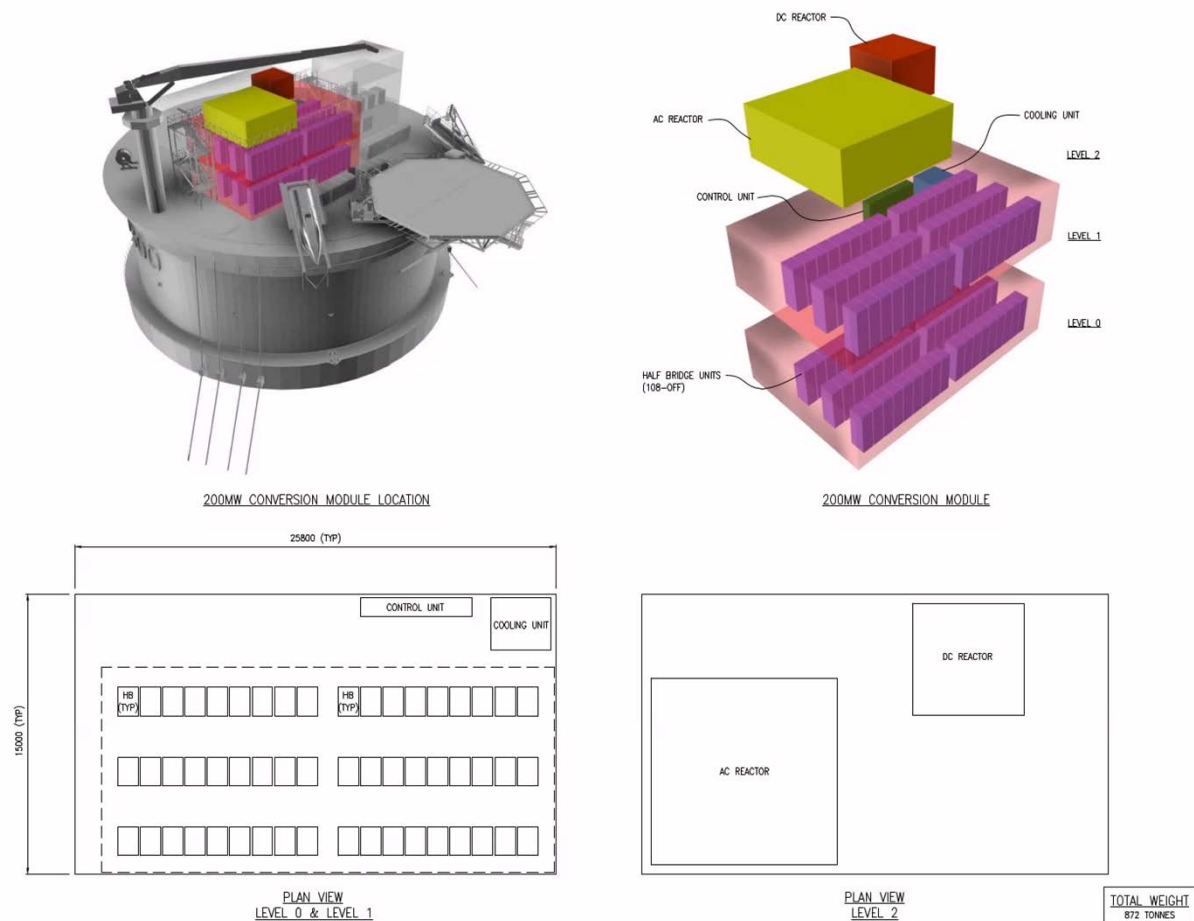


Figure 16-21: Overview of 200MW conversion module

16.3.7.3 Switchgear Modules

In order to segregate the electrical switchgear there shall be a Switchgear Module provided for each voltage category: High Voltage (above 52.5kV) and Medium Voltage (between 3.3kV and 52.5kV).

HV Switchgear

Metal-enclosed gas insulated switchgear (GIS) shall be used for voltages above 52.5kV.

Gas Insulated Switchgear utilises Sulfur Hexafluoride (SF6) under pressure (generally a few bars) as the insulating medium. This allows for relatively compact equipment suitable for installations indoors offshore where space is limited.

High voltage interface connections will depend on the distance: cables shall be used for long runs (e.g. between modules) whilst gas insulated busbar (GIB) ducting shall be used for short runs (i.e. within a module). The connection type selected shall also take into account the current rating, turning radius, supports, proximity to heat sources, proximity to other electrical equipment and cables.

Any High Voltage GIS switchgear shall be located in its own room to allow controlled access and reduce hazard exposure. The SF6 gas in particular shall be monitored and risk assessed due to its high global warming potential if released.

GIS switchgear is generally very low maintenance and can be remotely monitored to reduce the need for on site checks and inspections. Specialist personnel and equipment will be required for servicing and maintenance when working with SF6.

MV Switchgear

Switchgear at voltages between 3.3kV and 33kV shall be metal-enclosed Air Insulated Switchgear (AIS). This typically offers the most compact equipment for these medium voltages and is a well proven technology offshore utilised extensively for 3.3kV, 6.6kV, and 11kV equipment in the UKCS.

Switchboards are typically formed of incomers, feeders and bus ties with each tier incorporating the switching device and the associated controls and protections. Switchgear can be specified to be front access with cable entry either top or bottom to suit the cable routing.

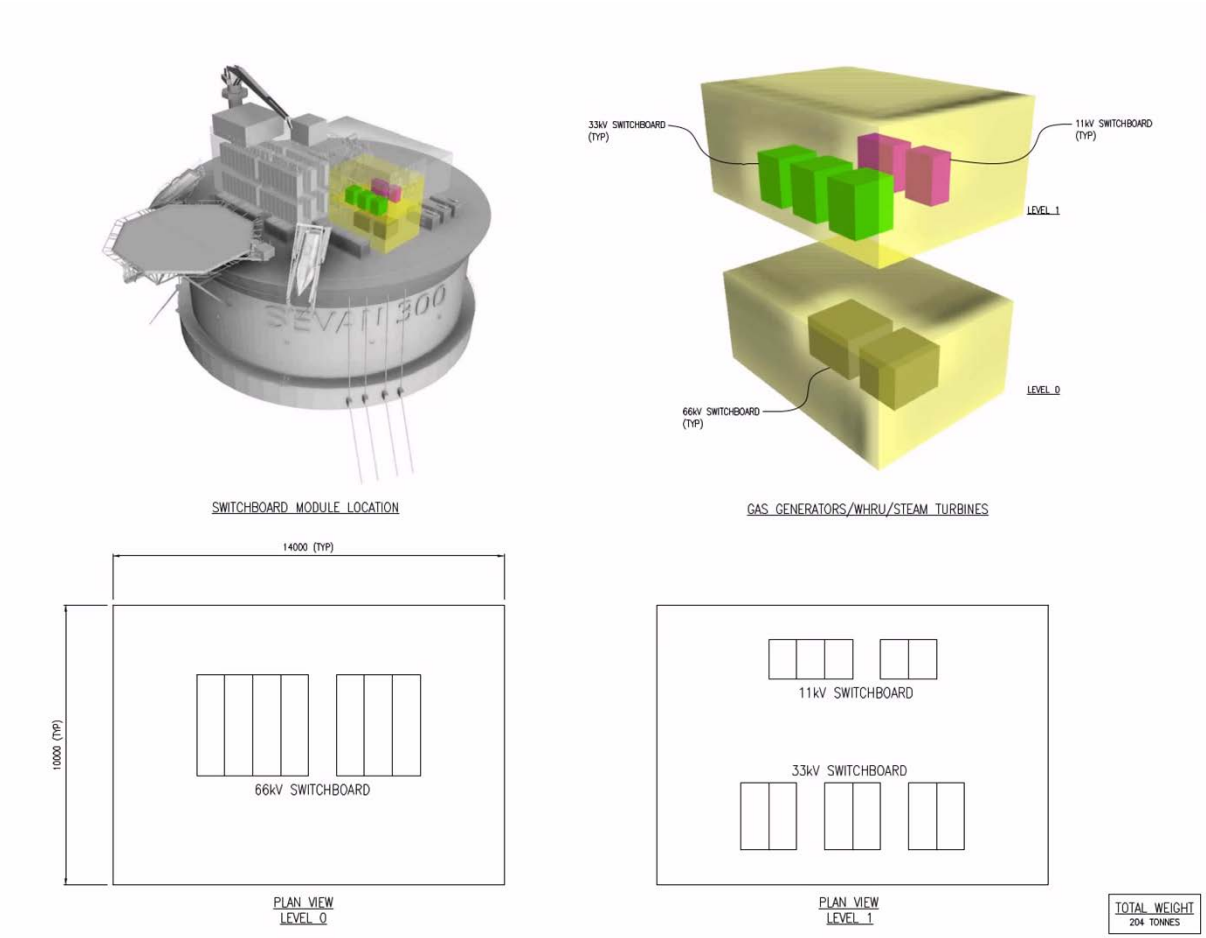


Figure 16-22: Overview of Switchboard module

16.3.7.4 Containerised Reactive Compensation

Where reactive compensation is required to support efficient power transfer via submarine cable this shall be provided by containerised equipment (e.g. shunt reactors) located on the main deck of the Sub Hub. This shall allow this additional equipment to be incorporated on Sub Hubs where it is required without compromising the Conversion or Switchgear module dimensions.

16.3.8 Cable Racks

Due to the large diameter, and hence weight, of the cables, heavy duty bespoke designed cable trays have been required to transmit cables of the same voltage on the topsides between the different modules as required.

Where practical equipment has been located in the modules and on deck space in close proximity to minimise cable runs and help reduce voltage drop due to cable resistance/reactance.

The transformers and switchgear are all bottom entry cabling and therefore the cables can be routed from this main cable tray beneath the process deck in the space between the main and process decks.

A central cable rack has also been designed between the transformer housing and conversion modules and switchgear module for running cables on the process deck between modules. This can also be used for hvac ducting.

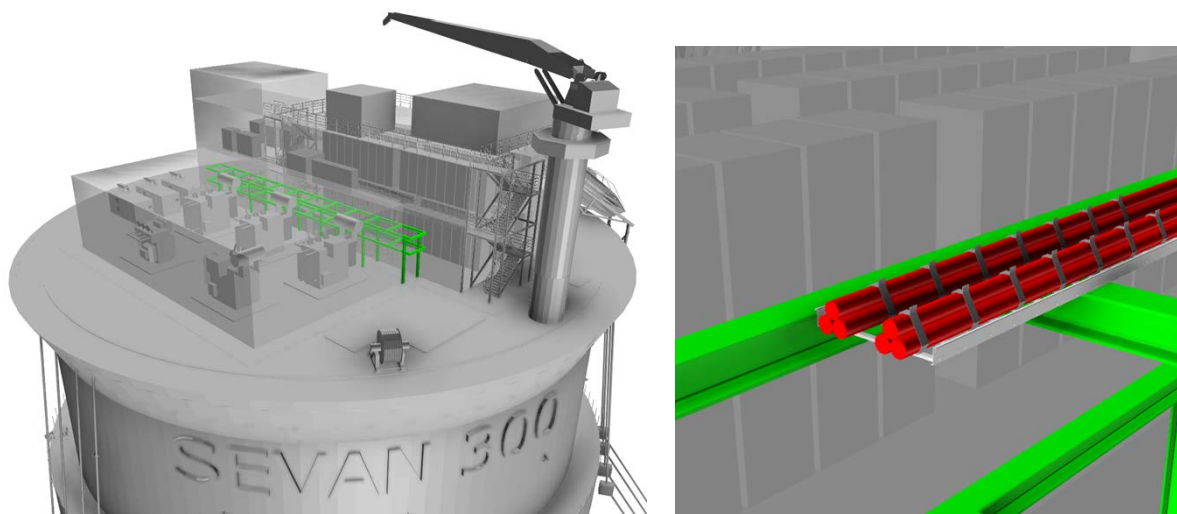


Figure 16-23 Central Cable Rack

16.3.8.1 Cable Segregation

Different voltage cables, such as the import cables and those going to the Sub Hubs will be required to be supported on different trays with minimum offsets interference maintained at all times to prevent electromagnetic interference.

In all instances the design of the cables trays has taken account of the weight of the cables and the motions of the vessel increasing the loading.

16.3.9 Pipe Racks

Several pipework systems are inherent in the Sevan concept such as ballast water, fire systems, water (potable and technical). These have been routed in hull void spaces.

In all cases the piping has been supported in such a way as to take account of thermal expansion / contraction and any loading that may occur during pressurised operation. This will be confirmed through piping analysis where required in further detailed design stages.

16.3.10 Hose reels

Hoses are required for bunkering of fluids to facilitate the ongoing operations of the Sub Hub. A double hose reel will be utilised. One hose will be provided for bunkering of diesel (Marine Fuel Oil) and the second as a secondary potable water supply. These are located on the Process Deck level next to the primary laydown area as shown below :-

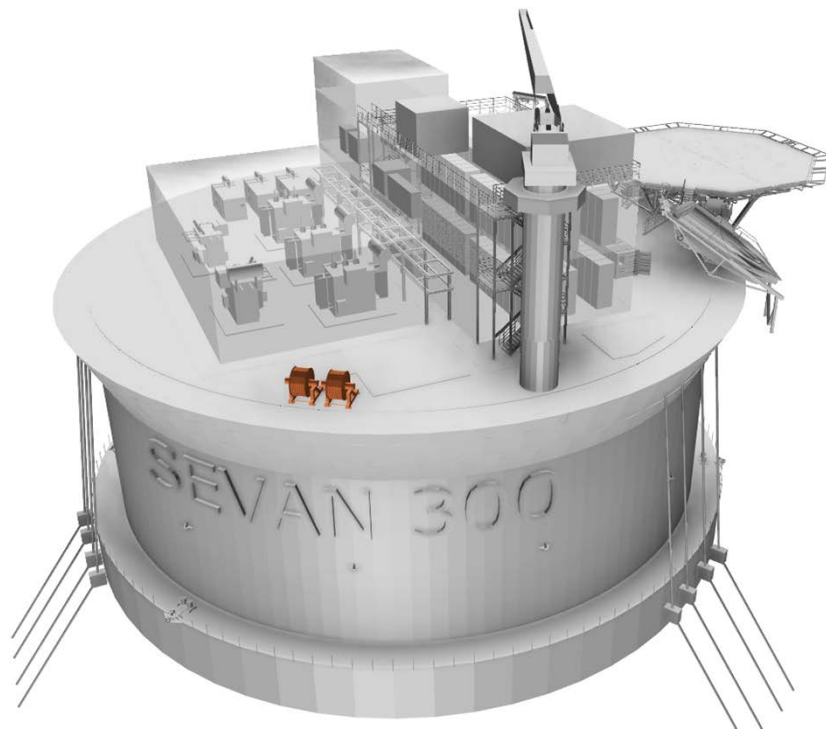


Figure 16-19 Location of the Hose Reels

The basis for these bunkering hoses are the reels located on the Sevan FPSO. This is an electrically driven reel powered from the existing Sub Hub supply. Lifting of the hose for connection would be via the crane.

Specification of the hoses for diesel and water have been made largely in line with an existing hose specification for a North Sea FPSO.

16.3.11 Bridge Link Area

The use of Bridge links has not been considered during this study. It is assumed that personnel will stay on the Main Hub and arrive and leave via helicopter. Therefore a flotel would not be required.

If this changes during the life of the Sub Hub with a major maintenance campaign required the use of a bridge link to provide access to a flotel can be investigated. There currently is sufficient deck space to mean this would not be an issue.

16.3.12 Removal of Equipment / Decommissioning of assets / Future Expansion

No consideration has been made with regards to removing redundant modules if an Asset is removed from a cluster group. In the event this happens, and it affects the output requirements of the Sub Hub the associated equipment would be retained on the Sub Hub and could be re-utilised either for spares or if additional new assets replace those that have been decommissioned.

16.3.13 Topsides Weight and Centre of Gravity Report

The same philosophy used on the Main Hub to calculate the topsides weight and C.O.G has been adopted on the Sub Hub.

Total Topsides Weight = HOLDt		
North (m)	East (m)	Vertical (m)
HOLD	HOLD	HOLD

16.4 Relocation/Redeployment Options

The Sub Hub has to be taken off-station when it reaches end of its service life. A Comparative Assessment will be carried out in line with the recommendations of the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) Guidance Notes in the Department for Business, Energy and Industrial Strategy (BEIS) to study options to Relocate/Redeploy/decommissioning the Sub Hub.

For details about how this will be approached see the Main Hub Section.

16.5 Further Areas of Study

The following is brief description of the further areas of study that should be taken further and not already covered in this report.

A further development of the concept would need to include design of the supporting structures for the topside modules including primary and secondary steelwork. This would be expected to be carried out taking account of the motion data provided by Sevan and the loads identified in this document.

The design of a Jack-up platform for use as a Sub Hub should be carried out to the same level of detail as with the Sevan FPSO concept as there have been areas identified as requiring this option for locating the Sub Hub water depth. These areas are so far contained only in the Southern North Sea.

The use of a SWACH hullform in place of the conventional Sevan 1000 hullform would offer significantly reduced cost of manufacture, lower amount of water ballast required and better utilisation of available space.

17. Cable Laying Study

17.1 Objective

The objective of this study is to understand the latest methodologies and technologies available for submarine cable laying and determine:

- The costs of laying submarine cable on a normalised cost per km basis
- The limitations of physical lengths of submarine cable along with jointing options
- The preferred methodologies for laying submarine cable in the North Sea
- The physical protections required for submarine cables
- Feasibility and options for incorporating junctions into submarine cables to allow for future network expansion
- Expected service life of submarine cables based on their materials, construction and installation and options for recovery or reuse beyond the expected operating life of UKCS oil and gas production

The cables within this study scope are identified on the proposed system block diagram in Figure 17-1 and described below.

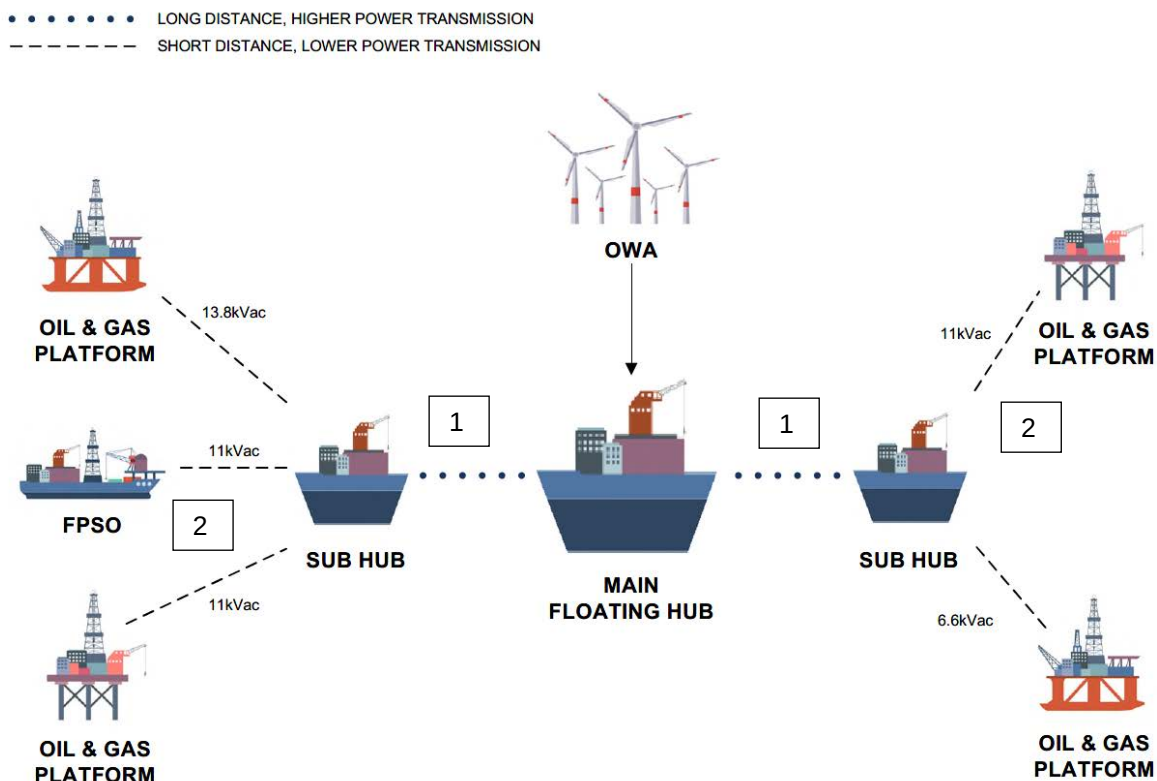


Figure 17-1: System Block Diagram with Cables Identified

1. Main transmission cables which run between the Main Hub and Sub Hub(s) which could be:
 - a. HVAC, or
 - b. MVDC
2. Distribution cables which run between the Sub Hub and Asset(s) which will be:
 - a. MVAC (in the range of 6.6kV to 33kV)

The costs, methodologies and limitations identified in this report will inform the costs of the overall system and determine how assets and Sub Hubs are clustered and the distances between them.

17.2 Methodology / Background

This main body of this study was completed using the resources in the public domain as well as discussions with experts in this field such as TechnipFMC. This included previous studies, case studies on completed subsea cable installations and equipment, cable, cable accessory manufacturers websites.

The costs obtained as part of this study have mostly been extrapolated from previous industry papers and validated with vendors in this market space. These are all referenced in the references table above. Several cable manufacturers and cable lay vessel specialists were contacted and costs from previous projects they had completed used to validate the research.

17.3 Discussion

17.3.1 Breakdown of Submarine Cables

Different cable types are used throughout a subsea cable network, depending on factors such as voltage and location of installation. Most cables consist of the same structure however and these are discussed below.

17.3.2 Design Elements of Submarine Power Cables

The market leaders in subsea cable production have a range of cables available for offshore subsea installation. This includes high voltage AC cabling (HVAC), medium voltage AC cabling and high voltage DC cabling (HVDC).

A breakdown of the cable construction is provided below.

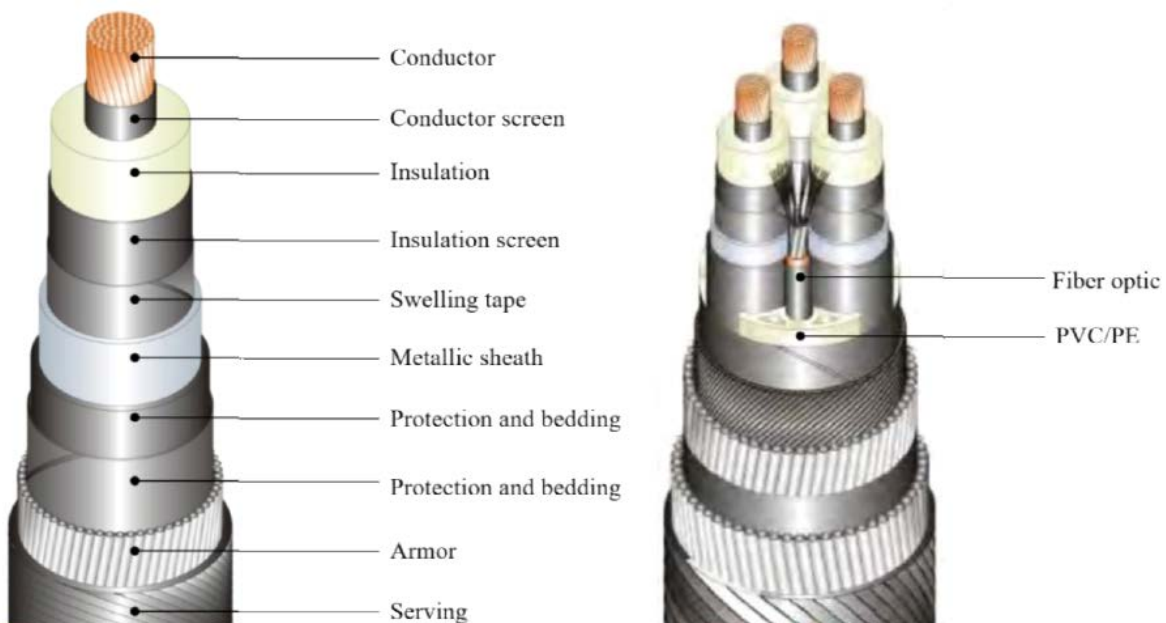


Figure 17-2: Static HVDC (left) and HVAC Submarine Power Cable (reference /74/)

Conductor

The conductor is the core of the cable. This allows current to flow through the cable and can come in single core formation (left hand image above) or three-core formation (shown in the right image above). The material of the conductor is generally copper or aluminium. Copper is generally selected ahead of aluminium for the core type of submarine cables because of its superior current-carrying capacity when compared with aluminium. However, the initial cost of aluminium cored cabling is far less than copper but when consideration is given to include repair costs there is no economic advantage. This is mostly

down to the aluminium cores required to carry a certain current will be larger than copper cores (Reference /97/).

Dielectric System

This consists of the conductor screen, insulation and insulation screen shown above in Figure 17-2. The conductor screen removes local stresses between the conductor and the insulation. This is because of its smooth surface. The insulation acts as a barrier between the potential differences of the inner core of the cable – the conductor – and the outer layers that form the rest of the cable. The material of this barrier is normally made up of cross-linked polyethylene (XLPE). The insulation screen is also made from the XLPE material. This acts as a layer of protection between the insulation and the swelling tape, protecting the insulation from the outer cores and retaining the barrier between inner and outer cores. (Reference /73/). Ethylene Propylene Rubber (EPR) can also be used for the insulation however its dielectric properties are not as good as that of XLPE and so this is normally the preferred choice.

Swelling Tape

When used, the main function is to absorb Figure 17-3 Table 17-1 moisture which distributes across the cable due to longitudinal welding seams.

Water-Blocking Sheath:

Most submarine cables are equipped with moisture blocking tubular metallic sheath - shown between the swelling tape and protection and bedding in Figure 17-2 – to reduce the ingress of moisture to the cable and maintain the dielectric system. This type of cabling which has the water-blocking sheath is known as a 'dry' designed cable.

A submarine power cable without an impermeable metallic sheath is known as a 'wet' designed cable.

Some of the common sheath types are:

- Lead Sheath
- Aluminium Sheath
- Stainless Steel Sheath
- Polymeric Sheath

Protection, Bedding and Fillers

This is applied beneath the armour to protect the moisture-blocking sheath from the armour. It is usually made from tape to provide a range of movement.

Fillers are used to do exactly that, fill the voids which are not occupied by other components of the cable. This ensures the cable conductors do not have room to move which could cause tension issues during the cable pulling stage for example.

Armour

The armour is placed on top of the protection and bedding in the construction of submarine cabling. The purpose of the armour is to provide structural integrity to the cable particularly from tension and to protect against mechanical loading.

The armour consists of metal wires – usually steel – wrapped around the cable for the entirety of its length.

Outer Serving

This acts as a protective layer, minimising external stresses and corrosion on the cable during the loading, laying, and burying of the submarine power cable. A type of polymer is the common choice of material for the outer serving.

Optical Fibre

The optical fibre in a submarine power cable is used for the following reasons:

- Fault detection and location
- Data transmission

- Measurements of temperatures (DTS), strain (DSS), insulation (PDM) etc.
- Detection of local movements of the submarine power cable

For three-core submarine power cables, the optical fibres are integrated between the cable cores. For single-core submarine power cables, the optical fibres are generally laid separately due to the different characteristics of the cables which can interfere with one another.

17.3.3 HVAC Cabling

High voltage AC cabling would be used for AC systems with a voltage of greater than 66kV to around 132kV. In terms of this study, that would focus on cable type number 1 shown in the Figure 17-1, or the cabling between the Main Hub and the Sub Hub.

High voltage AC cabling would be selected as an option for longer distance cable runs in the power distribution network. This is because of the extended reach of high voltage circuits when considering voltage drop. Up to around 80km, high voltage AC would be the most economical cabling solution as it is the cheaper technology (Reference /69/).

The main selection of high voltage AC submarine cables on the market are:

- Single-core lead sheathed cables (laid as three individual cables)
- Three-core lead sheathed cables, cross-section shown below in Figure 17-4
- Three-core aluminium polyethylene-laminated (APL) sheath
- Three-core aluminium polyethylene-laminated (APL) sheath and wire screen

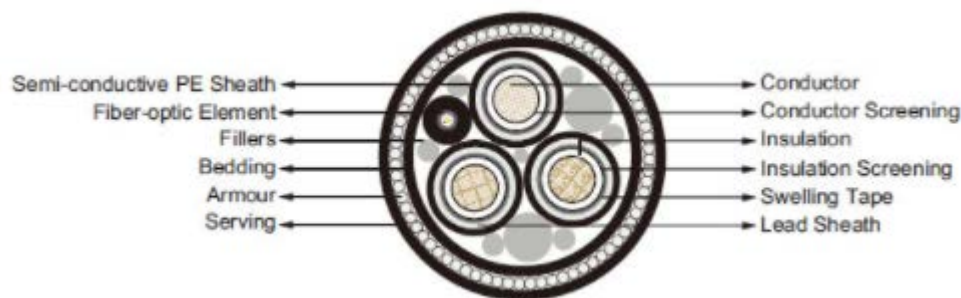


Figure 17-4: Cross-section of Three-core Lead Sheathed HVAC Submarine Cable (Reference /70/)

Cable sizes for high voltage AC circuits ranging between 66kV and 132kV vary from 185mm² up to 1000mm². Table 17-2 below provides the available cable size options for both single core and three core high voltage AC systems.

Cross-sectional Conductor Sizes for Single-Core and Three-Core HVAC Submarine Cables	
	185mm ²
	240mm ²
	300mm ²
	400mm ²
	500mm ²
	630mm ²
	800mm ²
	1000mm ²
	1200mm ²
	1400mm ²
	1600mm ²

Table 17-2: Cross-sectional Conductor Sizes for Single-Core and Three-Core HVAC Submarine Cables

17.3.4 MVDC Cabling

Medium voltage DC cabling would be used for DC systems with a voltage of up to 75kV. In terms of this study, that would again focus on cable type number 1 shown in the Figure 17-1, or the cabling between the Main Hub and the Sub Hub.

Medium voltage DC cabling would be selected as an option for longer distance cable runs in the power distribution network. This is because of the extended reach of high voltage circuits when considering voltage drop. Greater than 80km, this solution would be preferable due to the technology available to reach distances well beyond what AC can achieve, within reasonable economic boundaries.

The main selection of medium voltage DC submarine cables on the market are:

- Single-core lead sheathed cable
- Mass impregnated (paper insulation) lead sheathed cable

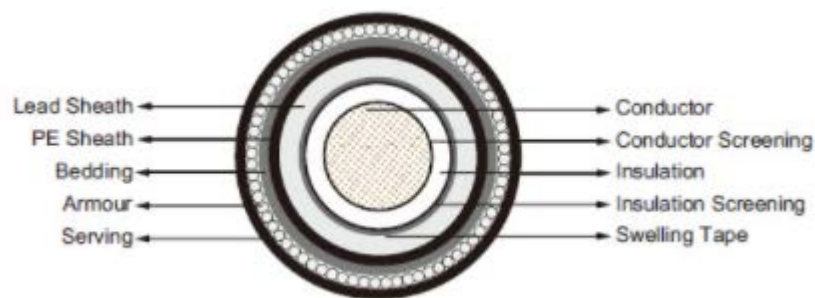


Figure 17-5: Cross-section of Single-core Lead Sheathed MVDC Submarine Cable (Reference /71/)

Cable sizes for medium voltage DC circuits up to 75kV vary from 500mm² up to 1600mm². Table 17-3 below provides the available cable size options for high voltage DC systems.

Cross-sectional Conductor Sizes for Single-Core HVDC Submarine Cables	
	500mm ²
	630mm ²
	800mm ²
	1000mm ²
	1200mm ²
	1400mm ²
	1600mm ²

Table 17-3: Cross-sectional Conductor Sizes for Single-Core HVDC Submarine Cables

17.3.5 MVAC Cabling

Medium voltage AC cabling would be used for AC circuits ranging from 6.6kV to 33kV. In terms of this study, this focuses on cable type number 2 shown in Figure 17-1, or the cabling from the Sub Hubs to the oil and gas platforms.

The cable runs from the Sub Hub to the oil and gas platforms are a relatively short distance, in comparison to the HVAC and MVDC cable runs discussed above. Therefore, utilising MVAC cable types is the best solution economically.

The main selection of medium voltage AC submarine cables on the market are:

- Three-core XLPE insulated cable
- Three-core EPR insulated cable



Figure 17-6: Cross Section of XLPE Insulated Cable

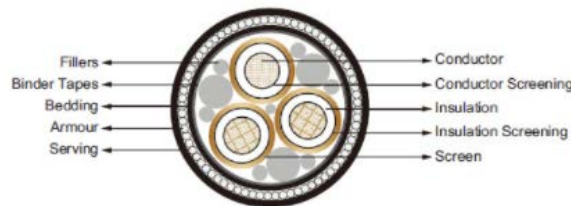


Figure 17-7: Cross Section of EPR Insulated Cable

Cable sizes for medium voltage AC circuits ranging from 6.6kV to 33kV vary from 35mm² up to 240mm². Table 17-4 below provides the available cable size options for medium voltage AC systems.

Cross-sectional Conductor Sizes for Three-Core MVAC Submarine Cables	
	35mm ²
	50mm ²
	70mm ²
	95mm ²
	120mm ²
	150mm ²
	185mm ²
	240mm ²

Table 17-4: Cross-sectional Conductor Sizes for Three-Core MVAC Submarine Cables

17.4 Static and Dynamic Cabling

17.4.1 Static Cabling Design Elements

The design elements of static cables are as described above in Section 17.4.1. However, static HV submarine cables have mostly a smooth sheath because of the reduced torsional impacts.

17.4.2 Static Cabling Use Case

Static cabling will be installed on the ocean floor – normally buried - and shall not have the flexibility of movement due to the environmental forces such as waves.

The main use case for static cables is between static assets. Whether this be the Main Hub to the Sub Hub as per Figure 17-1 or the Sub Hub to the oil and gas assets.

Some of the challenges that static cables face includes a rocky seabed, shoreline or foundation which places severe demands on the cable. Adequate protection of these cables is very important. When cable burial is not an option, this protection is offered in the form of cylindrical half-shells or split pipes. They provide abrasion resistance, and their weight also provides stabilising capabilities. In addition, protection for longer cable runs which will mostly be static cables can be provided in the form of a concrete mattress, rock dumping and rock bags. The most popular solution, as mentioned previously, is burial of the cable in the seabed. (References /72/ & /75/)

Further information on how static cables are installed can be found in Section 17.6.

17.4.3 Dynamic Cabling Design Elements

In contrast to static cables, dynamic cables are expected to move in the water due to external forces such as a floating asset.

Dynamic HV cables need to have a corrugated sheath to cope with the fatigue of the cable. Smooth lead sheaths used for static power cables are not designed to cope with the levels of fatigue experienced in a dynamic cable.

In response to the stresses placed upon a dynamic cable the structure of this cable type is quite different to a standard static cable type. A dynamic power cable has double armouring. The additional layer is added to provide torsional stiffness. A dynamic power cable also has a larger conductor cross-sectional area (CSA) due to thermal limitations imposed by protection devices such as bend stiffeners installed on the cable. By increasing the CSA, the induced heat when the cable is live is reduced solving the thermal problem of the cables (Reference /73/). An example of a dynamic power cable is shown below in Figure 17-8.

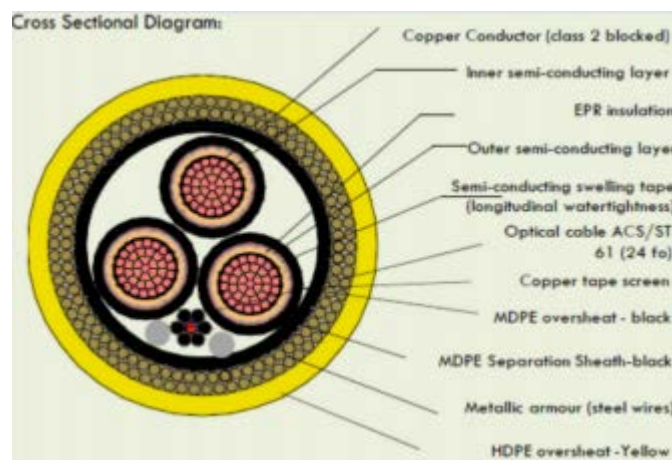


Figure 17-8: Cross-sectional Conductor Structure of a Dynamic MV Submarine Power Cable

17.4.4 Dynamic Cabling Use Case

This cable type shall be used more for floating devices such as floating offshore wind turbines (FOWTs). With floating platforms there must be a level of flexibility in the cable to allow for the movement of the FOWTs and the environmental impact stressed upon the cable by waves. This causes greater stress on the cables both mechanically and electrically in comparison with static cables.

Further information on how dynamic cables are installed can be found in Section 17.7.

17.5 Pre-Installation Planning

The first step of the overall cable installation process is to ensure the correct parties and authorities have been engaged and consent agreed that the subsea cable can be installed in the area chosen. Further consents will be required for the assets offshore, but this study focuses on the cable installation only.

Following on from obtaining the required consents a study phase will commence. This will identify a proposed route based on existing information on the area and look at any potential risks to the installation which may be encountered. After the study phase completion, a survey to inspect the route is required.

17.5.1 Cable Laying Survey/Site Investigation

The purpose of the cable laying survey is to identify a safe route for the cable. The desk top study phase identifies the potential route however the survey is critical for clarification of any assumptions made at that time and for optimising the early planning decisions.

Installation and burial contractors need the survey information to choose a suitable type and installation method depending on the seabed terrain and the method of fixing the cable to the seabed. If the incorrect cable type is selected and the protection is not suitable for example, this could result in cable transmission failures which would be inconvenient and expensive.

Burial of the subsea cable in the seabed is the most common solution for submarine cable installations. However, this is not the only method. Alternative methods of cable protection are discussed in Section 17.8.

Generally, two kinds of survey are undertaken, a geophysical survey and a geotechnical survey (Reference /76/).

Geophysical Survey

This survey is a non-penetrative survey and provides details for the entire route of the cable installation. A survey vessel covers the route of the cable installation and emits pulses via a magnetometer. This highlights any obstacles in the place of the proposed cable route including boulders and shallow faults in the vicinity. Seismic tests are also undertaken during a geophysical survey. Powerful air guns send seismic pulses to the seabed which maps out the different layers of the seabed. In addition to the seismic vessel, a hydrophone is dropped to the ocean bottom which detects the seismic energy of the seabed via pressure changes. Figure 17-9 below illustrates what is included in a geophysical survey.

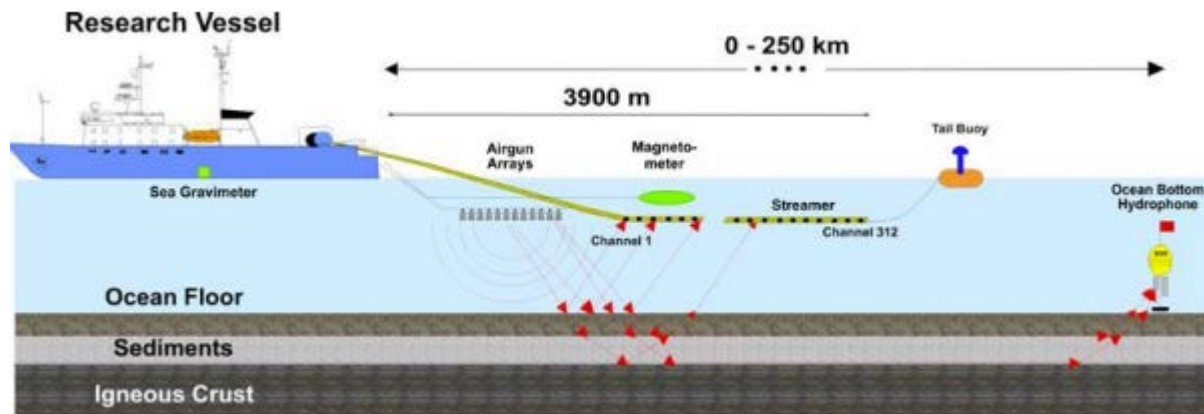


Figure 17-9: Illustration of a Geophysical Survey (Reference /76/)

Geotechnical Survey

This survey is penetrative and focuses on the soil conditions of the seabed. This results in only certain areas of the cable route being fully detailed as soil conditions are only taken at intermittent spots along the route. Drilling is done to obtain 6m soil samples which are then transported to a lab and analysed. The soil properties are then determined which provides valuable information on which cable type should be selected. Cone penetration tests are also completed to test the resistance of the seabed towards the penetration of a test cone. This test type will have a critical part to play in understanding the cable burial depth.

The two survey types mentioned above are mostly applicable to static cable type installations but are also valuable for dynamic cables, especially the geophysical survey.

17.5.2 Cable Design Characteristics

The results from the surveys have a large say in the cable design. Things such as the burial depth, soil conditions and design of J-tubes all affect the cable design. The burial depth for example, will determine the thermal conductivity to be considered when selecting the cable size. If the cable is buried near the top of the seabed the temperature may be warmer in comparison to a lower burial depth. This would need to be considered as this can increase the cross-sectional area of the cable in relation to the cable's current carrying capacity.

The cable design also influences the installation methodology. For example, a greater cable size may increase the cost of installation by reducing the selection of suitable vessels which have the necessary capabilities to deal with the cable weight, minimum bending radius, or maximum pulling factor (Reference /76/).

17.6 Installation Techniques for Static Submarine Cables

The survey will determine the route and the cable type required and leads onto the front-end-engineering design (FEED) stage and procurement stages. Once all equipment, materials etc has been procured and a timeline agreed for installation the process can begin. An overview of this is provided below.

17.6.1 Overview of Installation Process

The process begins with pre-lay grapnel run (PLGR), covering the length of the cable route, to clear any debris. The grapnel is towed from the vessel and is deployed to retrieve any abandoned human activity equipment such as fishing gear, which may be left along the cable route. The cable lay vessel (CLV) is then used to install the cable. The CLV must come equipped with a carousel cable storage facility for loading, transporting, and installing the cables. An example of this is shown below in Figure 17-10. Cable characteristics such as the bend radius and pulling factor are also to be considered when selecting the CLV to ensure it can handle the cable load and installing successfully.



Figure 17-10: Cable Lay Vessel Operations Example (Reference /77/)

Following the 'shore pull' part of the cable installation the CLV then lays the rest of the cable system to the required depth. This is usually around 1 meter below the seabed to avoid risks which may be posed by fishing or other man-made activities. The cable is laid to conform to the seabed contours which avoids the cable laying in suspension. The cable is constantly being tested during the laying process to ensure no damage occurs during the operation.

High redundancy dynamic positioning or DP2 has been a popular factor when considering the CLV choice. This allows cable laying at a reasonable speed without reducing the laying accuracy. This also allows for monitoring during the installation to gather key information on the burial results.

Where the cable encounters existing submarine cables or pipelines along the route, crossing methods such as rock dumping or mattresses are used. Consideration must be given to scouring of the cables via either of the methods mentioned. A proximity and crossings agreement will be made between the existing and new infrastructure owners (Reference /78/).

Depending on the cable selection the maximum length supplied by the cable manufacturer may not be suitable to cover the entirety of the route. Therefore, one or more cable joints will be required. The location of the joint will need to be carefully selected and must acknowledge water depth, soil conditions and exposure to wind resulting in stronger waves.

At the end of the cable lay, the cable shall either be connected to its destination, or a final splice is made to join the cable at a transition joint where the cable can be extended. The cable type would switch to a

dynamic type of cable at this point. Further details on the installation process of dynamic cabling are provided in Section 17.7.

17.6.2 Cable Burial

During the FEED stage of a project and following the survey, a cable burial target depth will have been identified. Usually this is around 1 meter. The two principal activities to be completed during the cable installation is that the cable must be lowered under controlled circumstances to the seabed and the cable then must be buried. There are two main cable burial solutions: a) simultaneous lay and burial (SLB) or b) post lay burial (PLB). The cable laying process is shown below in Figure 17-11.

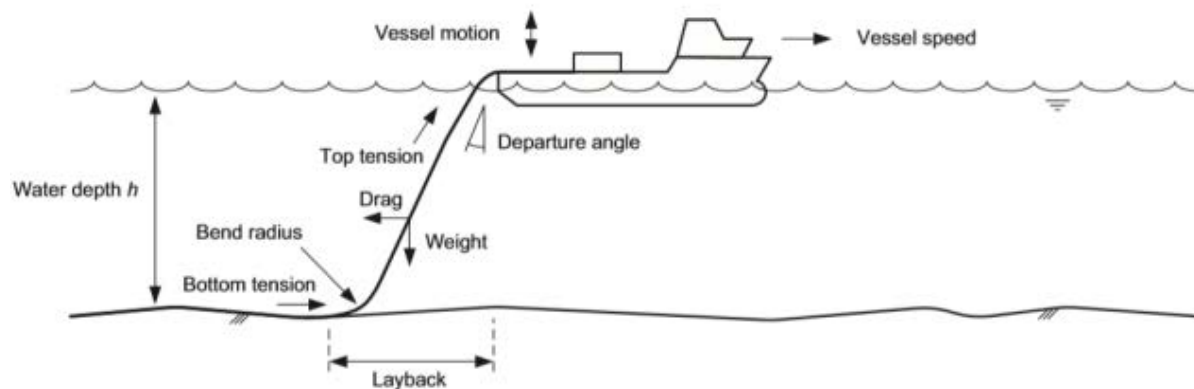


Figure 17-11: SLB Cable Laying Process (DNV, 2016)

SLB is completed by the same CLV. As the cable is being dropped from the CLV it is also being laid at the same time. PLB is when the install and the burial is completed by different vessels. A separate installation vessel follows the CLV and operates the installation tool following the CLV activities.

Some of the factors which affect how a cable is laid and what equipment is used to lay the cables are given below (Reference /79/):

- Seabed conditions
- Cable properties – considering lengths, mechanical properties, marine condition, and vessel size.
- Laying and burial combinations. Considers the seabed sediments conditions.
- Mode of movement and burial tool carrier system
- Anticipated performance. Considers predicted vs actual achievable burial depth, sediment stability, tool stability, speed of lay, maintenance.
- Water depth

17.6.3 Types of Equipment for Cable Burial

The types of equipment selected for cable burial are listed below:

- Cable ploughs
- Jet trenchers and sledges
- Mechanical trenchers
- Vertical injectors
- Mass flow excavators

The guide for selection of the cable burial equipment based on the seabed conditions is provided below in Figure 17-12.

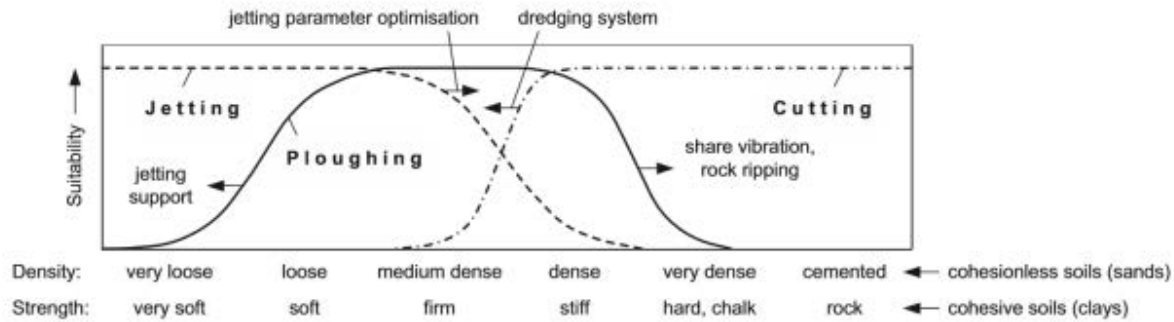


Figure 17-12: Guidance for Cable Burial Tool Suitability (Reference /80/)

Cable Ploughs

Cable ploughs dig a trench for laying the cable using mechanical force. Typically, this is used for SLB and so the plough is towed by the CLV during the installation process. However, they can also be used for PLB using a grabber and loading system to do this under the water. The cable is lowered by the CLV and passes through the plough which has been digging the trench simultaneously. This is shown in Figure 17-13 below. Once the trench has been dug the cable is dropped into it via the plough.

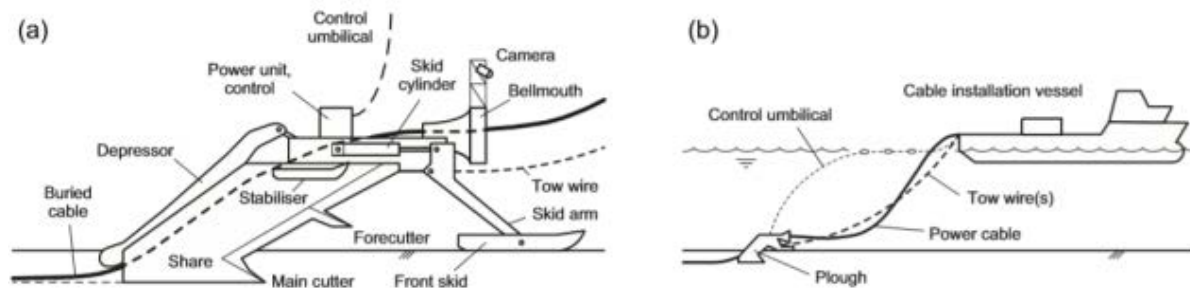


Figure 17-13: (a) Subsea Cable Plough Principal Components, (b) Cable Lay Operations (Reference /80/)

The advantages of a cable plough are (Reference /78/):

- The cable burial depth is equal to the plough share depth
- Can be used in a range of soils
- Instant cable protection when the cable is laid simultaneously
- They can be fitted with additional features such as jets for burying in sand, improving performance further

The disadvantages of cable ploughs are:

- Cable loading can lead to mechanical damage
- The high pulling force required to pull the plough through tough soils increases the potential severity of damage to the cable
- The tougher the soil conditions – stiff clay for example – the larger the vessel required, increasing the overall laying costs
- Potential to introduce residual tension in the cable causing wear over time

Jet Trenchers and Sledges

These are normally used where the seabed sediments can be fluidised, areas such as sand and clays for example. Jet equipment is normally surface fed, with water pumps on the CLV however, these jets can also be mounted onto equipment operating at subsea levels such as ploughs to aid with the installation. The surface fed systems require hoses and umbilicals to feed the machines. This causes restrictions to the depths at which they operate, less than 50m.

Jet trenchers use a series of small diameter nozzles mounted onto the jet legs located at either side of the cable. The legs are lowered until near vertical and the trencher – usually driven on tracks instead of

free-flying – moves forward forming a trench. The cable is run between the jet legs and is laid following the digging of the trench. This is either done via gravity or via a depressor which lowers the cable in a controlled manner. Figure 17-14 below shows a typical jet trencher installation procedure.

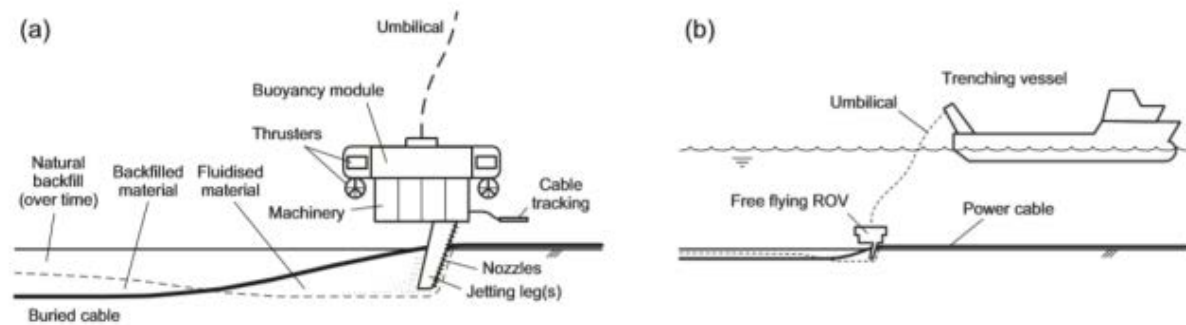


Figure 17-14: (a) Jet Trencher Principal Components, (b) Cable Lay Operations (Reference /80/)

Jet sledges are a hybrid of a jet trencher and a cable plough. These need to be towed or pulled.

The advantages of jet-based tools are (Reference /78/):

- They offer high burial speeds. The higher speed can offer a cost saving over the full length of the cable
- Minimal risk of damage to the cable
- Jet trenchers are used to carry out remedial and multiple passes to achieve burial, whereas ploughs are single pass only

The disadvantages of jet-based tools are:

- Application is limited by the seabed conditions, i.e., softer soils such as sand and clay. However, newer machines are increasing the seabed stiffness limits.
- Jet sledges cannot be used in areas where jetting in the near shore is prohibited

Mechanical Trenchers

Mechanical trenchers use a wheel or a cutting chain to form a trench which the cable falls into. These are used for high strength soils, such as stiff clay, and are independent of the CLV. The cable is loaded into the trencher and the trencher follows a surface laid cable, burying it as it goes. The operation of a mechanical trencher is shown below in Figure 17-15.

A mechanical trencher can also be used to complete the pre-lay cutting activities.

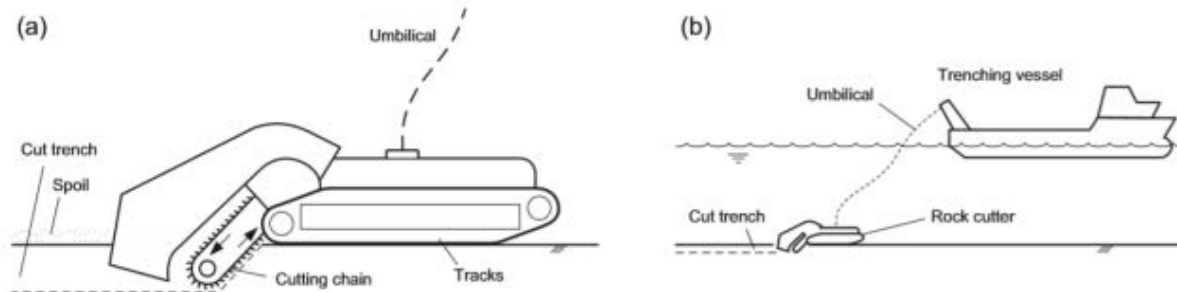


Figure 17-15: (a) Mechanical Trencher Principal Components, (b) Pre-Lay Operations (Reference /80/)

The advantages of mechanical trenchers are (Reference /78/):

- Mechanical cutters can cut through harder soil and do not need a high strength pull vessel to do so
- Although slower than a cable plough, decoupling the CLV from the trenching vessel can provide a cost saving in comparison
- They work better with bundled cables for example DC cables used at greater distances from shore

The disadvantages of mechanical trenchers are:

- They usually must be loaded with surface laid cables, and this increases the risk of damage to a cable
- It is a slow process. However, it must be used when soil conditions are tough. The cutting speed decreases with the greater the burial depth and results in increases to costs of the project

Vertical Injectors

These are usually mounted on sleds or tracks or suspended vertically over the side of a CLV. The main use case for vertical injectors is very deep burials.

Mass Flow Excavators

Though generally used for sandwave or mega-ripple pre-sweeping, mass flow excavators have also been successfully used as a post lay burial tool. The equipment is lowered towards the seabed from a vessel and used to either fluidise the seabed beneath the cable allowing it to sink further into the trench beneath or used to jet the seabed soils onto the top of the pre-laid cable within the trench. This is effective in areas where the seabed consists of loose sand (Reference /78/).

17.7 Installation Techniques for Dynamic Cabling

Dynamic cabling allows for greater levels of mechanical and electrical stress on the subsea cable. This is ideal for cables travelling from the seabed up to a termination point at a substation, floating wind farm or other asset. The greater levels of stress resistance allow for the cable to cope with the environmental conditions, sea motion and use of floating equipment such as floating wind turbines.

17.7.1 Overview of Installation Process

Dynamic cabling shall usually be installed following the installation of a static cable. Usually, the static cable will be terminated within a submarine or transition joint and the dynamic cable will be installed from the other end of the joint to its final connection point. This is illustrated below in Figure 17-16.

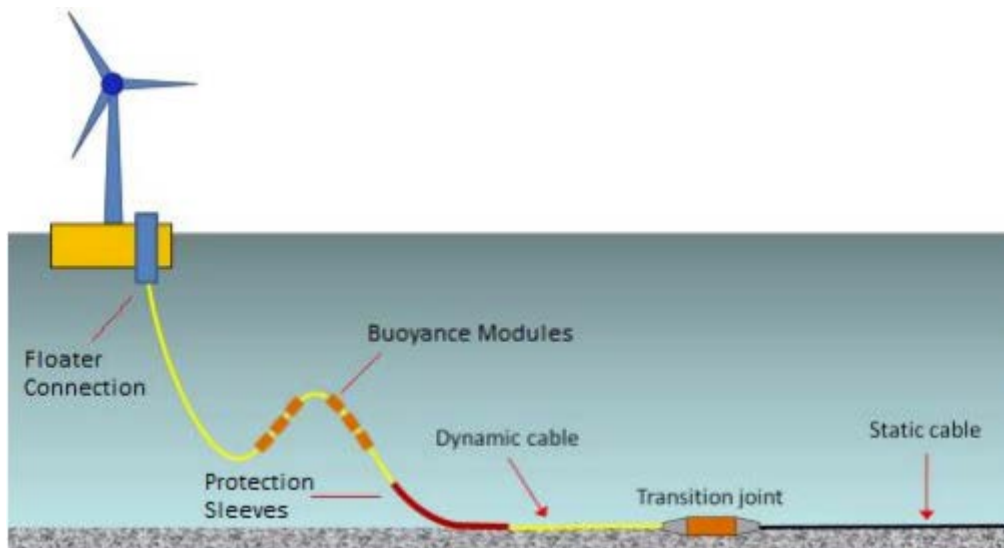


Figure 17-16: Components of a Dynamic Cable System (Reference /76/)

17.7.2 Dynamic Cabling Installation Techniques

Many different installation techniques or hanging configurations are available when installing dynamic cabling to a floating asset and these are shown below in Figure 17-17.

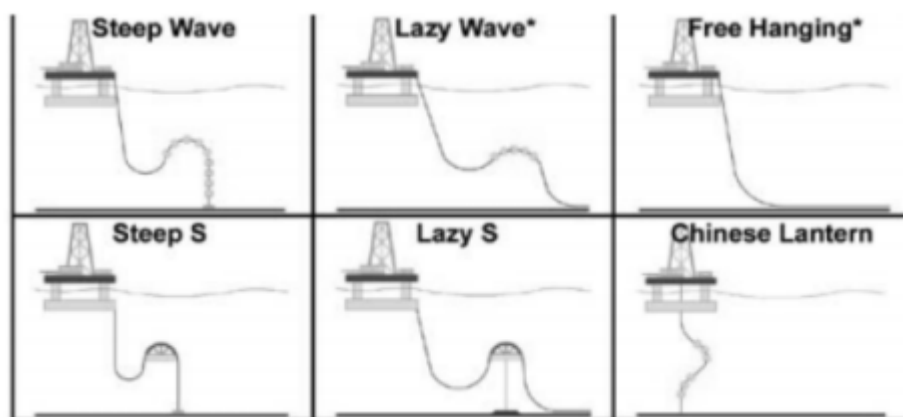


Figure 17-17: Dynamic Cable Installation Techniques (Reference /73/)

Steep Wave and Lazy Wave

Both hanging configurations make use of buoyancy modules. As shown in Figure 17-17 above the main difference between the 2 configurations is the steepness by which the dynamic cable touches the seabed. This affects the cable bend radius; a key factor in cable design. The lazy wave configuration is preferred to the steep wave in most circumstances due to the lower requirement for subsea infrastructure and the reduction in tension force.

Free Hanging

The simplest configuration. No buoyancy modules are required and so the install is simpler, and cost of this method is less than the others shown in Figure 17-17 above. However, the tension from the hanging point of the cable is considerably higher, especially when installed in deeper waters.

Steep S and Lazy S

Both these configurations have a subsea buoy along with a midwater arch connected to the cable. The differences between the two is that the midwater arch for the Lazy S configuration is connected to the seabed and the steepness of the touchdown point. The buoy used as the midwater arch also has a tension property resulting in lower tensions at the touchdown point for the Lazy S configuration.

Chinese Lantern

This method consists of a straight downward cable with a curve in the middle formed by buoyancy modules. This is the most difficult of all the configurations shown in Figure 17-17. This is due to the calculations required to be completed before the install.

The most common hanging configurations are the Lazy wave, Lazy S and Steep wave for dynamic cables (Reference /81/).

FOWTs use another configuration type when interconnecting with each other known as the W-shaped cable. The interarray cable between FOWTs does not touch the seabed and buoyancy modules are connected to the cable to form a W-shape in the cable, hence the name. This reduces the force of motion on the cable and results in a superior dynamic response in comparison to cables dropping to the seabed. A shorter amount of cable is also required meaning a saving in cost. However, at the time of writing this cable installation method is only a research and development project and has not yet been implemented to windfarm arrays for example (Reference /73/). The configuration of a W-shaped cable is shown below in Figure 17-18.

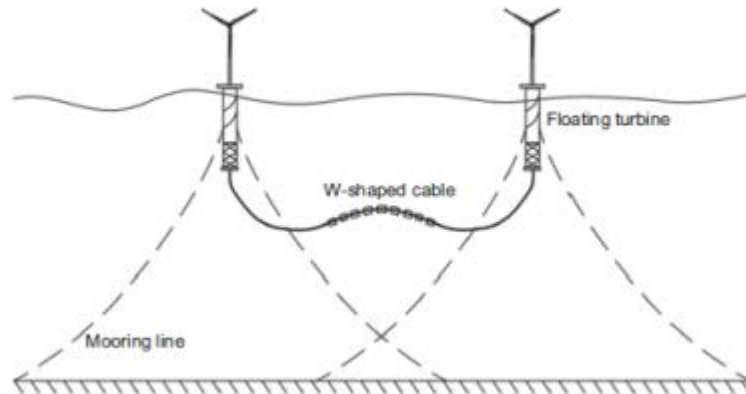


Figure 17-18: W-shaped Interarray Dynamic Cable Between FOWTs (Reference /73/)

17.7.3 Dynamic Cabling Ancillaries and Equipment

The components involved in a dynamic power cable installation are shown below in Figure 17-19. The main components affecting the dynamic cables are further discussed below.

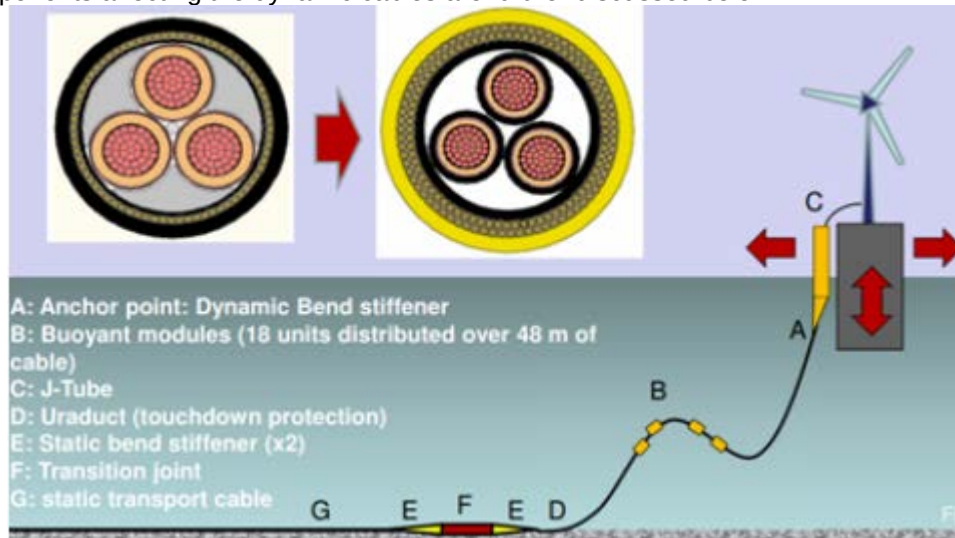


Figure 17-19: Typical Dynamic Power Cable Installation Components (Reference /73/)

Static and Dynamic Bend Stiffeners

These are attached to the top and bottom parts of a dynamic cable. The bottom part as shown in Figure 17-19 above has two bend stiffeners attached at each side of the transition joint. One is for the static cable and the other for the dynamic cable.

The dynamic bend stiffener (point A) at the top of the dynamic cable is required to cope with the heavy axial loads to avoid over bending and fatigue failure. A bend stiffener is in the shape of a cone with an opening for the incoming cable. Steel work is mounted to the stiffener along with a flange to transfer the load from here to the structure it is attached to. The low stiffness of the dynamic stiffener allows the transition between the floating installation and the cable to be seamless. An image of a dynamic bend stiffener is shown below in Figure 17-20. (Reference /73/)

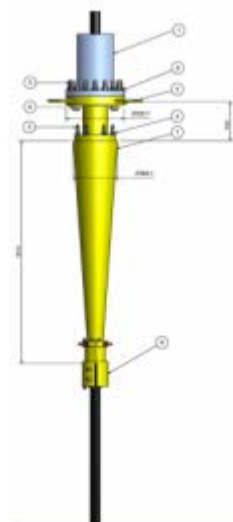


Figure 17-20: Dynamic Bend Stiffener

When designing a static or dynamic stiffener the most important information to consider is the following (Reference /82/):

- Cable diameter
- Load cases (tension vs angle)

- Operational environment
- Interface requirements with load bearing steelwork/end termination
- Fatigue loads and cycles (dynamic bend stiffener design)
- Tension and angle combination (dynamic bend stiffener design)

There is currently a gap in the market for HV dynamic power cables when considering dynamic bend stiffeners. These are available up to limited cable sizes for most cable types however for HV dynamic cables much larger dynamic bend stiffeners are required with a much higher stiffness. This is to cope with the larger cable sizes in HV cables and the heavier fatigue loads (Reference /83/).

Transition Joint

This provides a smooth connection between static submarine cables and dynamic power cables. The transition joints consist of the following components (Reference /84/):

- Three flexible moulded core joints to provide connection for each phase. Three core joints are covered by lead sheath and soldered to the metallic sheath of both the static and dynamic power cable.
- One fiber-optical cable joint
- Armouring

Uraduct (Touchdown Protection)

This is attached to the bottom of the dynamic cable at the seabed end to protect the cable against impacts and abrasion off the seabed. The uraduct consists of two half shells that overlap the cable for 50% with an interlock arrangement. Uraduct protection is also applied to areas such as rocky environments and shore landings to provide protection to the cables installed (Reference /73/).

Buoyancy Modules

These are possibly the most important part of the installation for dynamic power cables allowing for the motion and range of movement between the floating installation and the seabed transition joint. They consist of two main components; an internal clamp, and an external buoyancy module which are two identical halves clipped to the internal clamp (Reference /85/). The internal clamps should be designed to consider:

- Avoiding slippage
- Remove high induced stresses in the cable armour
- Mitigate damage to the sheath and remove the possibility of water ingress
- The diameter of the modules
- Submerged weight of the modules
- Spacings of the external buoyancy modules

The above influences the buoyancy of the dynamic cable and may result in undesired configuration at the hanging point, arch bend, and subsea touchdown point.

Over time the buoyancy modules will lose around 10% of their buoyancy. This figure needs to be accounted for when designing the system for its operational lifetime.

J-Tube

An open-ended section of tube or pipe, attached internally or externally to the fixed or floating asset. Used for guiding and protecting the cable to the destination (Reference /80/).

17.8 Protection of Submarine and Dynamic Cables

The most common form of cable protection for subsea cable installation is burial. However, certain conditions on the seabed result in burial not always being an option. This is further discussed below.

17.8.1 General

During the installation phase the cable design characteristics should be accounted for to ensure that mechanical load ratings of the cable are not exceeded from tension, bending, and crushing. Following installation, thought should be given to hazards which can affect the service life of the cable such as (Reference /80/):

- Marine and sediment conditions resulting in exposure to and movement of the cables
- Unsupported lengths of cable, for example on uneven terrain
- Movement of the cable between laying and protection causing abrasion on the outer sheath
- Penetration of fishing gear
- Damage caused by ship anchors
- Invasive activities such as dredging
- Dropped objects resulting in crushing
- Seismic activity
- Ice scour

17.8.2 Forms of Protection for Submarine Cables

The main forms of cable protection come from:

- Burial
- Armour
- Non burial protection

The above are all further explained below.

Burial

Section 17.6.2 discussed cable burial in depth.

Armour

The armouring must be designed to meet the tensional forces applied to the cable during the laying period as well as the service life of the cable. Table 17-5 below provides a philosophy for armouring telecom cables based on water depth. The shallower the sea depth the greater the protection provided by the armour needs to be due to greater chance of damage being caused by external threats such as fishing.

Water Depth	Armouring	Characteristics
Less than 200m	Rock Armour (RA)	Double armour with short lay in the outer armour layer, improved impact resistance and better flexibility to follow seabed topology
Less than 500m	Double Armour (DA)	Protected cable for areas with little or no burial depth
Less than 1500m	Single Armour (SA)	Used for areas with limited burial depth

Table 17-5: Types of Cable Armouring for Submarine Telecom Cables (Reference /86/)

The choice of armouring is also dependant on the cable route. Obstacles or activities that take place in certain areas may call for greater protection. Therefore, the choice of armouring is a balance between the capital costs to pay for the cable itself and installation costs and the costs which might be incurred should damages be realised i.e., repair costs and income losses if the network loses power. The initial costs of paying for additional armouring on a cable are known but the future costs of damages and the like can only be estimated. Armouring cannot be upgraded after a certain number of years and so the design life of the cable should also be considered.

Non-Burial Protection for Submarine Cables

Some of the more common non-burial protection methods include:

- Cast Iron half pipes
- Concrete slabs
- Cement bags or mattresses
- Rock dumping

Cast Iron Half Pipes

These are simply covers which are assembled over the cable once it has been laid. They provide strong protection from the cable against external threats and are mostly applied in areas such as near-shore waters.

Concrete Slabs/Cement Bags or Mattresses

These can normally be applied from sea level, but purpose built ROVs have also been known to be used for laying mattresses over longer lengths.

Rock Dumping

Vessels carry rocks and discharge them over the cable laid on the seabed. There are a few methods for doing this, rocks can be simply pushed over the side of the vessel, a bottom door unloads the rocks, or a flexible fall pipe can be used. The fall pipe option provides a better aesthetic finish to the placement of the rocks.

17.8.3 Causes of Damage to Dynamic Power Cables

The potential areas and activities that can damage submarine or static power cables are also applicable to dynamic power cables. However, there are also different challenges faced by dynamic cables which can occur during the installation process, by further human activities and from the operational wear and tear. The potential damages to all submarine cable types have been summarised in Table 17-6 below.

Damage Category	Kind of Damage	Applicable
Installation	Small bending radius	Yes
	Loss of dynamic positioning	Yes
	Anchoring damages	Yes
	Emergency cut	Less likely
	Loading/Re-loading	Less likely
	Kinks	Less likely
	Trenching	No
Human Activities	Fishing equipment	Less likely
	Jack up	Less likely
	Anchors	No
Operational	Free span	Yes
	Joint failure	Yes
	Geo-hazards	Yes
	Internal defects	Yes

Table 17-6: Overview of Submarine Power Cable Damages Applied to Dynamic Power Cables (Reference /73/)

Installation Damages

Mitigation of the installation damages can be achieved by having accurate control of the CLV and having a good knowledge of the surroundings of the area the cable is being installed.

Kinks and loading/re-loading are less likely because of the shorter length of dynamic cables in comparison to the static submarine cable types.

The emergency cut procedure is also less likely to happen due to the shorter installation time for dynamic cables.

Trenching is irrelevant for dynamic cables, and therefore is not considered an installation damage in the table above.

Human Activities

It is seen as less likely for fishing equipment to cause damage to dynamic power cables because fishing boats are not allowed to sail within 500m of FOWTs and other offshore structures (Reference /73/). This greatly reduces the chance of fishing equipment scouring or becoming entangled with the dynamic cables. The increased distribution of floating offshore windfarms has led to less accessible waters for fishing to take place, further reducing the risk of damage.

Any damages which may be caused by jack ups are also less likely with dynamic cables. Jack up vessels are generally used in depths of up to 120m. FOWTs for example are deployed at water depths of anywhere between 40m to 500m and so only jack ups used at depths between 40m to 120m can cause damage to the dynamic power cables. This can also be mitigated by using accurate positioning control of the CLV and advanced monitoring of the area surroundings.

Anchors are not expected to cause any damage because of the 500m restrictive zone placed around floating offshore windfarms and other offshore structures.

Operational Activities

The free span of dynamic cables can place a lot of mechanical stress and fatigue on the cable. Therefore, it is extremely important to ensure that the cable is properly designed and tested.

To avoid or reduce damages caused by joint failures equipment such as bend stiffeners can be installed. These will absorb the loads on the cable and help to avoid overbending.

Geo-hazards are unpredictable and cannot be eliminated. However, proper marine surveys can identify suitable or unsuitable locations for locating floating structures and therefore mitigate the geo-hazards presented.

Internal defects are also applicable to dynamic cables and are hard to prevent. They are considered rare among submarine cables though.

17.9 Post-Installation of Submarine Cables

17.9.1 Testing Requirements

Electrical tests to demonstrate the integrity of the cable system are completed following installation. These tests verify that the cable has not been damaged during the handling, shipping, and installation of the cable. There is currently no industry agreement on the recommended approach for cable types and lengths however Appendix I provides some further information on the installation testing methods.

Some of the testing methods used on HVAC cables are described below (Reference /78/):

- Very Low Frequency tests – using frequencies in the range of 0.1hz to 10hz.
- Resonance tests – a series test system is tuned to the natural frequency of the cable system (typically 20-30hz, determined by cable length).
- Soak test – where the cable system is connected to the grid
- Time domain reflectometry (TDR) – this involves a low energy, short-rise time pulse to be injected along the conductor of the cable, identifying any anomalies along the way. TDR techniques are used to verify the integrity of optical fibres used for communication and distributed temperature sensing (DTS) systems.

Partial discharge (PD) tests can also be performed alongside the HV tests. They provide a fingerprint for comparison during all stages of cable manufacture, installation, and subsequent in-service operation.

Testing for HVDC cables following installation is simpler compared with HVAC. This increases the likelihood of detecting a fault in the cable.

17.9.2 Assessments

Two assessments which should be completed following the installation of any submarine cabling are a Depth of Burial (DoB) assessment and a post-burial risk assessment (Reference /78/).

Depth of Burial Assessment

This should be completed along the entire cable length. During the installation process some cable installation tools may be used to collect data on the cable depth, condition etc. However, it is also common for a standalone survey to be completed to fully assess the DoB. The data collected is used to verify that the completed installation and protection works have been completed in accordance with requirements and the agreed contract.

A post-lay survey should be completed after all installation work has been completed. This survey will provide (Reference /78/):

- The position of the cable compared to the cable route identified at the FEED phase
- The DoB and/or depth of cover of the cable
- Verification that the condition of cable protection is still intact and in accordance with the design specification
- Confirmation that the minimum separation distance and minimum required height of cover at crossings are achieved and the maximum height of cover is not exceeded
- A detailed record of the cable length and any cross-profiles of the protection and adjacent undisturbed seabed at regular intervals
- Video or alternative survey method of the covered cable length
- A check of any existing infrastructure close to the cable route to ensure the infrastructure is not damaged
- The location of any scour or erosion along the cable route
- Locating and counting any free spans, with length and gap height
- A description of any previously unidentified wreckage, debris or other objects which may/has affected the cable system at some point
- Pinpointing where any damage to the cable is precisely
- Video of any damaged cables, the location of the damage etc

Post Burial Risk Assessment

The minimum burial depths, determined pre-installation, could be revised during a post-installation review of the risk assessment. The post-installation risk assessment methods should follow those of the pre-installation methods.

If it is identified during the post burial survey that the intended burial depth has not been achieved there are ways to counter this such as (Reference /78/):

- Post-lay trenching
- Additional Rock Placement
- Installation of mattresses
- Rock material within rock filter bags

The selection of remedial works mentioned above must consider the same factors discussed during the cable protection risk assessment.

Additional survey work is required to confirm that the design intent of the remedial works has been achieved.

17.9.3 Maintenance and Inspections

Maintenance can be split into 3 categories corrective maintenance, predetermined maintenance, and condition-based maintenance. The timeline for completing these maintenance methods is illustrated below in Figure 17-21.

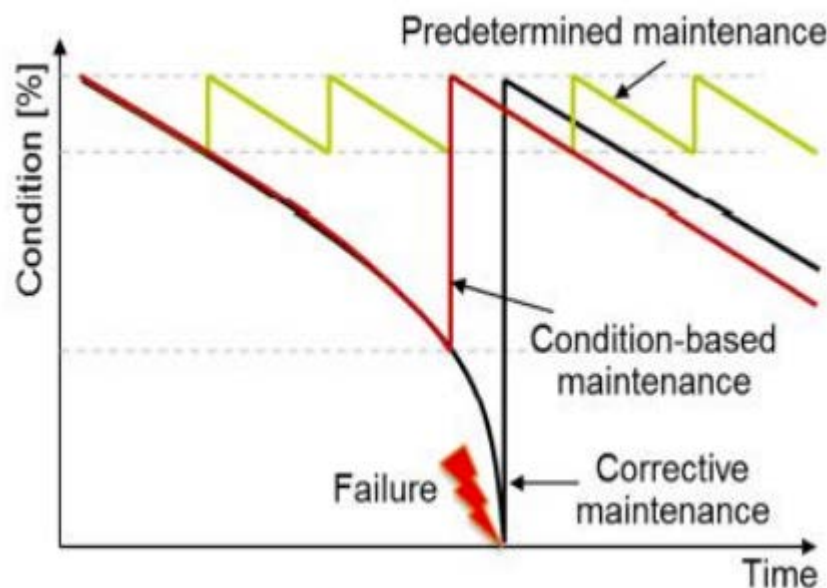


Figure 17-21: Effects of Maintenance Types on Inspected Object's Condition (Reference /87/)

Corrective Maintenance

This type of work is completed once a failure has already occurred. The cost of corrective maintenance is expensive. Locating the fault, organising the external survey, selecting, and organising the correct equipment and personnel, and undertaking the repair work all add up to a sizeable figure. The speed at which the work is to be completed also adds to the cost. The added complication of the weather conditions is also to be considered during the planning of corrective maintenance (Reference /89/).

Predetermined Maintenance

This performs preventative maintenance based on a specified time schedule in relation to the equipment installed along the cable length. The maintenance is usually carried out by regular surveys and so the condition of the cable and equipment is normally unchanged from the previous time. However, this survey type can be used to identify potential issues which are showing early signs during the inspection.

If this is the case condition-based maintenance can be implemented to avoid having to wait until failure and for the need of more expensive and corrective maintenance. Preventative maintenance can also be known as Time based maintenance or TBM.

Condition Based Maintenance

This type of maintenance is based on the condition of the existing cable. Condition based maintenance is not scheduled but would be advised following predetermined maintenance or TBM (Reference /76/). This category of maintenance requires high-quality operations and maintenance planning due to the economic costs and the challenge of trying to predict the remaining lifetime of the cable (Reference /89/).

17.9.4 Repair Methods and Procedures

Repairs due to failures of items such as cabling, protection sleeves, transition joints and connections during their operational lives are unavoidable. This can be due to human and natural activities. Faults in cables in water depths greater than 1000m are almost always caused by natural events such as underwater seismic activity and underwater landslides. Faults in cables of water depths less than 200m are almost always caused by human activities such as fishing (Reference /90/).

The process for repairing a damaged or faulty cable is as follows (Reference /90/):

1. Cable monitoring systems such as the fibre optic detect when a fault has occurred. The cable is then tested from the cable stations at each end of the cable in question to locate the position of the fault. After obtaining the location this information is passed to the cables ship.
2. The cables ship will load the necessary equipment and materials to complete the repair before sailing to the identified location.
3. The cables ship reaches the repair site. The operations start by utilising the ship grapnel hook to grab the cable. The cable is raised from the seabed and cut. If the cable has been buried an ROV may also be used to locate and/or cut the cable on the seabed.
4. After the cable is cut, the grapnel hook is recovered and replaced with a holding grapnel. This is lowered to the seabed using a rope and is towed along the seabed until the end of the cut cable is caught. The cable is then raised to the surface and recovered on board the cables ship.
5. The cable is tested, and any damaged sections removed.
6. The cable is sealed off to protect from water ingress and buoyed off the side of the cables ship.
7. Steps 4-6 are then repeated for the other end of the cable. With both ends now being cut to remove damaged portions, sealed from water ingress, and buoyed at the side of the cables ship.
8. Jointing the cables back together is the next step. Spare cable on board the cables ship is to be added between the two ends and should be of a sufficient length to replace the damaged section. However, prior to jointing the existing cables both sections should be tested to ensure all damaged areas have been removed.
9. When the cables are jointed together this is known as the final splice. The jointed cable is then lowered back to the seabed and further tests are made to ensure everything is working correctly.
10. If the cable was previously laid on the seabed, then no works to bury the cable are required. However, if the cable was previously buried, then reburial by means of ROV, water jetting the cable back into the pit and original burial target depth is required.

Figure 17-22 below shows joints on board a cables ship.



Figure 17-22: Damaged Cable Repair Joint on Cableship

17.9.5 Cable Lifespan

There are many experienced manufacturers of submarine cables with more entering the market. This has had a positive impact on the lifespan of submarine cables with competition ever increasing, new technologies are being developed continually improving the quality and lifespan of these cables. Other factors to be considered during the cable lifespan include the method of installation, the natural conditions, and sediments in the location of installation, and the protection provided to the cable. All these combined have a lasting effect on the lifespan of any submarine cable. Cables can generally be used for decades when considering the factors discussed above. However, should the cable be carrying an increased demand beyond its capacity this can significantly reduce the cable life. The usual guaranteed commercial lifespan for a cable is 25 years. However, cables which have been decommissioned had been in operation for 30-40 years prior to this (Reference /91/).

17.10 Network Expansion

As North Sea infrastructure and associated technology develops, it may be useful to utilise existing subsea electrical cabling and networks, rather than complete the full subsea cable installation process for each new asset or FOWF that is electrified.

A subsea electrical network could be designed with spare capacity to allow for future expansion. This includes the cabling being sized correctly to accommodate future additional demand.

Further research into this topic is required due to limited availability at this time.

17.11 Recovery of infrastructure

There are a few ways in which existing submarine cables which have been decommissioned can be dealt with. These are complete removal of the cable, partial removal of the cable or leave in situ.

Complete Removal of Cable

Being implemented the same way as the installation methodology – see Sections 17.6 and 17.7 – the de-bury of the cables is a complex task.

The process would begin with surveys. These would identify the cable burial depth, removal method and equipment and tools required. Thereafter, uncovering the cables via the same methods i.e., using trenching and jetting tools. In addition, the cables can also be pulled out from the soil if enough force is used and if the seabed conditions are soft soil (Reference /98/). The pulling of cables process is not this simple however as the seabed soil has formed around the cables after a period of burial. One method which can be used to loosen a cable buried in the seabed is by using under runs. This consists of a device being installed under the buried cables and being towed via a line from a vessel (Reference /99/). This is only suitable for cables which have been buried in depths under 1 meter and within softer soil conditions.

For conditions where the soil is more rigid, or the cable burial depth is greater than 1 meter then the methods such as jetting, ploughing, and trenching tools are more suited to loosen the cable from the seabed. The jetting and trenching tools are generally attached to an ROV and dragged along the seabed by a vessel as shown in Figure 17-23 below (Reference /100/).



Figure 17-23: ROV Attached to a Vessel

The high-pressure jetting tools transform the soil from a harder type to a more fluid like type of soil and allow for the cable to be retrieved more easily. The trenching tool utilises a cutting wheel which has attached replaceable cutting rocks which penetrate the seabed as the wheel rotates (Reference /99/).

The plough is preferred when the trench left behind by removing the cable is required to be reburied or refilled. This causes less disturbance to the natural environment and the seabed in comparison with jetting and trenching tool options (Reference /101/).

When alternative methods of cable protection such as concrete mattresses or rock dumping are used different, more expensive methods of removal are required. Mostly due to the alternative equipment required to remove the rocks or concrete mattresses as well as the environmental impact that is caused by damaging marine reefs which may have formed on the concrete mattresses for example (Reference /102/).

No matter the de-burial method, the submarine cable, via either end, shall be attached to a retrieval vessel where it is then spooled onto a drum or cut into lengths using a hydraulic cutting tool on board the vessel if the cable is not planned for reuse or recycle afterwards (Reference /103/). The cable decommissioning vessel should therefore be equipped with necessary tools to perform the cable pull, cable lift, cable spooling or cutting, and with necessary ROV and equipment depending on the methodology of de-burial (Reference /104/).

Partial Removal of Cable

This involves similar techniques used for the total cable removal except the entire cable is not being removed. Generally, if a decommissioned cable is buried and decommissioned and identified as needing to be removed following surveys, economic analysis and so on, the entirety of the cable will be removed. However, if a buried cable is part of a network which involves interarray cables and dynamic cables then it may be more cost effective to remove only the interarray cables and dynamic cables and leave the buried cables in situ.

Leave Cables in Situ

Should the choice be to leave the cables in situ, the cables must be buried at an appropriate depth or between 1 and 3 meters. This removes any possible risks to marine users in the future performing human activities such as fishing and limits the environmental and pollution impacts (Reference /103/). If seabed conditions are more fluid like or mobile, then consideration must be given to deeper burial of the cable to remove the risk of the cable becoming exposed (Reference /99/). This method can also include some cable removal and does not mean abandoning the cable in situ completely. For example, in areas where the cable may cross with pipelines or other submarine cables it makes sense to cut the decommissioned cable at these points to remove the crossing issue.

Following the decision to abandon cables these must still be monitored following the decommissioning to ensure the cables do not become exposed at any point. If a cable or a section of a cable was to become exposed, reburial would need to be completed. Surveys to monitor the abandoned cables can be completed by ROVs (Reference /100/).

The environmental impact of leaving cables in situ has not been fully understood. Total removal of cables has indicated that it will cause significant damage to the environment. The conductor materials – either copper or aluminium – can also potentially dissolve and contaminate the seabed sediment if the outer sheath of a cable were damaged (Reference /100/). However, it is unclear if the dissolved materials would have any substantial impact to the seabed sediment and environment (Reference /102/).

17.12 Cable Costs per km

Multiple cable manufacturers were contacted however, many were reluctant to disclose sufficient information to compile costs for specific cable sizes and voltages discussed in this study.

Various subsea cable projects have now been completed and are operational. From publicly available information for these projects, the cable costs have been extracted. Table 17-7 below gives a list of projects that have been completed and the cable cost per kilometre of the cabling.

Exchange rates of £1=€0.84 and £1=\$0.76 were applied to get comparative per kilometre cable costs. These have been rounded to the nearest £1,000.

Project	Cable Manufacturer	Voltage	Overall Cable Costs	Total Cable Distance (km)	Cost of Cable/km (£k)	Scope
North Sea Link (reference /92/)	Prysmian	DC (525kV)	€550,000,000	950	486	Turnkey Project
Hornsea 1 (reference /93/)	NKT	AC (220kV)	€139,000,000	170	687	Cable Supply
Nordlink (reference /96/)	Nexans	DC (525kV)	€625,000,000	623	843	Turnkey Project
Hornsea 1 (reference /108/)	ABB	AC (220kV)	\$250,000,000	340	559	Cable Supply

Table 17-7: Cable Costs from Previously Completed Projects

Further contract costs from upcoming projects are given below in Table 17-8. These costs are based on projects which are not yet operational and are progressing through the design stage.

Project	Cable Manufacturer	Voltage	Overall Cable Costs	Total Cable Distance (km)	Cost of Cable/km (£k)	Scope
Dogger Bank C (reference /94/)	NKT	DC (320kV)	€280,000,000	500	470	Turnkey
Gode Wind 3 (reference /95/)	Prysmian	AC (66kV)	€60,000,000	150	336	Design, Supply, Termination & Testing
Sofia (reference /109/)	Prysmian	DC (320kV)	€200,000,000	440	382	Turnkey

Table 17-8: Cable Costs from In-Progress/Upcoming Projects

HVAC Cable Costs

The HVAC cable costs range from £336,000/km to £687,000/km. The Gode Wind 3 project, being an inter-array cable for a wind farm, is representative of the cable runs required between the Sub Hubs and the Assets, however these costs exclude installation.

HVDC Cable Costs

The HVDC cable costs range from £382,000/km to £843,000/km. All the projects detailed are operating at much higher voltages and power ratings than this project and therefore these costs are seen to be higher than for the MVDC cable runs required between the Main Hub and Sub Hubs. The HVDC costs quoted are all for turnkey costs, and hence installation is included.

MVDC Cable Costs

The MVDC cable costs for offshore use are not well defined based on the novelty of the technology in this application. An evaluation has been performed based on low HVDC applications at 150 kV transmission, such as the BorWin1 project in Germany. This project installed 2 x 75 km cables at a total project cost of €40m (/110/ and /111/). This equates to a cost of £224,000/km. This has been utilised as the basis for the MVDC cable installation costs as it is considered even with a reduction in cable cost, there will be a minimum cost for installation which will prove to be the limit.

Comparison

The difference in cost is relatively small per km between the DC and AC systems mentioned in Table 17-7. However, missing information such as the conductor type – either copper or aluminium – and the cable size make it difficult to conclude on the more economically viable technology to be used. Further investigation and discussions with cable manufacturers is required to understand the costs associated with technologies and which should be put forward for different cable types. Section 17.4 in general, as well as in other studies which have been completed, it is recommended that DC technology is used for longer distance cable runs and AC cable types and voltages used at shorter distances.

To provide a conclusive analysis of the optimum solution when considering cable costs further research and discussions with cable manufacturers would be required.

17.13 Maximum cable length

Some of the factors which limit the cable length in both AC and DC cable systems are:

- Vessel load capabilities
- Cable size and weight
- Cable conductor type

Vessel Load Capabilities

One of the main things to consider for the cable length is what the cable lay vessel can carry and offload. Most CLV's have a certain tonnage they can cope with. Table 17-9 below has identified some subsea cable installation vessels and the limits on their capacity for carrying subsea cables.

Operator	Vessel	Total Cable Capacity (Tonnes)
Jan de Nul	Isaac Newton	10,000
Jan de Nul	JDN8625	4,000
VBMS	Ndurance	5,000
VBMS	Ndeavor	2,000
VBMS	Stemat Spirit	4,600
Global Marine	Cable Innovator	7,000
Global Marine	C.S.Sovereign	4,600
Global Marine	Networker	750
Nexans	C/S Nexans Skagerrak	7,000
Van Oord	Nexus	5,000
A2SEA A/S	Atlantic Carrier	500
Orange Marine	Pierre de Fermat	2,000
Deepocean	Maersk Connector	7,000

Table 17-9: Maximum Tonnage of Selected Subsea Cable Installation Vessels (Reference /105/)

Table 17-9 shows that there is a wide range of capabilities when considering CLVs and their maximum tonnage. Depending on the overall cable tonnage for a specific project the available CLVs may be limited for example if the total cable load was above 8,000 tonnes, then there is only 1 CLV which could be utilised based on the subsea CLVs identified in Table 17-9.

Cable weights for AC cables at both 132kV and 275kV have been provided below in Table 17-10 based on some typical sizes.

CSA (mm ²)	132kV		275kV	
	Copper Conductor	Aluminium Conductor	Copper Conductor	Aluminium Conductor
800	78	61	101	84
1000	90	68	112	90
1200	102	74	125	97
1400	110	79	133	102
1600	120	84	143	107

Table 17-10: Cable Weights (kg/m) Based on Typical Sizes of 3-Core HVAC Cables (Reference /105/)

Using the data provided in Table 17-9 and Table 17-10 the maximum length of cable that an installation CLV can accommodate can be calculated. Note this has only been completed for the 132kV cable size as this is more relevant for this study. A 4,000 tonne and a 10,000 tonne CLV have been used to obtain the maximum cable lengths in km.

CSA (mm ²)	4,000 Tonne Capacity		10,000 Tonne Capacity	
	Copper Conductor	Aluminium Conductor	Copper Conductor	Aluminium Conductor
800	51	65	187	153
1000	44	58	111	147
1200	39	54	98	135
1400	36	50	90	126
1600	33	47	83	119

Table 17-11: Cable Lengths (km) Accommodated by 4,000 and 10,000 Tonne Vessels (Reference /105/)

It can quickly be realised that the smaller CLVs are extremely limited in what they can carry, and the total cable lengths are heavily restricted for 132kV AC systems. When utilising a larger capability CLV the distance of cable that can be carried on board is greatly improved. However, this will come with significant cost increase for hiring the vessel and equipment needed to do this.

Cable Size and Weight

In addition to the data provided above in Table 17-9, Table 17-10 and Table 17-11 around cable sizes and weights, the current carrying capacity of cables must also be thought of. Table 11 below shows the current carrying capacity for 3-core 10-90kV AC power cables and for 3-core 100-300kV AC power cables. It also includes the differences in current carrying capacity between copper conductors and aluminium conductors.

CSA (mm ²)	10-90kV 3-Core XLPE Cables		100-300kV 3-Core XLPE Cables	
	Copper Conductor	Aluminium Conductor	Copper Conductor	Aluminium Conductor
95	300	235	N/A	N/A
120	340	265	N/A	N/A
150	375	300	N/A	N/A
185	420	335	N/A	N/A
240	480	385	N/A	N/A
300	530	430	530	430
400	590	485	590	485
500	655	540	655	540
630	715	600	715	600
800	775	660	775	660
1000	825	720	825	720

Table 17-12: Current Carrying Capacities for 3-Core XLPE AC Cables (Reference /106/)

Copper conductor cables are afforded a higher current carrying capacity in comparison with Aluminium conductor cables. However, as shown in Table 17-10 copper conductor cables weigh more and so limit the length of cable which can be loaded onto a CLV. Therefore, the cable length which can be loaded onto a CLV along with the current carrying capacity will play a significant role in the selection of the cable size and the number of cables required.

Cable Conductor Type

It can be seen in the various Tables above that there is a noticeable difference between copper conductor and aluminium conductor cables in aspects of the cable design. Copper conductor cables weigh more but have a higher current carrying capacity in comparison to aluminium conductor cables.

In addition to the restrictions mentioned above, further consideration should be given to cable manufacturers and the maximum factory length that can be manufactured. Cables can be extended, if the manufacturing length does not cover the required length, using joints.

17.14 Cable junctions

Underwater cable junctions are a technology that exists, but limited information is currently available on this equipment. The Greenlink Hub produced by MacArtney (Reference /107/) is a working example of this. Figure 17-24 below illustrates what the Greenlink Hub looks like.



Figure 17-24: MacArtney Greenlink Hub Image

The Greenlink hub also known as ‘subsea sockets’ are made to house multiple cables. These hubs can be used for multiple subsea marine renewable energy applications including wind (Reference /107/).

The Greenlink hub is available for MVAC systems up to 36kV and for HVAC systems up to 72.5kV. A wide range of conductor sizes can be used for this as well. The hub has a working depth of up to 100m which is relatively shallow however, there are other depths available upon request. The hub may be suitable for some set-ups which this study focuses on such as the type 2 cables shown in Figure 17-1 from the sub hub to the assets, but no such technology appears to be available for MVDC systems.

17.15 Conclusion

There are numerous technological solutions and methodologies available for completing a subsea cable installation in the North Sea. Key factors to consider when selecting the appropriate solution are the overall cost, cable size and seabed conditions.

Research indicates that for shorter cable runs up to around 80km AC cabling would be best suited due to economical savings it would provide. However, the publicly available costs gathered for a number of projects do not necessarily support this. Further research would need to be completed on projects under 80km as well as above looking specifically at the costs for cabling across both AC and DC cable types to define which solution is the most economically viable, especially for installation in the UKCS. Research also notes that DC cabling is better suited for longer distance subsea cable runs; this is mostly due to the lower losses produced in the DC cables compared with AC cables.

Both static cable types and dynamic cable types have been installed in the UKCS proving that it is possible to use the installation methods described in this study. Burial of cables is also a common solution for many of the projects looked at in this study.

17.16 Further Areas of Study

Some further areas of study leading on from this initial work which would be beneficial to understand and get more information on include:

- Seabed conditions of the UKCS for identifying most suitable cable installation methodology i.e. buried or non-buried etc.
- Accurate cable costs based on cable size, conductor type and installation methodology.
- Electrical subsea network expansion

18. EMS / PMS Study

18.1 Report Objective

The objective of this study is to consider the overall network control and monitoring requirements with a focus on safe and secure operations.

Where appropriate, modern integration standards such as IEC 61850 will be referenced. The study shall consider:

- Generation management
- Load management
- Storage management
- Large motor start inhibits
- Power quality management – voltage, frequency etc
- Network optimisation and efficiency management

In addition to the above general themes, the following scenarios shall also be studied as an integrated power management system will be crucial in responding to various outages:

- Main Hub Shutdown
- Sub Hub Shutdown
- Asset Shutdown

18.2 Background

The project is to study and develop a design for an offshore electrical power network that would act as an interface between distributed sources of renewable power and Oil & Gas installations with the intention to minimise equipment, modifications and infrastructure required on the platforms themselves. Instead, control and safety equipment, as well as power transformation and distribution equipment, would be located on new, dedicated infrastructure.

The overall concept is shown below in Figure 18-1. It is anticipated that an individual system will comprise primarily of a floating Main Hub Substation (Main Hub) which could incorporate generation, transformation, storage, controls and distribution. From the Main Hub a number of smaller Sub-distribution Hubs (Sub Hubs) could be supplied which would then provide the final transformation and power regulation to provide a suitable input to an individual Oil & Gas installation. The final cable run would be short enough that the power would be supplied at the appropriate voltage and frequency minimising the modifications required at the receiving installation.

The local Sub Hub would be equipped with suitable safety and control equipment to ensure that imported power is safe and reliable with the ability to reduce fault currents and harmonics to avoid unnecessary upgrades or modifications being made to the Oil & Gas platform itself.

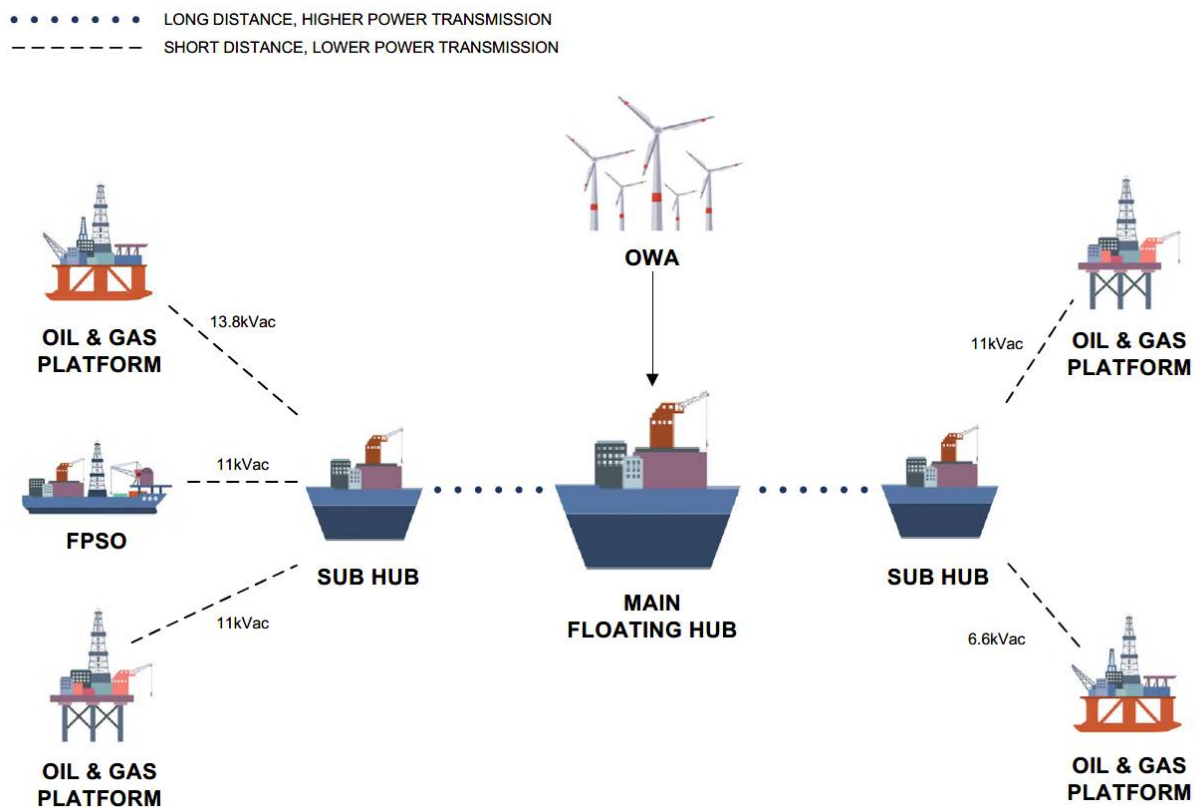


Figure 18-1: Scheme Overview

18.3 Energy Management System

18.3.1 Introduction

The Energy Management System (EMS) concept is to provide a safe and secure electrical power supply whilst optimising efficiencies and energy costs.

The main objectives of the EMS can be summarised as follows:

- Sustain availability of the Sub Hub(s) and Asset(s) power supply and distribution network, by means of automatic Frequency & Voltage regulation, Load Shedding and Load Sharing.
- Centralizing, displaying and recording the alarms and events occurring across the whole electrical network. This allows for analysis by operators in the event of a fault or other network issue as well as routine monitoring to detect issues before they can escalate.
- Supervising and remotely controlling the power supply network equipment via EMS Operator workstations.
- Communicating with the Integrated Control & Safety System (ICSS), feeding it with general information on the electrical network, status of plant as well as real-time generation and demand data; such integration will allow for specific control (e.g. Process loads starting authorisation).
- Configuring load shedding steps online and remotely.
- Completing live bus bar synchronising operations allowing generators to be brought online and the network to be reconfigured as required.

In order to achieve the above objectives, the EMS will incorporate the following key features:

- Main Hub Generators individual management:
 - Start / Stop / Coupling requests orders
 - Load Sharing, by Speed & Voltage adjustment setpoints
 - Unload / Disconnect / Stop requests orders
 - WHRU (Waste Heat Recovery Unit) control
 - OLTC (On Load Tap Changer) control
- Emergency Generators supervision and individual Start / Coupling / Return to normal & Stop request orders
- Dynamic Load Shedding allowing for variations in generation, demand and storage availability
- Manual Source Transfer initiating; Functions of Automatic & Manual source transfer being directly managed by dedicated switchgear devices.
- Monitoring and Control of the Electrical Equipment (fault discrimination)
- Large load start authorisation. EMS authorises / inhibits the starting of large loads, depending on the power reserve vs the loads' Active & Reactive power demand.

Conceptually the EMS is split up into two main components, the Power Management System (PMS) and the Electrical Control System (ECS).

Power Management System (PMS)

- Controls when inputs to the Main Hub 132kV bus, i.e. Wind Arrays & Generators, are taken online & offline, ensuring a stable and continued output at the required load is maintained.
- Coordinates the Power Sharing required between these inputs.
- Synchronises the bus bars.

Electrical Control System (ECS)

- Controls the Electrical Distribution for safe and secure operation.
- Coordinates the Load Shedding management requirements.

The EMS is based on maximising the integration of the Electrical Control System (ECS) and Power Management System (PMS).

18.3.2 Proposed Electrical Distribution Architecture

The study has considered wind power from a dedicated offshore wind array (OWA) for the Oil & Gas industry.

The input to the MVDC transmission system on the Main Hub is considered to be the following:

- Combined Cycle Gas Turbine (CCGT) Generators
- Offshore Wind Array
- Energy Storage

A dynamic combination of these inputs will provide balanced power to meet fluctuating demand from the connected Oil & Gas assets.

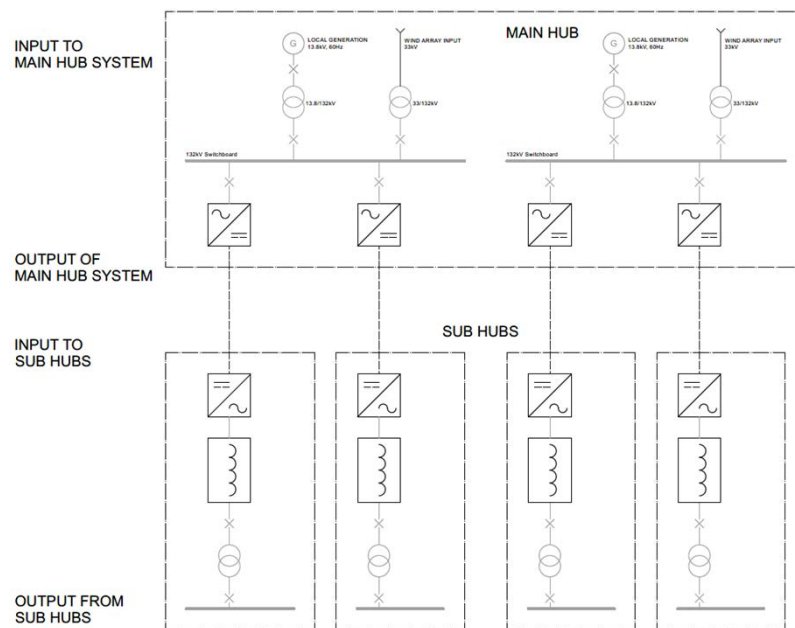


Figure 18-2: Single Line Overview

No direct power from shore connection for this concept is considered. For the concept proposed, the main provision of input power is supplied based on wind generation, or local Main Hub generation. For specific clusters, existing conventional fuel generation will be considered as an input candidate.

Future connection to the National Grid is considered as an opportunity, not a core concept for this design.

18.4 Power Management System (PMS)

The PMS, as part of the overall EMS, will be used to monitor, control and optimise the performance of generation and transmission systems. It is envisaged that the main system controller will be located on the Main Hub.

The PMS shall encompass, at a minimum, the following features:

- Ability to automatically switch generators, wind power and storage online or offline depending on load requirements.
- Ability to manually start and stop local generation from an operator workstation (HMI).
- Ability to communicate/interact with any manufacturer's Engine/Turbine and Generator Control systems
- Ability to communicate/interact with Asset incumbent PMS / ECS (where practical, see Note below).
- Ability to communicate/interact with Main Hub, Sub Hub and Asset ICSS (where practical, see Note below).

Note: Interactions with Asset systems has not yet been studied in detail. Due to the aging nature of the North Sea there are a wide variety of systems in use, some modern and sophisticated, with others older and less capable. The more modern systems may be easier to integrated with whilst older systems will likely require either modification or replacement. The benefits and practicalities of this will need further evaluation.

18.4.1 Load Management

The Main Hub PMS controller will monitor the load required from the Sub Hubs and Assets and sequence the starting and stopping of the various electrical generation and storage methods as required to ensure supply is available and not wasted. Unnecessary release of CO₂ is to be avoided while attempting to minimise fuel costs and maximise efficiency.

Whenever possible all available wind power should be utilised, minimising the requirement to operate local generation. To allow for local generation to run up (approximately 5 minutes for an LM6000 unit) local storage is likely to be needed to minimise disruption. Periods of excess wind output should be used to charge up available storage.

The Main Hub and Sub Hubs monitoring will work independently of the end user Assets. The Main Hub will prioritise to meet the moment-to-moment demand requirement from the Sub Hubs.

It is envisaged this will be done via communication from the main PMS controller, located on the Main Hub, to/from the various monitoring and control stations mounted local to the generating components (Generators, Wind arrays and Storage systems) and also via communications to/from the Sub Hub and Asset PMS/ECS.

Examples of the various minimum inputs and outputs to the PMS are:

POWER SOURCE – INPUT	POWER SOURCE OUTPUT
Running Status	Start
Available Status	Stop
Fault	
Tripped	
Control System Comms Fault	
Load	
Voltage	
Power Factor	
Fuel Availability (if applicable)	
Auxiliary Instruments (if applicable), e.g. Temperature, Vibration, Level,	

Table 18-1 Control System Inputs

As well as the minimum inputs / outputs, discussed above, predictive analytics around weather forecasting, turbine availability, production forecasting etc to ensure that gas turbines are only used as a measure of last resort would also be used.

Load management will need to consider the ramp up/down times of the various power sources. For example, an LM6000 gas turbine / generator system take a few minutes to ramp up from a start request to rated output.

Load shedding an entire platform is considered to be unacceptable. There is therefore going to be some benefit in gaining ability to load shed large loads on specific assets which will mean communication with the asset PMS and upgrade of that particular asset PMS.

Adding the capability to control existing main generator sets on specific assets would be a “nice to have” given the technical challenges of this, as well as the impact of power flows within the network. The base case is, therefore, to not allow asset generation to operate in parallel with the network.

Load management will also need to cater for planned vs unplanned changes in either inputs and outputs – a failed generator, the automatic starting of an electrical firewater pump, summer TAR season etc.

The following diagrams (Figure 18-3 and Figure 18-4) show how a “typical” Load and Network Topology would be configured (Note, only 1 off Sub Hub shown as an example).

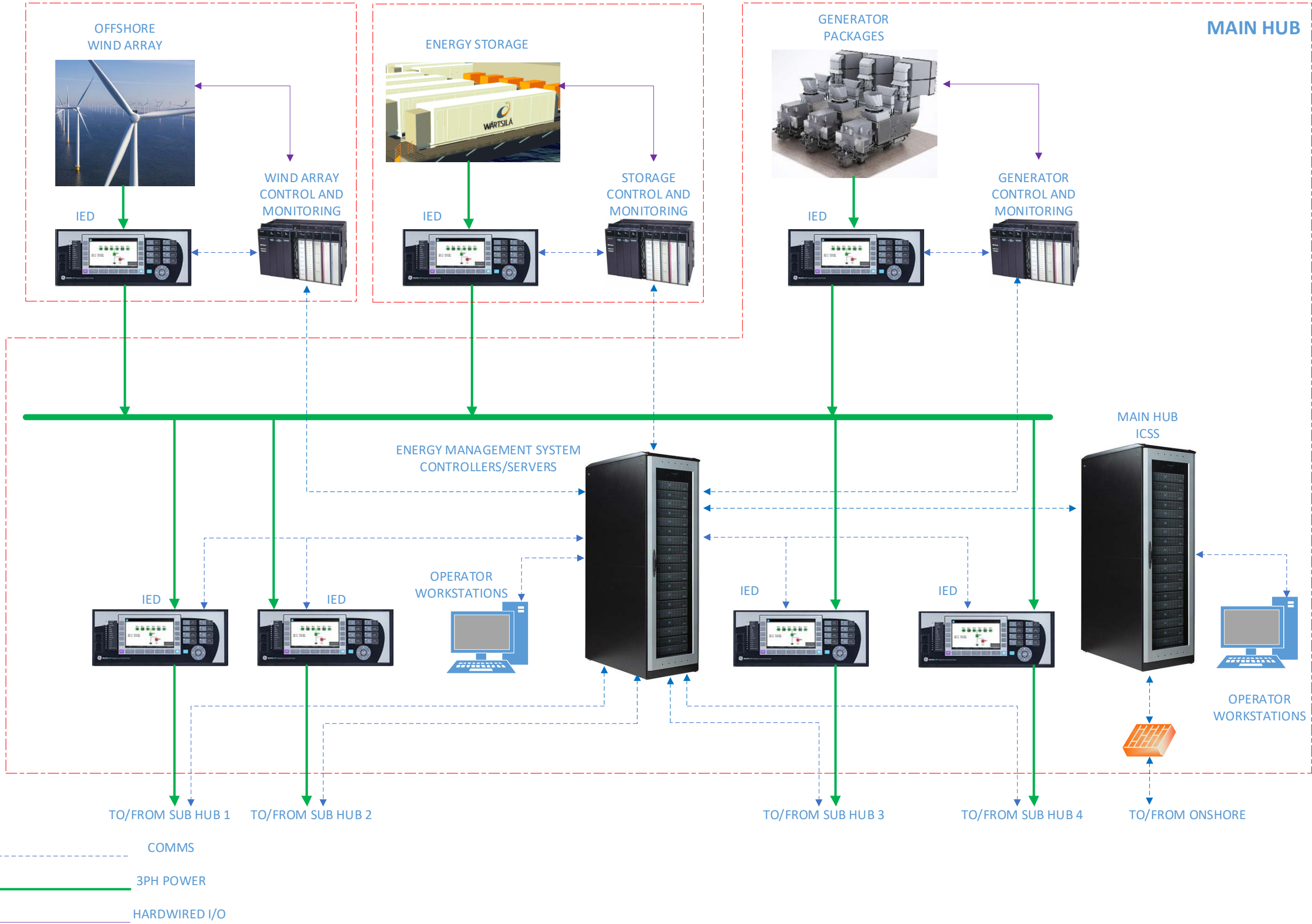


Figure 18-3: Main Hub Network Topology Concept

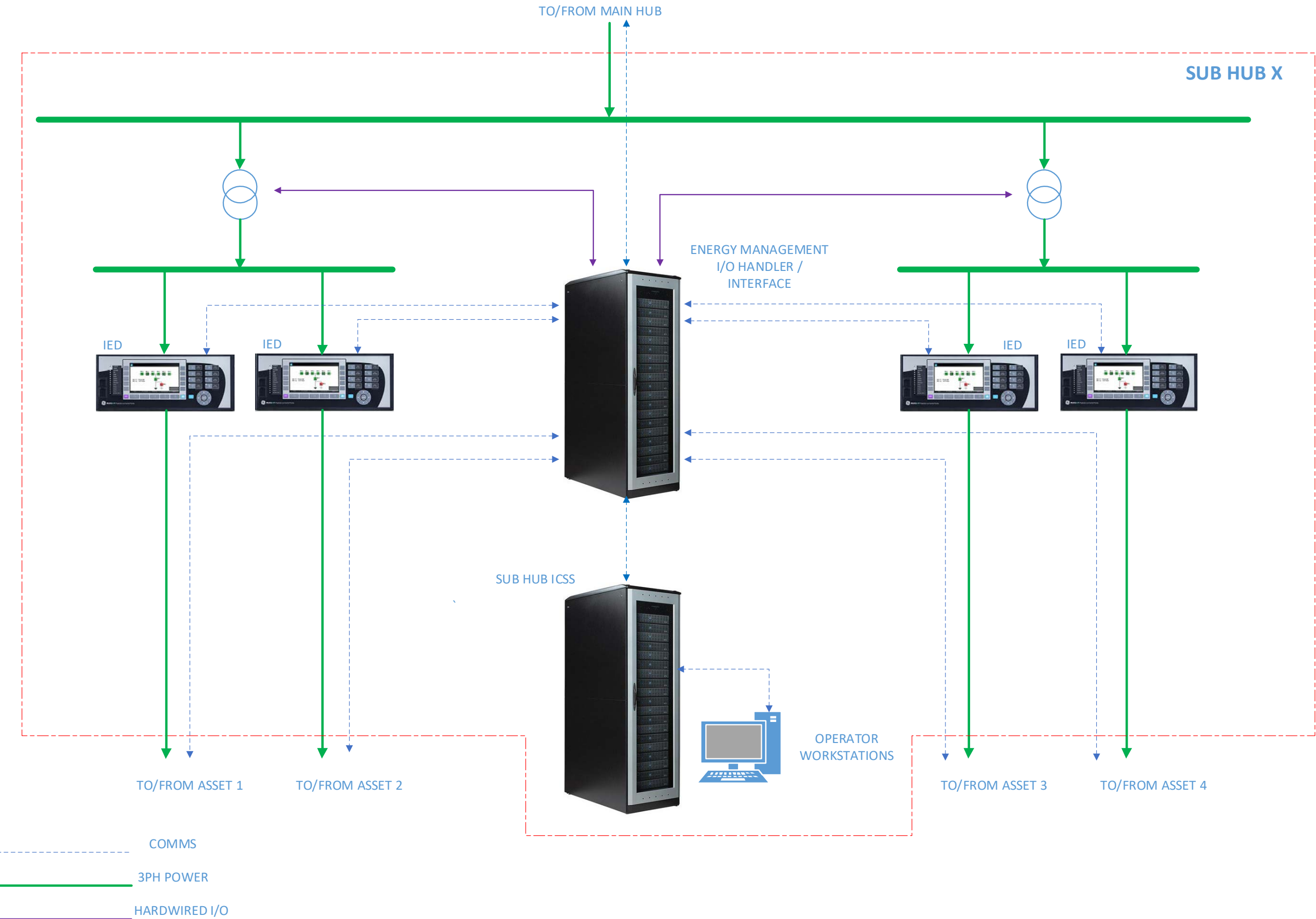


Figure 18-4: Sub Hub Network Topology Concept

18.4.2 Generation Control and Management

For the purpose of this study, “Generation” will include:

- CCGT Generators
- Wind Arrays
- Power Storage

Each Turbine Generator, Wind Array and Power Storage system will have its own local control/monitoring/I/O handler. This will then communicate over the network to the PMS.

It is envisaged the main source of power would be from the Wind Array with the CCGT Generators and Power Storage being secondary sources. The design would aim to maximise wind turbine power availability and usage, utilising the CCGTs to meet the balance.

18.4.3 Power Quality Management

The purpose of a Power Quality Management system is to ensure:

- Clean, Efficient Electrical Power at all times.
- Improve productivity and resilience
- Pay less for the power

Some common power quality problems which might be experienced are:

- Poor Power Factor
- Excessive Harmonics
- Voltage Disturbances

18.4.3.1 Power Factor Correction

Power-factor correction increases the power factor of a load, improving the efficiency for the distribution system to which it is attached and increases the Electrical System Capacity.

18.4.3.2 Active Harmonic Filters

Excessive harmonics can be reduced by using Active Harmonic Filters. This will improve the performance of the equipment, avoid device malfunction, extend life of electrical assets and prevent unplanned power outages.

18.4.3.3 Dynamic Voltage Regulator

Voltage disturbances need to be minimised as much as possible. This is a particular concern for an islanded network without the backing of a strong grid. Dynamic voltage regulation can improve the reliability of digital controllers, prevent device and tool malfunction, maximise power availability and reduce production losses.

Voltage regulation will be a key factor in PQM. The assets will be supplied in line with IEC 61892 which specifies a nominal voltage $\pm 2.5\%$ at the main switchboard. Based on other study work completed, this will be facilitated by on load tap changers on platform supply transformers located on the Sub Hub, as well as compensation available on the Sub Hub. These will both need to be controlled by PMS.

18.5 Electrical Control System (ECS)

The Electrical Control System (ECS) component of the overall EMS coordinates the Electrical Distribution and Load Shedding management requirements.

18.5.1 Electrical Distribution

Electrical distribution will be coordinated by the ECS component to distribute the power, e.g. to the Sub Hubs and on to the Assets depending upon power availability, power requirements and priority tables.

In order to do this efficiently there will need to be communication/interfaces with the various Intelligent Electronic Devices installed in switchboards, UPS, MVDC Bridge controllers etc.

18.5.2 Load Shedding

A majority of North Sea assets utilise some form of Power Management System or specific Load Shedding system.

Load shedding a whole asset is considered to be unacceptable and consideration needs to be given to what needs to be in place to mitigate against this as a requirement. This already dictates the need for conventional generation on the Main Hub to back up the OWA supply, and also a requirement to meet short term generation dips with energy storage. Energy storage will also have the positive effect of being an energy sink for times when there is excess wind.

An intermediate solution might be that issues with generation on the network result in a reduction of electrical power supply to all assets in proportion to their normal demand. The practicalities of achieving this would need to be explored further. The on asset PMS would then undertake appropriate load shedding in the same way as it would respond to the loss of a generator. In some cases it may be appropriate for backup generation to be utilised.

18.6 EMS Communications Network

The EMS will interface with the following equipment control systems via a communications network:

- Main Hub Turbine Generator Control and Management
- Wind Array Generator Control and Management
- Main Hub Storage Control and Management
- Main Hub Electrical Distribution
- Sub Hub Electrical Distribution
- Main Hub ICSS
- Sub Hub ICSS
- Asset PMS (where practical)
- Asset ICSS (where practical)
- Transformer on load tap changers (OLTCs)
- Condition monitoring equipment
- MVDC Bridges

The EMS communications network will conform to the IEC standard, IEC 61850. IEC 61850 is an international standard defining communication protocols for intelligent electronic devices (IEDs). It is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 reference architecture for electric power systems.

Three levels are defined by IEC 61850, noting that each level contains different devices:

- **Process Level.** This level covers the individual components such as circuit breakers, switches, current transformers and voltage transformers.

- **Bay Level.** This level covers the intelligent electronic devices which supervise and control the process level components. IEC 61850 defines a process bus to allow communications between IEDs and the Process Level components.
- **Station Level.** This level contains SCADA and HMI systems and is used for substation control and monitoring. Station level defines a station bus that is able to communicate with numerous IEDs located at the bay level.

18.6.1 System Vendor(s)

For the purpose of this study, and for costing and preliminary design, it has been assumed the EMS/ICSS control system would be provided by a single source (GE) for the Main Hub and Sub Hubs.

The chosen system vendor has been relied upon for their experience and advice in finalising the design of the overall network described here.

The incumbent EMS and ICSS system vendors on the various assets have not been investigated. Based on experience, it is known there is a range of different systems available, of different OEM, age, functionality etc. This is something that would need to be studied in much greater detail during future phases of study/design work. At this stage, it is assumed only very basic interaction between the Main Hub/Sub Hub EMS/ICSS and Asset EMS/ICSS.

18.6.2 Redundancy

Any ICSS and EMS/PMS system will require a high level of redundancy. This shall include the networking on the individual installations, as well as the communication links between. It is envisaged that the Servers and Controllers would all have a high level of redundancy which shall be determined through engagement with the system vendor.

18.6.3 Communication Loss

Communications loss will need to be considered, with the various control systems able to operate autonomously in some capacity if networking is lost. At a minimum this shall facilitate securing the electrical power network and ensuring it is put into a safe state. The individual systems shall also continue to record data when communications are lost to allow for event analysis and reestablishment of state if communications are restored.

Loss of communications between the following systems will need to be considered in more detail:

- Main Hub EMS and Main Hub ICSS
- Main Hub EMS and Sub Hub EMS
- Sub Hub EMS and Sub Hub ICSS
- Main Hub EMS and Asset EMS
- Main Hub EMS controller and IED's
- Main Hub EMS controller and Generation Local systems

18.7 Shutdowns

18.7.1 Main Hub Shutdown

A Main Hub Shutdown will remove power to the Sub Hub(s) and therefore normal power to numerous Assets.

Shutdown of the Main Hub would therefore only be actioned in the event that a “major” emergency situation is detected by the Main Hub Emergency Shutdown (ESD) and/or Fire and Gas (F&G) control system(s).

The status of the Main Hub going into shutdown would be communicated to the Assets. The Asset would lose its subsea power supply and the response to this dead bus situation would likely be backup generation starting. It is envisaged that this situation would be handled in the same way as a total loss of normal power on the asset.

There is no allowance made for backup normal power on the Sub Hubs so if the Main Hub shuts down all distribution power is lost. The Sub Hubs will have UPS/Emergency generation available but this is to maintain critical systems like comms/navaids and to enable a restart.

In this situation the assets would go on to emergency/essential power based on their own local systems – e.g. auto start of emergency generator based on loss of voltage detected.

Outwith the scope of this study, individual Assets will need to review their emergency/essential power systems based on expected frequency and duration of Main Hub (and Sub Hub) outages. This may be longer than is predicated for a local main generation outage.

It is not envisaged that an emergency situation on the Sub Hub or an individual Asset would require the Main Hub to be shutdown or for the main power supply to a Sub Hub to be turned off.

18.7.2 Sub Hub Shutdown

A Sub Hub Shutdown will remove normal power to numerous Assets.

Shutdown of the Sub Hub would therefore only be actioned in the event of a “major” emergency situation detected by the Sub Hub Emergency Shutdown (ESD) and/or Fire and Gas (F&G) control system(s).

The status of the Sub Hub going into shutdown would be communicated to the Assets. The Asset would lose its subsea power supply and the response to this dead bus situation would likely be backup generation starting. It is envisaged that this situation would be handled in the same way as a total loss of normal power on the asset.

18.7.3 Asset Shutdown

It is not envisaged that an emergency situation on an individual Asset would require the Sub Hub to be shutdown, however, the emergency response situation may dictate removing normal power to the Asset which would be most safely and effectively achieved by turning off the supply from the Sub Hub. This would need to be reviewed as part of a review of the safe operations of the Sub Hub when supplied by subsea power.

18.8 Vendor Proposal

GE were engaged to provide their advice and recommendations with regards how they would recommend supply and implementation of the EMS/PMS on the Main and Sub Hubs based on the initial design work completed.

18.8.1 Vendor Philosophy

The main priorities considered by GE when putting together their design were:

1. Energy efficiency
2. Security of electrical supply to the Oil & Gas assets

The EMS structure proposed interfaces closely with the power electronics in the MVDC bridges to achieve these priorities.

Note: the GE EMS also has the ability to interface with other equipment that would benefit the electrical network, e.g. STATCOMS installed on the Sub Hubs to maintain power quality and to mitigate against the lack of native inertia in the event that the MVDC power is lost, and Hydrogen production on the Sub Hub to mitigate against excess power from the generators. Such technologies have not yet been incorporated into the design.

18.8.2 EMS Functions

18.8.2.1 Load Sharing

There will be real time power sharing between on-line CCGTs and the OWA. The exact power sharing features will be specified depending on the operating philosophy which will be developed based on the actual capabilities of the CCGTs (acceptance & rejection), the WTGs control types & options (dynamic VAR control, line & voltage compensation, curtailment, wind reserve, ramp rate limit etc.), environmental constraints (acceptable NOx rejection, MECL requirements etc.) and predictive systems planned to be connected, wind power production capabilities etc.

The power sharing shall be based on Droop control, with the EMS able to dynamically adjust the droop curve's origin for both WTGs and CCGTs.

18.8.2.2 Load Shedding

The Load Shedding (LSD) function has to be completed for loads that are not locally managed, i.e. for loads controlled by the assets' independent ECS / PDCS / EMS. It is not considered acceptable for the system to shed an entire Asset, or worse, an entire Sub Hub.

To avoid Asset black out, LSD commands need to be sent immediately. As local on-asset generation is reduced or removed entirely, this can result in lower spinning reserve and inertia. Depending on the rejection capabilities of the CCGTs & WTGs there will be a need for complementary shedding focusing on the generators sets, in case of the sudden loss of a Sub Hub.

Taking into account the above constraints, the entire LSD scheme & principles will have to be developed with a "top-down" approach to save the assets in case of faults along the whole energy chain, from Main Hub/OWA to final asset, e.g. loss of MVDC link, Assets incomers' trip, issues on a Main Hub generator, issue with the OWA, etc.

GE propose 5 types of LSD:

- Fast Load Shedding 1 – To save the Assets, for Assets having no local EMS controllers. By sending EMS non affected HW LSD Digital Orders / LSD by group to each assets, through local asset's EMS remote concentrators. Existing LSD features of each assets' ECS / PDCS would need to be reworked to incorporate this non affected DO into the local load matrix.
- Fast Load Shedding 2 – To save the Assets, for Assets having local EMS controllers, "Standard" EMS dynamic LSD features.

- Slow Load Shedding – To save the assets: Done through analogue hard wired DO or by serial link (through ICSS or direct EMS to local ECS / PDCS). These commands could be based on a set point related to the maximum acceptable consumable power value per asset, with the local ECS / PDCS etc to calculate its own LSD table.
- Ultimate Load Shedding – to save the Main Hub. Direct hard wired orders to trip an entire Sub Hub.
- Power Generator Set curtailment. To save the Power Generator Sets from damage when losing a key consumer, i.e. an entire Sub Hub. This would need to be arranged based on the abilities of the CCGT and OWA to respond to very fast changes in load, as well as the abilities of any local storage to accept input.

18.8.2.3 GIS Live Bus Bar Synchronising

Due to the complexity of the operation and configuration of the 132kV and 66kV Gas Insulated Switchboards, including bus ties, the EMS must be able to control and monitor synchronization of sub bus-bars, allowing their re-closing after a partial opening.

Note: During partial sub-bus segregation of GIS, the Load Shedding and Sharing functions have to be dynamically re-calculated to allow partial Load Balancing across the system. This is a key feature of the GE's EMS solution.

18.8.2.4 Time Synchronising

The EMS shall achieve a time stamping accuracy of minimum 1 ms for any hardwired key data. This is important to allow efficient and accurate analysis of events and faults on the network. This accuracy level will be achieved using the Precision Time Protocol (PTP), with the time frame sent from a GPS clock. The synchro signal shall also be sent to Converters' controllers.

18.8.3 EMS Network Schematic

A proposed Network Schematic (shown in Figure 18-5), has been provided by GE and shows how the topology discussed in Section 18.3 could be implemented.

18.8.3.1 Structure

As any control failure would have a serious impact on the safety and security of the power supply network, the whole EMS architecture is based on hot redundancy. This includes Controllers, Remote Concentrators, HMI Servers, Networks and Time Synchronisation.

GE propose a 3-level architecture, with the different EMS levels linked by several sub-ethernet networks:

- The **High Level** is composed of Supervision Servers and workstations for local control and monitoring of the Electrical equipment, including the facility to view and analyse historical data.
- The **Medium Level** is composed of the EMS controllers which perform the process control functions.
- The **Low Level** is composed of remote I/O stations connected to the main EMS controllers and to the different sub-systems.

18.8.3.2 Ethernet Networks

The main EMS network provides the backbone of a high efficiency EMS. GE propose basing the Main Hub, Sub Hubs and Asset (if applicable) ethernet networks on two independent rings (each operating a Media Redundancy Protocol (MRP)) running in parallel under PRP. This structure ensures simultaneously a high level of availability (four communication paths) and a "null" change-over response time in case of failure.

Each MRP ring shall be interconnected (Main Hub to each Sub Hub) through dedicated ring coupling utilising fibre optics.

To complement the primary network, there shall be several sub-networks on each Hub to allow the various IEDs to be connected.

18.8.3.3 Protocols

GE propose to employ the following protocols, to be adapted as per the various IED capabilities:

- ICSS / Process Control System: Modbus TCP (ICSS Client), or preferably OPC-UA,
- GTG / STG and WTG's UCPs: Modbus TCP (EMS is master), by experience of UCP's capabilities,
- HV Switchboard Protection relays: IEC 61850 (EMS is consumer)
- LV Switchboard Protection relays: IEC 61850 is recommended and when any Modbus TCP (EMS is master)
- Emergency Diesel Generator(s) UCP: Modbus TCP is recommended (EMS master) and/or hardwired.
- MVDC Bridges: IEC 61850 and/or hardwired.
- UPS Control Panel: Modbus TCP is recommended (EMS is master) and/or hardwired.

18.8.3.4 Controllers

GE propose utilising several sets of EMS controllers, employing the following features:

- Hot redundancy, with segregated location of the devices by locating them in different rooms. This is to avoid one fault or issue causing failure of the whole EMS (e.g. fire, power supply failure etc)
- Two sets of controllers for the Main Hub (thus four controllers in total), to segregate the Load Balancing features (LSR and LSD) and the "normal" power distribution control features
- One set of controllers per Sub Hub (the electrical power distribution is less complex and of a less critical nature)
- Sub Hub controllers would allow local management and supervision in the event of loss of communications with the Main Hub controllers.
- If an asset was to be integrated with the EMS, this would require one set of controllers to allow power sharing with local power generators and Load Balancing features.

18.8.3.5 Supervision

GE propose similar segregation as for the main controllers, except for the Sub Hub & Asset systems (if applicable), which would remain in Simplex.

All of the local HMI servers and OWS will be "Clients" of the Main Hub's HMI servers, with autonomy in case of a loss of communications, followed by data base consolidation when the link is re-established. GE's EMS is based on PcVue software from Arc Informatique.

18.8.3.6 Cyber Security

Considering the high criticality of the EMS for this project, strict rules will have to be established and applied to prevent issues related to cyber security. It is anticipated that industry standard software, hardware and topologies would be used to prevent loss of data, external access, etc.

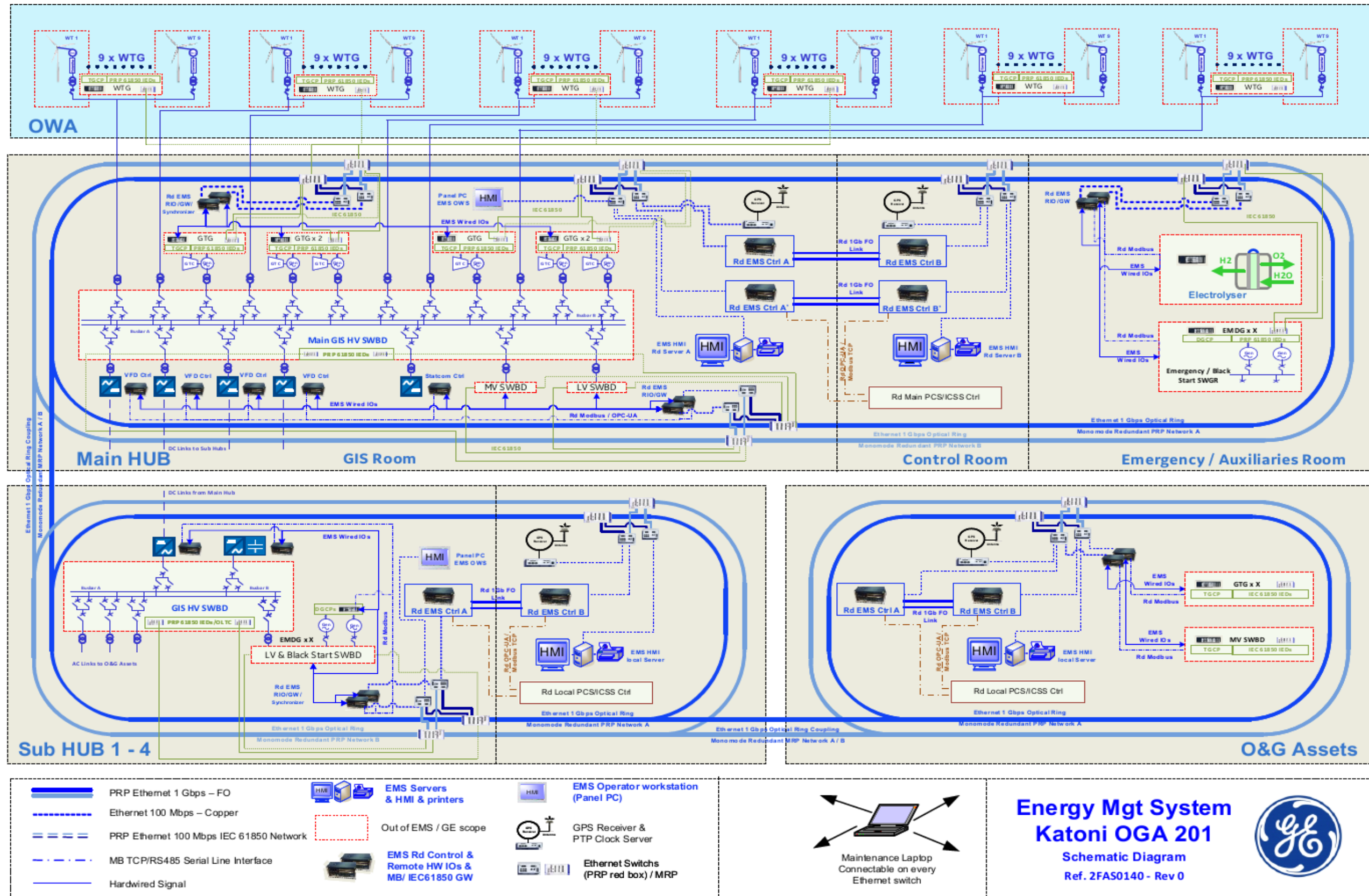


Figure 18-5 Network Schematic

18.9 Cost Estimates

It has been established that the EMS required for this type of network is a custom solution. However, it is based on existing and field proven technologies, devices and functionality.

Given the early stage of the project, preliminary high level costs have been provided by GE and these are summarised in Table 18-2 below.

Networked Asset	Estimated Cost
Main Hub and Sub Hubs	4-10M€
Oil & Gas Platforms	0.2 to 0.5 M€ per Asset

Table 18-2 Estimated Costs

The above costs are for on-asset equipment only. Subsea communications cables would need to be costed separately. Typically fibre optic cables are integrated with subsea power cables to reduce cable laying work.

In order to generate a more accurate cost estimate, GE would require a detailed Function Specification and Operating Philosophy, a full Scope of Supply and a fully detailed equipment list, including details of the assets to be interfaced.

18.10 Conclusion

The EMS/PMS and ICSS will form an integral part of this North Sea Decarbonisation project.

The overall network philosophy and selection of final control system vendors will be crucial if the control of the generation equipment, synchronisation and load sharing/shedding is to be optimised.

Communication protocols across the Main and Sub Hubs must also be considered carefully with consideration given to the existing Asset control systems and on-shore communication.

18.11 Further Areas of Study

The following further areas of study will be needed for future phases:

- Network philosophy evaluation
- Preferred System Vendor market evaluation
- Preferred Instrumentation market evaluation
- Control System Technology market evaluation
- Communication protocol market evaluation
- EMS/ECS Electrical Distribution philosophy design
- EMS/ECS/PMS Load shedding philosophy design
- Main Hub / Sub Hub / Asset Shutdown philosophy
- Comms failure shutdown philosophy
- Redundancy philosophy
- Comms philosophy between installations and shore (e.g. Fibre Optic Cabling, Copper Cabling, Line of Site, Satellite)
- More accurate Vendor costings

18.12 Opportunities / Risks / Assumptions

18.12.1 Opportunities

- Updating existing Asset EMS/PMS control systems?
- Possible future sharing of power from Assets to Sub Hubs?
- Could wind generation feed directly to the Sub Hubs in future?

18.12.2 Risks

- Comms loss between Main Hub, Sub Hub and Assets control systems
- Maintenance requirements on Sub Hub with minimal on-board labour
- Synchronisation of control system upgrades between Main/Sub Hubs and Assets.
- Accurate cost estimates prior to Define and Execute phases

18.12.3 Assumptions

- Single control system vendor for ICSS (DCS, F&G, ESD) and EMS
- IED type to be standardised across Main Hub, Sub Hub and Generation packages
- Generation package providers to provide IED's and bespoke package control and I/O handling.
- Existing Asset EMS/PMS system to be retained (communicating back to the Main Hub EMS control system).

19. Cost to Build

A cost to build has been developed for all of the configurations considered as part of this study focused on standardised configurations for the Main Hubs and Sub Hubs.

- 1 off 450 MW Main Hub with cabling as per CNS/OMF base case
- 1 off 100 MW Sub Hub with cabling as per CNS/OMF asset cluster 1
- 1 off 200 MW Sub Hub with cabling as per CNS/OMF asset cluster 2

For the purposes of the economic model the following configurations have been applied to both the CNS/OMF and SNS.

19.1 CNS/OMF

The infrastructure considered for the CNS/OMF region is considered as per the asset clustering base case. This comprises of:

- 1 off 450 MW Main Hub with cabling as per CNS/OMF base case
- 3 off 100 MW Sub Hub with cabling as per CNS/OMF asset cluster 1
- 1 off 200 MW Sub Hub with cabling as per CNS/OMF asset cluster 2

The cabling costs for the 100 MW Sub Hub are based on the worst case asset cluster so this is considered to be an over estimation.

19.2 SNS

The infrastructure considered for the SNS region is considered as per the asset clustering base case. This comprises of:

- 1 off 450 MW Main Hub with cabling as per CNS/OMF base case
- 4 off 100 MW Sub Hub with cabling as per CNS/OMF asset cluster 1

It is considered that based on the costs for the Main Hub, and the extra costs for cabling considered for the 100 MW Sub Hub compared to actual SNS infrastructure that this is an over estimation for the infrastructure, potentially in the region of 20 to 30%.

The costs reductions would be realised by:

- Reduction in Main Hub hull size
- Reduction in MVDC cabling costs
- Reduction in MVAC cabling costs
- Reduction in LM6000 GTs from 6 to 4

For the basis of the economic analysis the non-discounted number is utilised.

	Hull Costs	Cabling Costs	Power Generation Costs	MVDC Link 100 MW	MVDC Link 200 MW	Electrical Components	Mooring	Total
Hull Costs including mooring	£220,000,000						£23,000,000	£243,000,000
Subsea Cabling Costs		£80,260,000						£80,260,000
Subsea Cable Topsides Costs		£273,500						£273,500
LM6000 Costs			£120,000,000					£120,000,000
WHRU + Steam System			£72,000,000					£72,000,000
Gas Lift Riser + Flowline			£60,000,000					£60,000,000
Topsides Structure	£95,909,766							£95,909,766
13.8kV Switchboards						£900,000		£900,000
33kV Switchboards						£1,500,000		£1,500,000
132kV Switchboards						£2,400,000		£2,400,000
LV Switchboard						£500,000		£500,000
132/33kV 150MVA Transformers						£19,800,000		£19,800,000
132/13.8kV 100MVA Transformers						£18,000,000		£18,000,000
132/0.4kV 0.5MVA Transformers						£3,000,000		£3,000,000
MVDC				£37,800,000	£25,200,000			£63,000,000
UPS						£250,000		£250,000
DC Isolating Switch				£60,000	£30,000			£90,000
Topsides Cabling				£108,000	£72,000	£646,000		£826,000
Manhours	£13,540,000							£13,540,000
Subtotal	£329,449,766	£80,533,500	£252,000,000	£37,968,000	£25,302,000	£46,996,000	£23,000,000	£795,249,266
Margin (%)	15	15	15	15	15	15	15	
Contingency (%)	15	15	15	15	15	15	15	
Cost of Sales	£376,836,231	£92,613,525	£289,800,000	£43,663,200	£29,097,300	£54,045,400	£26,450,000	£912,505,656
Sales Price	£443,336,743	£108,957,088	£340,941,176	£51,368,471	£34,232,118	£63,582,823	£31,117,647	£1,073,536,066

Table 19-1 Main Hub Cost to Build

	Hull Costs	Cabling Costs	MVDC Link 100 MW	Electrical Components	Mooring	Total
Hull Costs	£103,053,435				£15,267,176	£118,320,611
Subsea Cabling Costs		£238,200,000				£238,200,000
Subsea Cable Topsides Costs				£126,000		£126,000
Topsides Structure	£18,000,000					£18,000,000
66kV Switchboard				£1,200,000		£1,200,000
13.8kV Switchboard				£150,000		£150,000
11kV Switchboard				£150,000		£150,000
MVDC Bridge			£12,600,000			£12,600,000
66/13.8kV 50MVA Transformer				£1,200,000		£1,200,000
66/11kV 50MVA Transformer				£1,200,000		£1,200,000
Frequency Converter				£6,500,000		£6,500,000
Reactive Compensator				£6,500,000		£6,500,000
0.4kV Switchboard				£500,000		£500,000
UPS				£250,000		£250,000
Electrical OEM Item 11						£0
Electrical OEM Item 12						£0
Electrical OEM Item 13						£0
Topsides Cabling				£87,500		£87,500
Manhours	£9,026,667					£9,026,667
Subtotal	£130,080,102	£238,200,000	£12,600,000	£17,863,500	£15,267,176	£414,010,777
Margin (%)	15	15	15	15	15	
Contingency (%)	15	15	15	15	15	
Cost of Sales	£148,238,117	£273,930,000	£15,860,038	£29,904,952	£17,557,252	£485,490,360
Sales Price	£174,397,785	£322,270,588	£18,658,868	£35,182,297	£20,655,590	£571,165,129

Table 19-2 100 MW Sub Hub Cost to Build

	Hull Costs	Cabling Costs	MVDC Link 200 MW	Electrical Components	Mooring	Total
Hull Costs	£102,725,000				£15,200,000	£117,925,000
Subsea Cabling Costs		£139,920,000				£139,920,000
Subsea Cable Topsides Costs		£150,000				£150,000
Topsides Structure	£18,000,000					£18,000,000
66kV Switchboard				£1,200,000		£1,200,000
13.8kV Switchboard				£300,000		£300,000
11kV Switchboard				£150,000		£150,000
MVDC Bridge				£150,000		£150,000
66/13.8kV 50MVA Transformer			£25,200,000			£25,200,000
66/11kV 50MVA Transformer				£3,600,000		£3,600,000
Frequency Converter				£1,200,000		£1,200,000
Reactive Compensator				£800,000		£800,000
0.4kV Switchboard				£500,000		£500,000
UPS				£250,000		£250,000
Electrical OEM Item 11				£500,000		£500,000
Electrical OEM Item 12				£26,000,000		£26,000,000
Electrical OEM Item 13				£6,500,000		£6,500,000
Topsides Cabling				£110,000		£110,000
Manhours	£9,026,667					£9,026,667
Subtotal	£129,751,667	£140,070,000	£25,200,000	£41,260,000	£15,200,000	£351,481,667
Margin (%)	15	15	15	15	15	
Contingency (%)	15	15	15	15	15	
Cost of Sales	£147,860,417	£161,080,500	£28,980,000	£47,449,000	£17,480,000	£402,849,917
Sales Price	£173,953,431	£189,506,471	£34,094,118	£55,822,353	£20,564,706	£473,941,078

Table 19-3 200 MW Sub Hub Cost to Build

20. Cost of Energy Determination

20.1 Report Objective

The purpose of this study is to identify a methodology for determining the unit cost of energy for typical North Sea offshore installations.

Additionally, a unit cost of energy range was estimated based on data from several offshore installations in the Central North Sea.

The information from this technical note will be used to aid the economic analysis of the overall project.

20.2 Methodology

To determine a unit cost of energy, the following contributing factors are considered:

- Fuel gas costs
- GT Maintenance / OPEX costs
- GT CAPEX costs
- GT life extension costs
- Impact of the UK Emissions Trading Scheme (ETS)

Using data for 19 platforms located in the Central North Sea /59/, the cost contribution of each of the above factors was added together to estimate a range of unit energy costs in £/MWh.

20.2.1 CNS Installation Data

Refer to Table 20-1 below for a summary of the data provided by the OGA for the CNS installations /59/. Asset names were withheld for confidentiality reasons.

Asset Number	Total Power demand (MW)	Total Energy Demand (MW)	OPEX (£MM/Yr)	CAPEX (£MM/Yr)	GT Life Extension Costs (£MM)
1	35.0	42.0	1.9	0.4	0.0
2	12.0	12.0	0.5	0.2	37.0
3	25.1	25.1	0.0	0.0	0.0
4	14.7	14.7	0.0	0.0	0.0
5	73.0	73.0	3.6	3.5	0.0
6	38.5	38.5	1.8	2.5	0.0
7	6.0	6.0	1.1	0.9	0.0
8	33.6	33.6	2.0	0.0	0.0
9	17.4	17.4	6.4	0.0	0.0
10	21.0	21.0	1.2	0.0	0.0
11	4.8	4.8	0.0	0.0	12.0
12	43.6	43.6	2.0	0.2	21.6
13	31.0	31.0	3.3	0.0	18.0
14	26.5	26.5	2.0	0.2	12.0
15	36.4	36.4	1.8	0.3	7.2
16	69.5	69.5	0.0	0.0	3.0
17	2.2	2.2	0.2	0.1	2.0
18	11.0	11.0	0.5	0.0	2.0
19	7.0	7.0	0.6	0.1	0.0

Table 20-1 - CNS Installation Data

20.2.2 Fuel Gas Costs

Four fuel gas costs were calculated; three based on assumed High, Medium, and Low gas price, and one based on current (10th February 2022) prices. The High, Medium, and Low prices were estimated based on historical data for the UK /117/. The values used to determine the cost of fuel gas are shown below:

High* – 150 pence a therm / 88.7 £/MWh
Medium – 90 pence a therm / 20.5 £/MWh
Low* – 60 pence a therm / 3.4 £/MWh
February 2022 – 180 pence a therm / 61.4 £/MWh

The fuel gas consumption rate was calculated based on the total power demand, the GT efficiency, and the total uptime, as shown below:

$$M = \frac{Q.F}{LHV.\eta}$$

Where,

M = Gas consumption rate, kg/s
Q = Total power demand, MW
F = Uptime, % = 90% (typical)
LHV = Gas lower heating value, mJ/kg = 46.4 mJ/kg
 η = GT efficiency, %

The total power demand is made up of the total electrical power demand and the power demand of direct drive equipment e.g., compression. Energy provided by Waste Heat Recovery (WHR) is not included in the fuel gas consumption estimation. Refer to Section 20.2.8 for WHR details.

The fuel gas costs were determined as follows:

$$C = \frac{M.LHV * 365 * 24 * P}{1,000,000}$$

Where,

C = Fuel gas cost, £MM/MWh
P = Fuel gas unit price, £/MWh

20.2.3 GT OPEX Costs

The GT maintenance / OPEX costs are the ongoing costs to run the gas turbines e.g., manhour / POB costs.

These costs were supplied as part of the CNS power requirement data provided by the OGA /59/ and are summarised in Section 20.2.1.

Estimated OPEX costs were supplied from the year 2024 to CoP for each platform. An average of the first 5 years OPEX costs was used as part of the total cost of energy determination.

Where data was not supplied by operators the average OPEX costs have been applied to each installation.

20.2.4 GT CAPEX Costs

The GT CAPEX costs are costs associated with e.g., unplanned equipment overhauls and replacement of parts.

As per the OPEX costs, the CAPEX costs were supplied as part of the CNS power requirement data provided by the OGA /59/ and are summarised in Section 20.2.1.

Estimated CAPEX costs were supplied from the year 2024 to CoP for each platform. An average of the first 5 years CAPEX costs was used as part of the total cost of energy determination.

Where data was not supplied by operators no value was attributed to each asset. This will affect the range of energy costs.

20.2.5 GT Life Extension Costs

The GT life extension costs account for any expenditure required to extend the original design life of the GTs e.g., full GT replacement.

The life extension costs, if applicable, were supplied as part of the CNS power requirement data provided by the OGA /59/ and are summarised in Section 20.2.1.

The GT life extension costs were converted to an equivalent yearly cost by assuming the GTs life is extended by 10 years, on average. For example, if the GT life extension cost is £10m, the equivalent yearly cost is $\text{£}10\text{m}/10 = \text{£}1\text{MM}$ per year.

20.2.6 Impact of the UK ETS

"The UK Emission Trading Scheme (ETS) is a cap-and-trade system which caps the total level of greenhouse gas emissions, creating a carbon market with a carbon price signal to incentivise decarbonisation.

Participants in the scheme are required to obtain and surrender allowances to cover their annual greenhouse gas emissions. Participants can purchase allowances at auction or trade them amongst themselves." /118/

The UK ETS applies in the following instance:

"The UK ETS will apply to energy intensive industries, the power generation sector and aviation.

It covers activities involving combustion of fuels in installations with a total rated thermal input exceeding 20 MW (except in installations for the incineration of hazardous or municipal waste)." /119/

The contribution from the UK ETS to total energy costs was estimated by determining which installations apply (i.e., total power demand greater than 20 MW) > estimating their total yearly CO₂ emissions > multiplying this by a typical UK ETS auction closing price.

CO₂ emissions were estimated by multiplying the estimated fuel gas consumptions rate (refer to Section 20.2.1) converted for a yearly basis and the equivalent CO₂ produced by burning a kg of natural gas, assumed to be 2.5 kg CO₂ / kg Natural Gas /61/.

The ETS costs were calculated by multiplying the yearly CO₂ emissions by the ETS clearing price, assumed to be 60 £/tonne /62/.

20.2.6.1 ETS Sensitivity

As the ETS is a trading system, the carbon price is not fixed and is sensitive to energy demands, fuel prices etc. Additionally, one of the purposes of the scheme is to achieve the UK's emissions reduction targets. The total emissions allowance is therefore decreased each year to help meet these targets. The UK ETS 2021 allowance was 155.7 MtCO₂e and is initially set to reduce by 4.7 MtCO₂e per year /120/. The scheme is to be reviewed in 2023 and 2028 and the yearly reductions may change to reflect an increase in the ambitions of the UK's emissions reduction targets /121/. This yearly allowance reduction may result in a rise in the average carbon price over time, as predicted by analysts. An article written in July 2021, discussing future EU carbon prices, states that "The European Commission predicts the price of CO₂ in 2030 could be around €85 per tonne, some studies say €120" /122/. It should be noted that this was written prior to recent increases in natural gas prices, where the highest EU carbon price had reached approximately 60 €/tonne.

Recent spikes in the price of natural gas in the UK and EU have impacted the carbon price, with the auction clearing price reaching 81 £/tonne in January 2022 in the UK /62/ and prices in the EU exceeding 90 €/tonne. This is a result of the high natural gas prices encouraging electricity generators to use more coal, which emits significantly more CO₂ per kWhr than natural gas, resulting in an increased demand for emissions allowances /123/.

The 60 £/tonne value used to determine the unit cost of energy in this technical note is approximately today costs. Future costs are expected to steadily rise as per the above analysis. Sensitivity can be performed based on estimated future trends during the economic analysis.

20.2.7 Carbon Valuation

There are two main methods used to determine a value on GHG emissions (carbon value):

- Social cost of carbon
- Marginal abatement costs

“The social cost of carbon (SCC) seeks to estimate the economic damage from emitting a tonne of carbon dioxide at a point in time. Carbon emissions contribute to climate change, which materialises in increased temperatures, rising sea levels, and increased frequency of extreme weather events, among others. These physical damages affect economic outcomes, such as GDP, productivity, or welfare. SCC aims to quantify these economic impacts caused by the emission of carbon. Because the damage of carbon is higher when the concentration of greenhouse gases are higher, the SCC usually increases over time.” /124/

Marginal abatement costs are the costs associated with reducing a unit of GHG emissions.

The SCC and marginal abatement costs are separate from carbon prices, which are simply the observed price of carbon in a particular market e.g., the UK ETS.

In 2009, the UK Government moved away from an SCC approach to carbon valuation towards a “target consistent” approach which is effectively a marginal abatement cost based on a target atmospheric CO₂ limit /125/. These estimated costs are used in the evaluation and appraisal of all policy decisions.

The OGA, as part of its strategy, also uses valuation of GHG emissions “to aid economic appraisals of activities that will result in changes in emissions and to support decision making with regard to selecting projects and development options consistent with the obligations on the OGA Strategy and Stewardship Expectation.” /126/

Figure 20-1 below shows the OGA UK’s forecast range of Social Cost of Carbon values as of 2020:

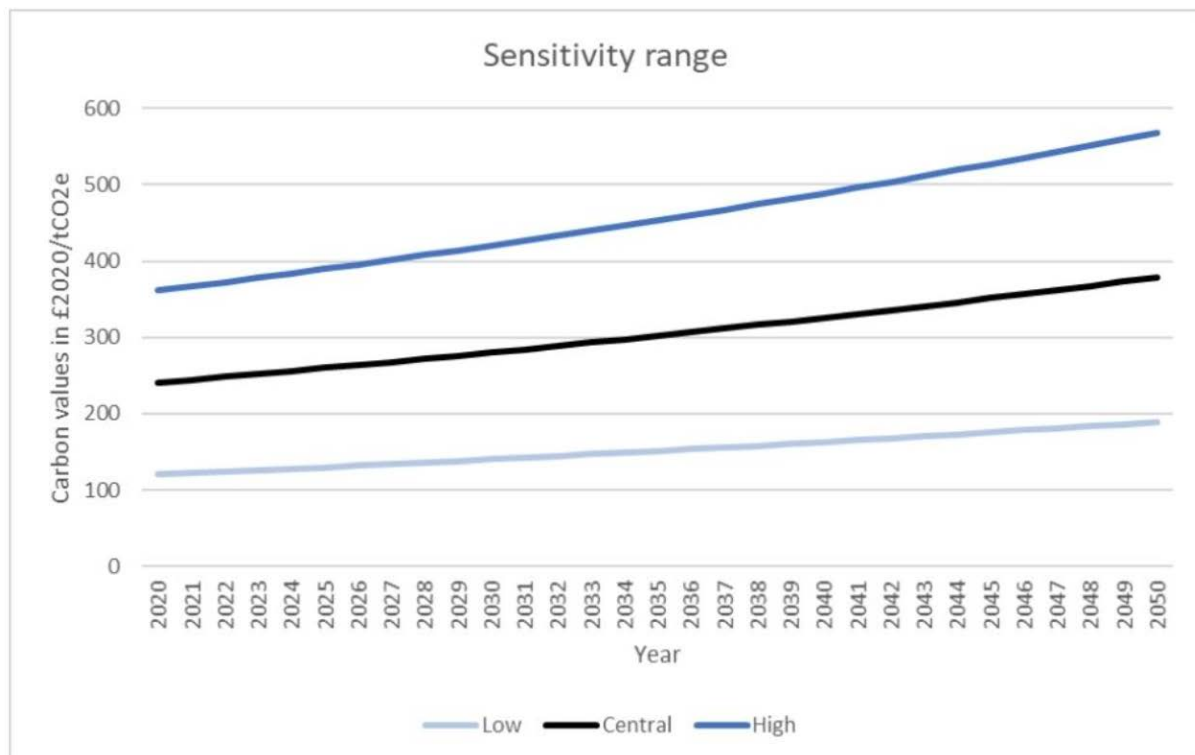


Figure 20-1 - UK Social Cost of Carbon Value Forecast

It can be seen from Figure 20-1 that the carbon value increases over time.

This carbon value is not directly used in this Technical Note to determine a unit cost of energy; however, it is important to understand as it influences the evaluation and economic appraisal of UK policy decisions and the OGA's strategy regarding projects and developments. It could be a metric which can be evaluated as part of the economic analysis, however it is not built into the CoED currently.

20.2.8 Waste Heat Recovery

The impact of WHR on total energy costs is captured by including WHR loads in the total energy demand value, which is used to estimate the final unit cost of energy. Where WHR is used the total energy demand > total power demand (value used to determine fuel gas costs). The total power demand is made up of the total electrical power demand and the power demand of direct drive equipment only and the total energy demand includes WHR loads.

The yearly WHR load, where applicable, was supplied as part of the CNS power requirement data provided by the OGA /59/ and summarised in Section 20.2.1.

Where WHR was used but the load was not supplied, it was assumed that total energy demand is 20% greater than the total power demand.

20.2.9 Unit Cost of Energy

The unit cost of energy was determined by dividing the sum of the yearly costs from each contributing factor by the total energy demand in a year. This provided a cost of energy in £/MWh.

The cost of energy was determined for each installation, for each of the high, medium, low and February 2022 fuel prices. An average value was taken for each, and the highest and lowest individual installation energy cost was noted for each fuel price.

20.3 Cost of Energy Results

Energy Cost (£/MWh)	Fuel Price Case			
	High	Medium	Low	February 2022
Average	230.0	156.0	119.0	267.0
Installation High	272.2	190.3	151.2	313.2
Installation Low	194.8	130.9	90.0	224.5

Table 20-2 - Cost of Energy Results

Figure 2 below shows the plots of the total energy demand of individual installations versus the estimated energy cost based on the four fuel price cases:

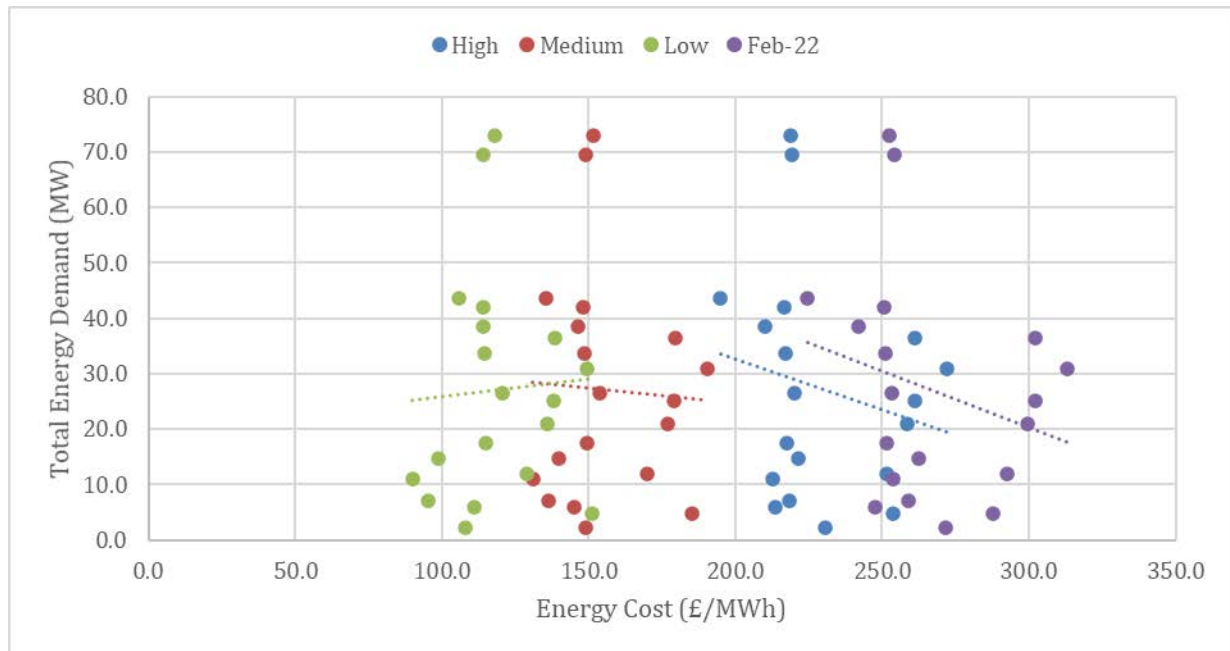


Figure 20-2 - Installation Total Energy Demand vs Energy Cost

Refer to Appendix 28.22 for more detail.

20.4 Discussion

Estimated energy costs were determined based on data for 19 CNS installations. The average energy costs range from 230 £/MWh to 119 £/MWh based on assumed high, medium, and low fuel costs.

The total energy cost is extremely sensitive to fuel prices and fuel costs can make up >90% of the total energy cost in some cases.

There is significant installation variability in energy cost, with a difference of >40% at low fuel prices.

It can be seen from Figure 2 that the unit cost of energy generally decreases as the total energy demand of the installation increases. This is likely due to economies of scale savings on OPEX costs.

The energy cost estimates calculated in this technical note will be used to aid the economic analysis of the project.

Market complications such as import / export arrangements for operators and pipelines have not been considered as part of this analysis. Spot rate variances for import and export of gas exists depending on operator specific terms of pipeline use.

Where no export route exists fuel costs could be considered neutral. Electrification of assets may warrant additional expansion of gas export infrastructure.

20.5 Conclusion

Based on the estimated energy costs in Section 20.3, Katoni would suggest a reasonable cost of energy range for the economic analysis would be between 90 to 230 £/MWh with the main focus on analysis between 130 to 190 £/MWh.

20.6 Further Areas of Study

The cost of energy for offshore installations was determined based on a high, medium, and low fuel gas price case. However, this was not done probabilistically, and the values used are based simply on qualitative analysis of historical fuel price trends.

Probabilistic Monte Carlo type evaluation of the cost of energy could be considered in future work. This would allow the inclusion of statistical confidence levels i.e., P10, P50, P90 analysis for the energy cost estimates.

20.7 Opportunities / Risks / Assumptions

One risk identified in this study and discussed in Section 20.6 above is the lack of probabilistic analysis applied to the estimated fuel price ranges. This may result in an overly conservative or overly optimistic energy price being used in the economic analysis. An attempt to combat this has been made by exploring average, high and low installation demands at high, medium, low and current gas prices.

21. Economic Analysis

21.1 Introduction

This report describes the findings of the application of an economic cost model which assesses the impact of the distribution and supply of non-carbon generated electricity to UKCS production platforms. The work should be read in conjunction with technical and engineering study work undertaken by Katoni Engineering.

Our economic analysis and modelling was undertaken in partnership with SPC Network.

SPC Network was founded in 2003 and has worked for over 50 clients worldwide.

The company undertakes Strategic Policy Development in regulated industries, by combining the knowledge of the team with specific and valuable skills to ensure rigorous analysis and exceptional advice. Underpinned with advanced academic training, the team has developed the key skills and rigorous required support our clients in evidence based policy work.

Katoni Engineering as part of this study work developed a bespoke economic model. This model is used to assess the economic cost of non-carbon powered gas production, compared to the existing practise of gas turbine generation on each platform asset.

The findings of the report are split to show the economic cost of decarbonisation in the Central North Sea and Outer Moray Firth (referred to CNS from herein), Southern North Sea (SNS) and across both locations.

Initial recommendations on the economic incentive and regulatory model that might enable this initiative have been developed and provided.

21.2 Philosophy

The economic cost of distribution and supply of non-carbon electricity in the NSCS can be considered conceptually as the price of electricity that an efficient company would require to build and operate the assets and supply the electricity to the platforms in the UKCS.

This approach is taken to allow us to provide a 'Base Case' for the economic analysis. This Base Case therefore includes:

1. a base technical case;
2. a base set of future capital costs;
3. a base set of existing operating costs; and
4. a base set of future operating costs
5. a base set of future energy costs (presented in this report)

With reference to future energy costs the assumption of an 'efficient company' allows us to provide a price which is realistic at today's prices. However, any future improvements in technology, access to easier low carbon generation in the future will provide upsides to the analysis.

This approach to model the economic cost of electricity supplied by non-carbon generation forms the "Base Case". However, in order to estimate the net economic costs of non-carbon generation we also need to model a "Counterfactual Case" - the existing method of gas turbine generation is continued.

The difference between the economic cost under the Base Case and Counterfactual Case forms the net economic cost of decarbonisation.

The Counterfactual

The Counterfactual case assesses what would happen if we did nothing i.e. the Status Quo. We assess this against the 'Base Technical Case' to allow us to assess the difference between an intervention or doing nothing.

The modelling approach use calculates a “levelised cost” over the lifetime of the project investment (2025 – 2040). This means calculating a fixed £/MWh price (at constant 2022 price levels) at which an efficient company can distribute and supply electricity over the period. This is sometimes called a life-cycle cost, which emphasises the “cradle to grave” aspect of the definition. This is consistent with the energy costing approach taken by Department of Business, Energy and Industrial Strategy (“BEIS”) in its publication “Cost of Electricity Generation”, August 2020.

The model covers to the CNS and SNS areas, since these are expected to be the areas with greatest potential benefit.

21.3 Basis

The modelling assumes that existing asset-based gas turbine generators (in the Counterfactual Case) are replaced in a phased approach from 2026 by wind turbine generating sources connected to platforms by a distribution network of the following infrastructure:

- A main hub including a supplementary gas turbine generating capacity to cover for periods of unavailability of wind sourced generation. It is assumed that the supplementary, centralised thermal generation capacity is used 53% of demand.
- High voltage cables connecting to sub hubs.
- Medium voltage cables connecting to the individual platforms.

The Base Case model cost components includes:

- The costs of the non-carbon electricity (e.g. from an offshore windfarm);
- Investment CAPEX of distribution assets (hubs and cables);
- OPEX for these assets;
- REPEX (renewal expenditure) of the assets over the period;
- ABEX (abandonment costs);

The economic analysis for the base case also includes tax liability for the hypothetical company that builds, operates and receives revenue compensation for the assets. We have also included for the cost of capital, this is the minimum expected return on investment taking account of the project risk, but bearing in mind that the hypothetical company will be owned as part of a wider diversified investment portfolio.

The Counterfactual Case Model takes account of:

- The costs of the gas fuel for the turbines;
- Cost of CO₂ emissions under the UK Emissions Trading Scheme (“ETS”);
- OPEX of the gas turbines;
- REPEX (renewal expenditure) of the gas turbines;

We have not included an assessment of ABEX (Decommissioning costs) as field decommissioning happens in each option so is a net zero impact.

We have included for a basic tax liability for the hypothetical company that builds, operates and receives revenue compensation for the assets. However, again this is limited to the elements of the research being considered i.e. power generation.

The base case also includes continued gas turbine generation. Even in the Base Case gas turbines generation will be retained for a portion of electricity demand, with the consequent costs of gas, turbine operation and CO₂ emissions. However, this can be more efficiently generated in one location (the Hub) therefore reducing gas costs and emissions.

21.4 Further assumptions

Table 21-1 summarises the inputs factors taken into account, and specific value used in the central scenario. One important observation from this table is the SNS has a larger number of, on average, smaller platforms, and a lower demand for electricity overall.

The consequence is that, compared to CNS, a larger infrastructure build cost is spread over a smaller volume of delivered electricity.

Inputs	CNS	SNS
Base Case Infrastructure costs		
Number of drilling platforms electrified in Base Case	19	26
Main hub	£1,028 million	£1,070 million
Sub Hubs	£1,853 million	£2,765 million
Platform modifications	£390 million	£140 million
Replacement Gas Turbines	£70 million / year	£80 million / year
Opex for replacement gas turbines	£29 million / year	£33 million / year
Counterfactual Gas Turbine opex		
Total opex	19 x £2.5m/year/platform	20 x £1m/year/platform + 6 x £2.5m/year/platform
Energy usage		
Energy demand	193 GWh/year/platform	64 GWh/year/platform
Non-carbon energy usage in Base Case	145 GWh/year/platform phased in by 2029	48 GWh/year/platform phased in by 2029
CO2 emissions: Base Case	38,026 tonnes/year/platform	12,596 tonnes/year/platform
CO2 emissions: Counterfactual Case	152,105 tonnes/year/platform	50,385 tonnes/year/platform
Energy fuel costs		
Fuel cost for gas turbines (£/MWh)	£109.34	
ETS CO2 cost (£/tonne)	£79 in 2022, rising at 5% p.a.	
Non-carbon energy cost from wind turbines (£/MWh)	£66-£46 (2025-2040) based BEIS "Electricity Generation Costs 2020" revalued to constant 2022 prices	
Financial inputs		
Real post-tax cost of equity	4.9%, based on return on equity of winning OFTO bids. See Ofgem, 'RIIO-2 Final Determinations – Finance Annex (REVISED)', para 3.115. the real cost of equity for the company is taken from Ofgem's analysis of OFTO returns, for the purposes of cross-checking the cost of equity for RIIO-2 price controls. The assumption is that the company would have a similar risk profile to an OFTO. However, in sensitivities shown below (see Table 21-2) it appears that this is not a critical assumption.	
Real cost of debt	4.0% assumption	
Gearing	85%, based on winning OFTO bids. See Ofgem, RIIO-2 Final Determinations – Finance Annex (REVISED), para 3.115	
Corporate tax rate	25%	
Annual Investment Allowance	£0.2 million	
Capital allowance: main pool	18%	
Capital allowance: special pool (cabling)	8%	
Abandonment costs	1% of total investment	
Tax refund on abandonment costs	Allowed	
Optimism Bias	20%	

Table 21-1 Model assumptions

21.5 Findings

Table 21-2 displays the model results for the central scenario, and a number of sensitivities. Under the central scenario the cost of electricity under the Base Case on non-carbon generation is less than the Counterfactual Case of continuing with the gas turbine generation, giving a net economic benefit in the CNS only. In the SNS there is an economic loss, and overall in both regions there remains an economic loss. The net economic benefit in the CNS is a consequence of the smaller number of larger platforms, requiring less investment per MWh in the distribution network compared to the SNS.

	Base Case (£/MWh)	Counterfactual Case (£/MWh)	Cumulative Discounted Economic Net Benefit to 2040
CNS only			
Central scenario	£210	£227	£1.0 billion
Sensitivities			
Capex overrun 20%	£228	£227	£0.0 billion
Project delay by two years	£213	£227	£0.8 billion
Gas turbine fuel cost: x 2	£255	£336	£4.8 billion
ETS cost: x 2	£247	£332	£4.9 billion
Cost of non-carbon generation: x 0.5	£195	£227	£1.9 billion
Cost of equity: +1%	£211	£227	£0.9 billion
Tax rate: -5%	£209	£226	£1.0 billion
Tax refund allowed on abandonment costs: disallowed	£212	£227	£0.9 billion
SNS only			
Central scenario	£366	£235	£-3.5 billion
Sensitivities			
Capex overrun 20%	£412	£235	£-4.7 billion
Project delay by two years	£354	£235	£-3.2 billion
Gas turbine fuel cost: x 2	£410	£344	£-1.7 billion
ETS cost: x 2	£402	£339	£-1.7 billion
Cost of non-carbon generation: x 0.5	£350	£235	£-3.1 billion
Cost of equity: +1%	£367	£235	£-3.5 billion
Tax rate: -5%	£363	£234	£-3.4 billion
Tax refund allowed on abandonment costs: disallowed	£371	£235	£-3.6 billion
CNS and SNS			
Central scenario	£259	£229	£-2.5 billion
Sensitivities			
Capex overrun 20%	£286	£229	£-4.8 billion
Project delay by two years	£257	£229	£-2.4 billion
Gas turbine fuel cost: x 2	£303	£339	£3.0 billion
ETS cost: x 2	£296	£334	£3.3 billion
Cost of non-carbon generation: x 0.5	£243	£229	£-1.2 billion
Cost of equity: +1%	£260	£229	£-2.6 billion
Tax rate: -5%	£257	£229	£-2.4 billion
Tax refund allowed on abandonment costs: disallowed	£262	£229	£-2.7 billion

Table 21-2 Cost of energy supplied offshore (£/MWh, 2022 price level)

In respect of the sensitivities:

- Capex overrun of 20% is sufficient to reduce the CNS case to breakeven, and increases the losses in the SNS;
- Delaying the project saves costs but also reduces the time available for the benefits of non-carbon energy;
- Doubling the cost of gas fuel increases the Counterfactual Case cost by 48% and the Base Case cost by 17%.
- Doubling the cost of ETS emissions increases the Counterfactual Case cost by 46% and the Base Case cost by 15%.
- In comparison to energy costs, cost of equity and tax regimes have little impact.

Other than for a capex overrun of more than 20%, the net economic benefit persists in all sensitivities in the CNS, and the net economic loss persists in all sensitivities in the SNS. Overall, for both regions, the net economic benefit is only positive in scenarios of higher gas prices and/or higher ETS carbon prices.

21.6 Breakeven analysis

Using our model we explored the circumstances under which the economic benefit becomes positive.

In Table 21-3 we explore the circumstances under which the economic benefit becomes positive. As suggested by the sensitivities of Table 2 the key variables that affect the project's ability to breakeven are the cost of gas and the cost of CO2 under the ETS.

The case for the CNS remains positive even if the price of gas was to be lower by 25% or the cost of CO2 emissions were to be rise by 2% p.a. (rather than 5% p.a. in the central case). By contrast, the case for the SNS remains negative even if the price of gas were to be higher by 46% or the cost of CO2 emissions were to rise by as much as 14% p.a..

The cost of wind generation is less significant, to the extent that the cost of wind generation would need to fall by 95% for the combined CNS and SNS to breakeven.

	Central Scenario assumption	Breakeven level
CNS only		
Gas turbine fuel cost (£/MWh)	£109	£82
ETS cost (£/tonne)	£79 + 5% p.a.	£79 + 3% p.a.
Wind generation cost	£66-£46 (2025-2040)	+53%
SNS only		
Gas turbine fuel cost (£/MWh)	£109	£329
ETS cost (£/tonne)	£79 + 5% p.a.	£79 + 14% p.a.
Wind generation cost	£66-£46 (2025-2040)	Less than zero
CNS and SNS		
Gas turbine fuel cost (£/MWh)	£109	£159
ETS cost (£/tonne)	£79 + 5% p.a.	£79 + 8% p.a.
Wind generation cost	£66-£46 (2025-2040)	-95%

Table 21-3 Breakeven levels of key assumptions

21.7 Conclusion

The findings above show that it is unlikely that that there will be a commercial profit for undertaking decarbonisation in the combined CNS and SNS without some form of regulatory intervention.

The scheme is marginal however, this uses historic gas and emissions pricing which may not prevail. These are the major drivers of a net economic benefit.

In comparison to energy costs, cost of equity and tax regimes have little impact, unless of course a tax regime is based on either of these input/outputs. The cost of delivery (CAPEX) has a relatively modest on the economic outcomes but we know that major projects suffer cost and timing overruns which would impact the economic effectiveness of the intervention.

It will be necessary to build an economic regulation structure to achieve the objective, including incentives for the construction of the infrastructure and use of decarbonised energy in the fields.

The timing of the intervention is also important. The later the intervention is undertaken the higher the deficit or lower the economic benefit depending on the costs of gas / cost of emissions. Further research is required to test sensitivities around Cease of Production (COP) dates for individual platforms too.

21.8 Further Areas of Study

21.8.1 Economic and technical analysis

Further study would be useful in the following areas to test the assumptions of this conceptual study:

1. Input costs – more detailed project costings, capital, operating and Repex and abandonment costs
2. Project phasing – more detailed analysis on project scheduling and how the scale of this intervention may be influenced by the available capacity in the market to deliver it
3. COP – on recommendation of the OGA a flat base of 2040 was used. Our research has shown timing is important and the benefits will be larger if COP were later than 2040 in some cases, the converse is true
4. Energy and emissions costs – compared to prices today the gas costs could be considered as conservative base are based on historical norms. A central and agreed view on gas and emissions pricing would be valuable.

21.8.2 Regulatory commentary

An assessment of the regulatory environment was out of the scope of this study. However, it is not possible to ignore this matter entirely.

If we assume no major changes in gas or emissions costs then the findings show that it is unlikely that there will be a commercial profit for undertaking decarbonisation without some form of regulatory intervention. If that is the considered view following further analysis then it is necessary to build an economic regulation structure to achieve the objective, including incentives for the construction of the infrastructure and use of decarbonised energy in the fields.

21.8.2.1 Recommended approach

The most obvious approach is that, following tenders, a company is appointed to build and operate the necessary infrastructure. The company could:

- Takeover the existing gas turbine energy sources. This may be important to ensure the decommissioning of the existing rig-based generators; and
- Build the infrastructure to distribute decarbonised energy within the SNS and CNS areas.

With this approach the company could be incentivised by:

- A guaranteed fixed price/MWh of energy supplied by either carbon or non-carbon sources, indexed by CPI each year to maintain its real value; and
- Penalty payments should it fail to deliver milestones in non-carbon energy availability.

It can be presumed that once non-carbon energy sources are established (e.g. wind) and fixed cost investment sunk, there will be a commercial incentive for the company to meet demand through non-carbon generation whenever available, due to its lower marginal cost compared to gas turbines.

Of course this also assumes no other, lower cost, source of non-carbon energy becomes available.

This analysis does not include any assessment of an offshore transmission licensing regime which would be merited perhaps.

21.8.2.2 Other approaches

Other regulatory approaches often used but not appropriate based on the findings of this report are:

- A Regulated Asset Base ('RAB') which is designed to provide a signal to investors that the asset values will be protected in the long term. This is not relevant here due to the limited life of the project.
- Rate of Return Regulation ('RoR') but this might lack incentives for an efficient project build.

22. Renewables Technology Review

22.1 Objective

The objective of this study is to review potential renewable power sources and battery storage technology that could be used to support operations or supplement the primary energy source (wind power) for the Oil and Gas industry.

22.2 Background

The use of renewable energy to reduce offshore emissions is one of the major aims of this project. However, the variable and non-dispatchable (i.e., cannot be switched off or on to meet energy demands) nature of some renewable and low carbon energy sources result in mismatches between energy supply and demand. This typically results in the need to balance energy loads with reliable dispatchable power sources, typically hydrocarbon based sources.

A key driver for this literature review is to study the available renewable power and energy storage technologies to understand how renewable energy utilisation can be maximised, with the aim of reducing the current reliance on hydrocarbon energy sources to meet energy demands.

22.3 Methodology

This report has been carried out as a literature review. The primary sources reviewed are research papers, news publications and industry publications. Google Scholar was used as the primary search engine for research literature.

It is important to note that throughout this report the cost per MWh of energy produced by the various renewable sources is compared to the £57/MWh of wind power. Although this is an accurate cost of the energy being produced by wind power when the wind is blowing and the turbines are spinning, it may not be fair to compare this figure to other renewable sources.

When evaluating the overall cost of wind power, it is important to consider the periods when wind speed is low. During these periods, the wind power would have to be supported by other power sources or energy storage would have to be considered to allow the energy generated by wind to be stored and used when production is not possible. The additional cost of this supplementary energy supply or storage should be included in the overall cost of wind power, which would lead to a figure much higher than £57/MWh. So, although it may be comparable to evaluate the cost of wind power to other energy sources such as solar or tidal which is also weather / seasonable dependant, it is not comparable to evaluate it to the cost of nuclear or Geothermal power generation which is a dispatchable power source.

22.3.1 Technology Readiness Level

One important part of the review process used during this literature review was the allocation of a technology readiness level to each technology. The following technology readiness level descriptions are used by the UK Government /128/ and were adopted for use in this literature review:

- TRL9 Operations
- TRL8 Active Commissioning
- TRL7 Inactive Commissioning
- TRL6 Large Scale
- TRL5 Pilot Scale
- TRL4 Bench Scale Research
- TRL3 Proof of Concept
- TRL2 Invention and Research
- TRL1 Basic Principles

Further information on how these TRL levels are distinguished can be found in /36/.

22.3.2 Complementarity

Complementarity, in this context, is the ability of different renewable energy sources to operate together in a complementary way.

The key form of complementarity analysed in this review is temporal complementarity which is complementarity that can be observed between two or more renewable energy sources in a certain region /159/. For example, where a certain renewable energy source typically performs well in summer months and another typically performs well in winter months, these would be said to have temporal complementarity. Utilising both sources instead of one or the other would result in the ability to meet a greater amount of the load demand and reduce the need for local generation or energy storage. This in turn reduces the reliance on hydrocarbon energy as the local generation would likely be from hydrocarbon based sources.

Wind energy has been identified as the most viable renewable energy source for this particular application. With this in mind each of the renewable energy sources studied in this review will be analysed with respect to how they can complement wind energy.

22.4 Scope

The review will explore the following technology:

- Wave and Tidal Power
- Solar Power
- Geothermal Power
- Advanced Modular Reactors (AMRs)
- Energy Storage

The following key topics will be discussed:

- Technological maturity and readiness (particularly in an offshore environment)
- Complementarity (i.e., how hybrid renewable energy sources can complement one another to enhance performance)
- Impact on utilisation of renewable energy and requirement for local power generation
- Modularity

Hydrogen technology with regards to energy storage and production is briefly covered under the energy storage section but is covered in greater detail in the Hydrogen Technology Study Section 23.1.

22.5 Discussion

22.5.1 Wave and Tidal Power

22.5.1.1 Description and Background

Wave and tidal power is power generated from the movement of wave and tidal flows. Waves are produced by wind passing over the surface of the ocean, whereas tides are produced by the gravitational pull of the moon and sun. Although wave power can offer a continuous energy source, of the two types of marine energy, tidal power is the most developed and the most reliable of the two.

Tidal energy is specifically energy produced by the natural movement of ocean water caused by the rise and fall of tides.

There are three different ways to access tidal energy /141/:

1. Tidal streams
2. Tidal barrages
3. Tidal lagoons

Tidal streams are fast-flowing bodies of water created by tides. Tidal stream turbines are the most common and can be installed on the sea floor or fixed to a floating structure. The flow of these streams rotates the turbine which creates electrical energy. The tidal power technologies that are used in tidal streams are likely to be the most applicable for location near offshore platforms.

Tidal barrages work similarly to dams and are typically constructed near shore across tidal rivers, bays, and estuaries. Tidal barrages have gates which open while the tide is rising allowing water to build up within the river, bay, or estuary. Once the water level is at its peak during high tide the gates are closed. The water can then be released through the barrage's turbines creating electrical energy. Due to this technology's reliance on features such as tidal rivers, bays, and estuaries it is not possible to locate this energy source in a location near to the offshore platforms.

Tidal lagoons are partly enclosed bodies of water and are often naturally occurring but can also be man-made. Energy generation from a tidal lagoon functions in a similar fashion to that of a tidal barrage. The key difference between the two is that tidal lagoons have the potential to generate continuous power by generating power during both the emptying and filling of the lagoon. These are also typically located near shore and it would not be possible to locate this technology near to the offshore platforms.

The UK's wave and tidal energy potential is estimated to be between 30-50 GW /142/. This is similar to the potential capacity for shallow water offshore wind.

The world's largest tidal energy plant, MeyGen, is currently under construction and will be located in Scotland, in the Pentland Firth. This power plant will have a 400 MW total capacity when completed.

22.5.1.2 Offshore Tidal Power

Most tidal power projects have been located near shore. This is partly due to the use of naturally occurring geographical features for tidal barrages and lagoons as well as the fact that tidal generators work better in shallow water /141/. Additionally, tidal stream power is often more effective when located in land constrictions such as straits or inlets as the water moves at higher velocities. It is also to allow for easy transmission of power by minimising cable lengths and utilising onshore electrical substations.

However, the nature of tidal stream power makes location near offshore platforms extremely feasible. There are even existing examples of tidal generators being used with batteries to provide power to subsea oil and gas equipment /143/. In 2017, a prototype power hub consisting of a single turbine achieved a successful eight month sea trial at the European Marine Energy Centre (EMEC) in the Orkney Islands, northern Scotland. This example was developed by a company called EC-OG, which was established in 2013 by a group of subsea engineers from the North Sea oil and gas industry. EC-OG are currently working to refine and further improve this initial design to better suit the requirements of the oil and gas field developers. EC-OG believe that this technology has the potential to provide a long term solution for providing green energy sources to remote offshore locations.

22.5.1.3 Potential Project Impact

Unlike wind energy, tidal energy is very predictable /144/. This will make it easier to match the power requirement from the GTs to the load, as peaks and troughs in energy production can be better predicted.

However, like wind energy, tidal power generation is seasonal, with peak energy production in the winter months /145/. This means tidal power does not have good temporal complementarity with wind since it follows the same seasonal patterns, as it is wind speeds that cause the variance in tidal energy produced throughout the seasons. It is therefore unlikely that for this project combined wind and tidal power would result in a significant increase in renewable energy utilisation and the reduction in fuel costs and emissions compared to using wind power alone.

Market analysis was carried out by the UKs Department for Business, Energy, and Industrial Strategy into electricity generation costs from different energy sources /146/. This analysis estimated the levelized cost estimates for energy projects commissioning in 2025 for different energy sources. It estimated tidal stream energy to cost £253 per MWh, compared to offshore wind at £57 per MWhr. It is therefore unlikely that utilising tidal or wave energy for this projects concept will be commercially viable in the near term.

The cost for location near offshore platforms would likely be greater than those predicted above since the tidal power station may need to be located in a non-ideal location with regards to energy potential; there would likely be increased costs of construction; potential increased maintenance costs; and water depth may make some existing technologies unfeasible. A case study analysis into the feasibility of providing electricity from ocean waves to remote offshore oil and gas facilities estimated the levelized cost to be €188 – 471 per MWh /147/.

22.5.1.4 Existing Facilities

As mentioned in section 22.5.1.1 the world's largest tidal energy plant, MeyGen, is currently under construction and will be located in Scotland, in the Pentland Firth. This power plant will use tidal stream turbines to achieve a 400 MW total capacity when completed. The MeyGen exported its first electrical energy to the national grid in November 2016, and more recently phase 1A of the project entered its 25 year operation phase in April 2018. The current location of MeyGen was originally identified by Atlantis in 2007 as a prime location for tidal energy generation due to its high flow, medium water depths and proximity to the mainland. Phase 1B is set to introduce a subsea power hub which will allow for multiple turbines to be connected to the grid via a single power export cable rather than each turbine having its own length export cable. This will significantly reduce the cost, environmental impacts and necessary construction efforts. The subsequent phases 1C, 2 and 3 are all aimed at further increasing the overall capacity of the project through the addition of turbines, improvements to the grid and to the power management facilities.

Other offshore tidal power generation facilities include the Shetland Tidal Array and the Orbital O2. The Shetland tidal array has been fully operation since 2016 and produces a power output of 600kW of energy to the Shetland grid. The Orbital O2 is the newer of the two having become fully operational in 2021 and also has a larger power output at 2MW. There is a proposal to instal a second Orbital O2 turbine alongside the existing turbine however this would not be operational until the end of 2023.

22.5.1.5 Technology Readiness Level

In terms of tidal power there are facilities such as Sihwa Lake Tidal Power Station in South Korea with an output capacity of 254MW that have been in full scale operation since 2011. This example is a tidal barrage which utilises a man-made sea wall on the coast of South Korea. Due to examples such as this, the TRL for tidal power as a whole would be 9 because it is a technology that is operation to a scale that is comparable to this project. But with reference to the specific requirements of this project, explicitly offshore tidal power, there is not many existing examples, and none of which are to the same scale as would be required by this project. Examples such as MeyGen and Orbital O2 do provide evidence of successful offshore tidal power, but these projects are currently only operational on a small (pilot) scale when compared to the requirements of this project. This means the TRL for tidal power with reference to this project is 5.

22.5.2 Solar Power

22.5.2.1 Description and Background

Solar power is the conversion of energy from sunlight into electricity. There are two main technologies used to generate electricity from solar energy /148/:

1. Photovoltaic Cells (PV)

Concentrated Solar Power (CSP) Photovoltaic cells are typically the most prominent of the two technologies and are most commonly used within solar panels to directly convert sunlight into electricity using the photovoltaic effect. Simply explained, this effect is when an electrical voltage and current is produced by a material when it is exposed to light. Overall PV technologies are considered simpler due to their lack of moving parts and this simplicity allows for them to be used in a wider variety of applications.

CSP involves using lenses or mirrors to concentrate sunlight and through concentrating the sunlight large amounts of heat can be generated. This heat can then be used to generate steam to rotate turbines and produce electricity. CSP requires direct irradiation while PV can generate power from diffused radiation. This means PV can be installed in many locations while CSP is limited. Also, due to the greater complexity of CSP technologies it is more difficult to scale down these energy sources to allow them to thrive in smaller scale applications.

Solar power is one of the cheapest forms of renewable energy and solar PV farms are now built on the gigawatt scale. The International Energy Agency suggests that solar power will be the single largest renewable energy source in the world by 2050 /149/. Stating that the combination of wind and solar PV will produce around 23000TWh by 2050, which equates to 90% of all the energy produced globally in 2020. Through the utilisation of batteries (and other energy storage technologies) it will allow for sufficient flexibility and reliability in the delivery of power.

22.5.2.2 Offshore Solar Power

Unlike wind, solar has not yet made the leap towards commercially viable large scale offshore farms, also known as high-wave solar.

There are several examples of floating solar on inland bodies of freshwater such as lakes and dams /150/; however, offshore “high-wave solar” projects are less common.

The offshore environment poses additional challenges:

- Larger waves and higher winds
- Large tidal movements and currents
- Salinity impacts the durability of components

22.5.2.3 Potential Project Impact

Solar demonstrates a high temporal complementarity to wind, as peak energy production for solar power is in the summer months whereas peak energy production for wind power is in the winter months. Therefore, due to these natural peaks and troughs these energy sources go through periods of producing excess energy and insufficient energy for the required load.

A combined solar-wind farm would be able to take advantage of more renewable energy, allowing for these peaks and troughs to be and reduce fuel gas consumption.

Additionally, if energy storage is to be utilised, a combination of wind and solar power may reduce the optimal energy storage capacity required /153/. This is due to their high comparability allowing the peaks and troughs of the two technologies to stabilise one another, delivering consistent power. This means that there should be fewer occasions where there is either too much power being generated and it needs to be stored, or too little power being generated and stored power needs to be used. Therefore reducing the total amount of power storage required.

Furthermore, there is significant space required between wind turbines, and solar panels could potentially be used in that space, increasing the amount of energy used per unit area.

Solar power is still highly variable and produces very little power in the winter months, and so cannot be used to provide base load and reduce the number GTs required.

The levelised costs of offshore solar is purported to be approximately £125 per MWh which is significantly higher than that of offshore wind which is estimated by BEIS to be £57 per MWh for projects commissioning in 2025. Onshore solar costs are estimated by BEIS to be similar to onshore wind at £44 and £46 per MWh respectively for projects commissioning in 2025 /146/. As offshore solar develops and receives greater investment, there is potential for the costs to significantly reduce, as seen for offshore wind. With more competitive levelised costs, a combination of solar and wind may be a viable and optimal option for providing electrical power to offshore platforms.

22.5.2.4 Existing Facilities

The first pilot offshore solar array, called Zon-op-Zee, was installed in November 2019 in the Dutch North Sea by developer Oceans of Energy. The pilot began as an 8.5kW array and was then expanded to 50kW in 2020. The plant is planned to further expand to 1MW, and to 100MW at a later stage /151/. In 2021, Oceans of Energy announced a second development for a 3MW array off the Belgian coast in the North Sea. This solar array will be located near an existing wind farm and will be essentially combined with the wind farm and is part of a demonstration project focussing on the complementary production profile to wind. The developers say this project will bring the levelised cost of offshore solar to €150 per MWh which is approximately £125 per MWh /152/.

Despite offshore solar power still being very much under development, floating solar power is currently operational with the second phase of a 320MW facility developed by Hangzhou Fengling Electricity Science Technology being completed in 2020. The first phase seen a 200MW facility completed in 2017, which was followed by the additional 120MW more recently. This facility is located in China with the PV panels floating on the Changhe and Zhouxiang reservoirs.

22.5.2.5 Technology Readiness Level

Solar power is one of, if not the most developed and widely available renewable energy source. It is present globally, throughout industrial and domestic applications, and is continuing to grow. With this in mind solar power, and in particular PV technology, generally speaking is clearly a TRL of 9. Even being slightly more specific to this particular project and looking at floating solar power would result in a TRL of 9 due to facilities such as the 320MW development by Hangzhou Fengling Electricity Science Technology.

These could be accredited a TRL of 9 because there are existing facilities that are on a scale that is comparable to this project. However, with regards to this specific project and its requirements, where an offshore application is being considered, solar power can only achieve a TRL of 5. Despite the Zon-op-Zee facility providing a good example of the potential for this technology, it is still only at the pilot stage.

22.5.3 Geothermal Power

22.5.3.1 Description and Background

Geothermal energy is thermal energy from the Earth's crust. It can be used to provide energy in the form of heat or can be used to generate electrical power.

Geothermal power is typically produced using hydrothermal energy from geothermal reservoirs via drilled Wells. There are three main types of geothermal power plant /129/:

1. Dry Steam Plants
2. Flash Steam Plants
3. Binary Cycle Power Plants

Dry steam plants use steam that is extracted directly from a geothermal reservoir to rotate turbines and generate electricity. The steam then cools and condenses to water and is injected back down into the reservoir to be used again. Flash steam plants use high pressure water from a geothermal reservoir and convert it to steam using a flash tank. Similar to the dry steam plants, this steam is then used to drive generator turbines and produce electricity. When the steam cools and condenses to water, it is injected back into the reservoir to be used again. This is the most common type of geothermal power plant.

Binary cycle power plants extract hot water from the geothermal reservoir before using this hot water to heat another water (or liquid) source and produce steam. Similarly to the others, this steam is then used to drive a generator turbine and produce electricity. Then when the steam cools and condenses into water, it is injected back into the reservoir to be used again.

Organic Rankine Cycles (ORC) are also used in geothermal applications to generate power from low temperature geothermal sources /130/. An ORC operates in the same way as conventional Rankine Cycles with the key difference being the fluid type used. Instead of using water, an organic fluid with a low boiling point is used to allow vapour to be produced at lower temperatures, this vapour is then used to rotate a turbine and generate electricity. The removal of the need for high temperatures makes it easier to achieve the boiling point of the fluid, this results in lower temperature geothermal energy sources to be used increasing the number of potential locations for the application of this technology.

22.5.3.2 Offshore Geothermal Energy

Installed capacity of geothermal energy globally is approximately 15GW, the vast majority of which is installed onshore /132/. Additionally, most geothermal power projects have been developed in areas with advantageous well locations i.e., high temperature reservoirs at easily accessible depths (2000 – 3000 km) /133/. These locations will likely be more difficult to identify and utilise offshore as the possible locations are limited to the regions around the respective offshore platforms.

Much of the discussion, research, and developments regarding geothermal energy in the offshore environment is based around two areas:

1. The repurposing of unproductive oil and gas platforms, that would typically be decommissioned, to produce geothermal energy /134//135/
2. Generating geothermal power from the produced water of high water-cut producing wells on operational oil and gas platforms /130//131/

Neither of the above are applicable to this project as a key philosophy for this project is to centralise the energy production to minimise platform modifications. It may be possible to utilise an unproductive platform to provide some geothermal energy to an identified platform cluster, but this would have to be determined on a case-by-case basis and is not part of a generic solution that could be applied to every platform cluster.

Additionally, the estimated total geothermal power that could be generated using all available produced water from North Sea fields is only 250 MW /136/. This is far below the required load capacity of the single cluster identified for this project and implies that any geothermal power generated using this method would be small in scale relative to the project as a whole and would have little impact.

Drilling of new wells offshore for geothermal power is not currently commercially viable /137//138/ and the reason that the two areas above are the focus of geothermal discussion, research, and development.

22.5.3.3 Geothermal Technology Developments

Two newer geothermal power systems are in development:

- Advanced Geothermal Systems (AGS)
- Enhanced Geothermal Systems (EGS) -

AGS generates electrical power by using a closed-loop system where a working fluid is circulated through a long wellbore which extracts the geothermal heat energy from the rock surrounding the wellbore /139/. The geothermal heat energy is transferred to the fluid from the surrounding rock through conduction. This heat energy can then be used to produce steam which is used to rotate a turbine and produce electrical energy.

EGS involve creating a man-made reservoir where there is hot rock but insufficient or little natural permeability or fluid saturation. Once the reservoir has been created fluid is injected into the subsurface under carefully controlled conditions, which causes pre-existing fractures to re-open, creating permeability within the rock /140/. Now that the reservoir has been created, the geothermal heat energy can be extracted from the reservoir via a well. The form the fluid is extracted in and exactly how it is used to produce electricity will depend on the specific characteristics of reservoir. However, the basic principles that are consistent throughout geothermal power of using steam to rotate a turbine and produce electricity will remain.

These new systems will potentially make scalable geothermal power more accessible and commercially viable, particularly in areas that don't have access to highly advantageous well locations. This may be a step towards commercially viable offshore geothermal power plants.

22.5.3.4 Potential Project Impact

One of the advantages of geothermal energy over other common renewable energy sources is its ability to produce a constant energy load due to its lack of natural fluctuations. This makes it better for providing base loads to an energy network because there are no peaks and troughs in its energy output that need to be managed. This means that it eliminates or at least reduces the need for large amounts of energy storage and complimentary energy sources.

This means that geothermal energy, rather than being used to simply complement the wind energy, could also be used to reduce the number of local power generators required as it can provide some of the base load requirement when the produced wind energy is insufficient. Therefore, additional costs to implement geothermal energy could be partially offset by reducing the number of GTs required.

Market analysis was carried out by the UK's Department for Business, Energy, and Industrial Strategy into electricity generation costs from different energy sources /146/. This analysis estimated the levelized cost estimates for energy projects commissioning in 2025 for different energy sources. It estimated geothermal energy to cost £133 per MWh, compared to offshore wind at £57 per MWh. Additionally, these costs will be based on onshore geothermal energy costs; offshore geothermal energy costs would likely be much greater due to the increased difficulty in its implementation and operation.

22.5.3.5 Existing Facilities

Onshore geothermal energy facilities are very well developed. With facilities such as the Geyser Geothermal Complex in California producing 900MW of power. This complex consists of 18 active individual plants and the geothermal field spreads across 117 square kilometres. But despite the scale of onshore geothermal energy production, there are currently no offshore geothermal facilities in full scale or pilot operation.

As mentioned previously, there is potential for existing platforms to be repurposed for the production of geothermal energy production however this is out with the scope of this project. The key philosophy for this project is to centralise the energy production to minimise platform modifications. Therefore, although the repurposing of existing platforms may be viable in certain scenarios, this contradicts the overall aim of this project.

22.5.3.6 Technology Readiness Level

Geothermal energy production is fully operational onshore and has been for many years, and as a result is unquestionably a TRL of 9. But when being specific to this project, and its application in an offshore environment, the TRL is less clear and considerably lower. There have been no existing facilities or developments identified with regards to offshore geothermal energy production, but this technology has

been demonstrated to work successfully through its onshore application and in principle its offshore application would not be excessively different. This technology would likely be best allocated to a TRL of 3 as the basic principle of its operation has been demonstrated in many onshore facilities and the principle of its specific application offshore has been considered as demonstrated in /10/.

22.5.4 Advanced Modular Reactors

22.5.4.1 Description

AMRs are the next generation of nuclear power that encompasses a wide range of technologies with the following shared attributes:

- Smaller than conventional reactors
- Modular design for factory fabrication and ease of transport
- Typically use novel coolants and/or fuels

These design features have potentially significant benefits in terms of sustainability, safety and reliability, and economic competitiveness /127/.

Small Modular Reactors (SMRs) is a term used to describe nuclear reactors with smaller than typical power outputs (<300MWe electrical power output). These are often associated with and likened to AMRs but care needs to be taken not to confuse the two. SMRs are categorised by their size and modular construction, whereas AMRs are defined by the underlying technology they use. An SMR may also be classed as an AMR and vice versa, but just because a technology fits one of the two categories does not automatically mean that it fits both. There are existing SMRs using scaled down conventional technologies, these would be classed solely as a SMR, but there are also SMRs in development utilising novel technologies seen in AMRs, these could be classed as both a SMR and an AMR.

SMRs typically have passive safety features and reduced staffing compared to conventional reactors. This is due to their smaller scale design leading to increased simplicity in their operation.

AMRs are designed to overcome the financial and safety barriers that inhibit the construction of conventional reactors. It is hoped that through AMRs it is possible to achieve large outputs from modules that are similar in physical size to that of SMRs.

22.5.4.2 AMR Technology Overview

In 2021, on behalf of the UK Department for Business, Energy and Industrial Strategy, The Nuclear Innovation and Research Office (NIRO) carried out an AMR Technical Assessment /127/.

The aim of the assessment was to determine a preferred AMR technology to take forward for an AMR demonstration programme for demonstration by the early 2030s.

The AMR technologies assessed are summarised in Figure 22-1 below:

System	Neutron Spectrum	Coolant	Outlet Temp (°C)	Fuel Cycle	Technology Readiness Level ²
HTGR / VHTR High / Very High Temperature Gas Reactors	Thermal	Helium	700 – 950 900 – 1000+	Open	7 / 5
SFR Sodium-Cooled Fast Reactors	Fast	Sodium	500 – 550	Closed	7
SCWR Supercritical Water-Cooled Reactors	Thermal / Fast	Water	510 – 625	Open / Closed	2
GFR Gas-cooled Fast Reactors	Fast	Helium	850	Closed	2
LFR Lead-cooled Fast Reactors	Fast	Lead	480 – 570	Closed	4
MSR Molten Salt Reactors	Thermal / Fast	Fluoride Salts	700 – 800	Closed	4 Thermal 3 Fast

Figure 22-1 - AMR Technologies /127/

It can be seen from there TRL description that none of the above technologies were in active commissioning or operations in 2021 and many were at bench scale research level or below. Indicating that it will still be a considerable amount of time before they are in operation and commercially available.

The technologies mentioned above were also assessed and compared against key criteria. Figure 22-2 below shows the assessment results:

	HTGR	SFR	LFR	MSR	SCWR	GFR
Timescales for delivery	Very High	Very High	Medium	Medium	Low	Low
Heat	Very High	Medium	Medium	High	Medium	High
Safety	Very High	Medium	Medium	Medium	Low	Low
Security	Very High	Medium	Medium	Medium	Medium	Medium
UK Value	High	High	Medium	Low	Low	Low
Economic Cost	High	Medium	Medium	Medium	Medium	Medium
Deployability	High	High	High	High	Medium	High
Adaptability	High	High	High	Very High	Medium	High
Waste & Environment	Medium	High	High	High	High	Very High
International	Very High	High	Medium	Medium	Low	Low

Figure 22-2 - AMR Assessment Criteria Results Table

The conclusion of the assessment pointed to HTGR as the preferred AMR for the UK Government to take forward for an AMR demonstration by 2030.

22.5.4.3 Molten Chloride Fast Reactor Technology Overview /35/

Engagement with Core Power Ltd for further information on the current and future AMR technologies led to some valuable insight on MSR technology. Specifically, Molten Chloride Fast Reactor (MCFR) was the technology discussed.

The main fuel for this technology is a liquid mix of chloride salts and fissile material. The reactor can be considered inherently safer than other AMR technologies due to its ability to operate at a pressure slightly above ambient while maintaining a relatively high temperature that provides good thermal efficiency for power generation. The low pressure means the reactor vessel is not at risk of being breached. A power conversion system then converts the thermal power from the reactor into mechanical and then into electric power. The design combined with the addition of various safety systems and features results in this technology being inherently safe.

The estimated uptime of this technology, due to its inherently simple design is estimated to be upwards of 95%. It is unlikely that there would be any regular shutdowns of this technology because this would require the chloride salt mix to be drained completely to prevent it cooling and solidifying within the reactor. However, there is an option to idle the reactor so power production can be stopped without having to drain and shutdown the reactor.

The estimated footprint of the reactor excluding the power conversion system and reactor ancillary room is approximately 12m x 10m x 10m (height, width, breadth).

The MCFR can provide approximately 700MW of thermal power with the suggested power conversion unit having an efficiency of around 46%. With this in mind, and taking into account the total life cycle cost of the a floating nuclear power plant, including initial fuelling, decommissioning, scrapping and waste handling is estimated to be less than 50.00 USD / MWh. However, MCFR is only likely to achieve pilot scale operation by the early 2030s.

22.5.4.4 Potential Project Impact

Since nuclear power is dispatchable and has very low refuelling requirements there are some clear benefits that utilising AMRs and SMRs could provide the project:

- Replaces the local power generation
- Significantly reduces emissions from combustion
- Potential OPEX savings due to fuel cost savings
- Potential CAPEX savings as it removes the need for supplementary wind power
- Removes any requirement for battery storage

All the above are major advantages that could significantly reduce the overall costs for the project and complexity of the design.

22.5.4.5 Existing Facilities

There are limited existing examples of nuclear power in the marine environment. Most uses have been for ship propulsion, namely nuclear submarines, and military supercarriers. There are also nuclear-powered icebreaker ships used in Russia.

Nuclear power is suited to the above uses due to their high power output and need to minimise refuelling.

One of the only small modular reactor designs in operation is Russia's Akademik Lomonosov floating power station, docked in Pevek Harbour. This power station provides heat to the town and electricity to the regional power system. The power station produces 70 MW of electricity from thermal reactor power of 300 MW. The reactors are derived from those used in icebreakers.

The nuclear reactors in the above examples are based on conventional technologies – Pressurised Water Reactors. This technology in part requires specialised infrastructure to fabricate and results in high upfront costs. For this reason and others, nuclear power in the marine environment has generally been limited to the few specific uses described above.

With increased interest to decarbonise and the development of AMRs, marine nuclear power for mainstream commercial use may become a more viable alternative to traditional power generation technologies.

22.5.4.6 Technology Readiness Level

Although there are examples of nuclear power in the marine environment, these are based on conventional PWR technology. There are currently no examples of AMR technology being operational in the marine environment, so the technology cannot achieve any higher than a TRL of 4. AMR technology is currently under development and will likely achieve a TRL of 4 in the near future with the AMR project being driven by the BEIS scheduled to provide an AMR demonstration by 2030. With regards to offshore applications specifically, it will likely lag behind the development of onshore AMR technology which as stated is scheduled for demonstration by 2030. Therefore, with regards to the offshore application being considered in this project AMR technology would achieve a TRL of 3. Although the offshore application of AMR will not specifically be under development, the development of the basic operation of AMR can be considered in line with the development of AMR technology in an offshore application, because this initial development needs to be completed before the technology can be developed with regards to the offshore environment.

22.5.5 Energy Storage

22.5.5.1 Background and Project Application

Due to the stochastic and variable nature of wind energy and other renewable energy sources, they must be combined with dispatchable energy sources in a power network to balance energy requirements. This is typically done using hydrocarbon-based solutions such as GTs and diesel generators; however, energy storage can potentially achieve the same outcomes and allow for up to 100% renewable energy utilisation in a power network.

Even if 100% renewable energy utilisation isn't feasible, energy storage could allow for a reduction in the number of GTs required to operate at a time, increasing GT operating flexibility and redundancy, and ultimately reducing emissions.

It can also be used to smooth ramp rates of generated wind power to improve the control of the GTs, which may improve overall efficiency of the GTs.

22.5.5.2 Energy Storage Technology Overview

There are several different energy storage technologies available. Below is a list of the main energy storage categories and some examples of specific technologies within those categories /153/:

- Mechanical
 - o Pumped hydro
 - o Compressed air
 - o Flywheels
- Thermal
 - o Thermo-chemical
- Chemical
 - o Hydrogen
- Electro-chemical
 - o Lithium-ion battery
 - o Lead acid battery
- Electrical
 - o Super-capacitors

These energy storage technologies are separated into different discharge duration categories, also known as energy to power ratios, which define the length of time an energy storage system can discharge energy at their power rating. In general, this is broken down into short, medium, and long duration energy storage /154/. Hence, for two energy storage technologies with the same power rating, a long duration technology will have a greater total energy storage capacity than a short duration technology.

Figure 22-3 below shows different types of energy storage and their typical areas of functionality:

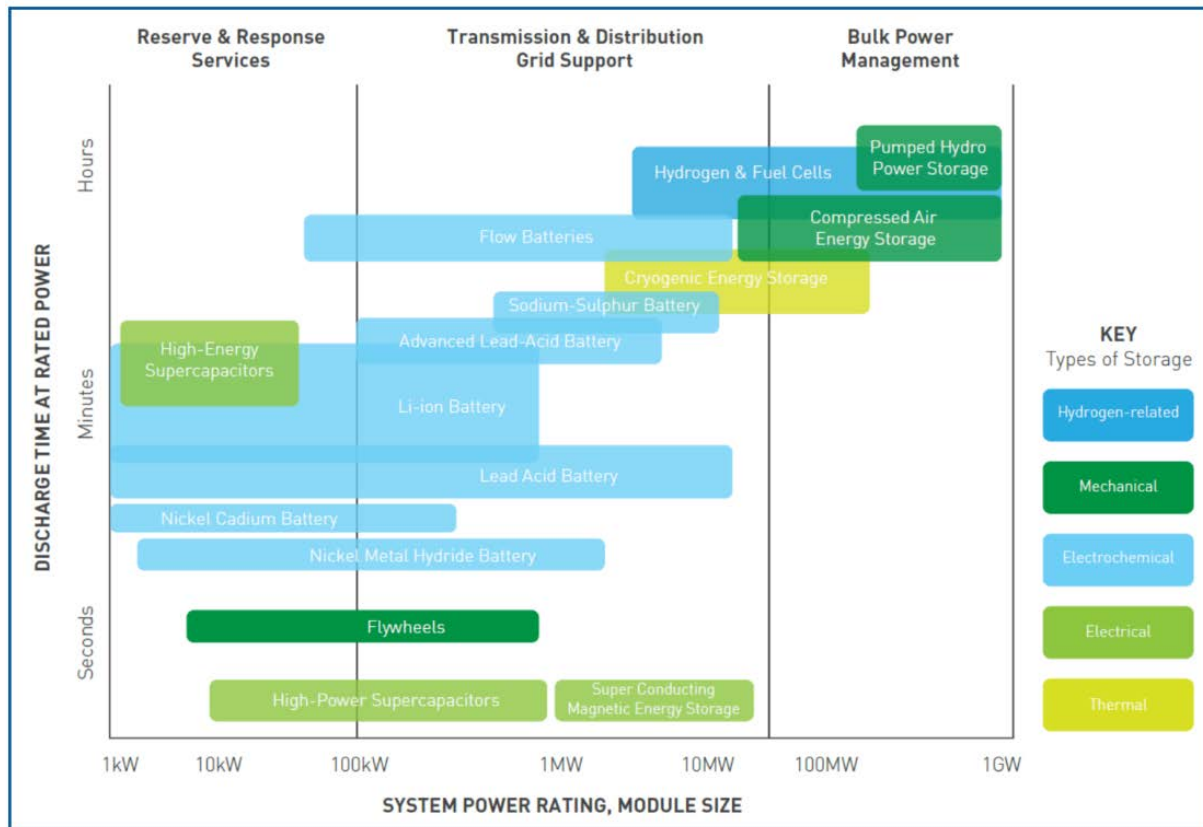


Figure 22-3 - Energy Storage Areas of Functionality /153/ Courtesy of Wind Europe 2017, Wind energy and on-site energy storage – Exploring Market Opportunities

The energy requirements for this project are in the 100s of megawatts, so a power rating >10MW would be required to provide significant project benefits. The peak difference between wind energy output and the demand could be in the 100s of MWs, depending on how much overprovision is used, and this output level could last for days at a time which puts the total overprovision of energy in the 1000s of MWh range. This overprovision of energy would make long duration energy storage the most suitable option for this project. Therefore, the energy storage technologies in the top right-hand quadrant of Figure 22-3 are those with the most suitable characteristics for this project. However, shorter duration energy storage may also provide benefits as these could be used to quickly balance energy loads, instead of using GTs /153/.

Pumped hydro power storage can be excluded as this typically utilises naturally occurring geographical features that will not be found offshore.

Batteries can also be excluded as the main energy storage solution due to their high cost per unit storage capacity/153/; However, there may be a place for these in an optimal solution, for balancing short duration energy load imbalances. Batteries may be considered for smaller capacity power storage and delivery to increase the flexibility of the overall power network. This will allow for situations where slightly too much or too little power is being generated and the batteries can be used to either store or supply this power. Batteries are better suited to this scenario than larger scale energy storage options which would likely be inefficient when storing or supplying small amounts of power.

This leaves Hydrogen, compressed air energy storage (CAES) and cryogenic energy storage as three potentially suitable technologies for this project.

22.5.5.3 Hydrogen

Hydrogen storage utilises the surplus electrical energy to generate hydrogen via electrolysis of water. This hydrogen is then compressed and stored in pressure vessels. These pressure vessels can be located subsea.

The stored hydrogen can then be used in two main ways:

- Comingled with fuel gas and burned in the GTs
- Used in a hydrogen fuel cell

Hydrogen fuel cells are more efficient than burning hydrogen in GTs; however, it comes at additional capital cost for the fuel cells as well as additional space and weight.

A separate Hydrogen Technology Study Section 23.1 was carried out to determine if Hydrogen energy storage could be feasibly utilised for this project and to determine an optimal storage solution. Refer to this report for more details.

22.5.5.4 Compressed Air Energy Storage

This method of energy storage requires four key stages, compression, storage, heating, and electrical power generation. Compressed air energy storage (CAES) uses surplus electrical energy to compress ambient air which can be stored in underground caverns or in pressure vessels. When additional electricity is required, the pressurised air contained within these underground caverns or pressure vessels is heated and expanded in a turbine to produce electricity /155/.

The air can also be used in a GT /156/. This would effectively mean the GT air compression can be operated on renewable energy increasing efficiency.

CAES is capable of storing large amounts of energy for long periods of time. This would allow for the excess energy produced during the natural peaks of a renewable source such as wind to be stored, and then used during the natural troughs when there is a shortage of electrical energy being produced. This would increase the stability of the electrical network by making the naturally fluctuating renewable power supply more stable and consistent.

22.5.5.5 Cryogenic Energy Storage

Cryogenic energy storage (CES), also known as liquid air energy storage (LAES), consist of three main steps, charging, storage, and discharge. The first stage is referred to as charging, this is where the air is liquified by using the excess electrical energy to power refrigeration units and cool the air to its liquid state. Next, the liquid air has to be stored in insulated tanks to maintain its liquid state. Finally, when additional electricity is required the liquid air is extracted from the tank, pumped at high pressure, reheated, and expanded through a turbine to produce electricity /157/.

Similarly to CAES, cryogenic energy storage is capable of storing large amounts of energy for long periods of time. Highview power are the leading provider of cryogenic energy storage and have built several commercial plants in recent years. These include a 50 MW / 250MWh plant in Manchester UK and a 50MW/ 500MWh plant in Chile /158/. However, both of these facilities are located onshore so the offshore feasibility of this technology without the utilisation of an existing platform is unclear. As mentioned previously, the utilisation of an existing asset to be repurposed for renewable energy production or storage would be on a case-by-case basis and therefore is out with the scope of this project where the intention is to provide a standardised solution that can be used throughout the industry.

22.6 Conclusion

22.6.1 Renewable Energy Sources

Below is a summary of the renewable energy sources discussed in this literature review compared against key criteria. Note that aspects of this assessment are purely subjective.

Energy Source	Technology Readiness (offshore application)	Cost	Complementarity (to wind)	Modularity / Scalability
Wave / tidal	Low	Very high	Low	High
Solar PV	Low	High	High	High
Geothermal	Low	High/very high	Medium	Low

Table 22-1 - Renewable Energy Source Comparison Table

From the literature review of renewable energy sources, Solar PV appears to be the next best to wind for utilisation on this project. It has the lowest cost of the technologies reviewed and has high potential for cost reduction as offshore solar further develops. It has high complementarity to wind and so may form an optimal hybrid energy mix when used in combination with wind power. It can also be scaled, similarly to wind.

Hybrid solar-wind should be considered in the future as a potential enhancement of the current base case design for this project.

Wave / tidal energy costs are very high and when combined with poor complementarity to wind, is not a good candidate for use in a hybrid energy system with wind.

Geothermal costs for this application would also likely be too high and it is unlikely geothermal could realistically achieve the scale required to be beneficial for this project.

22.6.2 AMRs

The NIRO assessment shows there is a wide array of AMR technologies in development, each at different stages of technological maturity.

A key takeaway from this assessment and its objectives is that AMRs are not yet a commercially proven power generation option. However, they have the potential to significantly reduce costs and complexity of the power generation system used in this project.

AMRs should therefore be considered for a future design as an enhancement of the current base case design for this project.

22.6.3 Energy Storage

To maximise variable renewable energy use in a power system, use of energy storage is a must.

It was identified from the literature review that energy storage technologies with high power ratings and long durations are most applicable for use on this project.

Three technologies were identified as potentially suitable candidates:

1. Hydrogen
2. CAES
3. Cryogenic energy storage

Hydrogen storage was taken forward for further study in the Hydrogen Technology Study Section 23. Refer to this report for further details and an overall conclusion regarding the use of energy storage for this project.

22.7 Further Areas of Study

- As per the conclusion of this report, it may be valuable to analyse a hybrid solar-wind system and its potential to reduce fuel gas consumption.
- Although hydrogen has been studied in further detail, it may be worth reviewing the other storage technologies (CAES and cryogenic energy storage) identified in this review in greater detail.
- AMR technology has the potential to be disruptive with regards to the base design of this project and so it may be worth studying the potential cost savings associated with utilising AMRs. With regards to AMR and its potential to greatly improve this base case design in the future, it may be worth developing this design with the future inclusion of AMR technologies in mind.

22.8 Opportunities / Risks / Assumptions

- This literature review covers several technologies that are under constant development. The conclusions of this literature review may become quickly outdated as technologies improve and costs reduce.

23. Hydrogen Technology Study

23.1 Objective

The purpose of this study report is to determine the technical and commercial feasibility of using hydrogen as an energy storage medium for storing surplus generated wind power to reduce fuel gas consumption and the associated emissions.

The report includes a literature review of hydrogen generation and storage and details the results of analytical modelling of using hydrogen storage as part of the overall power generation for this project.

23.2 Scope

The review will explore generation, storage, and use of hydrogen with respect to the scope of this project. As part of this the following key areas will be reviewed:

- Hydrogen Production
 - o Electrolysers
 - o Steam Methane Reforming
 - o Thermal Plasma Electrolysis
- Hydrogen Storage
 - o Subsea
 - o Topsides
- Hydrogen Use
 - o Fuel Cells
 - o Gas Turbines

The above key areas will provide important background information about hydrogen and its possible uses within this project.

The following topics are some of what will be studied, analysed and discussed in greater detail during this study to allow appropriate conclusions to be drawn:

- Fuel Gas Consumption
- Actual hydrogen content of the methane-hydrogen mix
- Storage Drawdown
- Available Space
- Hydrogen Generation and Storage Capacity

23.3 Background

23.3.1 Hydrogen

Use of hydrogen as a flexible energy carrier which can be utilised for both storage and transport has come to the fore in recent years as one of the key alternative energies which can be industrialised to drive emissions downwards and reduce the effects of greenhouse gases.

Katoni have explored various hydrogen options during this study, with TechnipFMC and their Deep Purple technology being a key influencer in this study.

TechnipFMC have recently carried out several studies relating to the market and growth of hydrogen demand over the next 30 years. Hydrogen technology for large scale energy generation is in its infancy currently and growth in technology and use will inherently reduce the costs of technology, lead to technological developments and improve use cases for the technology.

Hydrogen production scenario, global, Mtpa

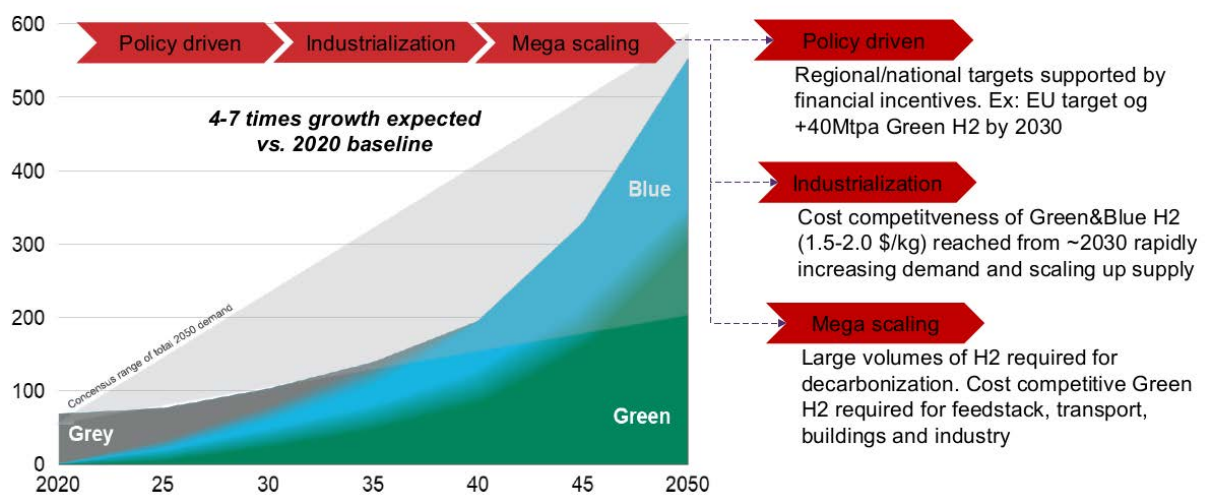


Figure 23-1 - Hydrogen Production Scenario (Courtesy of TechnipFMC)

Figure 23-1 details the expected growth in hydrogen generation via the natural stages of growth. The first is policy driven to set the direction of travel and provide industry with confidence. The next stage is development of appropriate technologies to boost the scale, and finally is mega scaling which is the large scale global roll out of solutions.

It is important to describe hydrogen on a colour scale based on generation properties. The National Grid describes the following hydrogen “colours” /170/:

- Green Hydrogen
- Blue Hydrogen
- Grey Hydrogen
- Black Hydrogen
- Brown Hydrogen
- Pink Hydrogen
- Turquoise Hydrogen
- Yellow Hydrogen
- White Hydrogen

Table 23-1 defines the different colours of hydrogen.

Hydrogen Colour	Description
Green	Hydrogen generated purely from renewable energy, i.e. wind, tidal, solar to electrolyse water.
Blue	Blue hydrogen is produced from natural gas using steam reforming. A by-product of steam reforming is CO ₂ , from blue hydrogen any CO ₂ produced will be captured and stored using CCS
Grey	Steam reforming without CCS
Black	Steam reforming without CCS using coal as energy source
Brown	Hydrogen gasification using biomass (coal)
Pink	Hydrogen generated from nuclear energy using electrolysis
Turquoise	Hydrogen generated from pyrolysis
Yellow	Hydrogen generated purely from solar power using electrolysis
White	Naturally occurring hydrogen produced similar to natural gas

Table 23-1 - Hydrogen Colours

For the purposes of this study Green Hydrogen is the most relevant. This mechanism would be excess power generated by the offshore wind array would be utilised to generate hydrogen to be able to replace a certain portion of hydrocarbon fuel gas to make up the deficit in times of low wind speed.

Global Green H2 projects announced¹ GW

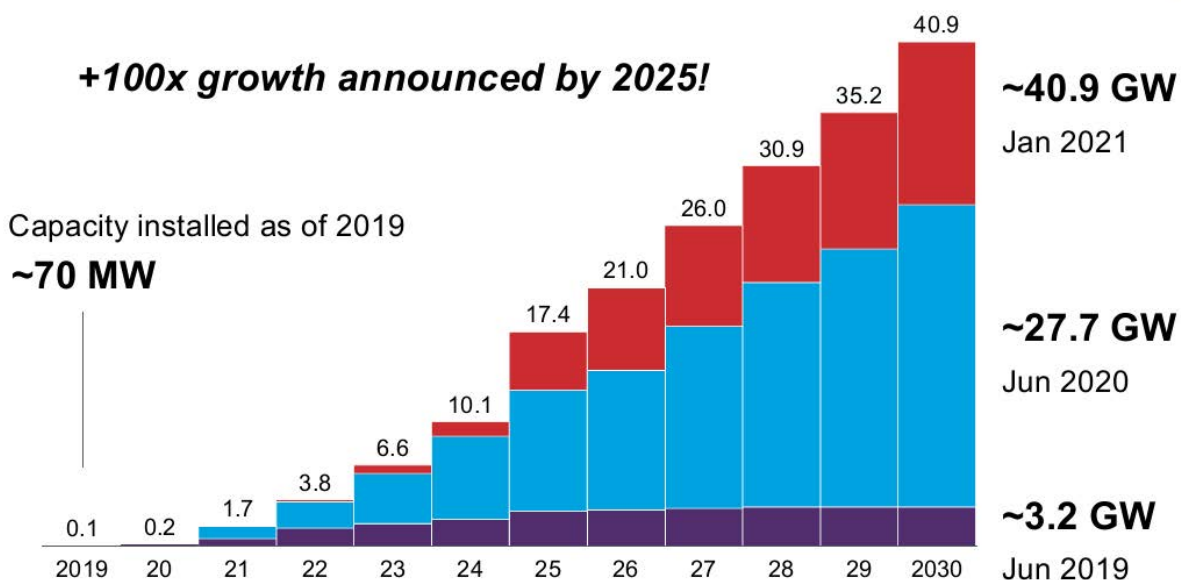


Figure 23-2 - Predicted Global Green Hydrogen Projects (Courtesy of TechnipFMC)

Figure 23-2 demonstrates the predicted global demand for hydrogen over the next decade. It is expected that by 2030 Green Hydrogen production will be 40.9 GW compared with the 2022 capacity of around 2 to 4 GW. This exponential growth would drive innovation to improve scale and drive efficiencies.

Several pilots are currently being developed for offshore hydrogen generation to support wind farm operations and for alternative uses such as hydrogen export to onshore. Deep Purple is one of these projects.

It is envisaged that the majority of the technology required to industrialise hydrogen as an energy storage mechanism exists with the exception of large-scale electrolysis plants. Several gas turbine manufacturers such as Siemens and GE are developing hydrogen gas turbines and existing gas turbines can be operated with significant quantities of hydrogen in the natural gas stream.

23.3.1.1 Hydrogen Generation

There are currently a number of methods for producing hydrogen as can be seen in the table below /3/. This table also gives information on whether the method of hydrogen production is viable for application in this project. The main hydrogen production methods identified in this table are discussed in more detail below.

Method		Source		Brief Description	Viable
		Primary Energy	Material		
Electrolysis		Electrical	Water	Direct current is used to split water into O2 and H2 (electrochemical reaction)	Yes
Plasma arc decomposition			Fossil Fuels	Cleaned natural gas is passed through plasma arc to generate H2 and carbon soot	Yes
Thermolysis		Thermal	Water	Thermal decomposition of water (steam) at temperatures over 2500 K	No – Requires high temperatures
Thermochemical processes	Water splitting		Water	Cyclical chemical reactions (net reaction: water splitting into H2)	No – Requires high temperatures
	Biomass conversion		Biomass	Thermocatalytic conversion	No – Biomass material required
	Gasification			Conversion of biomass into syngas	
	Reforming			Conversion of liquid biomass (biofuels) into H2	
PV electrolysis		Photonic	Water	PV panels are used to generate electricity	Yes
Photocatalysis				Water is split into H2 by using the electron-hole pair generated by the photocatalyst	
Photoelectrochemical method				A hybrid cell simultaneously produces current and voltage upon absorption of light	
Dark fermentation		Biochemical	Biomass	Biological systems are used to generate H2 in the absence of light	No – Biomass material required
High temperature electrolysis		Electrical & Thermal	Water	Electrical and thermal energy are used together to drive water splitting at high temperatures	No – High temperatures required
Hybrid thermochemical cycles				Electrical and thermal energy are used together to drive cyclical chemical reactions	Yes
Coal gasification				Conversion of coal into syngas	No – Coal required
Fossil fuel reforming				Fossil fuels are converted to H2 and CO2	Yes
Biophotolysis		Photonic & Biochemical	Biomass & Water	Biological systems (microbes, bacteria, etc.) are used to generate H2	No – Biomass material required
Photofermentation				Fermentation process activated by exposure to light	
Artificial photosynthesis				Chemically engineered systems mimic photosynthesis to generate H2	
Photoelectrolysis		Electrical & Photonic	Water	Photoelectrodes and external electricity are used to drive water electrolysis	Yes

Table 23-2 - Hydrogen Generation Technology

23.3.1.2 Electrolysis

Electrolysis is the use of electricity to separate water into hydrogen and oxygen /4/. This process uses an electrolyser which is made up of an anode, a cathode, and an electrolyte. The exact operation of the electrolyser will depend on the electrolyte used but the basic principle of using electricity to separate water into hydrogen and oxygen is consistent across all types of electrolysis.

The source of hydrogen is fresh water which is able to be generated in substantial quantities offshore. It's main energy source for the reaction being electricity which can come from renewable sources such as offshore wind, electrolysis can achieve zero greenhouse gas emissions in its production of hydrogen.

The premise of electrolysis in this system would be utilising excess power generated by renewables which cannot be utilised by the platforms.

23.3.1.3 Reforming

Reforming, and in particular steam methane reforming, utilises high temperature steam to produce hydrogen from methane /5/. Typically, this methane is sourced from natural gas. In this process, methane reacts with steam under pressure through use of a catalyst, this reaction produces hydrogen, carbon monoxide, as well as a relatively small amount of carbon dioxide. This is an endothermic reaction, meaning that it must be supplied with heat for the reaction to proceed. This is followed by the "water-gas shift reaction," the steam and carbon monoxide are reacted in the presence of a catalyst to produce carbon dioxide and hydrogen. Finally, a process called "pressure-swing adsorption" is completed, where the gas stream has any carbon dioxide or other impurities removed, effectively leaving pure hydrogen.

Reforming technology is the largest generator of hydrogen in industry as a feedstock, however it is difficult to achieve "green" reformed hydrogen.

23.3.2 Hydrogen Storage

The basic principles of hydrogen storage are consistent no matter whether the hydrogen is located topside or subsea. After the hydrogen has been produced, it can either be stored as a liquid or a gas. Typically, the storage of hydrogen as a gas is done at high pressure, because although hydrogen having the highest energy per mass of any fuel, it has a low energy per unit volume /6/. This means that to store a large amount of energy a large volume of hydrogen is required.

Hydrogen can also be stored as a liquid, but this requires cryogenic temperatures due to the boiling point of hydrogen being -258.8°C at one atmospheres pressure. Also, hydrogen can also be stored within a solid, through absorption.

23.3.2.1 Topsides Storage

Topsides storage systems for hydrogen would typically operate at medium pressures, typically 30 barg which is a typical electrolyser discharge pressure. The medium storage pressure results in a large amount of storage area to retain considerable quantities of hydrogen.

In addition to this, storage of hydrogen poses a significant risk, in the order of magnitude higher than natural gas due to hydrogens propensity to leak due to the small molecule size.

It is for these reasons that topsides storage is not considered as the preferred option for this project. The solution provided by TechnipFMC is included in the analysis.

23.3.2.2 Subsea Storage

Subsea hydrogen storage is facilitated by high pressure storage of hydrogen, which results in larger masses of hydrogen to be stored in a smaller volume. The gas from the electrolyser would be compressed utilising a special hydrogen compressor and routed via a flexible riser to a subsea storage bank array.

The arrays are designed in a modular way so can be expanded if required and can be utilised to store hydrogen for long periods of time.

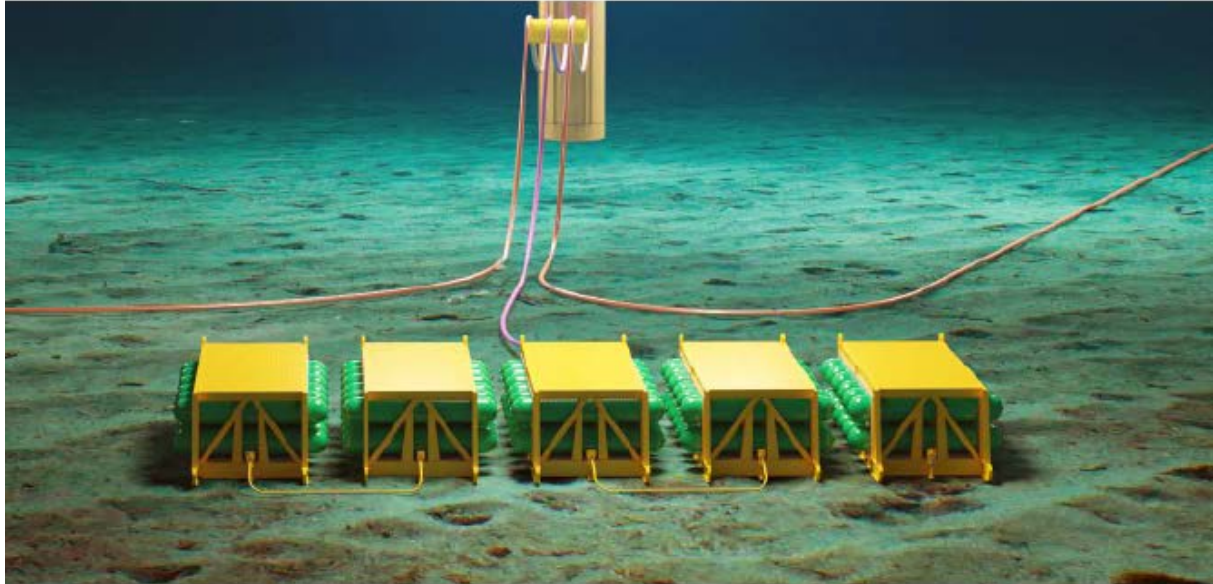


Figure 23-3 Deep Purple Subsea Storage System (TechnipFMC)

Currently the method of storage of large inventories of hydrogen is being studied to develop a concept which is safe, the materials and components selected are suitable for this duty, and development of cost-effective, repeatable and scalable methods for installation of all components of the system are being developed.

Subsea storage of hydrogen also offers considerable safety benefits for the use of hydrogen, which is an important consideration.

The system is also considered to be a key technology to integrate into offshore wind arrays to offer baseload to sustain operations during power fluctuations with 16 tonnes of stored hydrogen offering 300 MWh worth of dispatchable power storage. To put this into context a lithium-ion battery with 3 MWh would weigh 23 tonnes (Tesla Megapack).

23.3.3 Hydrogen Use

23.3.3.1 Fuel Cells

Fuel cells can cleanly and efficiently produce electricity from the chemical energy in hydrogen and other fuels /7/. Fuel cells can produce electricity directly from the chemical energy contained within the fuel source allowing them to achieve higher efficiencies than conventional combustion engines or turbines. In the case of hydrogen there are only three products produced from this process, heat, water, and electricity. This allows fuel cells to achieve much lower emissions than conventional combustion technologies and fuel cells are in fact capable of zero emissions. Also, fuel cells are considerably quieter during operation due to having fewer moving parts.

23.3.3.2 Gas Turbines

Currently many offshore platforms utilise gas turbines to produce electricity. The platforms have an abundance of natural gas which can be used to power these turbines and generate electricity. Although this is a viable option for the platforms both logistically and economically, it is not environmentally friendly. The burning of hydrocarbon-based fuels produces greenhouse gases and pollutes the environment.

If a source of hydrogen or a means of hydrogen production was provided to these platforms with existing gas turbines, it is possible to operate these turbines on a hydrogen and natural gas (methane) mix /8/. Typically, low quantities of hydrogen can be added to the natural gas and burned in the existing gas turbines with only minor modifications or alterations and in certain scenarios can be done without any changes. As the quantity of hydrogen being used increases so too does the likelihood of needing to make modifications and adjustments to the existing gas turbines, fuel handling systems and pipework. But by introducing hydrogen into the natural gas, it is possible to reduce the emissions of the gas turbine while retaining its efficiency levels.

23.3.4 Existing Facilities

Hydrogen is already being used as a fuel source for power generation in many applications across the world. For example, the Fusina hydrogen power station located in Italy runs on 100% hydrogen, a petrochemical plant in South Korea runs on 95% hydrogen, and a steel mill in China operates on 60% hydrogen /8/. All these existing facilities are located onshore which is not applicable to the application being considered in this project and there are currently no offshore facilities that produce or utilise hydrogen for power generation.

However, the worlds first pilot project for offshore hydrogen production is planned to take place in the North Sea /9/. Neptune Energy's Q13a oil and gas platform is going to be home to a plant that will produce green hydrogen using electricity generated from wind power. This will be a major first step towards large scale hydrogen production in the North Sea and there is potential for the existing platforms reaching the end of their life to be repurposed for hydrogen production.

TechnipFMC are currently running a small-scale concept of their Deep Purple design which is due to run until 2023, before a larger 2 MW offshore pilot facility.

23.4 Hydrogen Modelling Methodology

The use of hydrogen as a solution for storing surplus wind energy was modelled using the analytical modelling tool, developed as part of the Renewables Generation Analysis Section 8.1, as a basis.

A conclusion of the Renewables Generation Modelling Report was that the optimal provision of wind power without storage provision is a wind farm sized to approximately 105% of the base power demand.

The purpose of the hydrogen model is to determine potential fuel savings and emissions reductions from using hydrogen storage and to determine whether hydrogen storage can impact the optimal provision of wind.

23.4.1 Actual Hydrogen Content

Current gas turbine technology can handle quantities of hydrogen in the fuel. The selected power generation option selected for this project are GE LM6000 Combined Cycle Gas Turbines. These gas turbines are marketed as being able to operate with high quantities of hydrogen present in the fuel.

The values reported are 30 vol%. Volume percent is typically the equivalent of 30 mol% for the purposes of gas analysis, however there are small variances.

When this high-volume percent is analysed more, especially with the consideration of heating values, LHV considered in this case, the high volume percentage results in a low mass percentage.

A 30 vol% is equivalent to a 4.4 mass%. This therefore means the contribution of hydrogen to the amount of fuel required, and in particular the energy content of the fuel is lower than what the volume percentage would suggest. The large variance is due to the molecular weight of hydrogen in comparison to the weight on methane.

23.4.2 Storage Drawdown

The hydrogen model developed is based on a finite hydrogen storage for Case 1 and 2. This storage has been modelled on a 30 minute timestep, with the change in hydrogen mass being dictated by periods of excess energy production.

The recharge of the hydrogen is based on the output of generated rate available on a basis of 0.0069 kg/s/MW. This generated basis is added to the total storage.

Analysis has been conducted to predict based on the installed hydrogen generator the optimum storage volume of hydrogen. This value has been calculated to be the maximum volume which can be charged without impacting generation, i.e., the cumulative mass of hydrogen generated is equal to the storage volume.

As the calculated basis is iterative the peak cumulative volume has been calculated.

Increasing the concentration of hydrogen in the fuel gas reduces the volume of hydrogen storage required.

23.4.3 Surplus Electricity Basis

The Renewable Generation Modelling study analysed two wind provision cases of interest, known as the P_{95} and $P_{\text{optimised}}$ cases, and determined the potential excess generated wind power for these cases.

These cases were developed by using the Dudgeon wind farm as a basis. The energy production data for a year of Dudgeon production, in 30-minute time steps, was used to extract load factors which were then used to model several wind provision cases for the project power requirements. For more details refer to the Renewables Generation Modelling Analysis Section 8.1.

The P_{95} case represents wind provision based on the 95th percentile load factor for the analysed wind farm data and results in wind provision only slightly higher than the base power demand.

The $P_{\text{optimised}}$ case represents wind provision based on the 65th percentile load factor for the analysed wind farm and results in wind provision significantly higher than the base power demand. This case was determined as an optimal point where fuel gas cost savings begin to significantly diminish compared to wind installation costs, based on the wind power profile.

The excess generated power for these cases is summarised in the table below:

	Peak Excess Power	MWh per annum	Equivalent MW
P_{95}	7.85	4,428	0.5
$P_{\text{Optimised}}$	221	499,016	57.0

As the excess power generated for the P_{95} case is minimal, the $P_{\text{optimised}}$ case was used as the basis for the hydrogen modelling.

23.4.4 Available Space

The basis for the floating Main Hub is a Sevan 1000 FPSO.

Most of the deck space on the Main Hub will be used by electrical equipment and the power generation equipment. A portion of the remaining deck space is available for hydrogen production equipment and is shown (red hatching) in Figure 23-4.

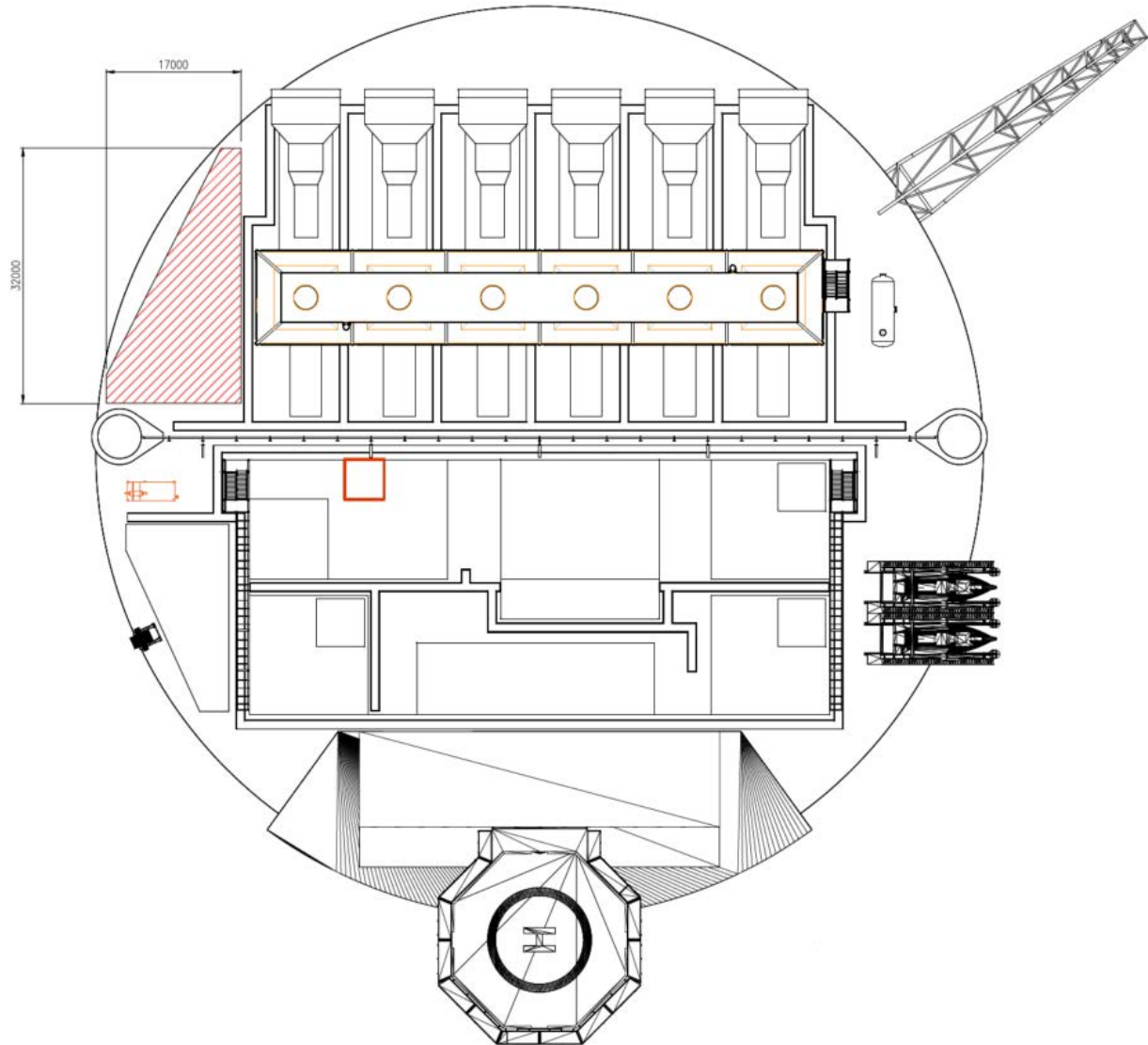


Figure 23-4 - Sketch of Main Hub Deck Layout

The hatched area in Figure 23-4 has a maximum width of 17m and a maximum length of 32m for an approximate area of 300m².

23.4.5 Hydrogen Generation and Storage Capacity Basis

As part of this project, several stakeholders in the energy industry and in particular the North Sea were approached by Katoni for collaboration and knowledge sharing.

One of the companies approached was TechnipFMC. TechnipFMC are a leading technology provider to the energy industry with substantial experience in subsea and offshore developments.

TechnipFMC have developed their Deep Purple system which integrates proven technologies to provide an offshore green hydrogen energy solution. "The system consists of offshore wind turbines and offshore hydrogen technologies for the production, storage and transportation energy in the form of pressurized green hydrogen" Section 8 and /162/.

Using the information for the $P_{\text{optimised}}$ wind generation case and the available space, TechnipFMC's Deep Purple team developed an estimate of the hydrogen production and storage systems. Two cases were provided and are summarised in Table 23-3 below:

Estimated solution	Estimated price	Electrolyser capacity [MW]	Volume H2 stored [tonnes]
Topside H ₂ production & storage	20 MEuro (£16.6M)	10 (4 x 40 ft containers)	2 (2 x 40 inch containers, stacked), 12 hours production.
Topside H ₂ production & subsea storage	32 MEuro (£26.6M)	12.5 (5 x 40 ft containers)	12 (one module), ~3 days production.

Table 23-3 - Deep Purple Hydrogen Options

One case was based on topsides production (10MW) with topsides storage (2 tonnes), and the other is based on topsides production (12MW) with subsea storage (12 tonnes). The use of containerised units can allow for stacking, however it will significantly reduce the operability of the solution. It is evident that the total electrolyser capacity is constrained by the available space, and the maximum size of current electrolyser technology available.

Through discussions with TechnipFMC it was also agreed that the hydrogen was best utilised by mixing with the fuel gas and burning in the GTs as opposed to the energy being generated in a hydrogen fuel cell. Utilising this concept reduced system costs by removing fuel cells from the design at a trade off in energy storage efficiency. The efficiency of the electrolyser technology is typically higher than that of a combined cycle gas turbine, however with the fact that the thermal generation technology is already part of this design it was considered the additional efficiency compared to the reduction in CAPEX cost would be less of a benefit. In addition the LM6000 GT selected for this application can handle significant volumes of hydrogen in the fuel gas composition.

The information above was used to model the hydrogen generation, storage, and consumption to determine potential hydrocarbon fuel consumption and emissions reduction that could be achieved.

Hydrogen generation has been calculated to be 0.0069 kg/s/MW. This equates to a conversion efficiency of 83% which is a typical conversion efficiency for electrolyzers. This number does not include any net power draw associated with hydrogen compression.

23.4.6 Cases Modelled

Using the Renewables Generation Modelling Report analytical modelling tool and the hydrogen generation and storage capacity data provided by TechnipFMC as a basis, the fuel cost and emissions reductions achieved by utilising hydrogen storage was estimated for several cases.

The cases analysed are summarised in Table 23-4 below:

Case	Wind Provision Case	Electrolyser Capacity (MW)	Peak Hydrogen Generation (kg/s)	Storage Volume (tonnes)
1	P _{optimised}	10	0.07	2
2	P _{optimised}	12.5	0.09	12
3	P _{optimised}	221	1.53	Unlimited

Table 23-4 - Cases Modelled

Cases 1 & 2 cover the two hydrogen production and storage cases provided by TechnipFMC.

Case 3 assumes unlimited storage capacity and electrolyser capacity equivalent to the peak excess wind power generated by the P_{optimised} wind provision case. This can be used to determine the maximum fuel consumption and emission reduction that can be achieved by utilising hydrogen storage for the P_{optimised} case.

Three sensitivity cases were also carried out and are described in Table 23-5 below:

Sensitivity Case	Description
1A	Case 1 with unlimited storage volume
2A	Case 2 with unlimited storage volume
3A	Case 3 with the H ₂ concentration increased from 30 to 50 mol%

Table 23-5 - Sensitivity Cases Modelled

Case 1A and 2A sensitivity cases were used to determine what the optimum storage requirement would be with conventional technology available, and Case 3A explored what the potential next generation of hydrogen generation, storage and next generation gas turbine optimisation for hydrogen.

23.4.7 Key Assumptions

The following is a list of key assumptions used in modelling the use of hydrogen storage:

- The GT efficiency (LHV basis) is not impacted by the presence of Hydrogen in the fuel gas composition. This assumption is based on latest generation of turbine control systems where on reduction of firing temperature to compensate for high hydrogen fuels efficiency may decrease by 0.5%.
- The maximum hydrogen composition that can be used in the LM6000 GTs is 30mol%
- Mol% and Vol% considered to be the same for the simplification of the calculation basis
- The fuel gas hydrogen composition does not need to be consistent / stable i.e., storage can be emptied in full, and the GTs can switch between fuel with and without hydrogen
- The cases are modelled based on the use of combined cycle GTs
- No energy demand is included to account for hydrogen compression, or the generation of fresh water.

23.4.8 Fuel Gas Consumption Determination

This section describes the methodology used to determine the hydrocarbon fuel gas consumption rate based on the use of hydrogen production and storage.

A HYSYS simulation case study was used to plot a table of fuel gas hydrogen mole fraction vs lower heating value (LHV) and hydrogen mass fraction.

The HYSYS simulation PFD is shown in Figure 23-5 below:

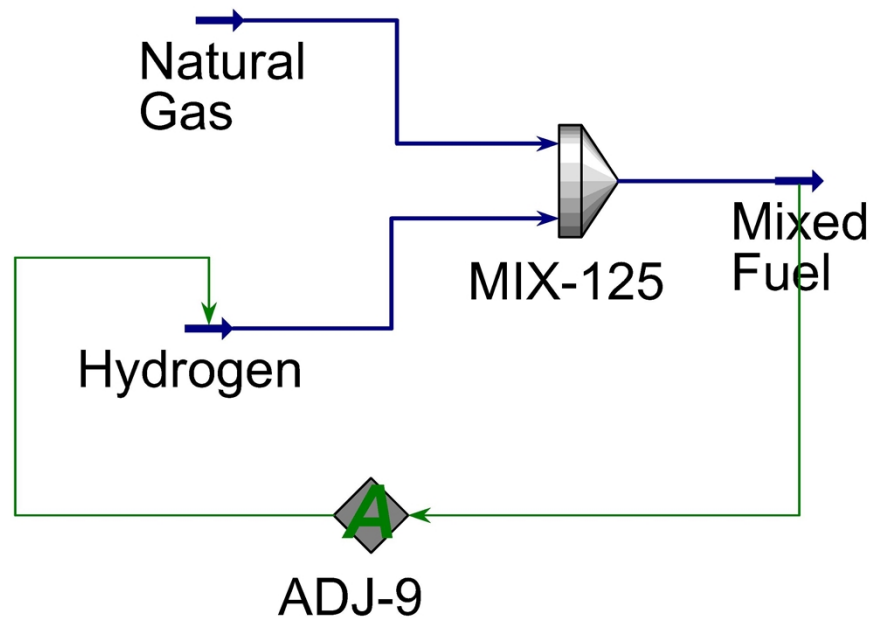


Figure 23-5 - HYSYS Simulation PFD

The simulation used a typical fuel gas composition for the “Natural Gas” stream.

The results of the case study were then used to plot a graph of hydrogen mole fraction vs LHV and a polynomial equation was generated from the curve.

Using this polynomial equation and manually selecting the hydrogen mole fraction in the mixed fuel composition, the mixed fuel demand can be determined for each time step as follows:

$$\text{Mixed Fuel Demand} = (E * \eta / (A * Y_H^3 + B * Y_H^2 + C * Y_H + D))$$

Where,

E = Excess win energy (MW)

η = GT efficiency (LHV basis)

Y_H = Hydrogen mole fraction in mixed fuel (set to 0.3)

A, B, C and D = polynomial constants

The excess wind energy that is utilised is constrained by the electrolyser capacity i.e., any time steps with excess wind energy greater than 10 or 12.5MW (depending on the case) were set to 10 or 12.5MW maximum.

To account for storage constraints, a hydrogen storage balance is also calculated by determining cumulative difference between the hydrogen generated and hydrogen used. Where the cumulative difference falls below the selected storage limit, 100% hydrocarbon fuel is used by the GTs.

The mass flow of hydrogen used at each time step is calculated by multiplying the corresponding hydrogen mass fraction in the fuel gas by the mixed fuel demand. The hydrogen mass fraction is determined using the HYSYS case study data (hydrogen mole fraction vs mass fraction).

The hydrocarbon fuel gas mass flow at each time step is then calculated by subtracting the hydrogen mass flow from the mixed fuel demand.

The total mass of fuel used at each time step is then calculated and from this the total yearly fuel gas demand can be estimated and compared against that estimated for no hydrogen.

23.5 Results

The results of the three cases analysed are shown in Table 23-6 :

Case	Hydrocarbon Fuel & Emissions Reduction (%)	Fuel Cost Saving (£/year)	Peak Storage (tonnes)	Estimated PBT (years)	Estimated PBT with ETS (years)
1	0.08	65,800	2	252.2	251.7
2	0.27	217,700	12	122.2	121.7
3	3.47	2,775,000	4,400	-	

Table 23-6 - Results of Modelled Cases

Table 23-6 details the results from the hydrogen modelling assessment. This table details the expected pay back time based on fuel savings and does not take into consideration the OPEX costs associated with maintaining the hydrogen system. Case 3 does not have an associated cost for pay back time as 4,400 tonnes of subsea storage is not a scale of concept which has been developed therefore no costings are available.

The sensitivity case results are shown in Table 23-7:

Case	Hydrocarbon Fuel & Emissions Reduction (%)	Fuel Cost Saving (£/year)	Peak Storage (tonnes)
1A	0.3	238,300	35.8
2A	0.38	303,200	48.1
3A	4.67	3,731,521	2,260

Table 23-7 - Results of Modelled Sensitivity Cases

Table 23-7 demonstrates the benefits associated with increasing storage volume of hydrogen and what the peak storage volume has been determined to be based on the maximum concentrations of hydrogen being utilised. Case 3A demonstrates that the storage volume can be reduced by increasing the concentration of the fuel.

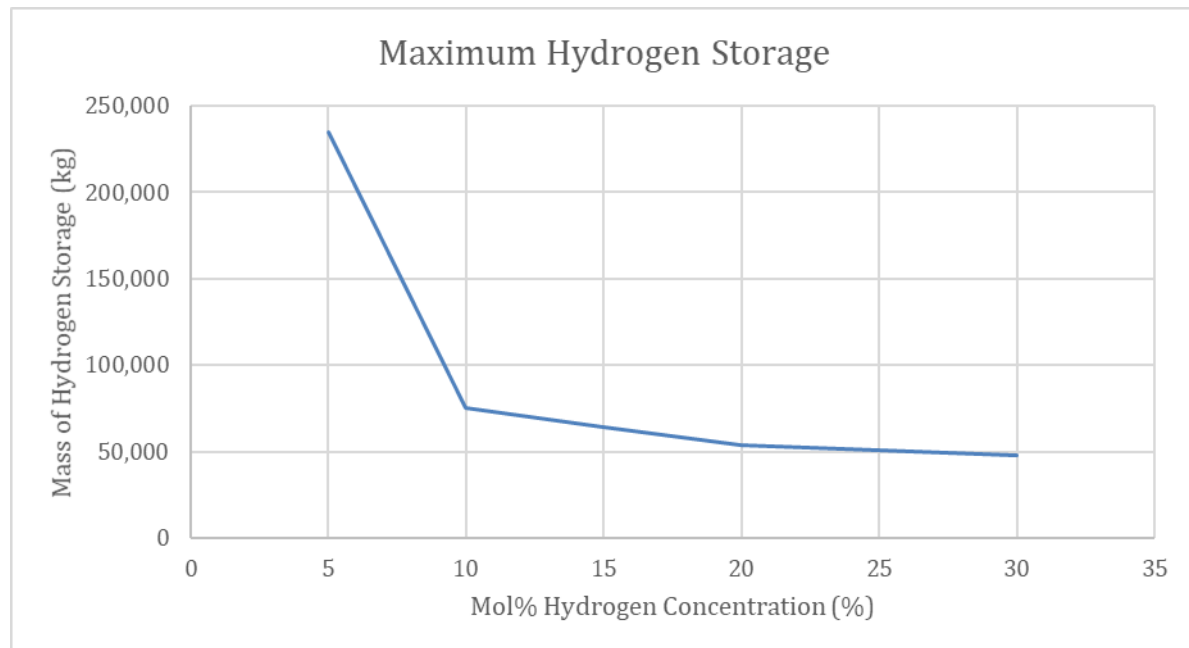


Figure 23-6 Hydrogen Storage (12.5 MW Generation)

Figure 23-6 details the relationship between required storage volume of hydrogen and the hydrogen concentration of the fuel mixture.

23.6 Discussion

Based on the analysis conducted on utilising hydrogen as a supplementary fuel to reduce the amount of hydrocarbons being generated it can be seen that based on the technology available on the market at the moment there is a limitation for a project of this scale.

Table 23-6 demonstrates the positive relationship between storage volume and the emissions reduction potential of hydrogen. Utilising similar input of electrolyser power, by having a larger storage volume the emissions reduction potential can be increased by 3 times as demonstrated by Case 1 and Case 2.

Case 3 demonstrates the maximum potential of a large hydrogen system. The potential to reduce emissions by a further 4.7% from the base case is a significant benefit, the challenge is providing a system which can utilise an over provision of power of this quantity. However without being able to quantify the pay back time for the system, it is considered on the basis of only the fuel savings, a large hydrogen system of this size would not be economical for the sole purpose of providing energy storage in this concept integrated into a Main Hub without a substantial increase in gas price or in ETS.

When evaluating Case 1A and Case 2A against the base cases it can be considered that for the size of the generating units selected in 10 MW and 12.5 MW respectively that a considerable increase in storage volume does not equate to a considerable decrease in fuel costs. This suggests that based on the load factor for the wind farm that there is diminishing returns based on an infinitely sized storage volume.

Although Case 2 represents a relatively optimal hydrogen storage solution based on the space limitations, the hydrocarbon fuel and emissions reductions that can be achieved are only 0.27% of the base case. With yearly fuel cost savings of £217,700 per year and an estimated capital cost of £26.6M, this results in a pay back time well beyond the estimated life of the development.

Case 3 represents a scenario where the only limitation on the amount of surplus electricity converted to hydrogen is the GT hydrogen composition limitation. For this case a maximum hydrocarbon fuel and emissions reduction of 3.5% can be achieved based on the wind energy profile, which represents fuel cost savings of £2.8M per year. Case 3A shows that an increased inlet hydrogen composition limit in the fuel gas from 0.3 to 0.5 results in a relatively insignificant improvement in fuel cost savings.

Figure 23-6 however demonstrates a positive reduction in maximum storage volume required based on increasing concentration of hydrogen in the fuel gas stream. Based on the batch nature of generation it is considered best to utilise the full volume of hydrogen stored as quickly as possible, so that when wind production increases again the full storage volume can be utilised for energy storage.

23.7 Conclusion

The results of the modelling show that using hydrogen storage to take advantage of surplus wind energy for the $P_{\text{optimised}}$ wind provision case results in an increase in the unit cost of energy for the project for a minimal reduction in the total emissions.

Even if all surplus energy could be used for hydrogen, the total emissions reduction and fuel cost savings that can be achieved are considered to be not significant enough for hydrogen to form a core part of the concept.

It is Katoni's view that using hydrogen storage as means to reduce emissions and fuel costs by utilising surplus wind energy is not a commercially viable strategy for this project and the potential emissions and fuel savings are negligible.

Using hydrogen storage will not impact the conclusion of the Renewables Generation Modelling Report, which suggests a wind provision close to the base load requirement is optimal.

The key challenge associated with offshore hydrogen is the size and space of the equipment required to generate the hydrogen at the scale this project is evaluating. When working with Technip FMC, based on the available space on the Main Hub, and the hazardous nature of hydrogen production, the size of the equipment which can be accommodated is limited.

It is considered that the basis considered for hydrogen production in this study is directly related to this concept based on available footprint area and mixing hydrogen production in with gas turbines. There are other alternative concepts which may help support oil and gas operations in a better manner, particularly on a significantly smaller scale.

23.8 Further Areas of Study

This study specifically analysed how hydrogen storage, by utilising surplus wind energy, can impact emissions and fuel costs; however, hydrogen could also be used in conjunction with fuel cells for other functions, such as smoothing GT ramp rates. These other uses and how they could impact the system operability and project economics is a potential area of further study for consideration.

24. Advanced Modular Reactor

24.1 Objective

The objective of this study is to detail the information provided by Core Power (UK) Ltd regarding the use of Advanced Modular Reactor technology as an alternative to Combined Cycle Gas Turbines (CCGTs) and Wind Turbines for power generation for the platform electrification concept studied on this project.

24.2 Background

The use of advanced modular reactors for power generation was identified in the Renewables Technology Review Section 22.6.2 as a disruptive technology that could be applied as the main power generation source on the Main Hub as part of the design concept developed for this project.

The key benefits that AMRs could bring to the design are:

1. Replacement of both the CCGTs and Wind Turbines – potentially simplifying the design, reducing CAPEX and OPEX, and reducing space and weight requirements
2. Stable, dispatchable power generation
3. Emissions reduction approximately equivalent to using a variable renewable energy technology such as wind or solar, resulting in reduced emissions compared to the current base design

However, AMR technologies are at a relatively early stage of development, with many of the most developed concepts only at TRL 5 (Pilot Operations); therefore, application of AMRs is only a consideration as a future design improvement on the base design (CCGTs + Wind Turbines).

For more information regarding AMR technologies, refer to the Renewables Literature Review Section 22.6.2

24.3 AMR Application as a Floating Offshore Power Plant

The following information was provided by Core Power (UK) Ltd, with edits by Katoni, and provides key information on the application of AMR technology for a floating offshore power plant concept.

24.3.1 AMR Technology

24.3.1.1 Technology Selection

Core Power's mission is to deploy sustainable advanced atomic power at sea for the powering of ships and offshore structures.

Core Power is, in principle, technology agnostic, in the sense that Core Power is cooperating with different Advanced Reactor Designers selecting the technologies that best fit a given type and size of installation, to co-fund, co-develop, and license the technology for marine deployment, as well as taking part in defining and designing the assets on which the advanced reactors will be installed.

The main criteria leading the selection of viable advanced reactor technologies can be summed up as follows:

Safety: the technology must allow a certain degree of walk away safety / fail safety / passive safety at design level;

Proliferation resistance: the technology must incorporate features that mitigate proliferation risks;

Waste mitigation: the technology must incorporate features that mitigate waste issues;

Affordability: the total life cycle cost of the technology must make it competitive with existing technologies;

Size: the technology must be sized as to allow factory fabrication and installation on a marine asset.

Given the requirements of this project Core Power consider that the best technology in this range is Terra Power Molten Chloride Fast Reactor, MCFR.

24.3.1.2 MCFR Description and Configuration

The Molten Chloride Fast Reactor is an integral advanced reactor operating in the fast spectrum.

The reactor runs on a homogeneous fuel, acting also as primary coolant, made by a liquid mix of fissile material and Chloride salts.

Different type of fissile materials and different level of enrichment can be used, in principle these type of reactor could also be run on Plutonium, as a waste burner.

For marine operations the best fissile material is most likely High Assay Low Enriched Uranium (HALEU) which is low enriched Uranium enriched close to the maximum range approved for civilian use, i.e. above 16% and less than 20%.

The reactor operates slightly above ambient pressures and at relatively high temperature. The low pressure is a great safety feature, as the reactor vessel does not risk being breached, while the high temperature allows a good thermal efficiency for the power conversion cycle.

The reactor is made up by a core, containing a large inventory of fuel salts, which are constantly recirculated from the core to the primary heat exchangers, being constantly mixed in the process.

This ensures a very effective utilization of the fuel, contrary to what happens in the case of reactors using fuel rods, in which rods located close to the centre of the core get depleted before the ones at the periphery, shortening the fuel cycle and requiring the reactor to be opened and the rods replaced and shuffled.

The primary heat exchangers are integral to the core structure. All is arranged inside the reactor compartment, within the reactor shielding.

An intermediate loop, using non fissile molten salts, is used to transport the heat from the reactor to the power conversion system.

The power conversion system can be of different types, it could be a closed loop steam Rankine cycle or a closed loop Brayton cycle. Both options are being evaluated.

In the power conversion system thermal power will be converted into mechanical and then into electric power, and then fed to the electric power distribution system, for onboard uses and to be dispatched offboard

24.3.2 Availability / Uptime

The uptime of traditional nuclear plants, such as Pressurized Water Reactors (PWR) is extremely high.

An MCFR is much simpler than a PWR, both due to physics and design. This consideration leads us to consider that the uptime will be more than 95%.

24.3.3 Start-up and Shutdown

The operation of an MCFR should minimise start-ups and shutdowns where possible. The reason is that shutting down the MCFR will eventually lead to the freezing of the molten salts, either in the core or in the intermediate loop, which in turn would require melting the salts before restarting the reactor. For this reason, in standard running conditions, idling the MCFR rather than shutting down would be the best option.

Idling is performed by actuating the control drums into the idle / zero power position, which is also the fail-safe position. An idled MCFR will produce very little thermal power, sufficient to keep the primary and secondary salts molten.

By rotating the control drums away from the zero-power position the reactor will immediately provide thermal heat, and hence, power generation.

The time constant for the start up from idle, ramps up, ramps down and from full power to idle mainly depends on the characteristics of the power conversion system. In any case, the MCFR is excellent at load following

The actual shutting down of an MCFR is performed by draining the liquid fuel salts from the core of the reactor into a drain tank. The drain tank geometric configuration is such as to negate the possibility of a chain reaction. In addition, the internal surfaces of the drain tank is covered by neutron absorption material (contrary to the internal surfaces of the core, which are covered by neutron reflecting material); therefore, the drained reactor is subcritical. The draining of the reactor core is also an important safety function.

The secondary loop salts would also be drained in parallel. This operation is foreseen in case of either medium- or long-term shutdown of the reactor.

24.3.4 Safety

The MCFR is fitted with a triple safety system in respect to the control of criticality, each system is fitted with its own redundancies.

The first safety system is the control system of the reactor, made up by a series of control drums with a fail-safe position that ensure the reactor becomes subcritical.

The second safety system is the draining system, which flushes all the fuel from the core and the heat exchanges to a drain tank which, as previously described, is configured to ensure that the fuel cannot become critical.

The third safety feature is a poisoning system, this is a final safety feature that will be actuated only in an emergency. The poisoning system effectively kills the reactor by injection neutron absorbing material into the reactor core, making the reactor subcritical. The poisoning of the reactor is a final safety feature from which the reactor cannot recover.

The MCFR has other important safety features, which are inherent to the physics of this type of reactor.

The most important one is the fact that the reactor operates at ambient pressure, or slightly above it, and that it cannot be pressurized even in the case of overheating. Consequently, no pressure build up is possible inside the core, and the reactor containment vessel is not subject to breach from mechanical ruptures due to a reactor accident. This is possibly the most important safety feature when compared to a PWR. By virtue of this safety feature, even in case of the worst possible reactor accident, the area exposed to radiation would be limited to the reactor compartment only.

Another safety feature is the negative void reactivity coefficient of the fuel salts, which is also the one that allows the MCFR to excel at load following: by virtue of this feature the reactivity of the reactor decreases as the fuel salts heat up, while it increases as they cool down, hence the reactor is impervious against overheating. This is also extremely important differentiator to PWR.

A final safety consideration is related to cooling, which is an essential safety feature for a reactor. The deployment at sea guarantees the ample supply of coolant. Even in dead plant conditions fail safe flooding valves can ensure passive cooling and recirculation of sea water.

24.3.5 Main Hub Reactor Location / Configuration

A single MCFR core can provide up to about 700 MW thermal, which consistent with the project requirements.

The core would be paired with a series of integral primary heat exchangers, for the actual power rating.

All would be arranged in a reactor compartment, located above the double bottom of the offshore structure.

The reactor compartment would be enveloped by the shielding, which can be preliminarily considered as a 1.0 meter thick reinforced concrete / steel sandwich wall.

A buffer space, approximately 2.0 meter wide, would surround the shielding. The buffer space would comprise a double (one internal and one external) watertight fire resistance bulkhead.

NOTE: the reactor does not pose a fire hazard, the fire-resistant bulkheads are needed to protect the reactor, not the other way around.

24.3.6 Steam Turbine Selection

The reactor would be paired with a supercritical Rankine power conversion system, like the ones used in coal / oil fired power plants. This is a very mature technology that can, in principle, be bought off the shelf.

Since the power conversion system also acts as primary cooling system for the MCFR, suitable redundancy should be considered.

In principle, a double redundancy could be considered in case of single reactor installation, (2 x steam generators, 2 x steam turbines, 2 x condensers, each at least 50% of the capacity).

In case of multiple redundancy installation, a triple redundancy is most likely sufficient (3 x steam generators, 3 x steam turbines, 3 x condensers, each at least 35% of the capacity).

Circulation pumps should always be at least 3 x 50% of the capacity.

For preliminary considerations the following can be quoted:

- Efficiency:
 - o 43% for subcritical variant,
 - o 46% for supercritical variant
- Frequency 50 or 60 Hz
- Main steam conditions:
 - o SPP – Inlet pressure up to 260 bar
 - o Inlet temperature up to 600 °C
- Reheat steam conditions:
 - o SPP: 610°C

24.3.7 Footprint and Weight

A 720 MW thermal MCFR can be preliminarily considered having a mass lower than 3.000 t.

The reactor compartment, including shielding, can be estimated in about 12 x 10 x 10 meters (height, width, breadth).

The reactor compartment would be located above the double bottom and be surrounded by a 2.0 meters wide buffer space / void.

A technical / reactor ancillary room would be located above the reactor, housing electric motors and control system. A reactor control room shall also be provided.

The footprint, volume, mass of the supercritical Rankine power conversion system, including the generators and the electrical machinery would be as per standard for that technology.

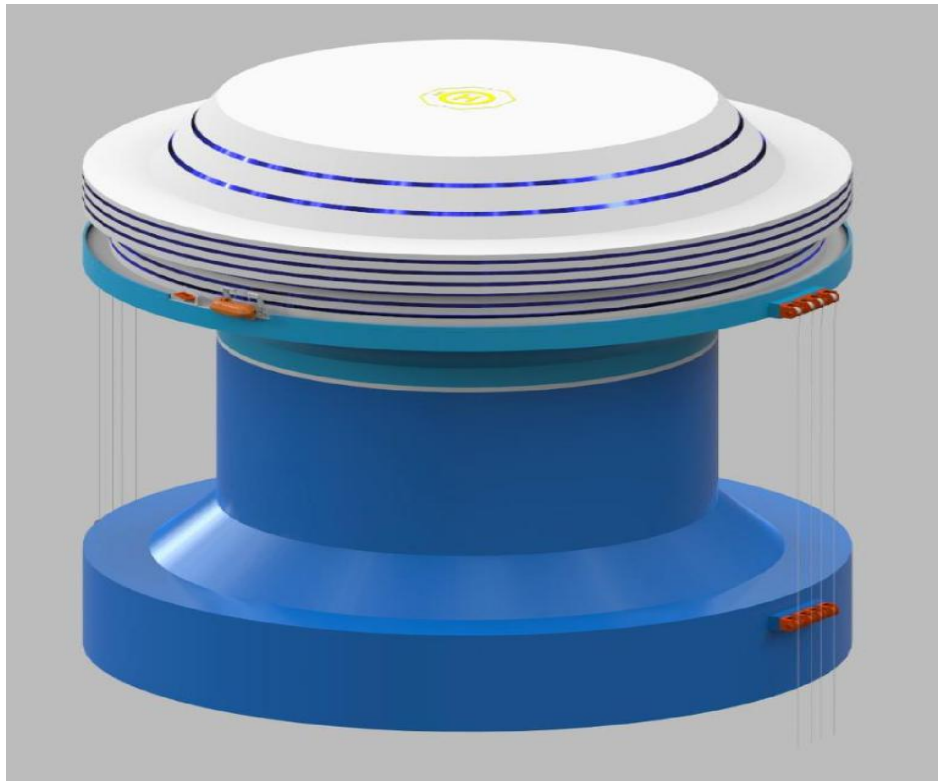


Figure 24-1 - Artistic Impression of the Floating AMR Power Plant

24.3.8 Costs

It is anticipated that the total life cycle cost of the Floating Nuclear Power Plant, including initial fueling, decommissioning, scrapping and waste handling would be less than 50.00 USD / MWh (Total System LCOE).

In case of low utilization / low capacity factor, due to external constraints, the figure would increase.

This estimated levelized costs are lower than both offshore wind and CCGTs, which are estimated by BEIS to be approximately 47 and 99 £/MWh for projects commissioning in 2030 Section 22.2. Additionally, to make power generated from variable renewable energy stable and dispatchable, the unit energy costs would be significantly higher than those estimated by BEIS, since energy storage would also be required.

24.4 Conclusion

Core Power advised that MCFR is an AMR technology that would be well suited for offshore power generation applications.

An MCFR has multiple safety features, including those inherent to the physics of the operation of the reaction; can operate using a range of fuels, including those approved for civilian use; has potential for high availability; has operational flexibility and good load following capabilities; a relatively low footprint requirement; and levelised costs are anticipated to be lower than both offshore wind and CCGTs.

The information provided by Core Power confirms that AMRs have potential to improve upon the base case design for this project; however, the technology requires further development to demonstrate technical and commercial feasibility for application at this scale.

25. Decommissioning Power Assessment

25.1 Objective

This assessment will analyse the case for electrification of assets beyond their normal hydrocarbon producing life.

For some period after Cessation of Production (CoP), the asset continues to require electrical power generation to support the plugging and abandonment of wells, making the asset safe, flushing and purging operations, and preparation for decommissioning. All of this typically involves personnel living and working on the asset and the use of electrical equipment.

Once any gas flow from the reservoir is stopped, electrical supply typically comes from diesel driven generators, either existing power generation on the platform, or installing new dedicated units (often hired, containerised diesel generator sets). These are then in service almost constantly for a number of years with significant OPEX and associated carbon emissions.

There is an opportunity to lower CAPEX and OPEX spend, as well as reducing carbon emissions, by providing electrical power via subsea cable for the duration of this post-CoP period which may further justify adoption of the proposed distributed network described by this project.

This Technical Note aims to:

- Identify typical decommissioning power requirements for an Oil & Gas platform covering both drilling activities and essential systems
- Identify the typical duration for which power will be required
- Calculate the potential CAPEX, OPEX and emissions savings over the duration if power is imported rather than generated locally using diesel engines
- Evaluate whether the identified savings justify including assets in the electrification project which might otherwise not justify inclusion based on normal production demand and asset life expectancy

25.2 Methodology / Background

Decommissioning power requirements have been estimated based on previous study work completed by Katoni. Detailed analysis was carried out of platform load schedules along with discussions with platform personnel who advised on loads necessary for different stages of decommissioning.

It should be noted that electrical demand will be different if the platform has integrated drilling facilities, vs if a standalone drilling rig is brought along to complete Plug & Abandon.

The Decommissioning Programmes published on the United Kingdom government website have been used to determine approximate durations of decommissioning programmes to understand costs and emissions.

Costs were determined based on:

- Fuel usage
- Emissions costs per the ETS
- Estimated annual CAPEX and OPEX spend for equipment maintenance

For subsea power costs were based on the findings of the Economic Analysis Section 21.5 which determined a cost/MWh of £210. For the purposes of this analysis it is assumed that CAPEX and OPEX spend on the asset itself is minimal as the subsea power import requires only static equipment.

25.3 Discussion

25.3.1 Decommissioning Power Requirements

Previous study work has carried out detailed analysis of decommissioning power requirements for fixed platforms with integrated drilling facilities. The demand data presented in below shows the range identified by this study work.

Table 25-1: Decommissioning Demand Data

	During Drilling	Post-Drilling	Emergency
Demand [MW]	4.9-7.5	1.5—2.9	0.6-0.9

Power demand varies with different drilling operations, e.g. Pulling Casing is typically the peak power demand.

Power demand fluctuates depending on the exact equipment in operation and will likely vary over the course of a day, and over the course of a full decommissioning programme.

To calculate fuel and emission costs an average demand of 60% was applied to the Drilling demand figure above.

25.3.2 Decommissioning Duration

Decommissioning programmes published by the UK Government were assessed for proposed durations. The mean length of the available decommissioning programmes is approximately 5 years with the Plug & Abandonment stage often taking as long as 4 years.

Table 25-2: Decommissioning Programme Durations

Asset	P&A	Flushing	Facilities Safe	Make Safe	Overall
Approved Programmes					
Thistle Alpha /172/	4 Years	+3 Quarters	+5 Quarters		6 Years
Heather /173/	3 Years		+2 Years		5 Years
Fulmar A /174/	4 Years		+2 Years		6 Years
Draft Programmes					
Dunlin Alpha /175/	4.5 Years		+1 Year		5.5 Years
Brae Bravo /176/	2 Years		1 Year		3 Years
Brae Alpha /176/	2 Years		2 Years		4 Years
Brent Alpha/177/	3 Years		2 Years		5 Years
Brent Bravo /177/	1 Year		1 Year		2 Years
Brent Charlie /177/	4 Years		2 Years		6 Years
Cormorant Alpha /178/	5 Years		1 Year		6 Years

25.3.3 Power Generation Options

There are a number of options for providing power generation post-CoP when fuel gas is no longer available. These will depend on the existing generation equipment, its condition and availability, but options could include:

- Retain platform main generation and run on liquid fuel
- Retain platform emergency generation and run on liquid fuel
- Hire in containerised or open generator sets and run on liquid fuel
- Purchase containerised or open generator sets and run on liquid fuel
- Utilise a subsea import power cable
- Utilise a renewable generation package

Previous analysis has shown that there is often minimal difference between rental and purchase of generator sets when looking at durations of around 4 years.

The advantages and disadvantages along with opportunities and risks are summarised in the table below.

Table 25-3: Comparison of Power Generation Options

Option	Advantages/Opportunities	Disadvantages/Risks
Platform Main Generation	Minimal additional CAPEX No topsides modifications No impact on electrical distribution	Ongoing OPEX Higher emissions and running costs when running GTG on liquid fuel at lower demand Poor reliability of old equipment
Platform Emergency Generation	Minimal additional CAPEX No topsides modifications Minimal impact on electrical distribution	May not be able to meet complete power demand Ongoing OPEX Higher emissions and running costs due to age and efficiency of equipment Poor reliability of old equipment
Hire or Purchase Containerised Diesel Generating Sets	Lower fuel and emissions compared to larger generator sets running inefficiently Newer equipment offers greater reliability	Moderate CAPEX Some topsides modifications required Gensets likely to take up valuable landing/laydown space Shorter maintenance intervals Impact from exhaust fumes and noise
Hire or Purchase Open Diesel Generating Sets	Lower fuel and emissions compared to larger generator sets running inefficiently Newer equipment offers greater reliability	Moderate CAPEX Extensive topsides modifications
Subsea Power (existing)	Lower costs and emissions Lower OPEX No need to continuously bunker diesel and refuel Variable demand can be met	Reliance on subsea cable and associated system uptime
Subsea Power (new)	Lower costs and emissions Lower OPEX No need to continuously bunker diesel and refuel Variable demand can be met	High CAPEX and moderate topsides modification
Renewable Generation Package	Minimal OPEX Minimises the need to bunker diesel and refuel Lowers CO ₂ emissions Can be used for lighthouse mode when personnel have left and minimal support is required	Low power outputs and low voltage Moderate CAPEX Requires space on weather deck or other open area

25.3.4 Comparison of Costs

For a 5 year duration the following costs have been established assuming a demand of 2.94MW (60% of 4.9MW peak).

Table 25-4: Comparison of Decommissioning Power Costs

Power Generation Scenario	CAPEX Estimate (£)	OPEX Estimate (£)	ETS Estimate (£)	Total Estimate (£m)
Main Platform Generation on diesel	1.00	13.77	8.47	23.24
Hired Diesel Generation	5.85	10.01	7.02	22.89
Subsea Power (existing)	0 ^{Note 1}	27.04 ^{Note 2}	0 ^{Note 3}	27.04

Table 25-4 Notes:

Note 1: No CAPEX expenditure is expected if the subsea power solution already exists

Note 2: OPEX costs are based on the imported power charged at a unit rate of £210/MWh. This is based on 2.94MW demand over 5 years. In reality this demand will fluctuate and so the overall cost could be higher or lower.

Note 3: ETS for the subsea power solution is already costed into the unit price. The platform will generate minimal/zero emissions if electrified via subsea cable.

Cost Basis:

- Cost per tonne of CO₂ is 79GBP/tonne (2022 figure, rising at 5%pa Section 21.6)
- GTG performance curves used from previous study work:
 - o Peak load total fuel usage is 1.7 m³/h
 - o Average load total fuel usage is 0.85 m³/h
 - o Peak load total CO₂ emitted is 43,746 t/year
 - o Average load total CO₂ emitted is 21,839 t/year
- Finnings 2812KVA generator technical data from previous study work:
 - o Peak load total fuel usage is 1.07 m³/h
 - o Average load total fuel usage is 0.74 m³/h
 - o Peak load total CO₂ emitted is 27,539 t/year
 - o Average load total CO₂ emitted is 18,115 t/year

25.4 Conclusion

This assessment has found that Decommissioning Programmes are typically expected to last for approximately 5 years, during which the average platform electrical power demand is around 3MW.

Based on the calculated unit rate of energy for the concept discussed in this study, it could be cost neutral to power the platform via subsea power rather than utilise containerised diesel generator sets.

The use of subsea power reduces offshore manning for operation and maintenance of power generation, reduces the requirements for diesel bunkering, frees up working deck space for other uses, provides a higher level of reliability and doesn't degrade the working environment with further pollutants (including both emissions and sound).

Given the relative neutrality of costs over conventional power generation it is recommended that the anticipated Decommissioning Programme length be factored into the duration over which an asset can benefit from subsea power.

26. EOR and Reuse Opportunity Assessment

26.1 Objective

The study will detail how a network of subsea electrical equipment could revolutionise the ability to produce previously stranded reservoirs, or enhance oil production.

The study will document the use of equipment such as:

- Subsea Compressors
- Subsea Water Injection
- Multiphase Pumps

In addition to this the study will discuss how this electrification concept could support redevelopment of existing assets with concepts such as green hydrogen reutilising existing oil and gas infrastructure.

26.2 Background

26.2.1 Stranded Field Development

In the North Sea there are substantial known reserves which remain undeveloped for a variety of reasons. These reasons can be either, economically unviable, technically unviable, capacity constraints for receiving facilities or a combination of all these factors.

By providing a power infrastructure in the North Sea this may change the strategy to develop these fields if substantial quantities of power can be distributed into subsea processing technology.

Providing power for items such as subsea rotating machinery and Electric Submerged Pumps (ESPs) has historically been a barrier based on the costs of subsea cabling, and electrical distribution equipment from platforms. If opportunities for network expansion can be designed into systems when the infrastructure is being implemented for larger scale electrification then it could change the economic case for development of reserves.

Several opportunities have been identified of similar schemes such as Siemens Gas To Wire (GTW) project for Marginal Field Development Company (MFDevCo) in 2019. This project aims to /179/:

Develop numerous stranded fields containing gas reserves in the UK North Sea, however many are currently too small to be commercially viable for recovery.

GTW involves using gas produced from North Sea fields to be generated into electricity offshore, and then transmitted to the shore via spare capacity with subsea cables used for windfarms.

Reservoirs which have insufficient pressure to enable production to potentially tieback infrastructure could benefit from application of subsea processing facilities and pressure boosting systems. Technologies such as ESPs, subsea processing and compression and multiphase pumping can all be incorporated to boost wellhead pressure to enable fluids to be produced to assets located further away without significant on platform investment on systems such as gas lift.

26.2.2 EOR and IOR

Enhanced Oil Recovery and Improved Oil Recovery are also concepts which could be supported by use of the electrical distribution infrastructure proposed for the electrification of the North Sea. There exist opportunities for advanced waterflood of reservoirs, or increased water injection flowrates which cannot be supported by existing infrastructure.

Expansion of systems on an existing asset, or use of emerging technology such as low salinity water injection, could offer significant benefits to reservoir performance and recovery, however projects can be deemed unviable if the existing assets cannot support the increased equipment size and weight on the platform.

Use of new subsea water injection systems could be facilitated in areas outwith the reach of platforms for optimal reservoir support if the electrical network can be provided to support this.

26.2.3 Infrastructure Reuse

Post Oil and Gas, there are potential uses for the Main Hub and Sub Hub infrastructure. Providing reliable low carbon power, with the ability to support large amounts of processing equipment, could facilitate the following technologies:

- Large scale desalination
- Offshore green hydrogen generation
- Offshore Carbon Capture and Storage to depleted oil reservoirs
- Relocation for Oil and Gas emissions reduction
- Relocation to tie into the National Grid

All these options could be future uses for the infrastructure after the first deployment of the system has been utilised.

26.3 Discussion

26.3.1 Subsea Compression

26.3.1.1 Åsgard, Norway

In September 2015 Åsgard became the world's first subsea compression facility. The system produces from the Mikkel and Midgard reservoirs and is predicted to increase recovery by 282 million barrels.

Mikkel has been producing gas and condensate since August 2003. The field lies 35 kilometres south of the Midgard deposit on Equinor's Åsgard field in the Norwegian Sea. It has been developed with a subsea production facility tied back to the seabed installations on Midgard, which in turn form part of the Åsgard development.

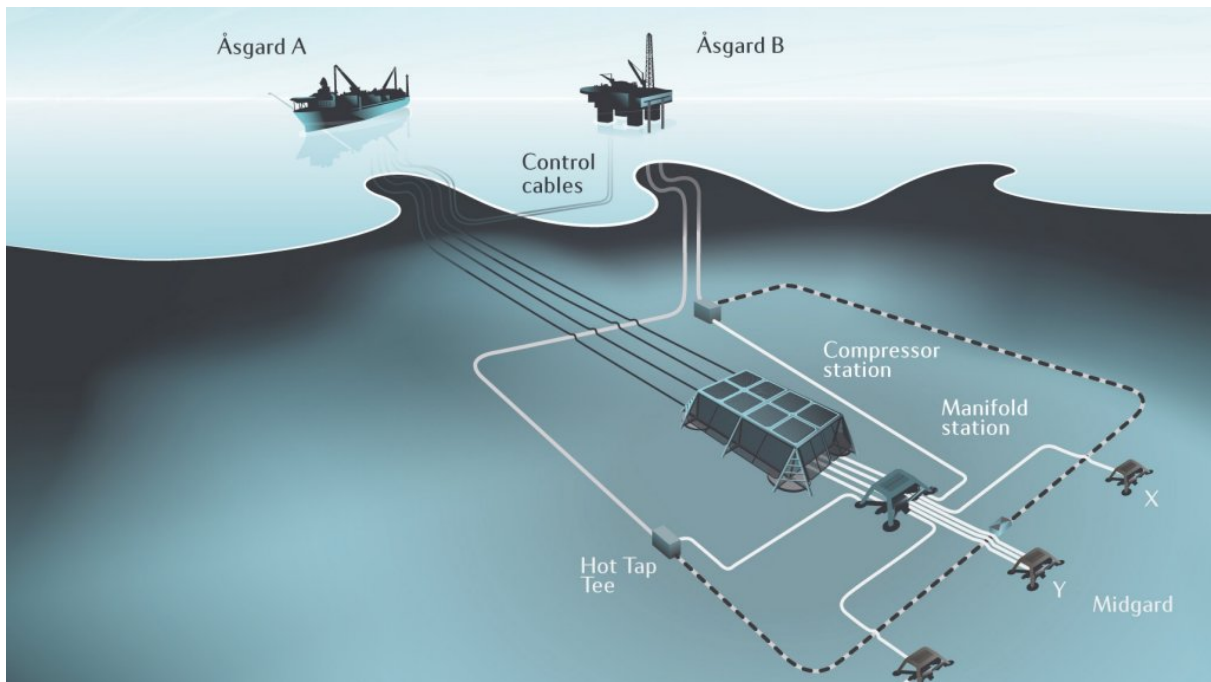


Figure 26-1 Midgard Subsea Manifold (Equinor) /182/

The Midgard and Mikkel gas reservoirs in the Åsgard field have been developed as subsea field installations. The wellstreams from both fields, located 50 and 70 kilometres away respectively, are sent in the same pipeline to the Åsgard B platform.

Analyses showed that by the end of 2015 the pressure in the reservoirs would have been too low to ensure stable flows and satisfactory production on the Åsgard B platform. Compression was needed to ensure high gas flows and recovery rates.

26.3.1.2 Benefits

By installing the subsea compression system for Asgard, Equinor have enabled a substantial increase in recoverable reserves. Equinor and Aker report the increase in production will be 282 to 306 million barrels of oil equivalent. It is anticipated that installation of the subsea compressor will extend production from Asgard by 15 years.

Subsea compression systems have the potential to:

- Increase recovery
- Provide access to stranded assets
- Decouple additional topsides equipment and reduce brownfield modifications
- Reduce OPEX
- Reduce emissions

26.3.1.3 Conclusion

Facilitation of a larger electrical network could allow for marginal gas and condensate fields to be produced, or to extend the life of existing fields if the bottleneck for roll out of these projects is electrical distribution to stranded locations from existing oil and gas assets without substantial electrical upgrades.

Use of an MVAC electrical distribution system could allow large quantities of power to be transferred to facilitate systems such as this, minimising platform brownfield modifications.

26.3.2 Subsea Multiphase Pumps

26.3.2.1 Moho Nord and TotalEnergies Experience

The Moho Nord project in 2018 utilised multiphase pumps to pump highly viscous fluids of 800 cP to the Moho FPU located in Congo. The project successfully delivered a solution to enable production from marginal reservoirs by utilising pumps capable of increasing the pressure of oil, water, gas, and solids by between 50 and 130 bar /183/.

TotalEnergies have installed multiphase pumps on ultra deep water developments in Angola for GirRI, Pazflor and CLOV as they have been found to result in cost and emissions reduction compared to conventional technologies.

TotalEnergies at present have 14 subsea multiphase pumps installed and operating.

26.3.2.2 Benefits

Use of subsea multiphase pumps, like subsea compressors, have the potential to:

- Increase recovery
- Provide access to stranded assets
- Decouple additional topsides equipment and reduce brownfield modifications
- Reduce OPEX
- Reduce emissions

26.3.2.3 Conclusion

Facilitation of a larger electrical network could allow for marginal oil fields to be produced, or to extend the life of existing fields if the bottleneck for roll out of these projects is electrical distribution to stranded locations from existing oil and gas assets without substantial electrical upgrades.

Use of an MVAC electrical distribution system could allow large quantities of power to be transferred to facilitate systems such as this, minimising platform brownfield modifications. Use of MV motors can further simplify equipment by eliminating transformers.

26.4 Subsea Water Injection

26.4.1 Seabox

Generally, oil fields require water injection to maintain pressure and energy in the reservoir to optimise production and recovery. The water has to be treated, i.e. all organics killed and major particles removed, to avoid plugging of pores and stop reservoir from turning sour. In some cases, sulfate level and salinity must be reduced. Subsea water treatment offers a step change in cost reduction, flexibility, and increasing recovery.

Moving the process from topside to seabed offers many benefits including reduced weight and more space available topside. At the seabed, a different and simplified water treatment method can be applied, which allows for a range of different water qualities, including sulfate-free and low salinity water. The approach is a departure from the traditional concept of one big topside facility to a topside 'decoupled' and 'distributed' solution with water treatment modules located near wellheads. This approach represents maximum flexibility and enables increased capacity when and where it is needed.

A commercialised option to provide subsea water injection is available from NOV which is the Seabox and SWIT technology.

The Seabox technology offers a modularised approach to water injection, allowing the injection of bulk water for IOR to highly treated water for EOR.

The IOR system comprises of the basic package of electrochlorination, solids settlement chamber and histidine-rich glycoprotein (HRG) cells.

Electrochlorination will create hypochlorite which will act as a biocide, the solids settlement chamber will remove larger inorganic and organic solids settling particles larger than 24 microns. The HRG cells will decompose neutrally buoyant organic material and will also kill any remaining bacteria in the water.

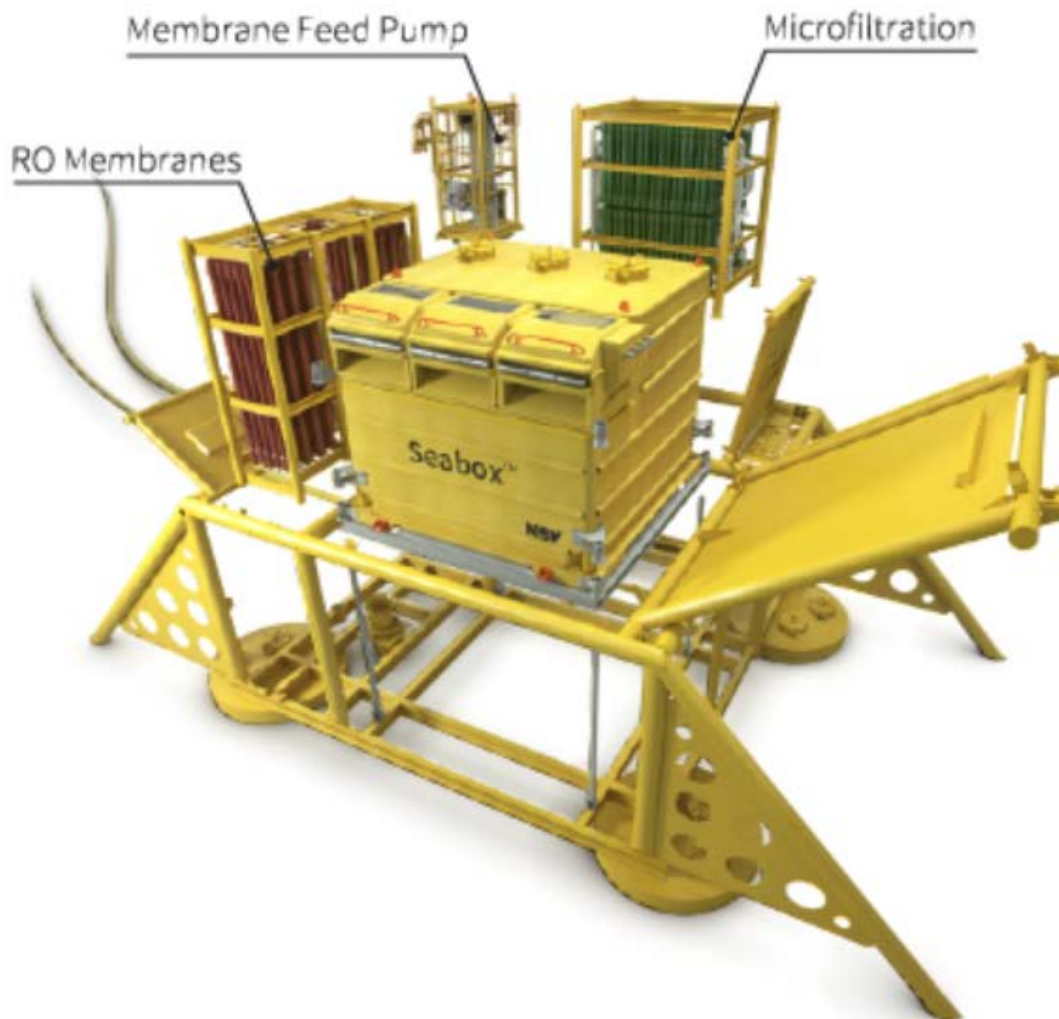


Figure 26-2 NOV Seabox Technology

The second configuration of Seabox facilitates the injection of water for reservoirs with a tighter tolerance for solids. The configuration uses the Seabox IOR configuration with the addition of microfiltration to facilitate removal of solids to 0.1 microns.

The final configuration of Seabox is the EOR configuration. This consists of the 1st and 2nd configuration with the addition of reverse osmosis to provide low salinity water.

Treated water from the Seabox System is routed to an injection pump to be injected into the reservoir.

26.4.2 System Benefits

Use of subsea water injection can offer considerable benefits if the correct application is found. This system can provide the following benefits:

- Less power requirements for injection as no risers and limited frictional pressure drop to overcome
- Improved sweep locations as Seabox can be deployed to suit optimal injection location
- Reduction in brownfield modifications and additional large heavy equipment
- Ability to produce satellite wells to distant platforms for production.

26.4.3 Conclusion

It is considered for a Seabox system to be incorporated, having the ability to power several of these systems using an MVAC transmission in a ring main configuration could facilitate wider scale water injection development.

Several Seabox pilot facilities have been installed and trialled, it is considered this technology is at TRL 6 or 7 level.

NOV claim based on a 20 km traditional tie back configuration that the Seabox can offer double the recovery factor for oil, a 40% reduction in CAPEX costs and 70% reduction in CO₂ emissions /181/.

26.5 Infrastructure Reuse

As the design life of the Main Hub, Sub Hub and Offshore Wind Array is expected to be a minimum of 25 years, it is critical to consider further use opportunities for the equipment once the initial deployment is concluded. Platform CoP and investment in the future in oil and gas may change, so it could be that redeployment is never required. However, if the asset clusters begin to decline in production with no additional development opportunities, then options to utilise the infrastructure are required.

Based on the considerations of the design for the purposes of this study the following has been considered.

- Large scale desalination
- Offshore green hydrogen generation
- Offshore Carbon Capture and Storage to depleted oil reservoirs
- Relocation for Oil and Gas emissions reduction
- Relocation to tie into the National Grid

26.5.1 Offshore Desalination

Floating desalination plants have been discussed in recent years with the push for hydrogen technology. There is a requirement, if hydrogen from electrolysis is to be maximised that large quantities of desalinated water will be required as a feedstock to the process.

Use of ground water and aquifers are a potential option; however, this will affect the water table and could have unintended consequences. In addition, not every geographical area in the UK has an abundance of fresh water, noted by frequent water shortages and rationing in the South of England.

A way to provide this feedstock is to repurpose the Sub Hub infrastructure for large scale, offshore desalination. The facilities required would already exist on the Sub Hubs; high voltage electrical systems and the ability to lift large quantities of water.

It is considered with minor modifications the Sub Hubs could be repurposed for this with a pitstop upgrade in a shipyard. As the design of the Sub Hubs are standardised, the MVDC transmission module could be retained for connection to the Main Hub, and the distribution transformers and switch gear would be removed and replaced with a large membrane module.

Existing infrastructure such as pipelines could be utilised to pump water from the Sub Hubs back to shore.

Alternatively, the infrastructure could be moved closer to shore to reduce the frictional pressure drops and maximise the generation of desalinated water. It would be considered that on the Main Hub the power generation system would likely become obsolete, and the desalination process only utilised with renewable energy. It is likely that based on repurposing of the infrastructure that there would be limited or no fuel gas available for this system to operate.

It could be possible that based on development of hydrogen that the thermal power generation system could operate with hydrogen only fuel, however based on current technology this is unlikely to be possible.

26.5.2 Offshore Green Hydrogen Generation

This approach would be similar to offshore desalination. Instead of maximising desalination, the Sub Hubs could be repurposed to generate substantial quantities of hydrogen on the same basis. The obsolete electrical distribution equipment could be removed, and a hydrogen generation system installed in its place.

An alternative approach to this could be that the Sub Hubs and Main Hub are relocated to allow the Sub Hubs to be repurposed for specific functions, e.g., one produces desalinated water, the second generates hydrogen, the third acts as a compression station and exports hydrogen into disused oil and gas infrastructure. This relocation of infrastructure could incur substantial costs; however, it would allow the systems to be completely interlinked.

26.5.3 Offshore Carbon Capture and Storage

Large scale Carbon Capture and Storage (CCS) projects in the UK are currently under development such as the Goldeneye project.

The Main Hub could be utilised to facilitate large scale CCS projects by providing non-hydrocarbon power to disused oil and gas infrastructure. Using the Main Hub and Sub Hub infrastructure as currently implemented, the gas export pipelines could be reversed to platforms and on platform compression systems used to reinject CO₂ into the disused reservoir. This is the concept currently being developed for Golden Eagle.

The opportunity that having the Main Hub and Sub Hub infrastructure in place is it could reduce the CAPEX costs associated with powering this system from shore.

With the repurposing of gas pipeline infrastructure for CO₂ use then the ability to power platforms would be lost. Therefore, a power from shore connection would be required.

The Main Hub could be used as an interface point and distribute power from shore to assets via the same means as configured for distribution to supplement the incoming wind power.

26.5.4 Relocation for Oil and Gas Emissions Reduction

An alternative option is relocation of the equipment to a region with a longer CoP once the existing deployment is complete. This could be relocation outside of the UK / EU or relocation within.

26.5.5 Relocation for Alternative Industry

An alternative use case for large power systems offshore may be found in the future, such as server farms or alternatives. These systems require large quantities of power to operate, so it could be that the Main Hub and Sub Hub could facilitate these systems further from shore. The intermittency of the OWA may prove to be a challenge for this system unless battery technology advances.

26.5.6 Relocation to tie into the National Grid

The final option for reuse is to move the system closer to shore to interface with the National Grid. The Sub Hubs at this point would become unused and it would only be the OWA and Main Hub which would be relocated. The Main Hub would still be able to act as the substation for the OWA and power would be exported to shore via the MVDC transmission system.

27. Conclusion

The study presents a technically feasible industrialised approach to large scale electrification of the United Kingdom's North Sea region.

The concept successfully achieves the objectives of repeatability, modularity, scalability, and a consumer driven approach i.e., minimisation of modification to existing assets.

The design could feasibly reduce emissions, in the CNS / OMF by 43% and SNS up to 75%. Based on the economic model applied it is currently an economically viable solution for electrifying the assets identified in the CNS/OMF. However, the economics are marginal, and economic viability of this approach for the combined CNS and SNS assets would likely require regulatory intervention.

Significant optimisations can be made to progress this study with more detail, the information utilised in this study is with more formal support of operators, and opportunities for further areas of study have been identified where Katoni have addressed how to approach the concept, with a view that detailed study and engineering work will be required to prove the concept.

28. Appendix

28.1 15 Year Analysis

Analysis detailed in Section 8.4 has been expanded for 15 years. As the duration of the installation extends, the benefit from installing wind power to supplement local generation significantly increases.

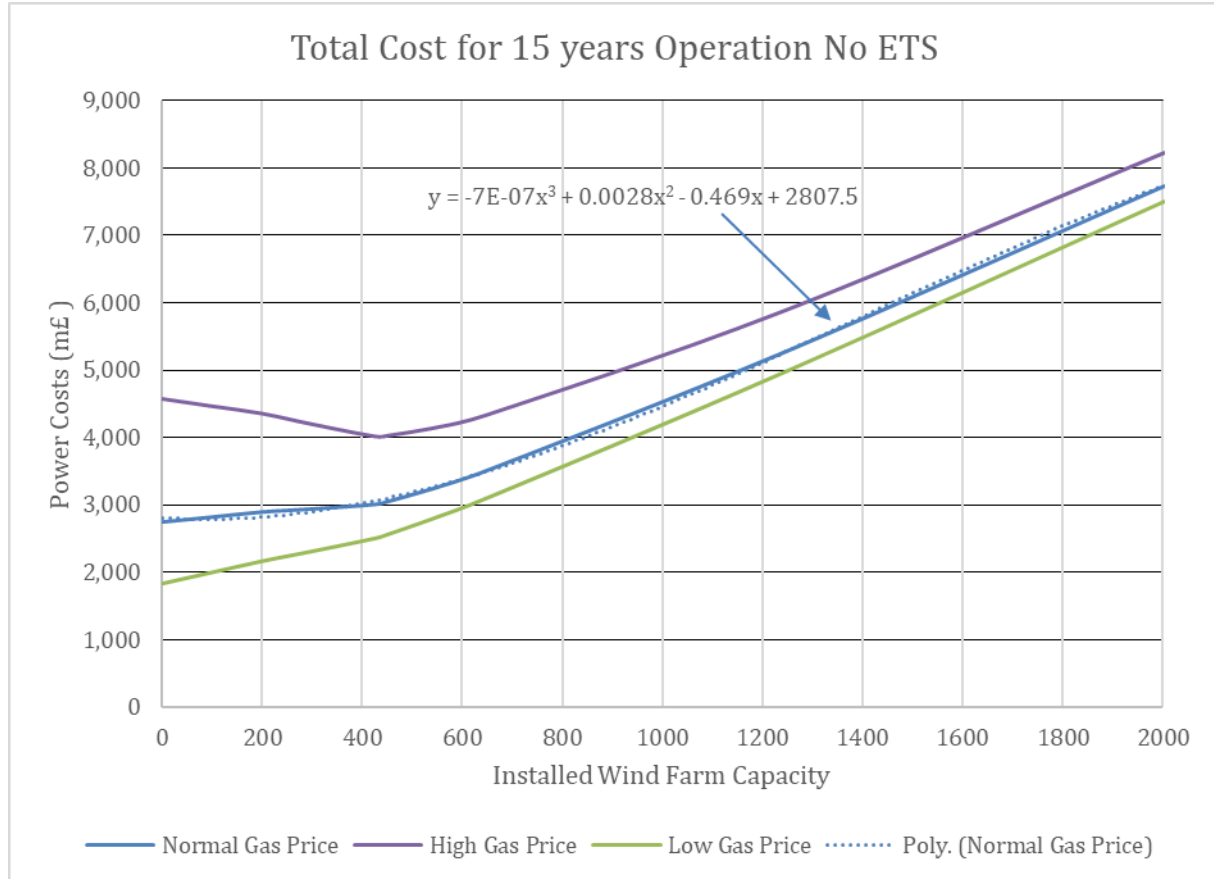


Figure 28-1 Project Energy Costs (15 Years) No ETS 420 MW Demand Combined Cycle

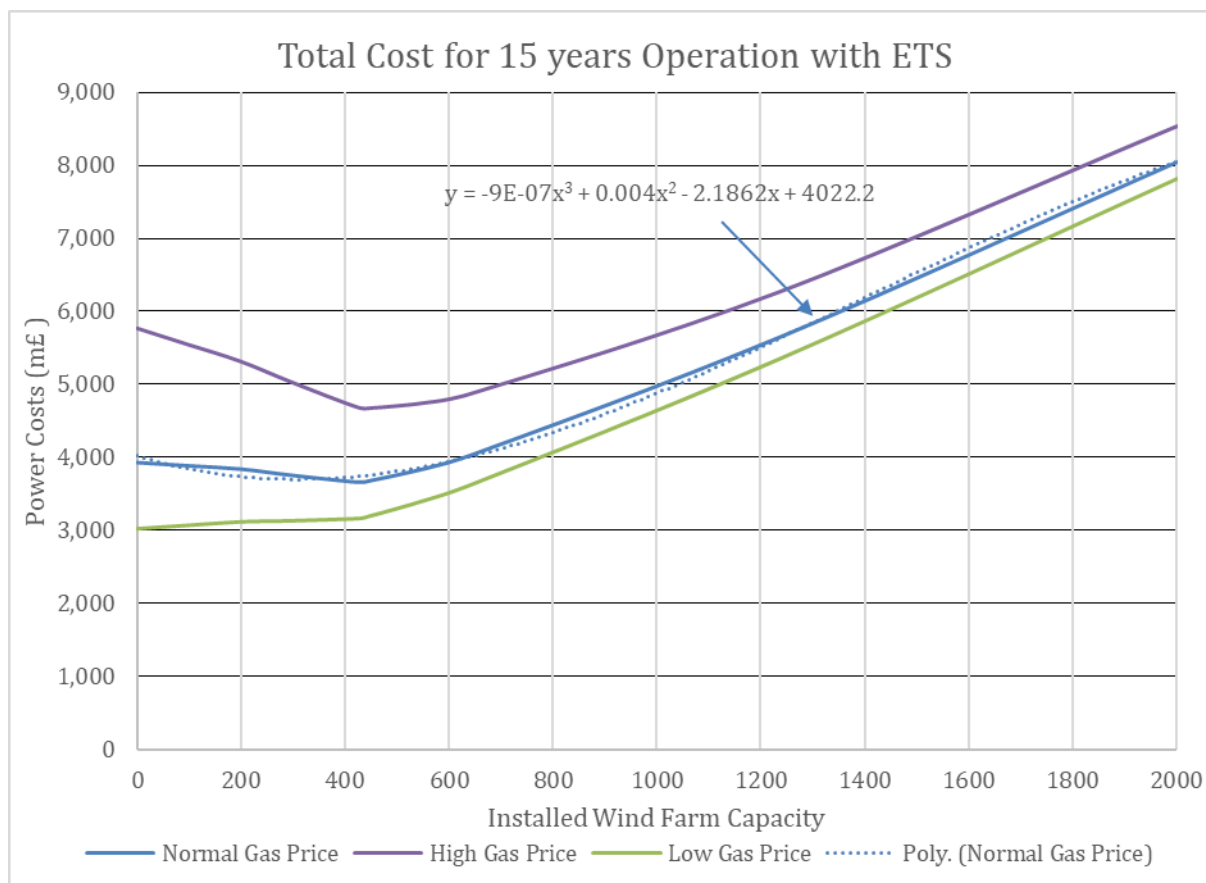


Figure 28-2 Project Energy Costs (15 Years) with ETS 420 MW Demand Combined Cycle

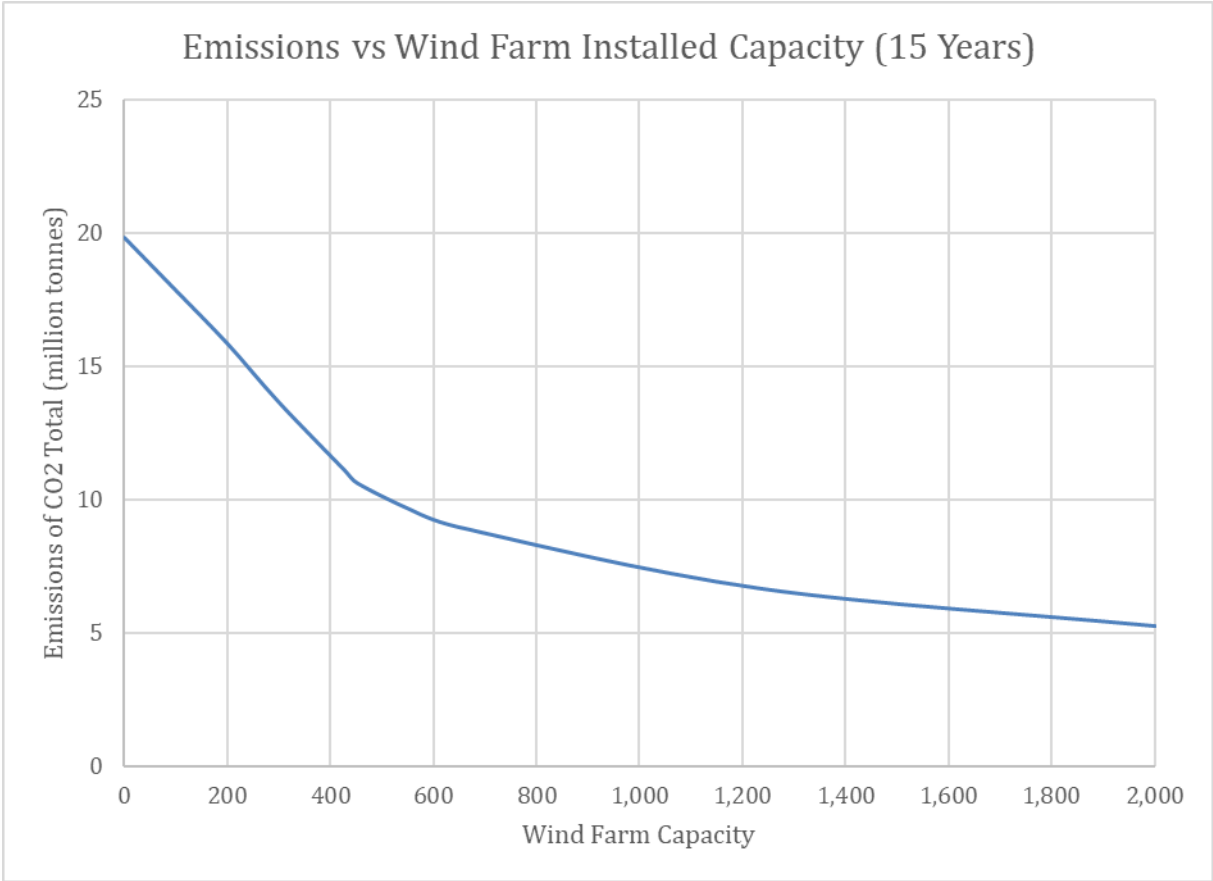


Figure 28-3 Total Emissions Reduction from Main Hub (15 years) Combined Cycle

28.2 20 Year Analysis

Analysis detailed in Section 8.4 has been expanded for 20 years. As the duration of the installation extends, the benefit from installing wind power to supplement local generation significantly increases. When ETS is included in the analysis as shown in Figure 28-5 for high gas price considered in addition to current ETS prices it is estimated that installing a large overprovision of wind power is potentially more economical than installing none.

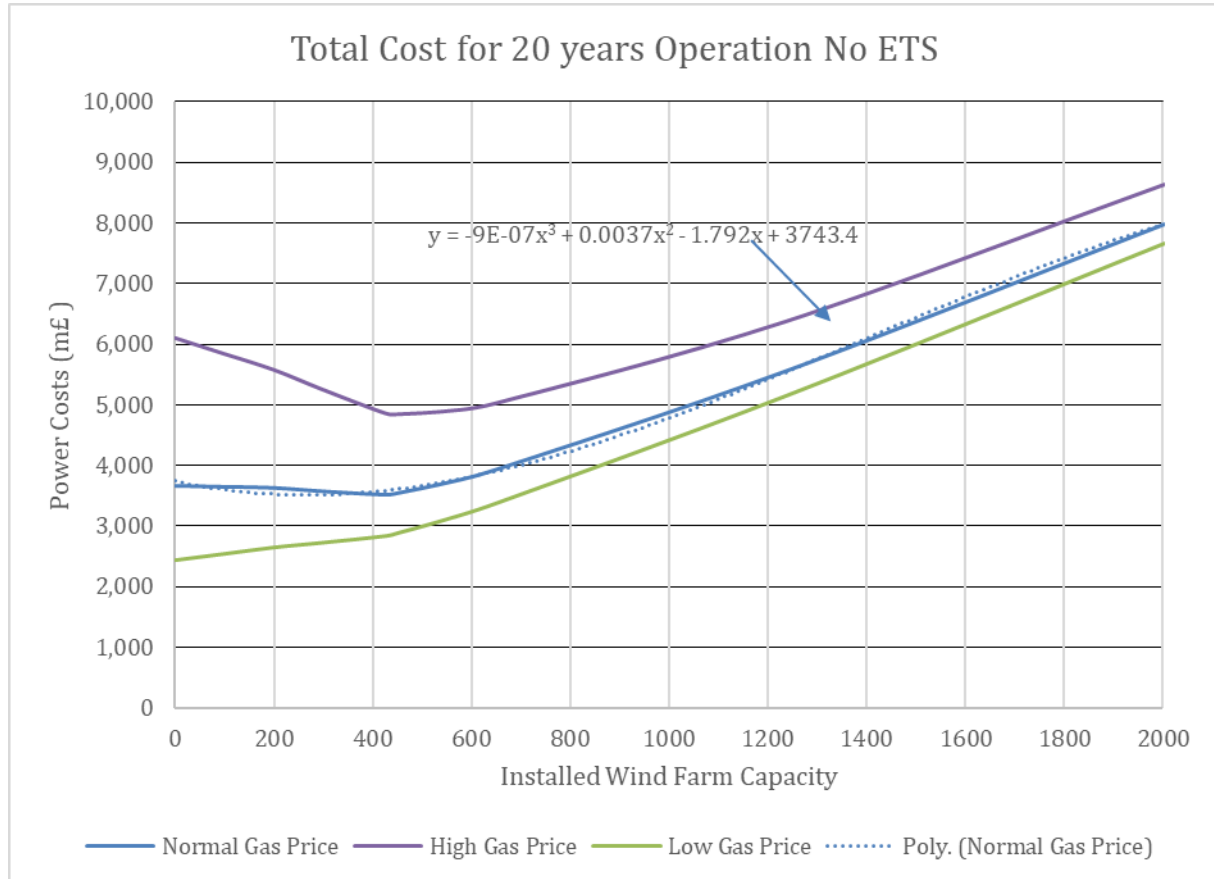


Figure 28-4 Project Energy Costs (20 Years) No ETS 420 MW Demand Combined Cycle

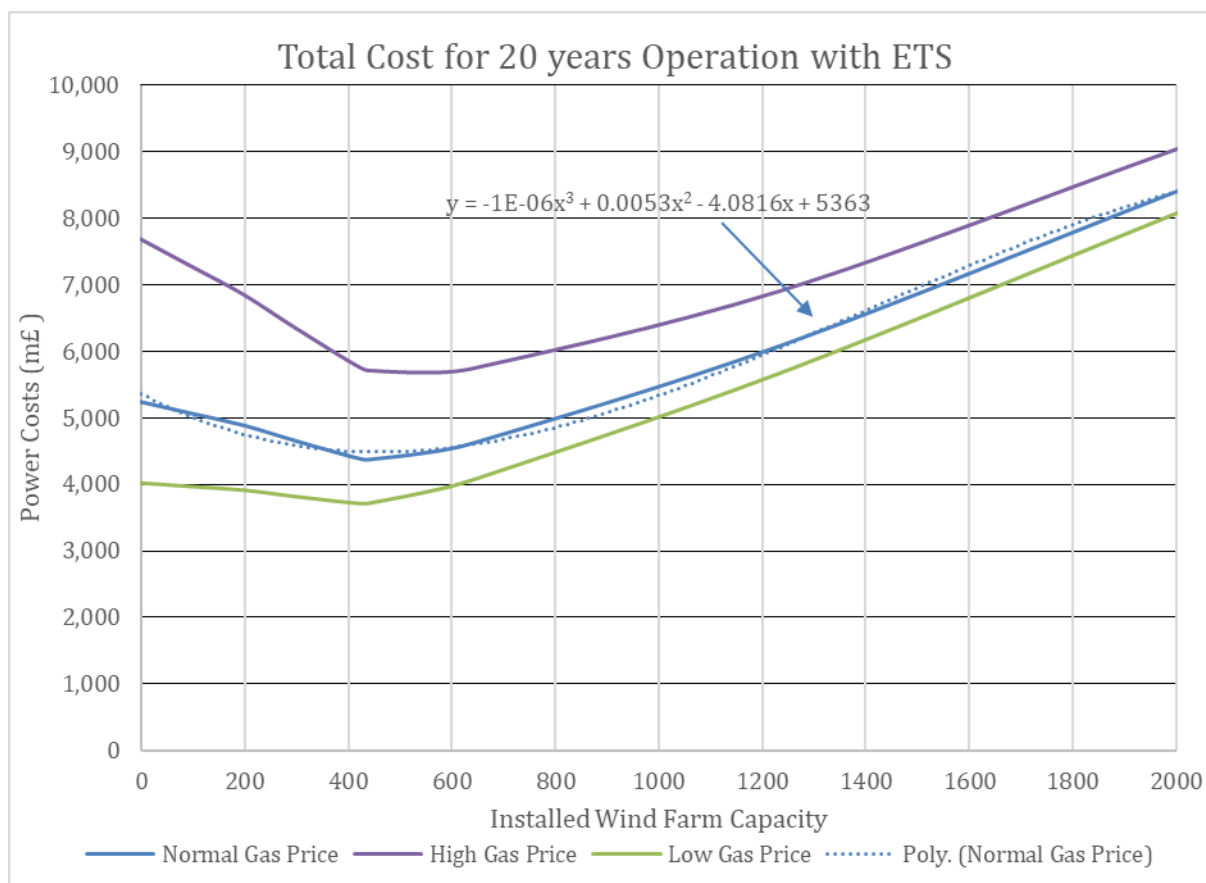


Figure 28-5 Project Energy Costs (20 Years) with ETS 420 MW Demand Combined Cycle

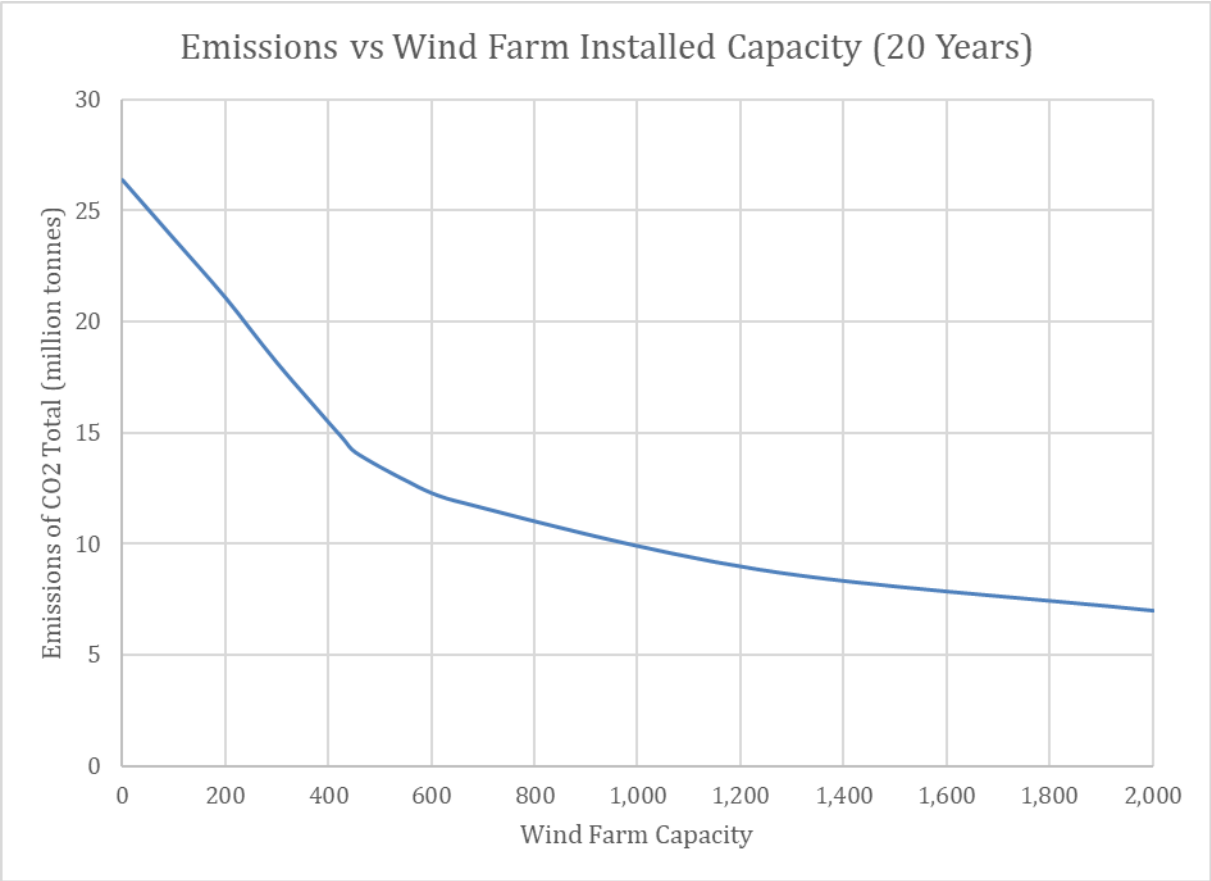


Figure 28-6 Total Emissions Reduction from Main Hub (20 years) Combined Cycle

28.3 ABB ZS1 Switchgear Data

Electrical characteristics					
Rated voltage	[kV]	7.2	12	17.5	24
Rated insulation voltage	[kV]	7.2	12	17.5	24
Rated power frequency withstand voltage	[kV / 1min]	20	28	38	50
Rated lightning impulse withstand voltage	[kV]	60	75	95	125
Rated frequency	[Hz]	50 / 60	50 / 60	50 / 60	50 / 60
Rated short time withstand current	[kA / 3 s]	...50	...50	...50	...31.5
Rated short time withstand current	[kA / 1 s]	63	63	63	
Peak current	[kA]	...164	...164	...164	...80
Internal arc withstand current	[kA / 1 s]	...50	...50	...50	...31.5
Internal arc withstand current	[kA / 0.5 s]	63	63	63	
Main busbar rated current	[A]	...4 000	...4 000	...4 000	...3 150
		630	630	630	630
		1 250	1 250	1 250	1 250
		1 600	1 600	1 600	1 600
Circuit-breaker rated current	[A]	2 000	2 000	2 000	2 000
		2 500	2 500	2 500	2 300
		3 150	3 150	3 150	2 500
		3 600	3 600	3 600	2 500
Circuit-breaker rated current with forced ventilation	[A]	4 000	4 000	4 000	3 150

Units: ... 12 kV - 17.5 kV - 63 kA

Width [mm]		1 000						
Height [mm]		2 200/2 595 ⁽¹⁾						
Height with gas exhaust duct [mm]		2 700 ⁽⁴⁾						
Depth [mm]		2 089				2 139		2 154
Rated current [A]		1 250	1 600	2 000	2 500	3 150	3 600	4 000
IF	Incoming/outgoing	x	x	x	x	x	x	x
BT	Bus-tie	x	x	x	x	x	x	x
R	Riser	x	x	x	x	x	x	x
RM	Riser with measurements	x	x	x	x	x	x	x
M	Measurements							

Reference: [1VCP000138](#)

28.4 ABB ZS2 Switchgear Data

Electrical characteristics

Rated voltage kV	[kV]	36
Rated insulation voltage	[kV]	36
Rated power frequency withstand voltage	kV 1min	70
Rated lightning impulse withstand voltage	kV	170
Rated frequency	Hz	50-60
Rated short time withstand current	kA 3	...31.5
Peak current	kA	...80
Internal arc withstand current	kA 1 s	...31.5
		1250
		1600
Main busbars rated current	A	2000
		2500
		3150
		1250
Branch connections rated current	A	1600
		2000
Branch connection rated current with forced ventilation with fan	A	2500
Branch connection rated current with forced ventilation with fans (available only with VD4 vacuum Circuit Breaker)	A	3150

... 36 kV - ... 31.5 kA

Depth (mm)		2400				2600				
Height (mm)		2310				2310				
Height with gas exhaust duct (mm)		2662				2662				
Width (mm)		1000				1200				
Rated current (A)		1250	1600	2000	2500*	1250	1600	2000	2500*	3150*
IF	Incoming/outgoing									
	with Fixed Voltage Transformers									
	with Fixed fused Voltage Transformers									
	with removable fused Voltage Transformers									
	Fused Switch (Circuit Breaker Feeder)									
BT	Bus-tie									
R	Riser									
RM	Riser with measurements									
M	Measurements									
IFD	Direct incoming/outgoing									
	Direct incoming/outgoing with measurement (with Withdrawable fused Voltage Transformers)									

Reference: [1YTS030001](#)

28.5 Hitachi ELK-04 Switchgear Data

ELK-04, 145 kV ELK-04, 170 kV		Product-ID	1HDG008100M0040
Rated voltage	kV	145	
Rated short-duration power-frequency withstand voltage, 1 min	kV	275	
Power-frequency withstand voltage, 1 min across open contacts	kV	315	
Rated lightning impulse withstand voltage, 1.2/50 µs	kV	650	
Rated lightning impulse withstand voltage, 1.2/50 µs, across open contacts	kV	750	
Rated frequency	Hz	50 / 60	
Rated continuous current	A	up to 3150	
Rated short-time withstand current, up to 3 s	kA	40	
Rated peak withstand current	kA	104	
Rated filling pressure (abs. at 20 °C) circuit-breaker / other components	kPa	0.7 / 0.6	
Minimum functional pressure (abs. at 20 °C) circuit-breaker / other components	kPa	0.6 / 0.52	
Temperature range (ambient)	°C	-30 ... +40	
Enclosure		three-phase	
Type of installation		indoor / outdoor	
Bay width	mm	1000	

Reference: [1HC0130351](#)

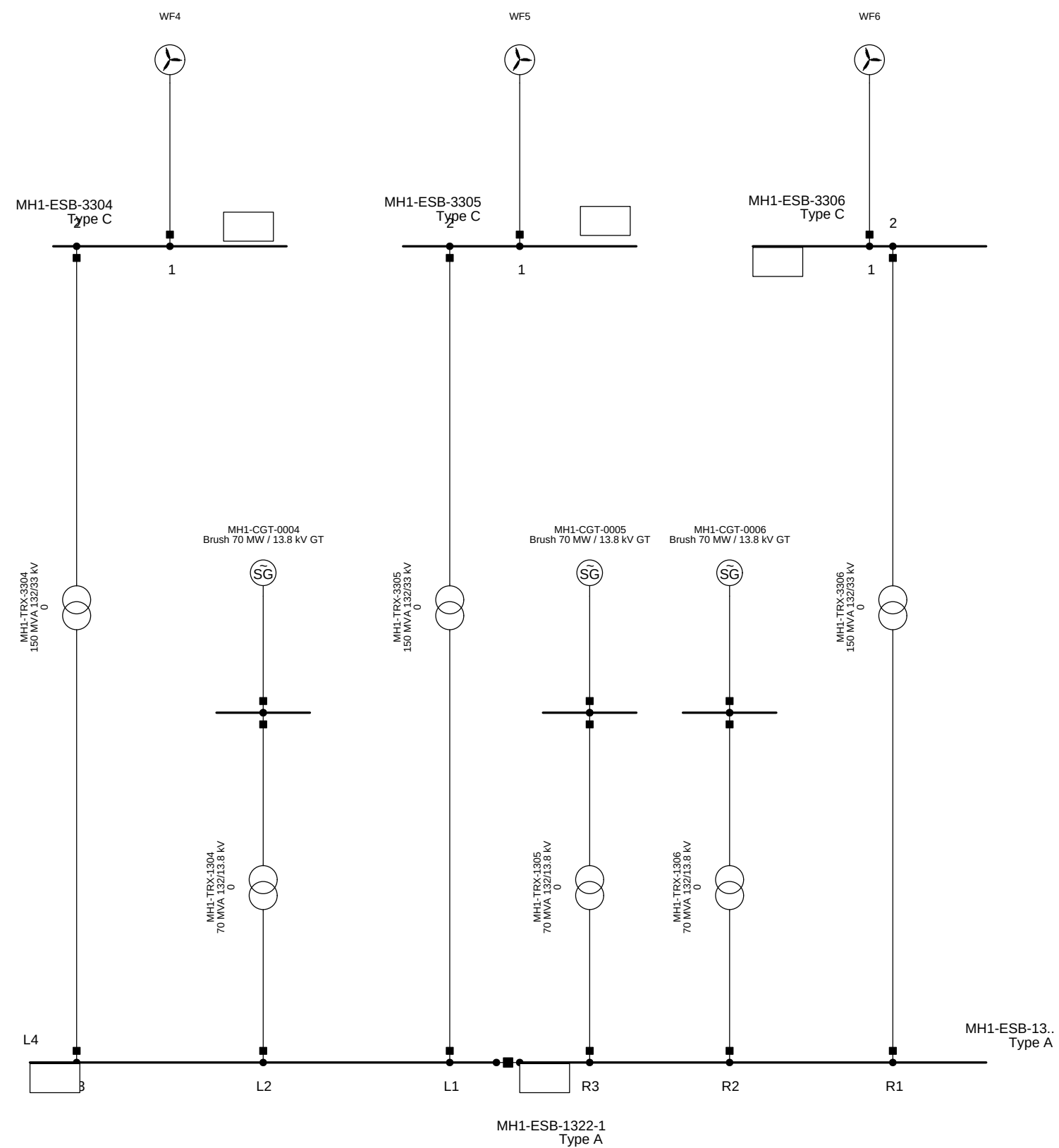
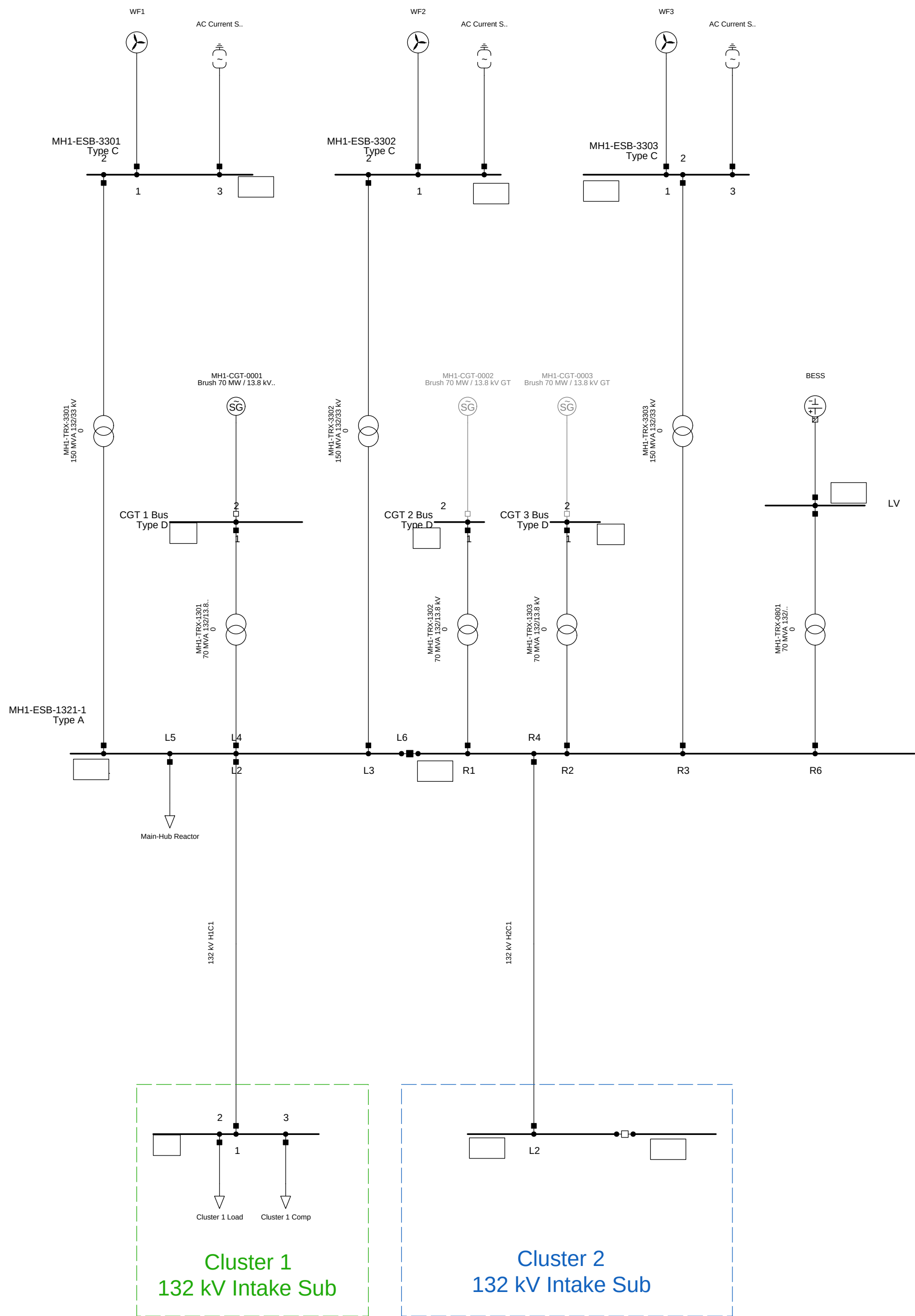
Circuit-breaker

Rated short-circuit breaking current, 50/60 Hz	kA	40
Rated short-circuit making current, peak value	kA	108
First pole-to-clear factor		1.3/1.5
Drive type		spring
Rated opening time	ms	26 ... 35
Rated closing time	ms	45 ... 55
Reclosing time	ms	≤ 300
Rated operating sequence		O - 0.3s - CO - 3min - CO
Number of mechanical operations	class	M2
Rated capacitive switching currents	class	C2

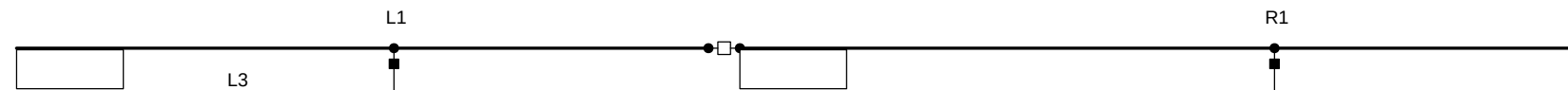
Reference: [ELK-04 C 145 2GHV008915 0315](#)

[VD4 technical data](#)

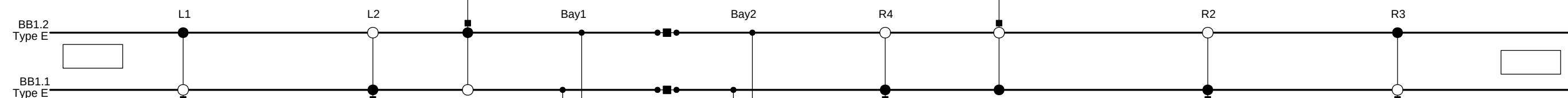
28.6 CNS Cluster Model Single Line Diagram



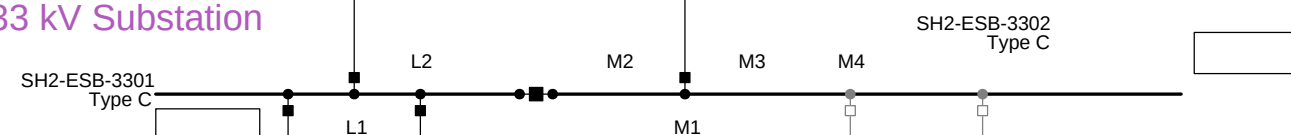
Sub-Hub 2 132 kV Intake



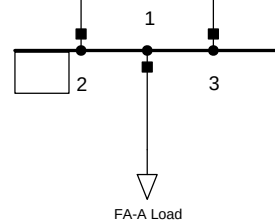
Sub-Hub 2 66 kV Sub



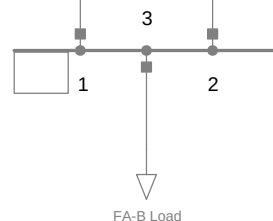
Sub-Hub 2 33 kV Substation



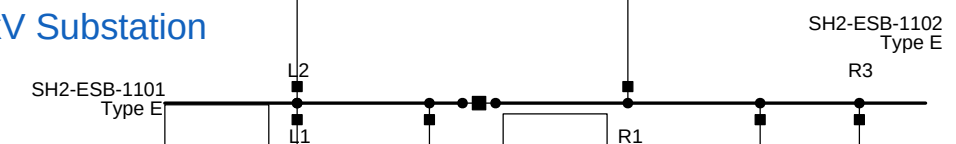
Forties Alpha - A
36kV 25kA 1sec



Forties Alpha - B
36kV 25kA 1sec



Sub-Hub 2 11 kV Substation



Asynchronous Machine
4.9 MW 11 kV



Alba Northern
12kV 40kA 1sec

AN Load



External Grid



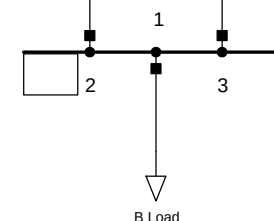
A Load
12kV 40kA 1sec



Sub-Hub 2 6.6 kV Substation



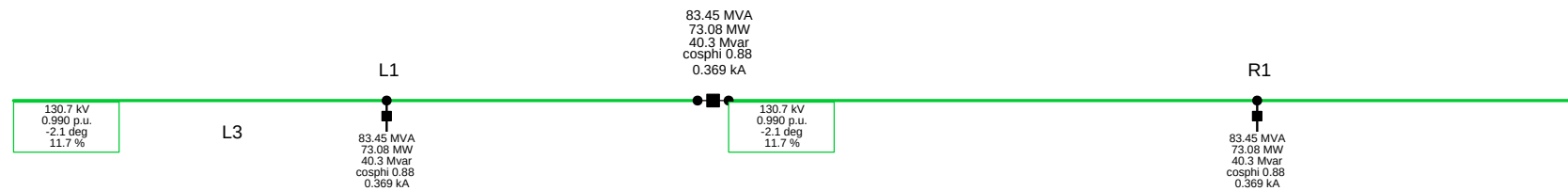
Britannia
Type F



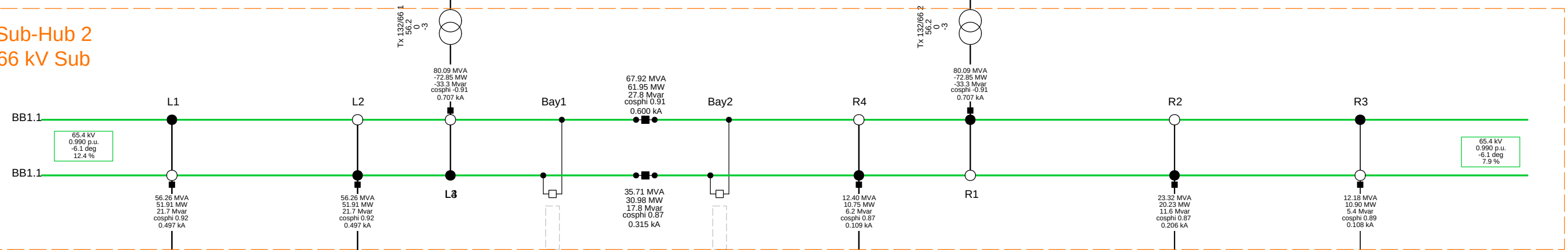
28.7 CNS Cluster Load Flow 2A Results



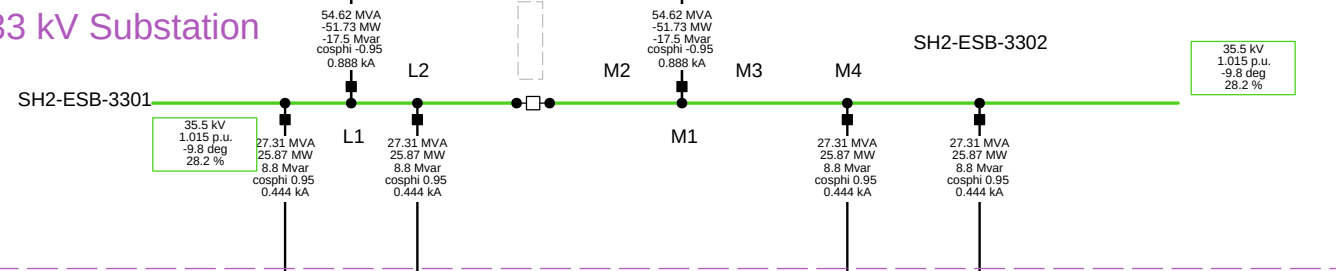
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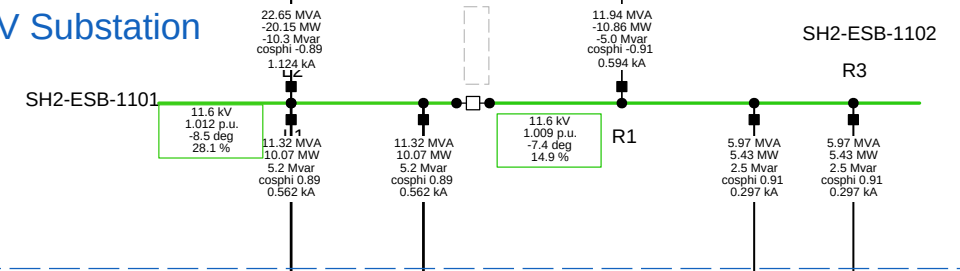
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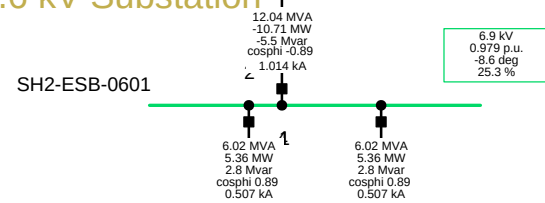
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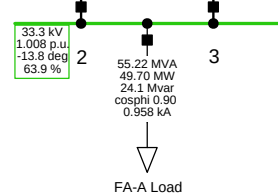
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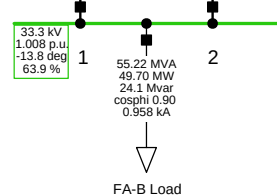
Sub-Hub 2 6.6 kV Substation



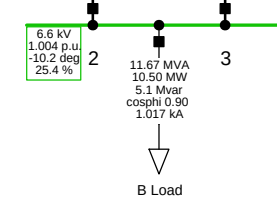
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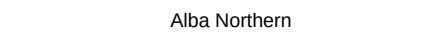
Forties Alpha - B



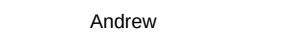
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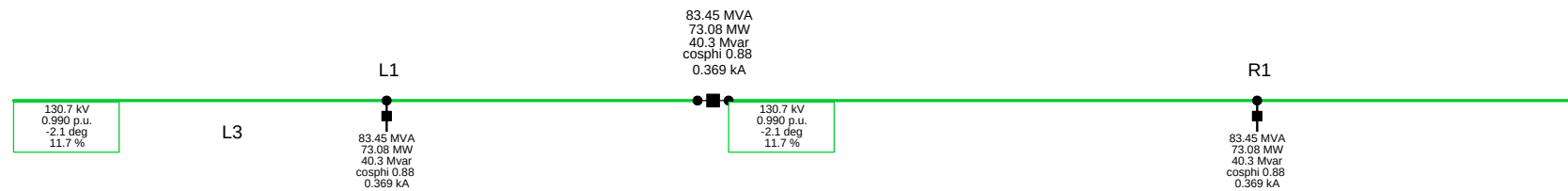
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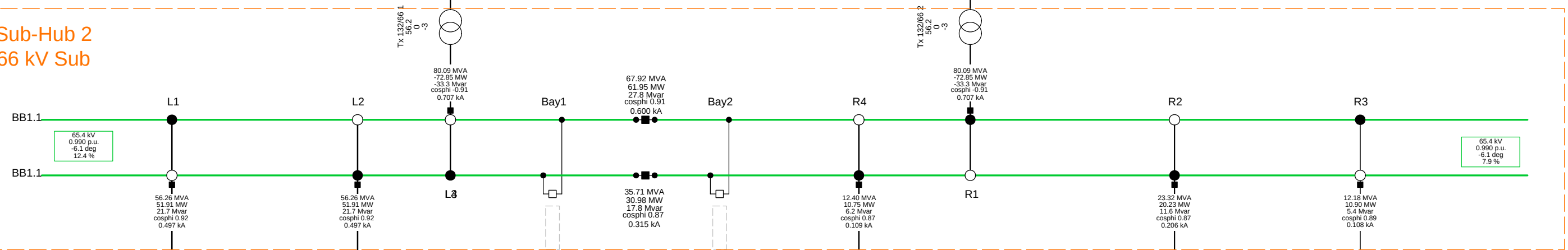
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	Electrical Distribution Modelling		Graphic: Cluster 2 SLD
	HVAC		Date: 30/03/2022
	LF2A- 70% Load (PF 0.9) + 100% WTG		Annex:

28.8 CNS Cluster Load Flow 2B Results

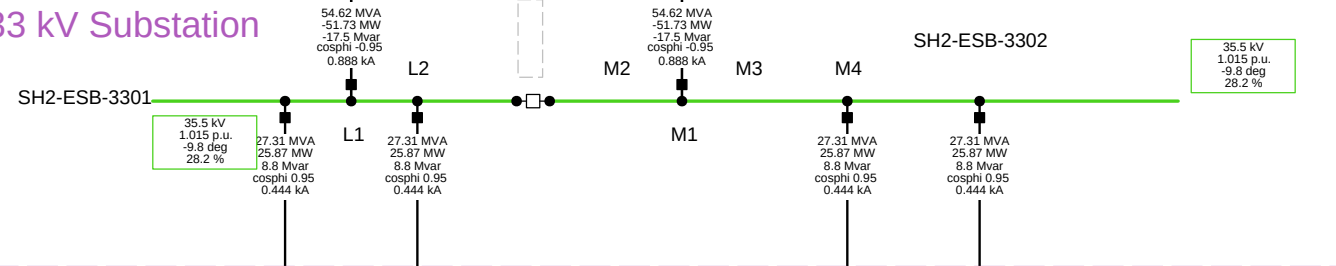
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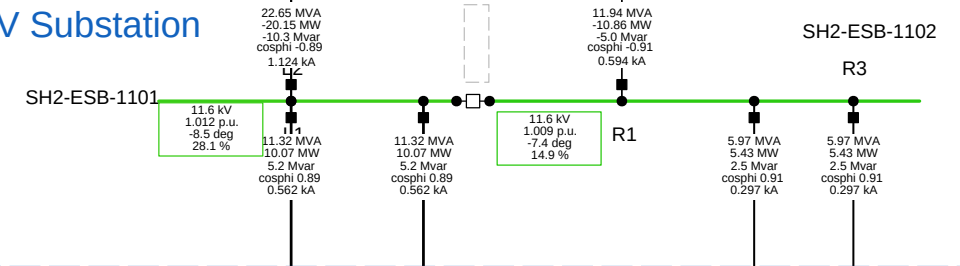
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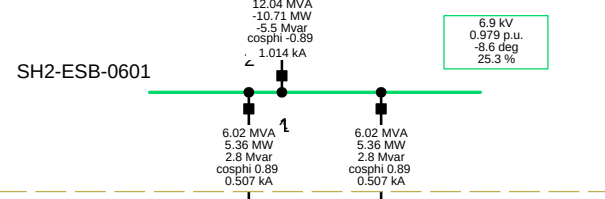
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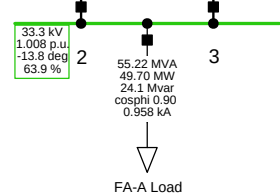
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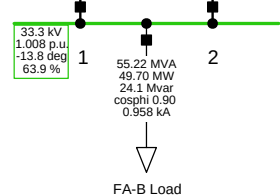
Sub-Hub 2 6.6 kV Substation



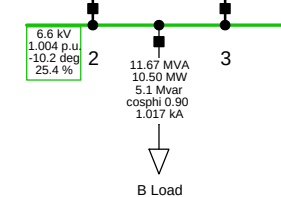
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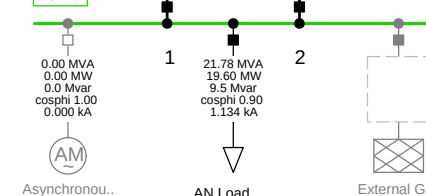
Forties Alpha - B



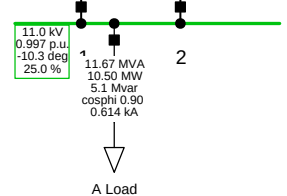
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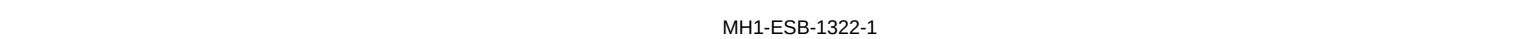
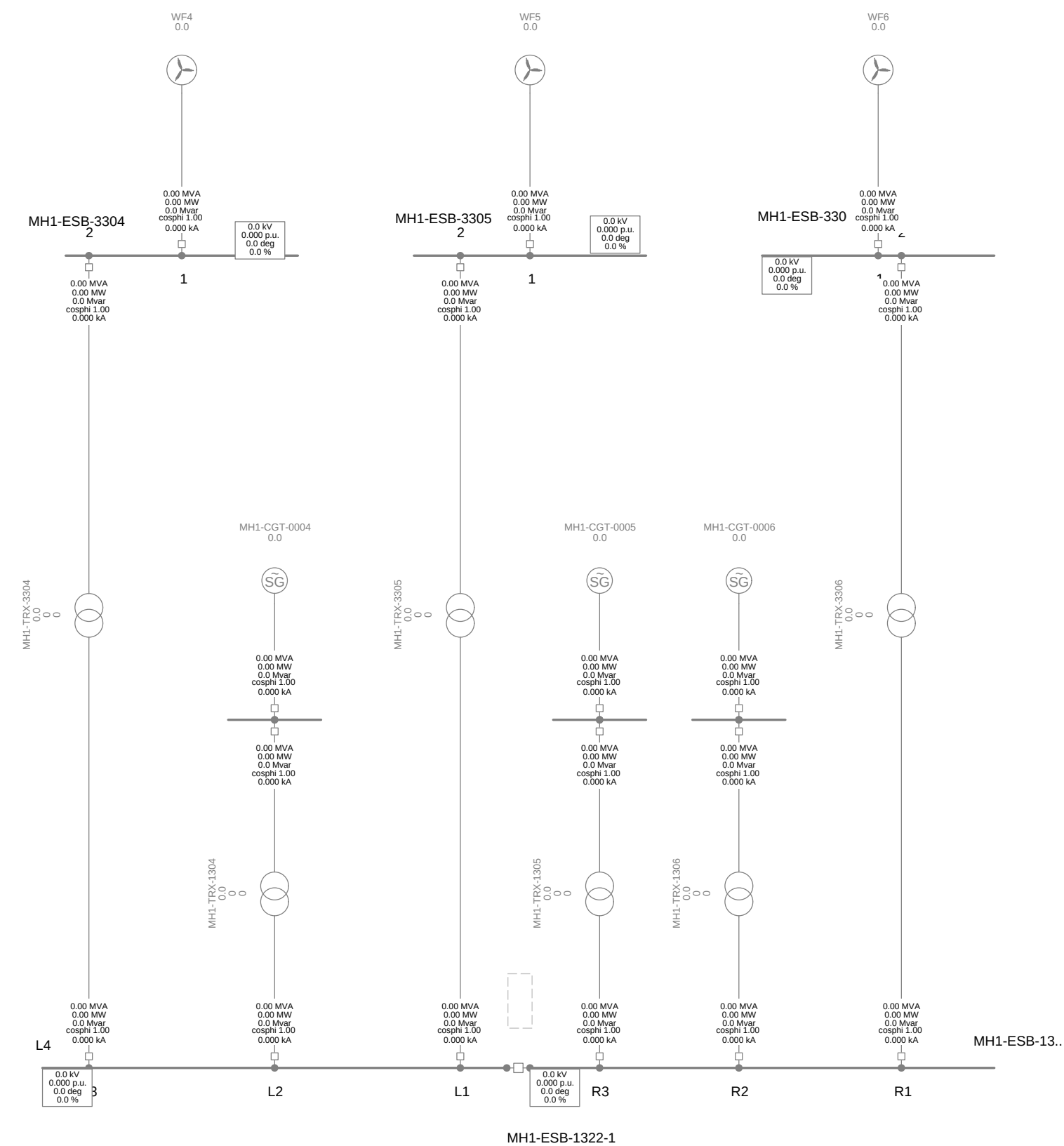
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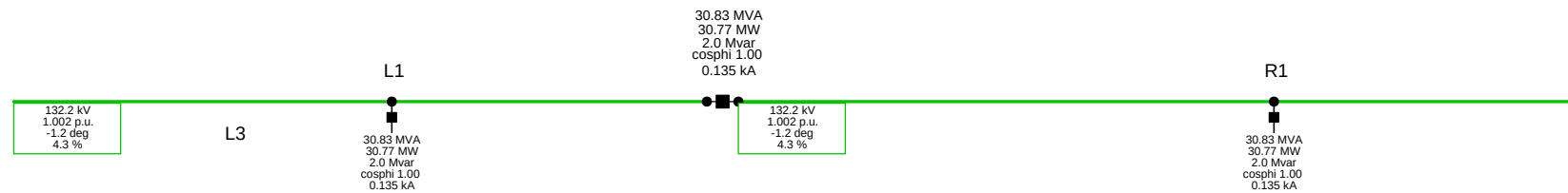
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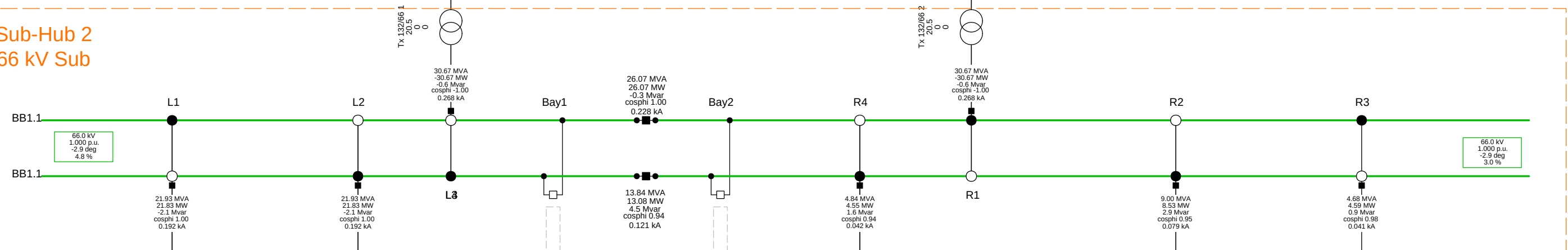
28.9 CNS Cluster Load Flow 3A Results



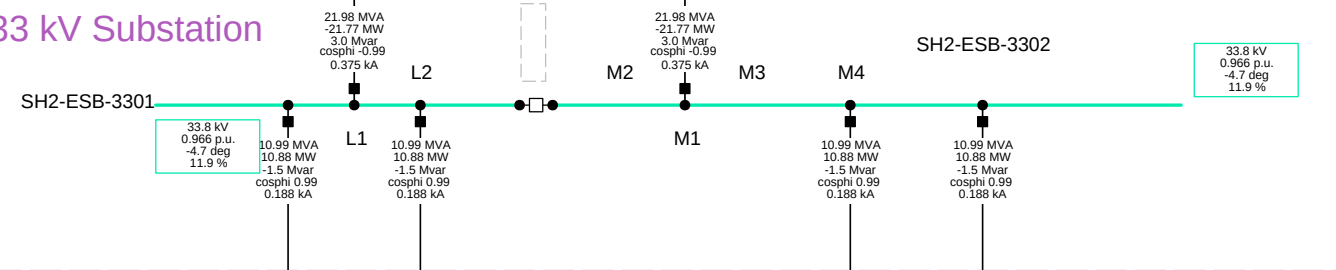
Sub-Hub 2 132 kV Intake



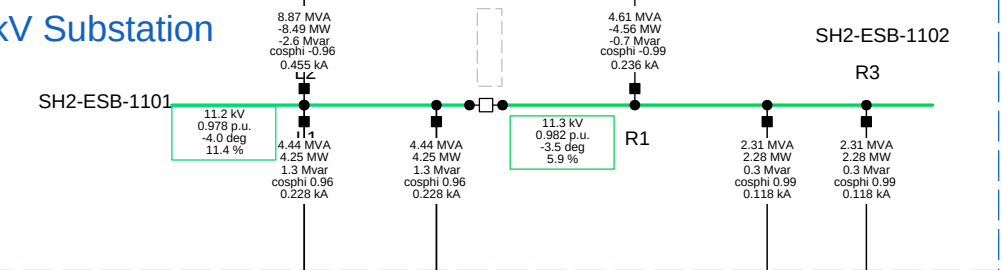
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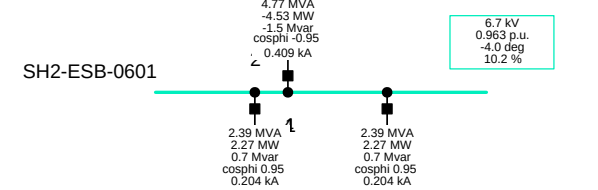
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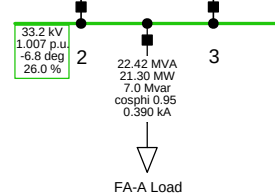
Sub-Hub 2 11 kV Substation



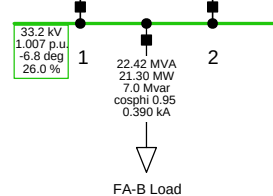
Sub-Hub 2 6.6 kV Substation



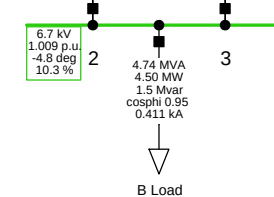
Forties Alpha - A



Forties Alpha - B

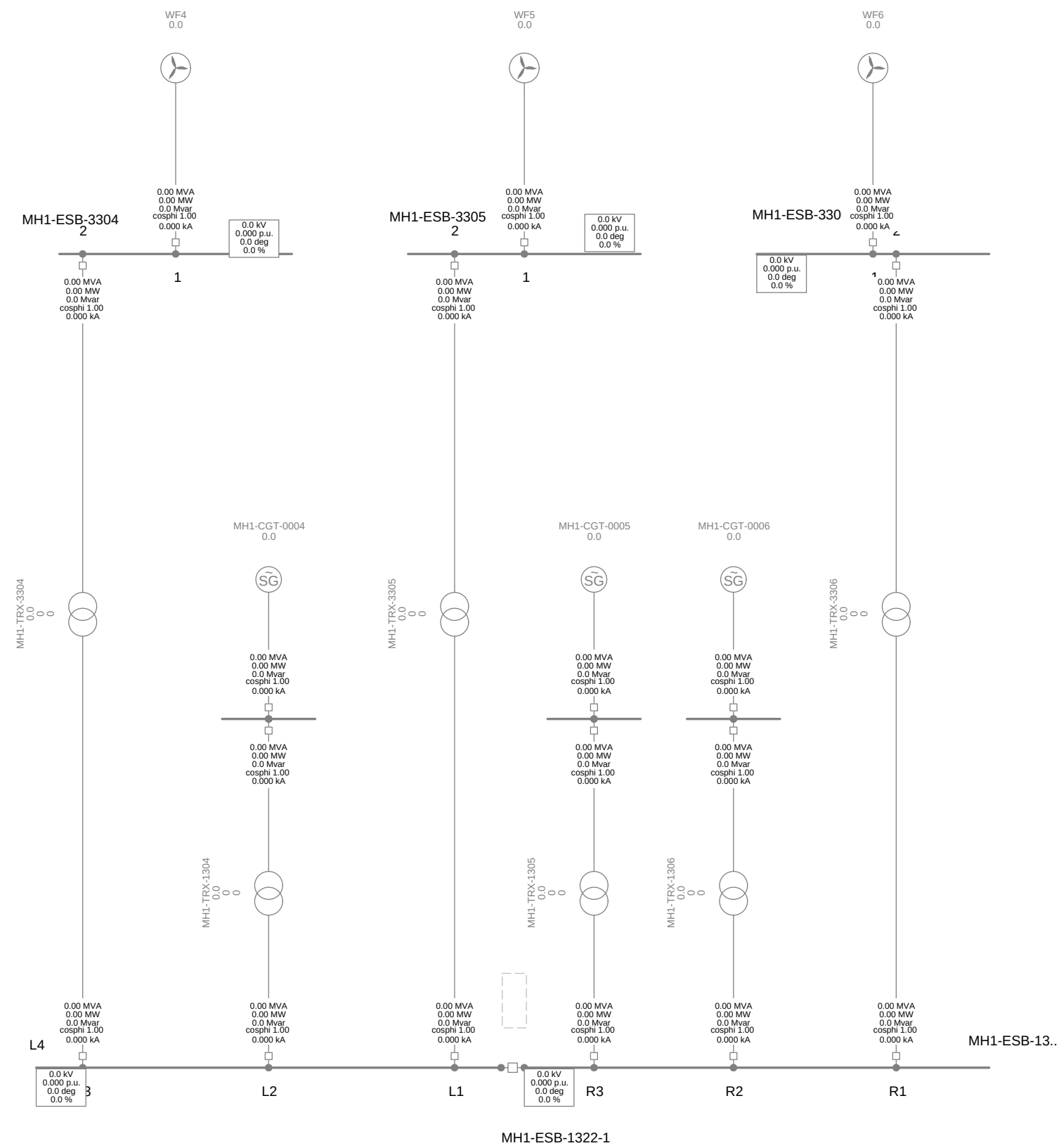
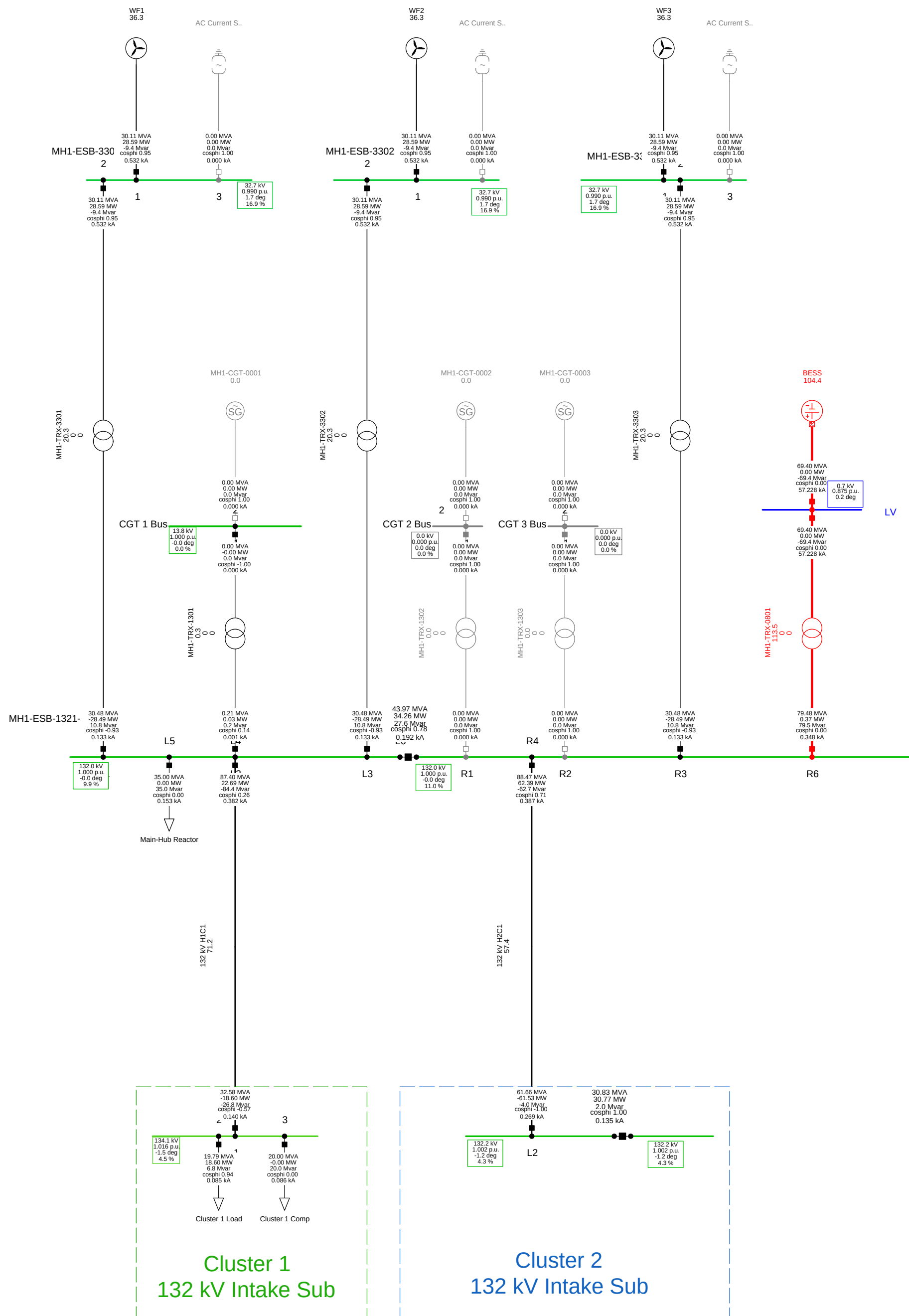


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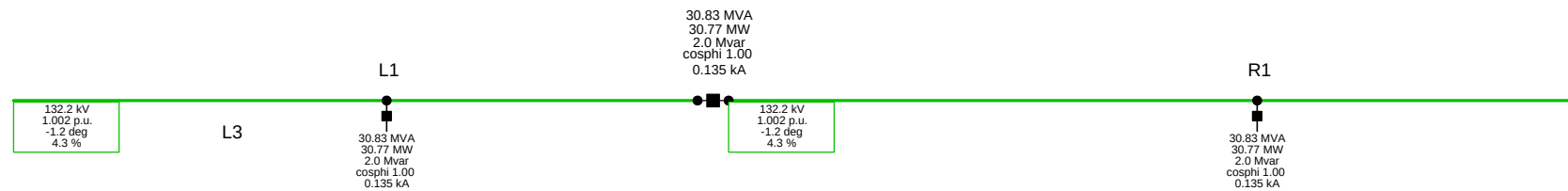


 Katoni Engineering PowerFactory 2022	Electrical Distribution Modelling HVAC LF3A- 30% Load (PF 0.95) + 100% WTG	Project:
		Graphic: Cluster 2 SLD
		Date: 30/03/2022
		Annex:

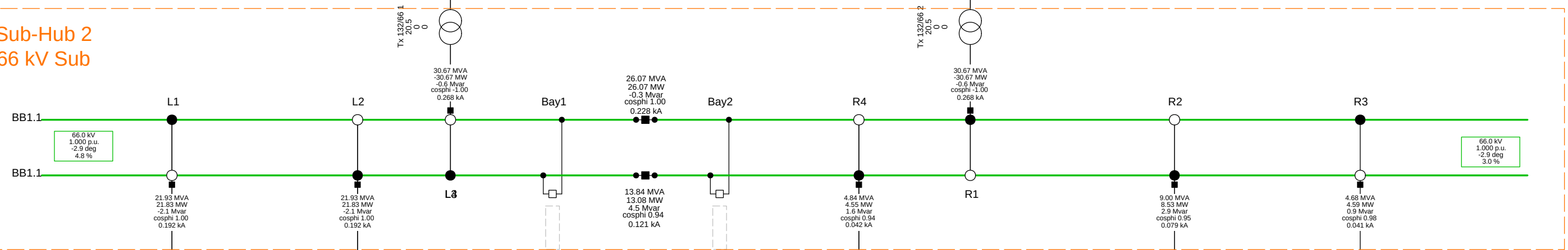
28.10 CNS Cluster Load Flow 3B Results



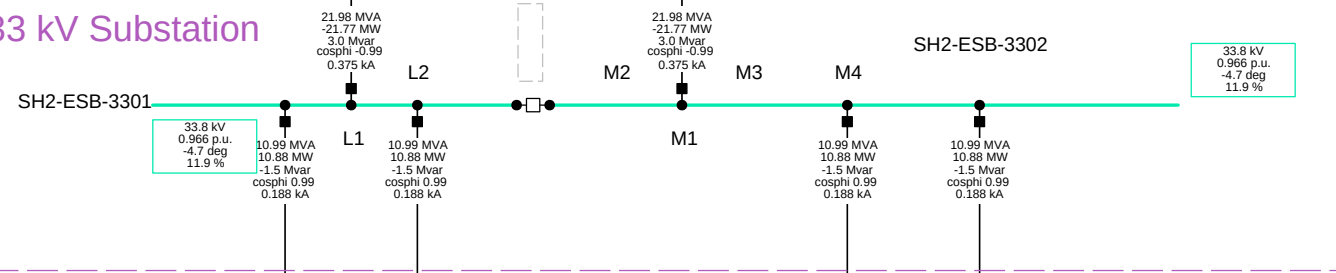
Sub-Hub 2 132 kV Intake



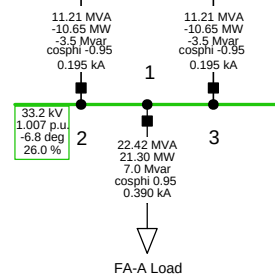
Sub-Hub 2 66 kV Sub



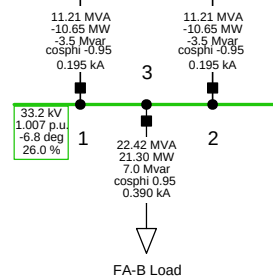
Sub-Hub 2 33 kV Substation



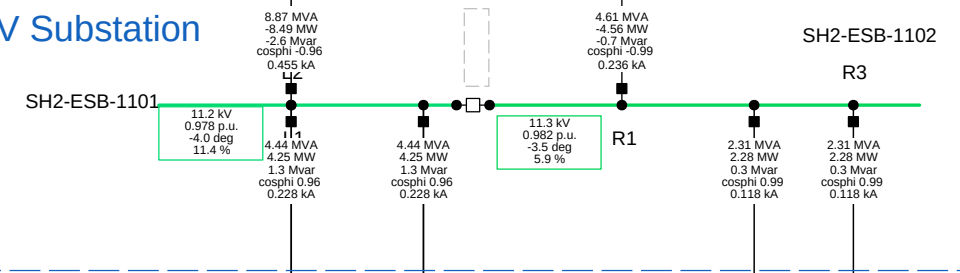
Forties Alpha - A



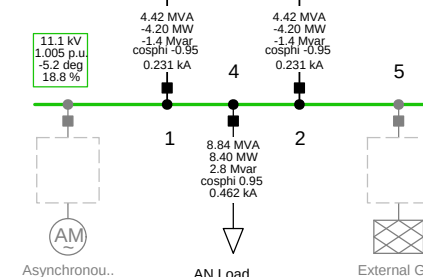
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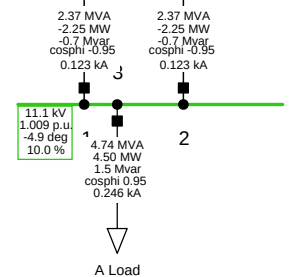
Sub-Hub 2 11 kV Substation



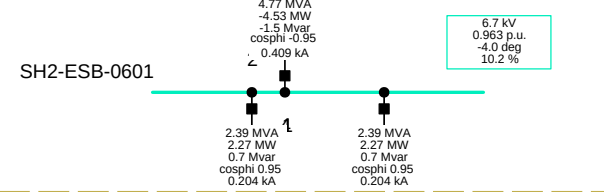
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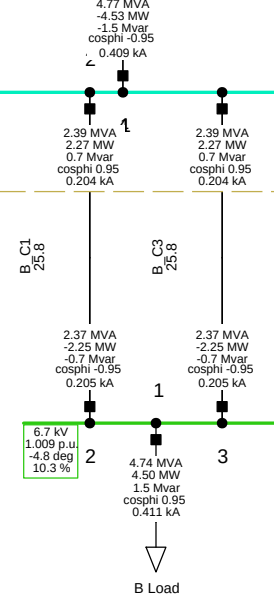
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Sub-Hub 2 6.6 kV Substation

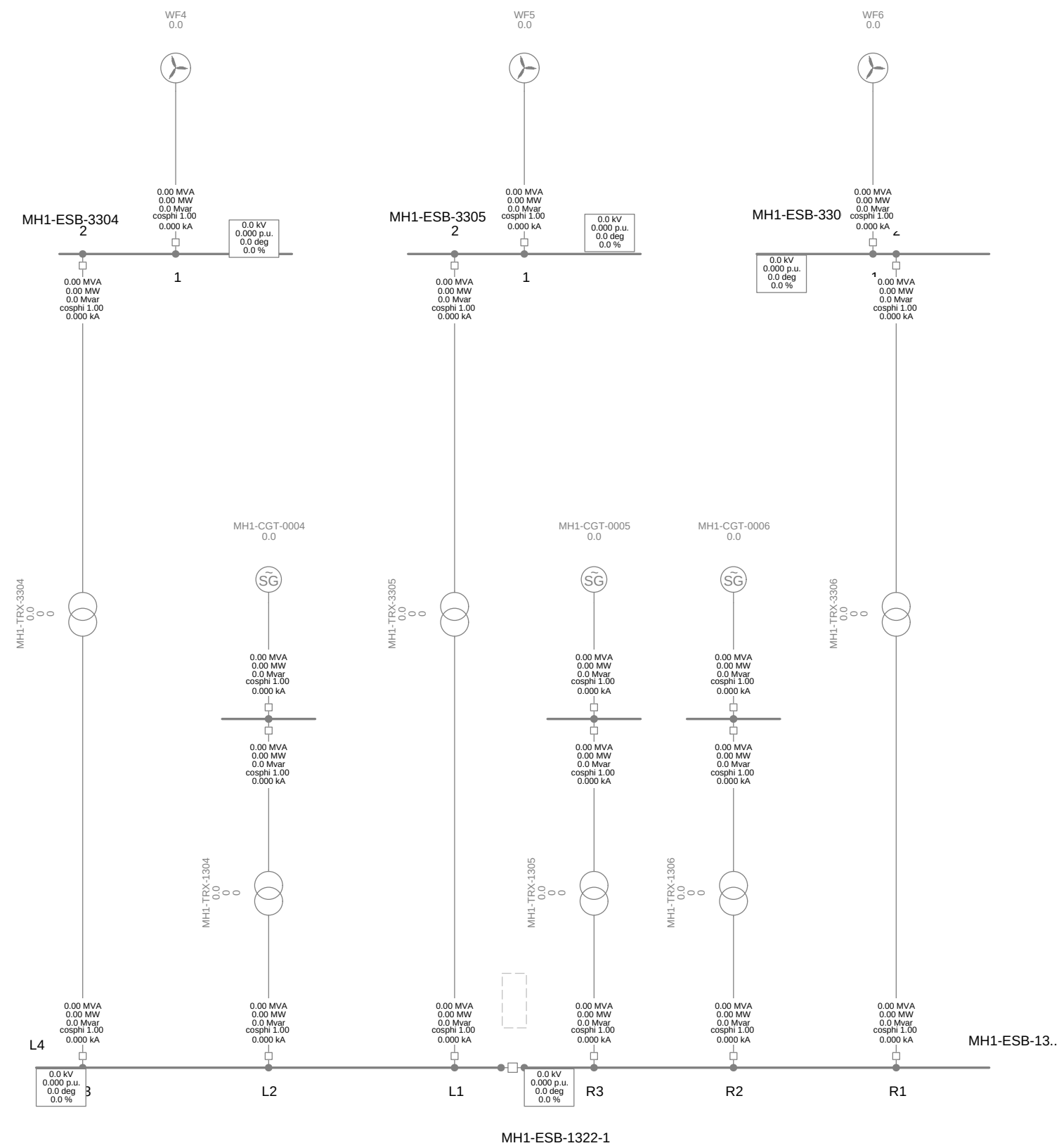
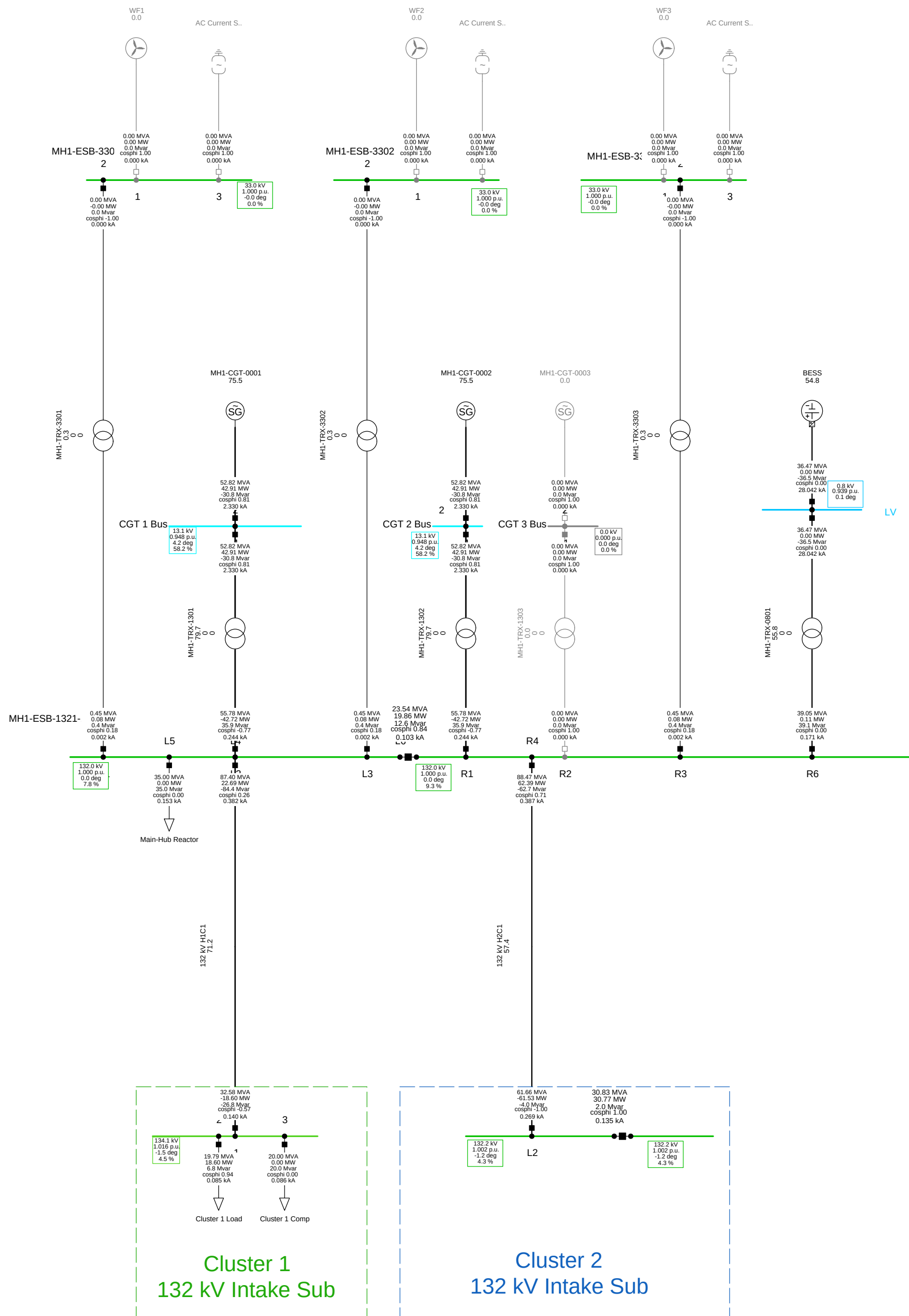


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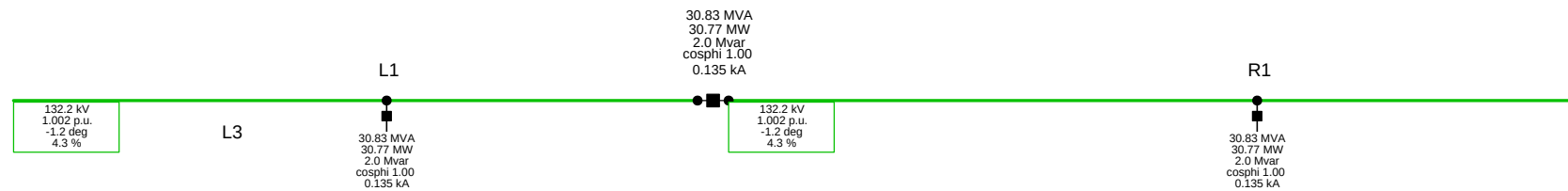


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	HVAC		Date: 30/03/2022
	LF3B- 30% Load (PF 0.95) + WT Curt		Annex:

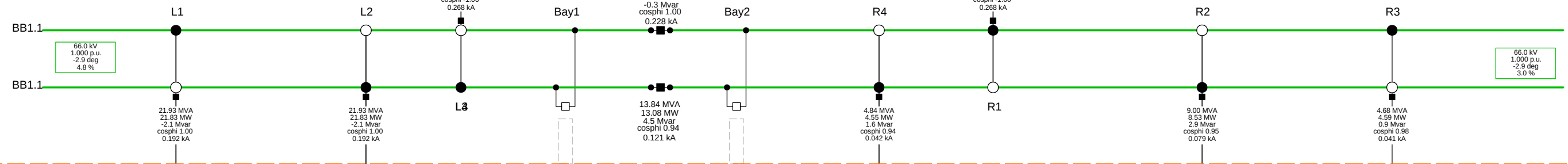
28.11 CNS Cluster Load Flow 3C Results



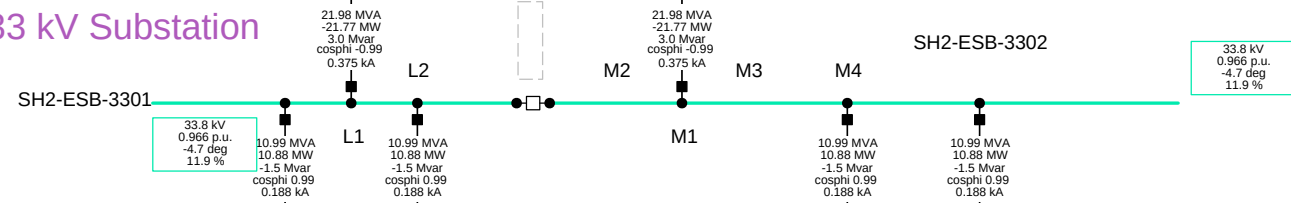
Sub-Hub 2 132 kV Intake



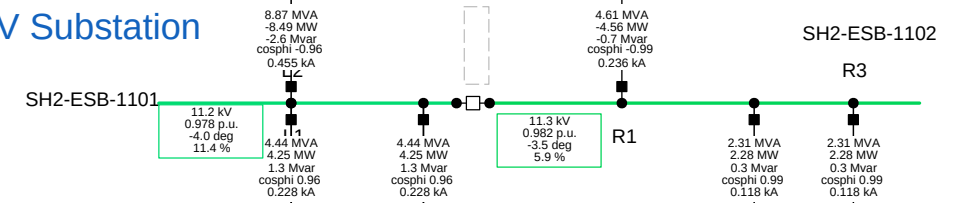
Sub-Hub 2 66 kV Sub



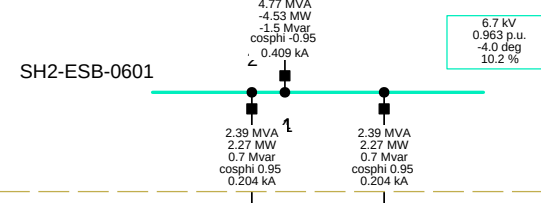
Sub-Hub 2 33 kV Substation



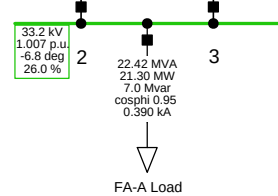
Sub-Hub 2 11 kV Substation



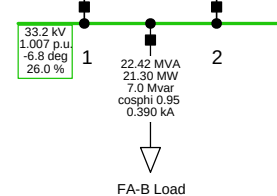
Sub-Hub 2 6.6 kV Substation



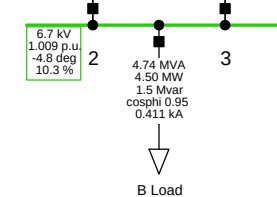
Forties Alpha - A



Forties Alpha - B

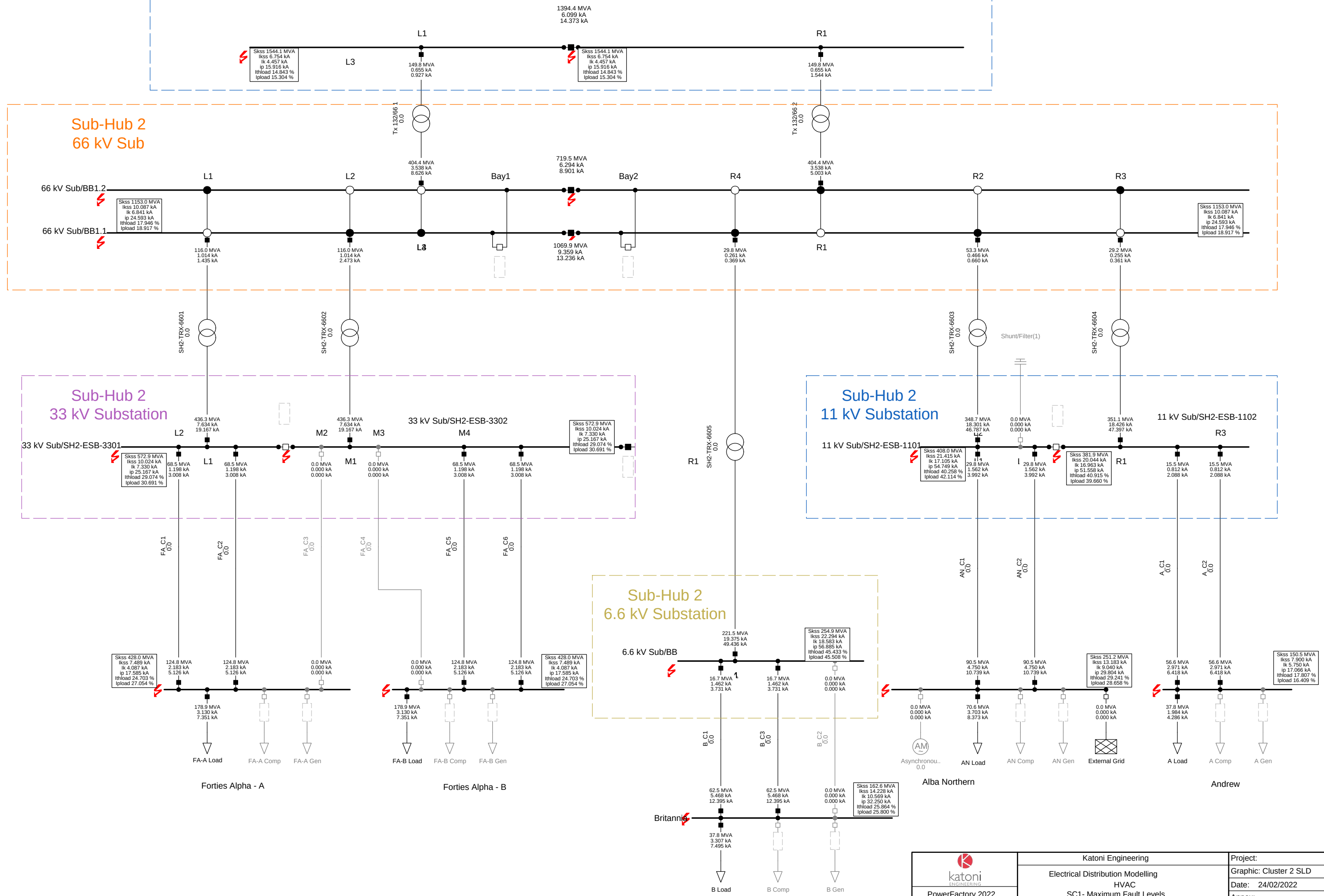


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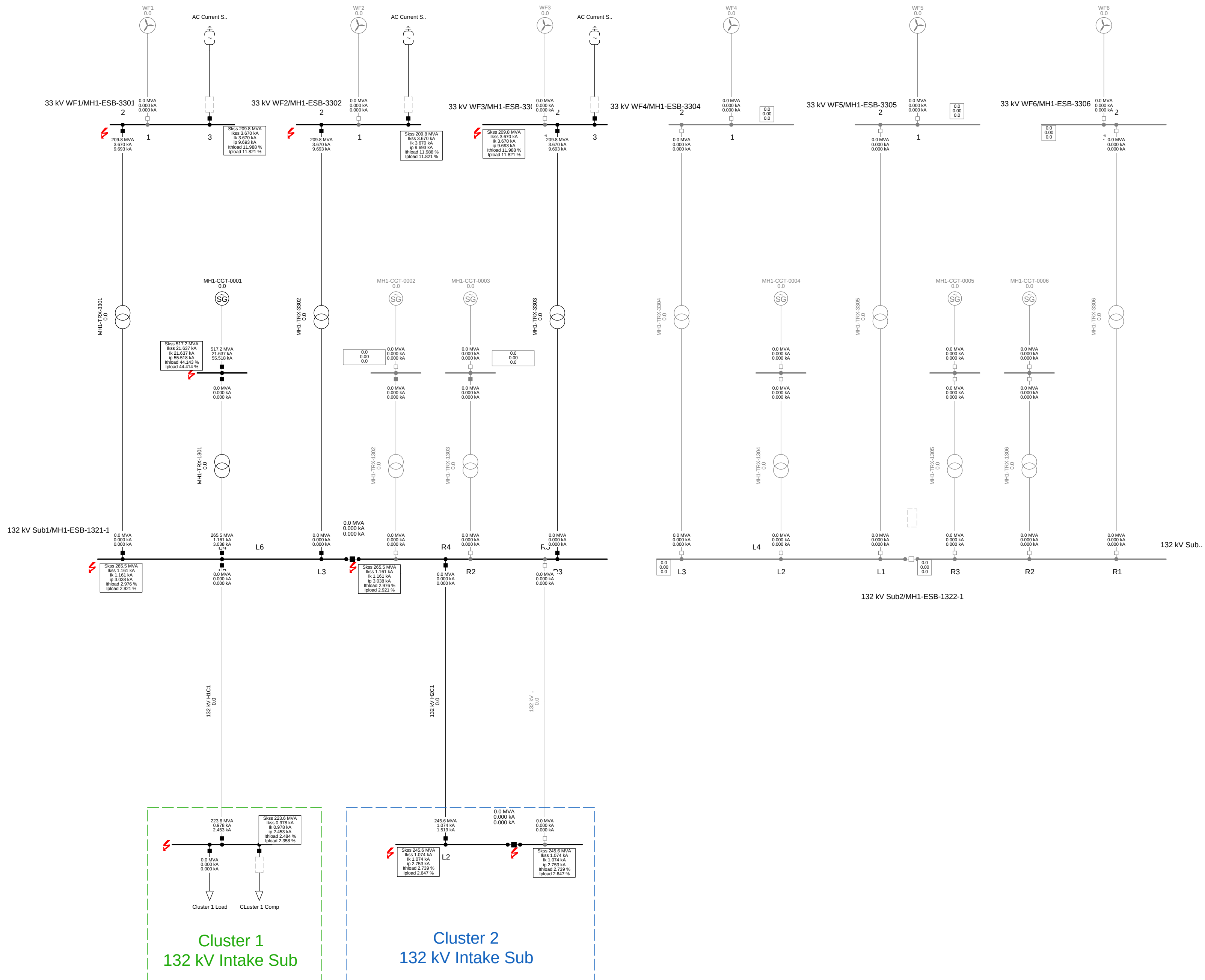


28.12 CNS Cluster Short Circuit (Maximum) Results

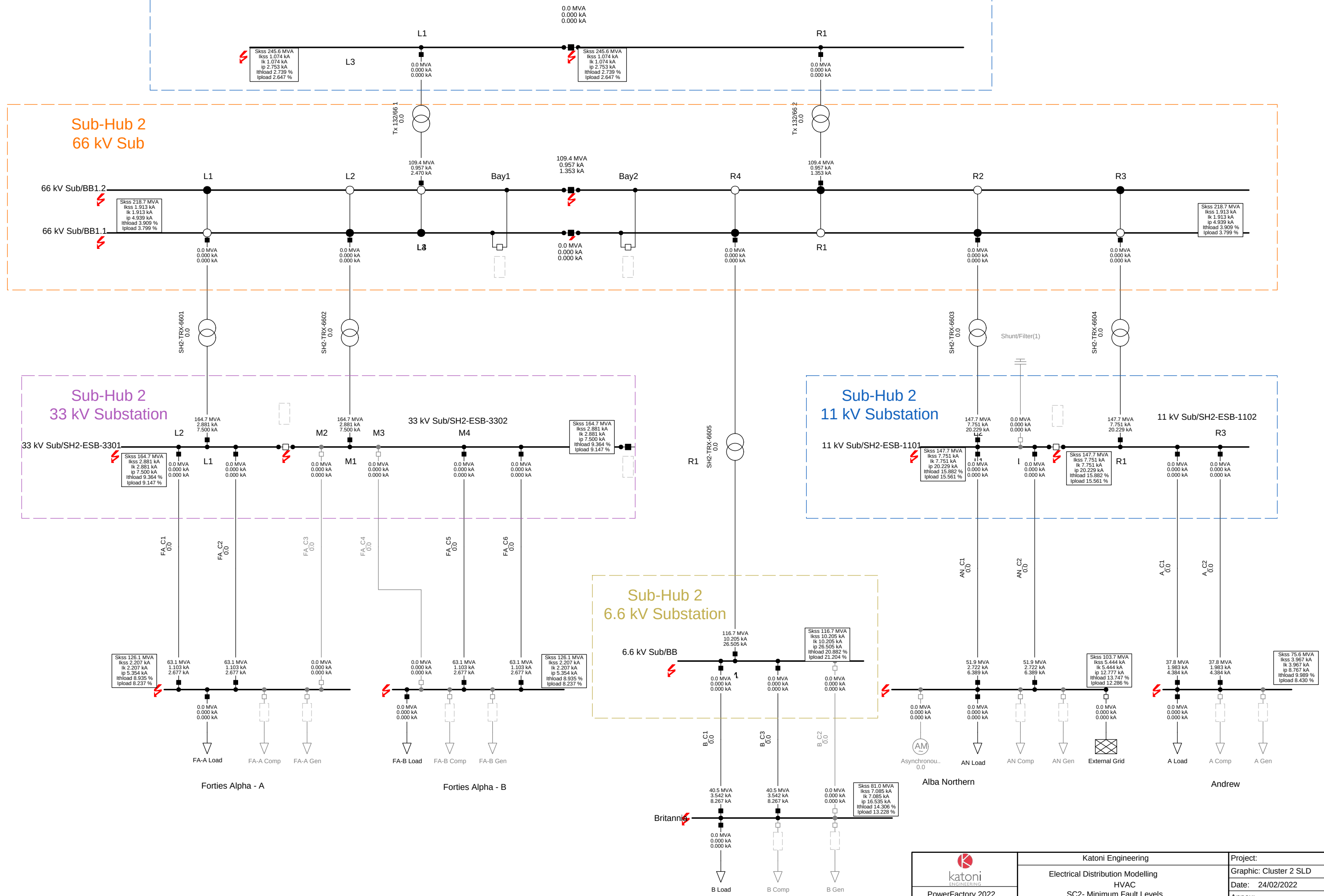
Sub-Hub 2 132 kV Intake



28.13 CNS Cluster Short Circuit (Minimum) Results



Sub-Hub 2 132 kV Intake



28.14RMU Datasheet

Characteristics - Electrical and Mechanical

Characteristics of Ringmaster		
Rated voltage (Ur)	kV	12
Rated frequency (fr)	Hz	50/60
Rated lightning impulse withstand voltage (Up)	kV	75 ⁽¹⁾
Rated power frequency withstand voltage (Ud)	kV	28 ⁽¹⁾
Rated current		
Ring switches (Ir)	A	630
Circuit breaker (Ir)	A	200/630
Ring switch rated short time withstand, 3 s (Ik)	kA	21
Ring switch earth short time withstand, 3 s (Ik)	kA	21
Ring switch peak making current (Ip)	kA	52.5
Ring switch earth peak making current (Ip)	kA	52.5
Circuit breaker short time withstand, 3 s (Ik)	kA	21
Circuit breaker earth short time withstand, 3 s (Ik)	kA	21
Circuit breaker peak making current (Ip)	kA	52.5
Circuit breaker earth peak making current (Ip)	kA	52.5
Internal arc withstand - gas enclosure (1 s)	kA	21 kA (AF) ⁽²⁾
Internal arc withstand - cable box (1 s)	kA	13.1 kA (AF) ⁽³⁾
Number of operating cycles		
Mechanical		
Ring switch (main)		5 000
Ring switch (earth)		1 000
Circuit breaker (main)		2 000
Circuit breaker (earth)		1 000
Electrical		
Circuit breaker (at rated short circuit breaking current)		10
SF6 gas		
Pressure	bar G	0.55
Weight (RN2d/RN6d)	g	592
Weight (RE2d)	g	703

(1) Ud=38 kV or Up=95 kV BIL as option, the offer is available, please contact us

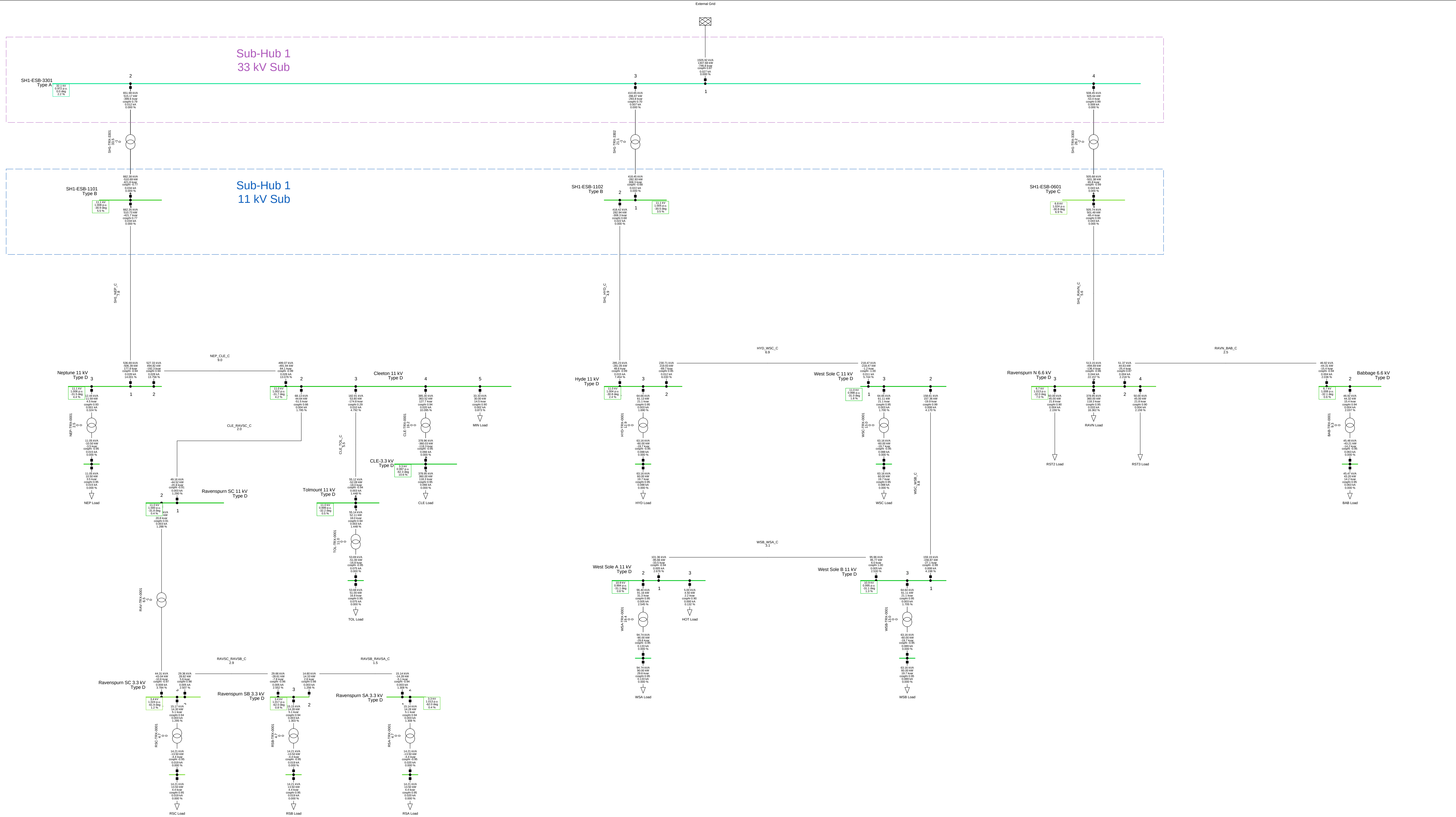
(2) 21 kA (AFLR) as option, the offer is available, please contact us

(3) 21 kA (AF) as option, the offer is available, please contact us

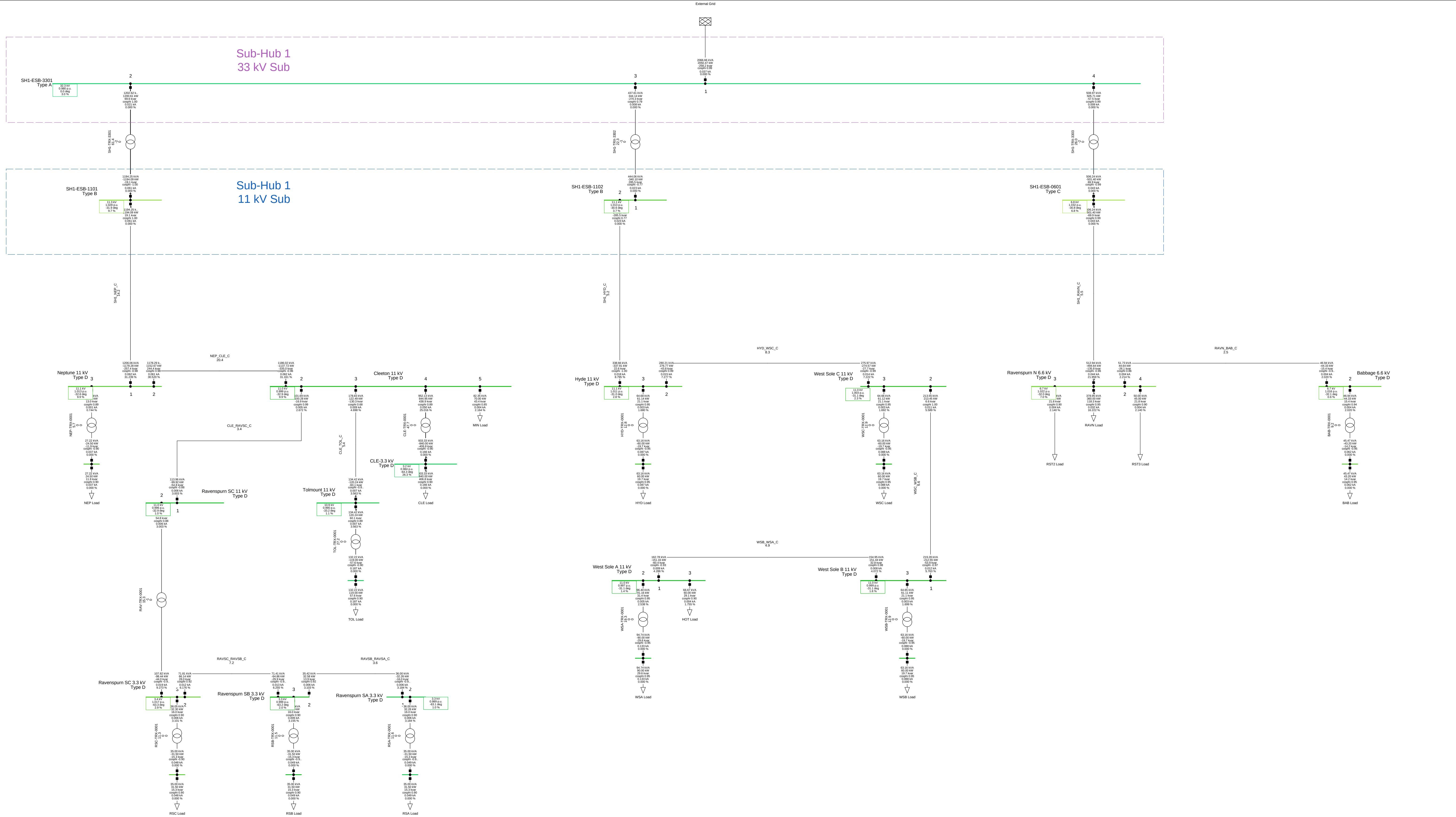
28.15 SNS Cluster Model Single Line Diagram

28.16 SNS Cluster Load Flow 1 Results

28.17 SNS Cluster Load Flow 2 Results



28.18 SNS Cluster Load Flow 3 Results



28.19 SNS Cluster Short Circuit (Maximum) Results

28.20 Sevan Report - Decarbonisation Study - Study Summary Report

KATONI – Decarbonisation Study

Study Summary Report

B2	01.04.2022	Updated	LAA	OSK	ASK
B1	25.03.2022	Issued for Information	TEAM	TEAM	TEAM
Rev.	Date	Reason for Issue	Org.	Chk.	App.
		Project Title			
		KATONI – Decarbonisation Study			
		Project No	Phase	Document No	
		657	10	657-SE-Z-00-RA-0001	
		Document Title			
		Study Summary Report			
Contract No:		Client Document Number		No of pages	
				46	
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Revision Record

New text added from the previous revision is marked in blue.

Rev.	Date	Description of Change
B1	25.03.2022	First version
B2	01.04.2022	Added cost info in chapter 10

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1 EXECUTIVE SUMMARY

The study has looked at using the 300-hull and the 1000-hull as sub hub and main hub respectively in a decarbonisation study for UK central and south North Sea. Information related to location, equipment onboard the units, deck layouts, weights and CoG have been provided by Katoni Engineering. Sevan has provided hull details and 3D models in which Katoni could arrange the equipment and establish the layout.

After concluding on the hull sizes, layouts and weights Sevan performed investigations on stability, global performance and mooring.

Environmental condition for the exact locations is not available for the study. However, weather data for Shelley field is assumed to be representative as its location is close to the central North Sea units.

Due to shallow water in the south North Sea, bottom fixed structures are recommended for the sub hubs.

Both the 300-hull and the 1000-hull are FPSO designs with the ability to carry large deck weights in combination with a large internal storage volume for crude oil. When used as main hubs and sub hubs there is no crude oil storage. Therefore, both hulls buoyancy is very large compared to the loaded weight from the equipment and need to operate with full ballast tanks in order to reach operational draft.

With regards to stability this results in a very large margin between the usage and capacity as can be seen in chapter 7.

Due to the shallow water depth at the locations, the mooring lines become quite long. The ULS 100-year conditions are dimensioning. Offsets and motions found on main hub and sub hub are as expected for this size units in these conditions and are well within requirements for using flexible cables and risers.

Main Equipment Lists listing all hull and mooring equipment are provided. Utility requirements for the power import/export and power transformers are not quantified, however assumptions are that parts of this need cooling.

The sub hubs are without LQ which reduces the onboard marine system. The main hubs have a fully equipped LQ which

The deck space, stability and motion performance show that the Sevan hulls are well suited for use as sub hubs and main hubs. Taking the study to next step hull optimisations to adapt buoyancy with the deck load as well as moving parts of the deck modules to inside the currently unused space inside the hull are options that can be further investigated.

2 INTRODUCTION

Katoni Engineering (hereafter KE) is performing a study of decarbonising the British oil sector by electrification of offshore installations.

The principle comprises main floating hubs which imports green power from wave and/or wind turbines, in addition to having their own power generation from large gas turbines. Target is to have a total of 1 GW onboard power that through transformers and switchboards are distributed to sub-hubs located close to groups of offshore oil installation suitable for electrification. Refer to Figure 2-1.

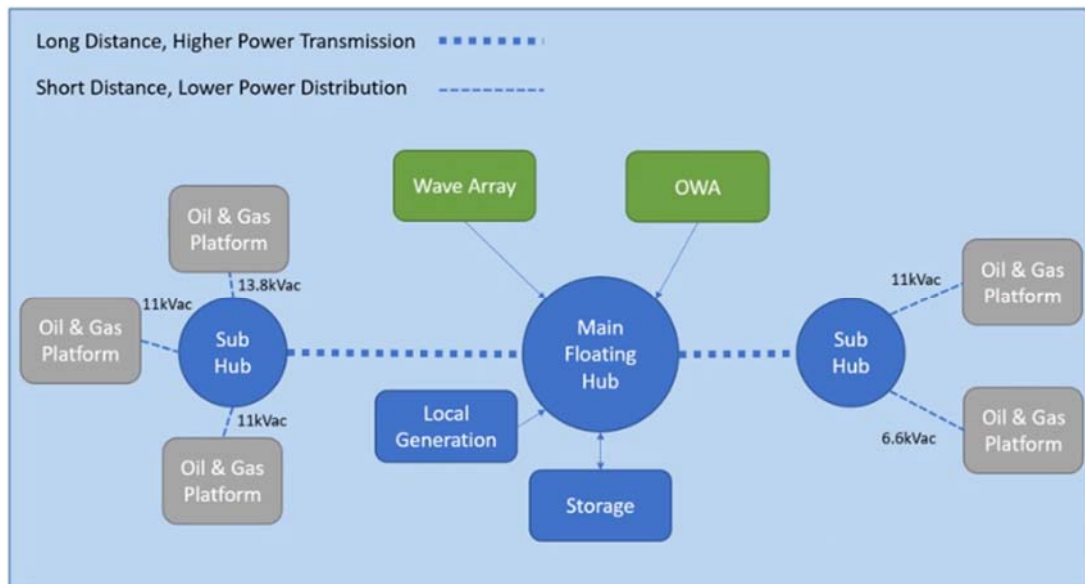


Figure 2-1 Principle of electrification

The concept is based on the use of Sevan hulls for both main hubs and sub hubs where water depth is too large for bottom fixed structures. Therefore, as part of the overall development plan KE has asked Sevan SSP (hereafter Sevan) to support with knowledge regarding

- hull sizing of suitable units for both the main hub and the sub hubs
- cable integration
- equipment layout
- total costing of the concept

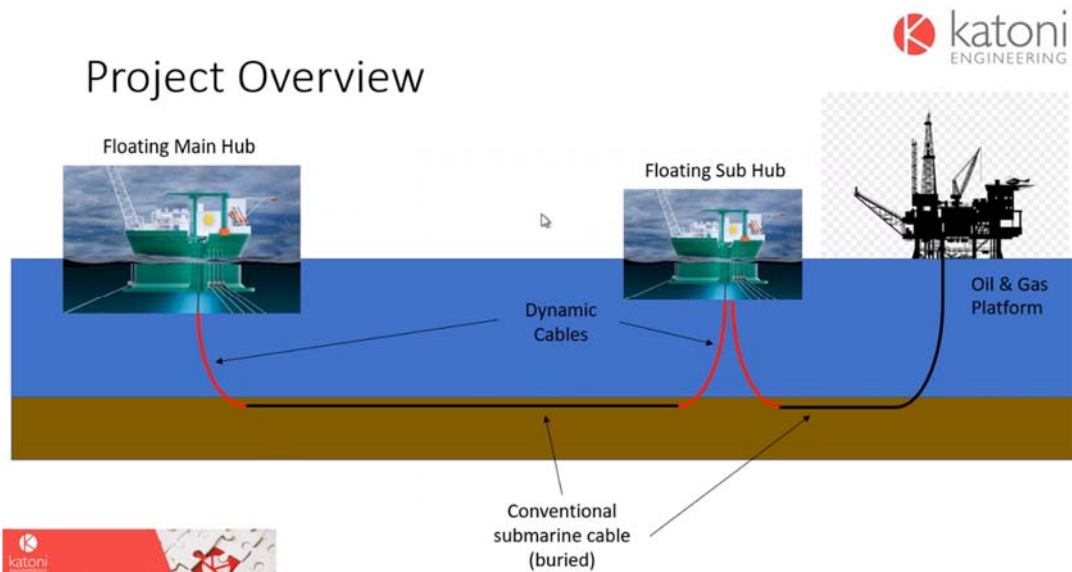


Figure 2-2 Power distribution

Deliverables from Sevan are

- Study Summary Report
 - o this document
- 3D models of Marine Equipped Hulls
 - o 3D models of 3 hulls provided
- 2D General Arrangement / Tank Plan of Marine Equipped Hulls
 - o GA's of Goliat and 300-unit provided
- Main Equipment Lists

Input from KE to Sevan are:

- Topsides equipment/modules including weight and VCG
- Deck layout for power modules

A Sevan project team is established to cover activities within the following disciplines:

- Project Management
- Global Performance and Mooring System
- Hull Sizing, Weight and Stability
- Marine and Utility Systems
- Layout and Arrangements
- Cost Estimate

3 GENERAL INFORMATION

3.1 Abbreviations

Table 3.1: Abbreviations

Abbreviation	Description
DNV	Det Norske Veritas
FPSO	Floating Production Storage and Offloading
GA	General Arrangement
HVAC	Heating, Ventilation and Air Conditioning
IMO	International Maritime Organisation
IMR	Inspection, Maintenance and REpair
ILT	In Line Tensioner
KE	Katoni Engineering
LQ	Living Quarter
MODU	Mobile Offshore Drilling Unit
NTE	Not To Exceed
POB	Persons On Board
PD	Process Deck
SB	Service Block
SWACH	Small Waterplane Area Circular Hull
UK	United Kingdom
UK HSE	Health and Safety Executive
VCG	Vertical Center of Gravity
WL	Water Line

3.2 References

- /1/ HSE RR387 Stability Research Report 387, UK HSE387
- /2/ IMO I810E-2010 Code for the Construction and Equipment of Mobile Offshore Drilling Unit

4 RULES, STANDARDS AND REGULATIONS

Sevan SSP FPSO hulls are based on Rules and Requirements from DNV class.

Further, national technical requirements may also be applicable and shall be considered in case of a commercial project. In general, the design will be governed by following order of precedence:

- National/regional authorities' rules which may be site dependent.
- Classification society.
- Operator site specification.
- Marine operation warranty surveyor rules.
- Industry standards.

Using Sevan SSP hull designs for other purposes which do not involve storage of hydrocarbons may waive some of the requirements normally applying for FPSO's.

5 BASIS OF DESIGN

Two different hulls are required, one for main hub and one for the sub hub. The concept assumes use of 2 x Main Hubs and 8 x Sub Hubs. Environmental conditions for the various units may vary depending on location.

5.1 Main Hub

Each main hub will carry modules and equipment required to generate high voltage power from the main hub and transform this to suitable voltage and required power to offshore installations within a practical distance from the sub hub.

For the main hubs the following key characteristics apply:

- Manned unit
- Full accommodation with all facilities
- Primary and Secondary rescue systems
- Fuel gas import (via flexible riser)
- Flare tower
- Bunker stations for water, diesel, etc
- Safe side and hazardous side divided by a fire wall
- Cranes for material handling (up to 150T)
- Gas turbines for power generation
- Facilities for power import and export (cables)
- Transformer systems for generating high voltage
- Deck load (systems related to power generation, transformers and export) approximately 30000 T

The area required to arrange the modules and equipment corresponds with a Sevan 1000-unit. The 1000-hull has been used for the Goliat FPSO operating in the harsh environment at the Goliat field in the Barents Sea since 2016.

Table 5.1: Key data for the 1000-unit

Item	Value	Units
Diameter main hull (at wl)	93	m
Diameter main deck	104	m
Diameter process deck	110.5	m
Diameter bilge box	109	m
Height of bilge box	3.25	m
Elevation Main Deck	42	m
Elevation Process Deck	48.5	m
Ballast Draft	22	m
Loaded Draft	22	m
Scantling Draft	25	m
Lightship draft		m
Maximum Displacement	162.000	t
POB	100	persons

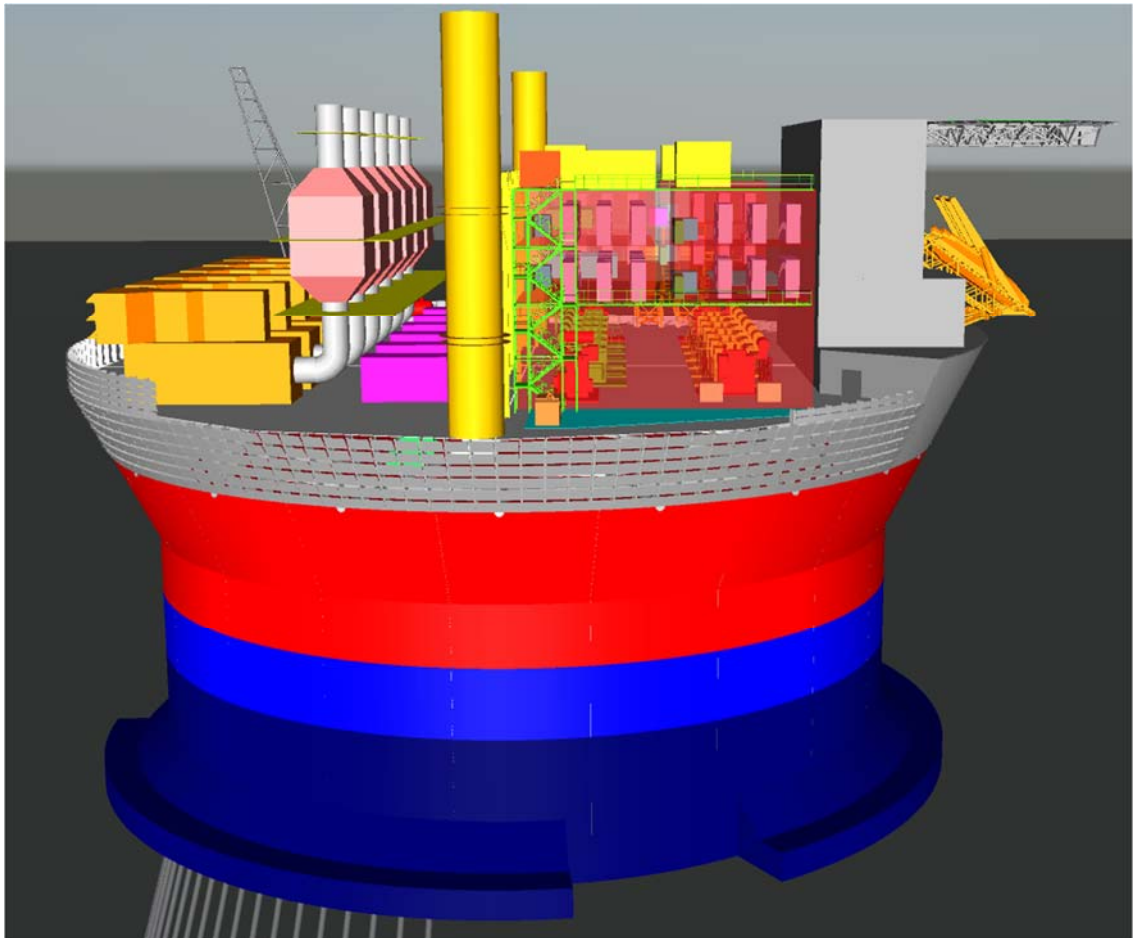


Figure 5-1 Main hub

5.2 Sub Hub

Each sub hub will carry modules and equipment required to receive high voltage power from the main hub and transform this to suitable voltage and required power to offshore installations within a practical distance from the sub hub.

For the sub hubs the following key characteristics apply:

- Unmanned unit
- Emergency overnight accommodation
- Helicopter access
- Crane for material handling,
- Rescue system for maximum POB + helicopter crew
- High voltage electrical equipment for power import and export (cables)
- Diesel Generator for local power
- Deck load (power receiving, transformers and power transfer, supporting structure) approximately 2200T

The area required to arrange the modules and equipment corresponds with a Sevan 300-unit. The 300-design has been installed at 3 locations in the central North Sea operating as FPSO's and have proven they are suitable for the harsh environmental conditions occurring in this area.

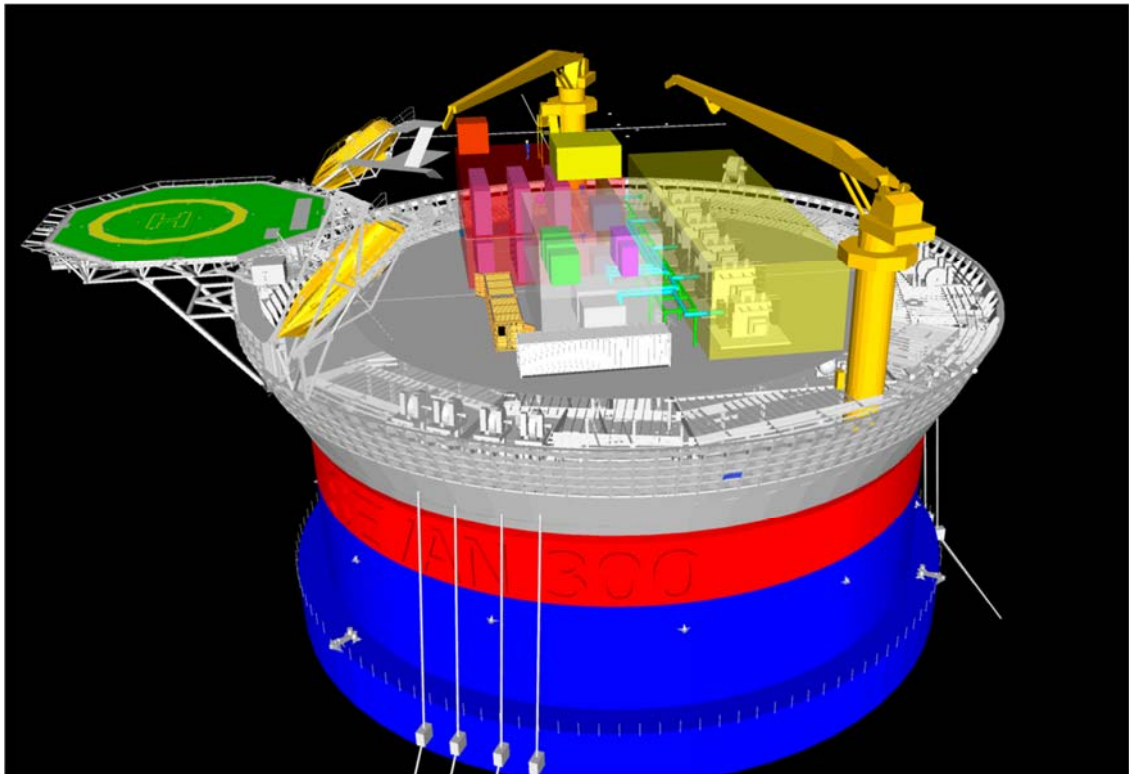


Figure 5-2 Sub hub

Table 5.2 Key data for the 300-unit

Item	Value	Units
Diameter main hull (at wl)	60	m
Diameter main deck	66	m
Diameter process deck	72.5	m
Diameter bilge box	75	m
Height of bilge box	2	m
Elevation Main Deck	27	m
Elevation Process Deck	33.5	m
Ballast Draft	13.75	m
Loaded Draft	13.75	m
Scantling Draft	15	m
Lightship draft		m
Maximum Displacement	42000	t
POB	0	persons

5.3 Location of the units

Two systems each comprising one main hub and four sub hubs are considered. One system is considered for the central North Sea with location as given in the table 5.3 below.

Table 5.3 Central North Sea system location

Unit	Location	Water Depth (m)
Main Hub	57.592, 0.9001	104-106
Sub hub 1	58.4007, 0.0937	130-136
Sub hub 2	58.047, 1.1588	133-137
Sub hub 3	57.341, 1.5838	90-92
Sub hub 4	56.942, 1.9093	87-90

On the map below the units' locations are shown. The large marker represents the main hub.

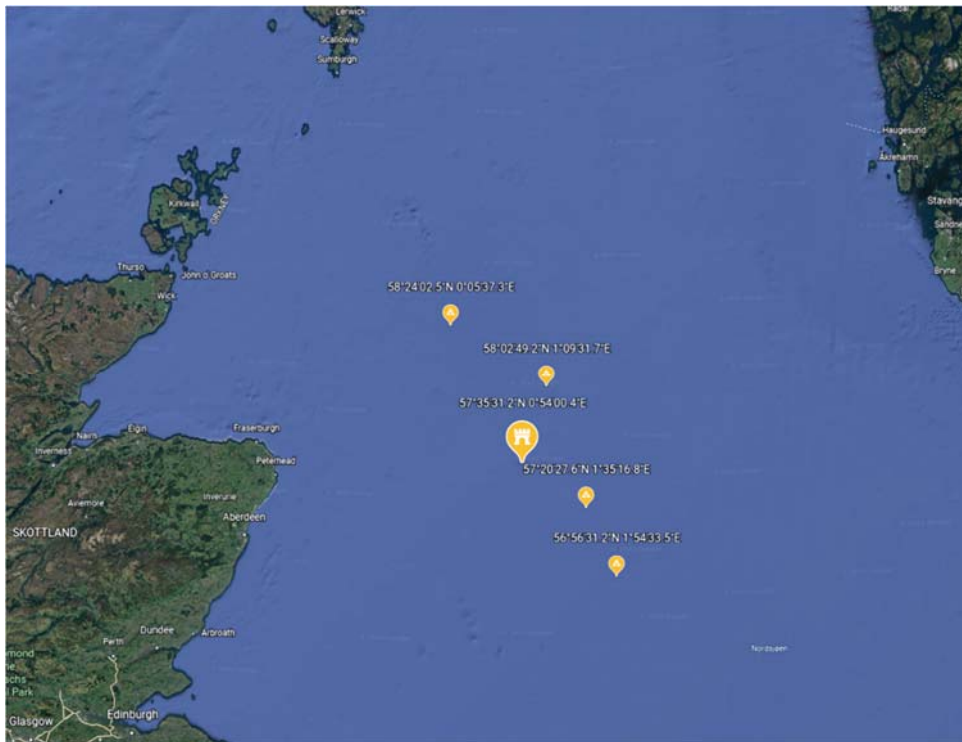


Figure 5-3 Central North Sea system

A similar system is considered for southern North Sea with the following locations:

Table 5.4 South North Sea system location

Unit	Location	Water Depth (m)
Main Hub	54.097, 2.183	65-70
Sub hub 1	53.906, 0.924	40-45
Sub hub 2	53.516, 1.715	20-30
Sub hub 3	53.141, 2.143	25-30
Sub hub 4	54.524, 2.263	15-18

On the map below the units' locations are shown. The large marker represents the main hub.

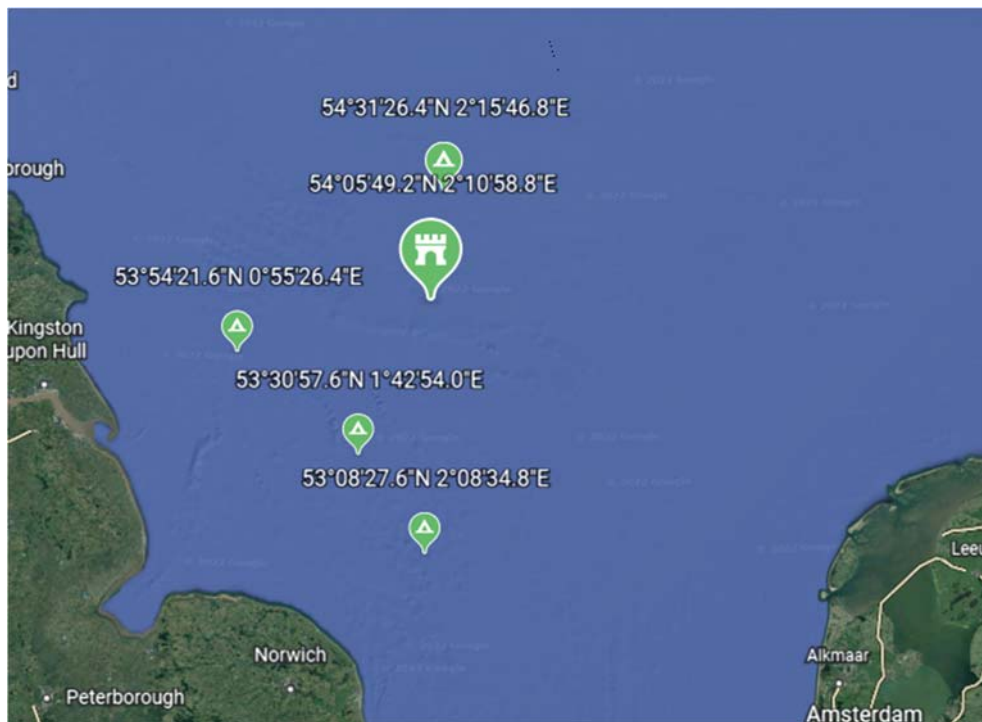


Figure 5-4 South North Sea system

Water depth for the southern North Sea sub hubs is too shallow for Sevan units. For these four units it is recommended to use bottom fixed structures.

The water depth at the main hub location is on the limit as it leaves little room for arranging the gas fuel riser and power cables. However, Sevan has in earlier cases looked at steps which allows operation at these water depths.

5.4 Environmental conditions

Exact environmental conditions for these locations are not made available to Sevan. From past projects Sevan has environmental conditions from Shelley, Chestnut and Huntington which are all within 45km from the Central North Sea main hub – refer to map below.

There are only marginal variations in the conditions between these three fields. Summary can be seen in Appendix A.

Water depth variations are 95m (Shelley), 122m (Chestnut) and 90m (Huntington).

For Motion and Mooring analysis metocean data and water depth for Shelley field are used.

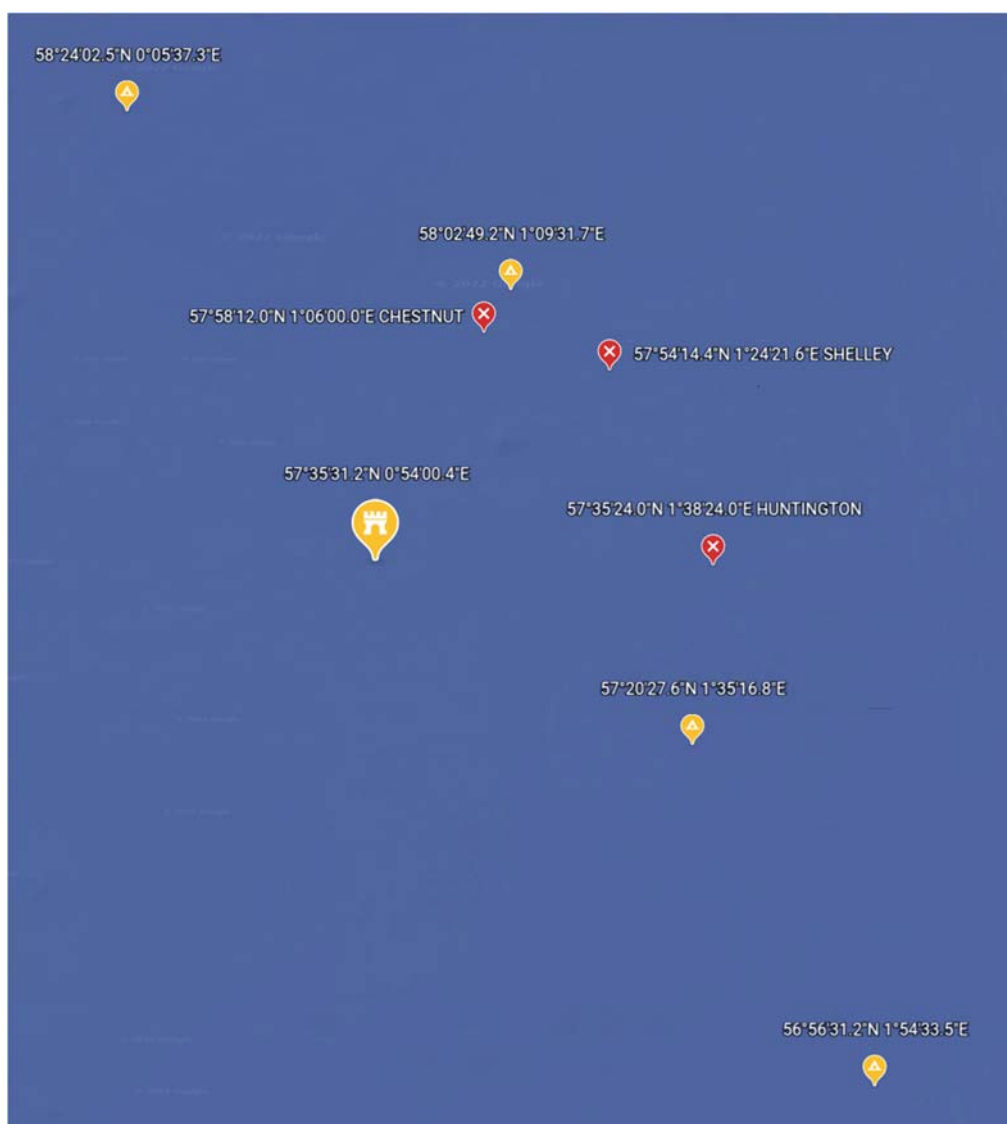


Figure 5-5 Locations with known weather data

6 GLOBAL PERFORMANCE AND MOORING SYSTEM

6.1 Mooring System

The mooring system is based on a passive mooring system with no use of thrusters. For Sevan units it normally consists of from 6 and up to 16 mooring lines (divided in 3 clusters), where one cluster is directed towards the direction of the most severe wave conditions. Depending on environmental conditions and unit size this cluster may have 1-2 lines more than the other clusters.

Base case for Sevan units is a chain-polyester-chain mooring system combined with suction anchors. Mooring system is tightened during installation of the unit and retightening of the system during field life are expected due to polyester creep.

The mooring system has tensioning devices. These are either on the unit (fairlead and winches) or in line tensioning (ILT) devices used in combination with fixed termination of the mooring lines on the unit.

For the main hub a winch and fairlead systems are assumed. For the smaller sub hubs using ILT can be considered as replacement for the larger and heavier winch/fairlead system.

For this analysis, both mooring systems are configured with equal mooring line setups in all three clusters. In both cases, cluster headings are towards 30, 150 and 270 degrees.

Table 6.1 Main hub mooring system

Item	Value	Units
No of mooring lines	15	item
Bottom chain length	160	m
Bottom chain diameter	170	mm
Polyester line length	1025	m
Polyester line diameter	290	mm
Top chain length	50	m
Top chain diameter	170	mm

Table 6.2 Sub hub mooring system

Item	Value	Units
No of mooring lines	12	item
Bottom chain length	150	m
Bottom chain diameter	140	mm
Polyester line length	900	m
Polyester line diameter	240	mm
Top chain length	50	m
Top chain diameter	140	mm

Size of suction anchors depends on seabed conditions. Available geotechnical data for the Shelly, Chestnut and Huntington show suitable soil conditions for use of suction anchors.

6.2 Global Performance

Environmental conditions used are given in 5.4.

Analysis of the mooring system has consisted of generating models using DNVs WADAM. Input to these models is the hull geometry and hydrodynamic coefficients based on scaling values from comparable hulls using data from model tests. The mooring system is designed using DNVs MIMOSA (frequency domain) with a ULS 100-year directional condition and a governing safety factor of 2.0 for the mooring line tension.

Main hub:

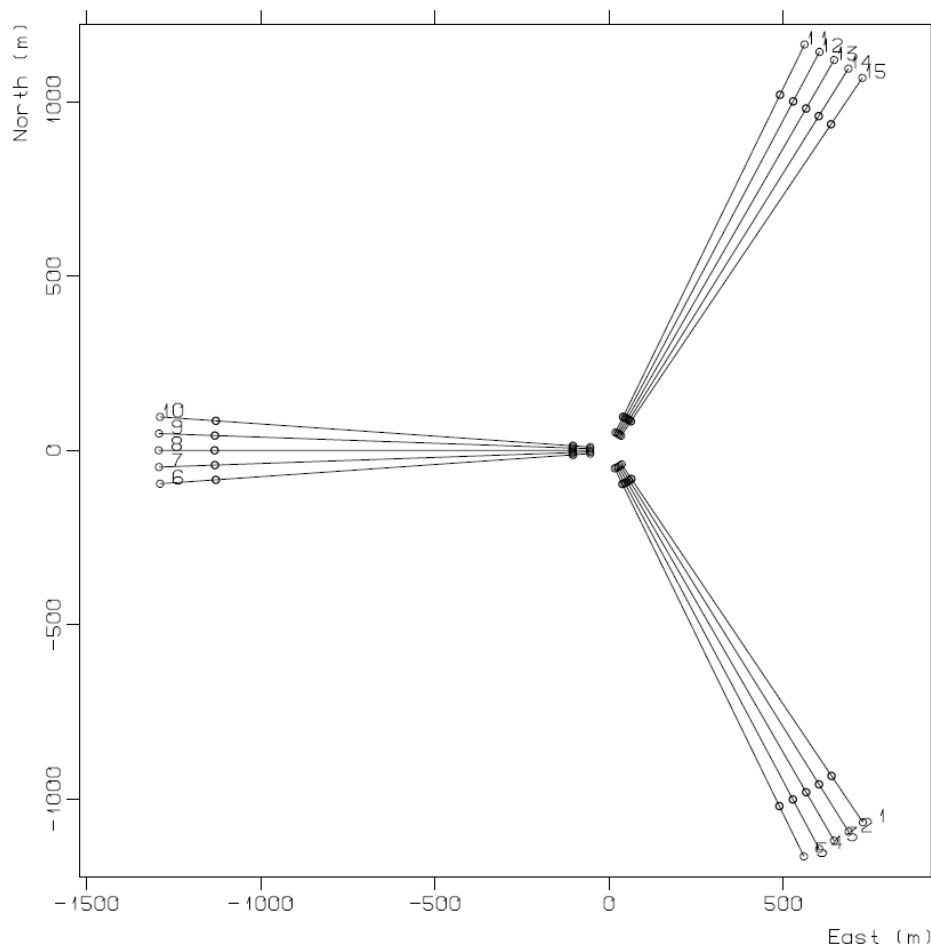


Figure 6-1 Mooring line layout – Main hub

Table 6.3 Main hub - Mooring analysis results

Wave heading (deg)	Max Loaded Line	Mooring Tension Results		Mooring Offset results
		Max Tension (kN)	Safety factor	Max offset (m)
0	11	12165	2.00	27.3
45	15	7956	3.06	13.5
90	1	8315	2.93	27.5

135	1	11102	2.19	21.0
180	5	8790	2.77	18.0
225	6	8508	2.86	21.6
270	9	10305	2.36	18.6
315	10	11698	2.15	32.5

Sub hub:

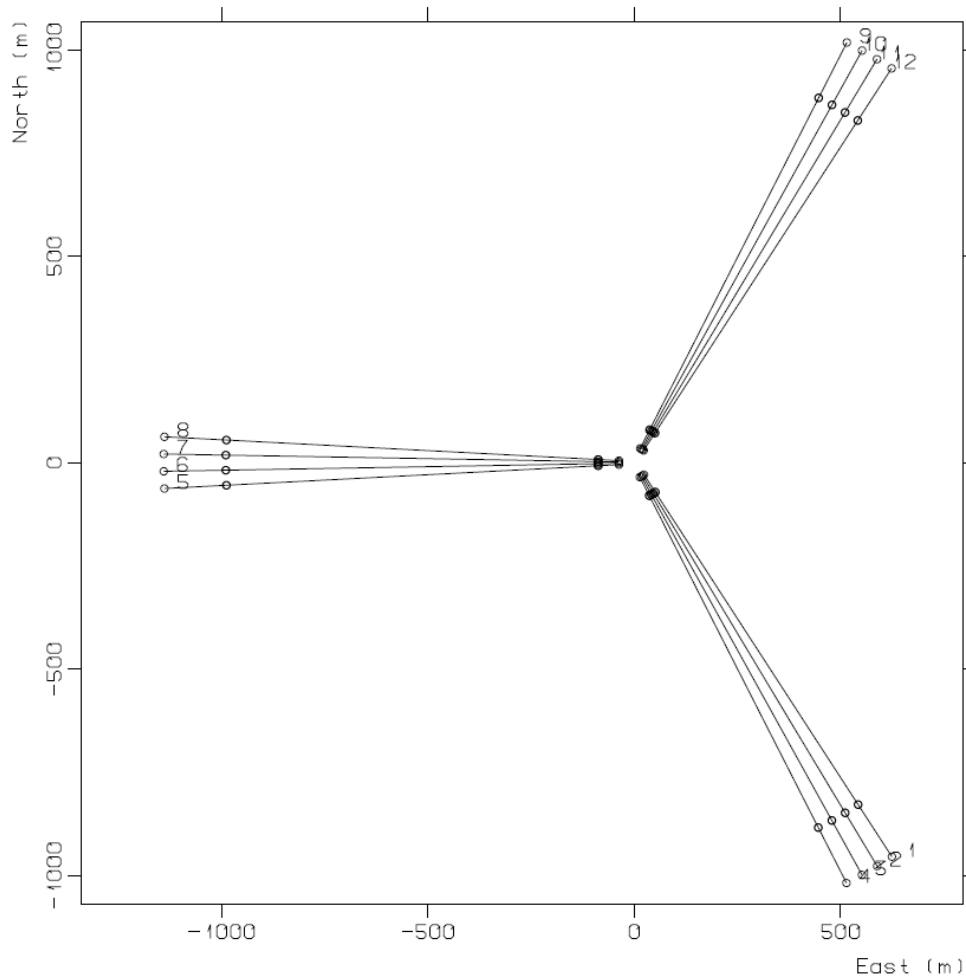


Figure 6-2 Mooring line layout – Sub hub

Table 6-4 Sub hub - Mooring analysis results

Wave heading (deg)	Max Loaded Line	Mooring Tension Results		Mooring Offset results
		Max Tension (kN)	Safety factor	Max offset (m)
0	9	7566	2.32	19.2
45	12	6719	2.61	14.8
90	1	4963	3.54	17.8
135	1	6725	2.35	16.9

180	4	7125	2.46	19.0
225	5	6199	2.83	19.0
270	7	8443	2.08	19.9
315	8	6455	2.72	18.9

Motion performance assessment is done by taking the most ominous weather condition and applying it in an in-line condition orthogonal to the coordinate system to have all rotations as roll.

Table 6-5: Motion performance - Main and sub hub

Unit	Max heave (m)	Max roll (deg)
Main hub	8.42	12.19
Sub hub	11.76	17.98

7 HULL SIZING, WEIGHT AND STABILITY

7.1 Hull Sizing

Based on weight input of topside equipment from Katoni a quick hull sizing activity has been performed. The hull size is given, based on a Sevan 1000-unit size, but the exercise is carried out to establish basic input for both stability calculations and motions and mooring evaluations.

Table 7-1 NTE weight and VCG

Area	Weight [t]	VCG [m]
Process area	28,300	55.50
Utility area	2,000	55.50
Main Deck area	4,000	44.00
Topside total	34,500	53.84
Hull	36,382	18.23
Platform Total	70,882	35.56
Weight reserves	4,118	48.50
NTE Weight	75,000	36.77

Explanation to the values used:

- Process weight; based in input from Katoni
- Utility Area: Estimate by Sevan. Cover weight of LQ & service block below LQ
- Main Deck area. Cover the weight of process deck, bulwark, support structure for process deck and any system & equipment arranged on Main Deck
- Hull weight and VCG; estimated numbers based on hull geometry
- Weight reserve; a rough estimate with VCG 6.5m above Main Deck.

The total lightship weight is estimated to 75000t, with a Not to Exceed VCG of 36.77m above baseline. These numbers are used as basic input for the stability calculations carried out further down in this report.

Radii of gyration is estimated as input to the motion and mooring analysis. The values estimated is shown in table below:

Table 7-2 Radii of gyration 1000 unit

AREA	Rx [m]	Ry[m]	Rz[m]	Mass [kg]
Hull	30.419	30.133	39.931	2.43E+07
	31.433	31.138	38.116	3.64E+07
Steiners theorem	3.767	3.767		3.64E+07
hull about waterplane of 22m	31.658	31.365	38.116	3.64E+07
loadcase (from Napa)				
ballast and other fluid about COG for loadcase	33.821	33.751	40.223	8.68E+07
Steiners theorem	3.429	3.429		8.68E+07
deadweight above waterplane of 22m	33.994	33.925	40.223	8.68E+07
Process area				
(from autocad abote WL of 22m	43.000	43.000	30.126	2.83E+07
LQ and SB				
(from autocad abote WL of 22m	39.500	56.800	45.600	2.00E+06
Main Deck (PD, Flare, bulwark)				
(from autocad abote WL of 22m	57.500	68.200	47.000	4.00E+06
weight reserve				

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(from autocad abote WL of 22m	43.000	43.000	30.126	4.12E+06
TOTAL for hull at 22m draft	36.310	36.955	38.191	1.62E+08

Explanation to the values used:

- Hull; scaled values from exiting unit (Goliath)
- Ballast and fluid; values from Napa stability model and LD02D
- Steiners theorem added to take into account the offset of caluated values and the waterplane area
- Process area, LQ&SB, Main Deck. Values calculated based on input from autocad 3D model
- Weight reserve; same values as process deck used

7.2 Main hub

1000-unit (Goliath hull)

Following key elements are presented:

- The calculation methodology
- The Regulatory basis presenting the rules and regulations applicable for the stability analysis
- The intact stability requirements
- The damage stability requirements
- The loading conditions

7.2.1 Reference System

The following co-ordinate system is applied for all hydrostatic stability calculations performed for the unit (right-hand rule):

- X-Axis Through the axis of the hull cylinder, +ve forward (towards LQ)
- Y-Axis Through the axis of the hull cylinder, +ve towards PS
- Z-Axis Coincides with the axis of the hull cylinder, +ve upwards
- Trim +ve forward/bow/LQ down
- Heel +ve SB side down

The reference system origin is defined as the intersection of the hull cylinder axis with the inside (top) of the bottom plating (moulded line). The vertical 0-level (top of bottom plating) is termed as baseline.

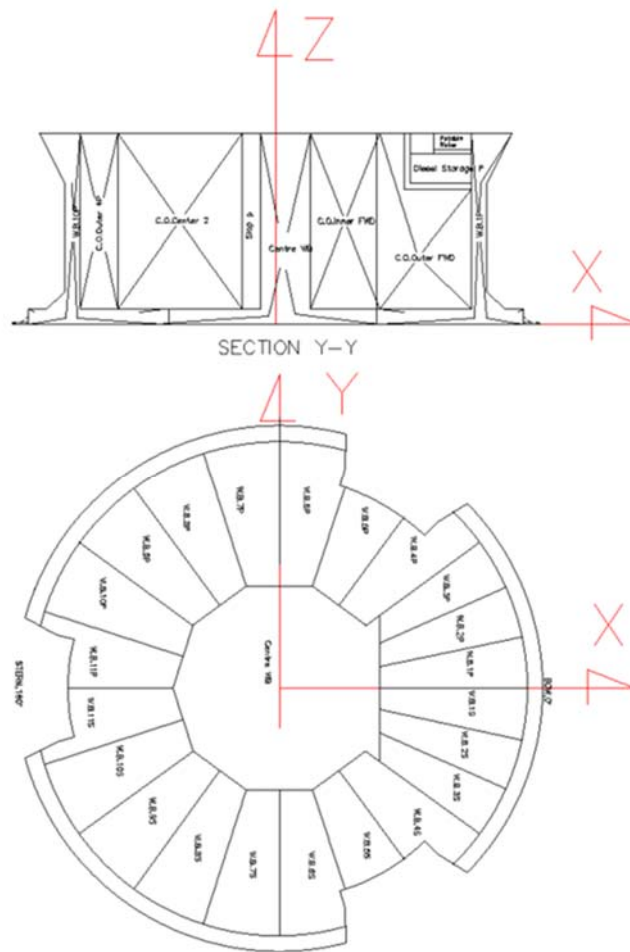


Figure 7-1 Reference system

7.2.2 Hydrostatic Software

All the stability analysis is performed using the NAPA software package.

This software can assess stability around any axis, which is important for a hull of cylindrical shape. The software also contains a module computing wind heeling moments according to the method, formula and coefficients specified in the MODU Code.

The NAPA software is capable of computing equilibrium flotation after damage to one or more compartments according to both the “lost buoyancy” and the “added weight” methods.

7.2.3 Hull Stability Model

A detailed intact buoyancy model is based on the Tank Plan.

The hull is modelled to the inside of the outer hull plating (“moulded lines”) and an allowance added to the hull for the skin given an average shell thickness.

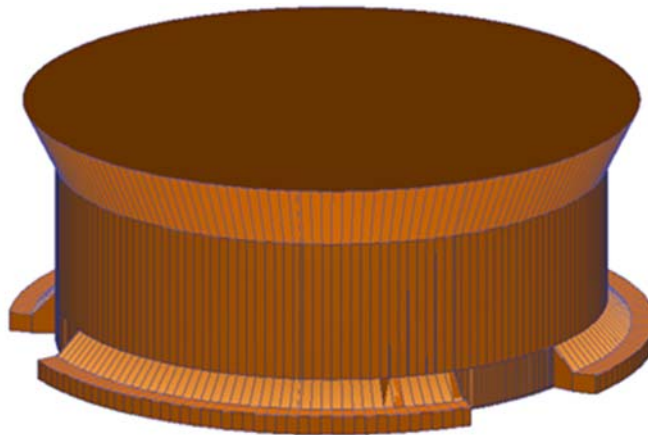


Figure 7-2 Hull Stability Model

All the watertight compartments inside the intact hull are modelled separately. These are typically all tanks, void spaces etc. These compartment models are then combined into an arrangement that is used e.g. when loading all the tanks of the unit.

When damage stability is evaluated the compartment models are also used to work out the hydrostatics for each damage case.

7.2.4 Wind Heeling Moment

The wind heeling moment is calculated by a macro facility within the stability software. This facility calculates the windage area and its lever arm for every combination of draught, angle of heel and azimuth angle.

The macro operates on a simple 3D wind model, which is a model of the main building blocks of the complete unit. The figure below shows the wind model sectioned with a series of level lines. The wind moment calculation uses a wind velocity profile given in Table 7-1.

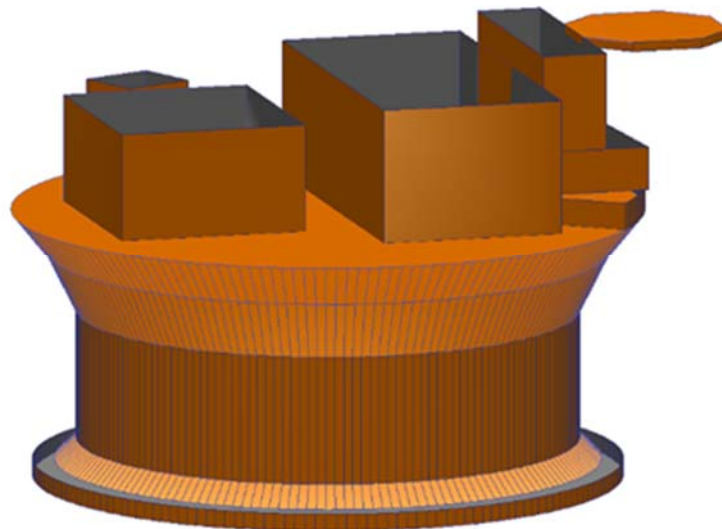


Figure 7-3 Wind Model

Table 7-3 Wind velocity profile & wind model components

H [m]	COEF	NAME	STYPE	COEF	AREA [m ²]
0.00	1.000				
15.30	1.100	WIHULL		0.500	13580.5
30.50	1.200	BOTTOM		1.100	9329.4
46.00	1.300	BULWARK		1.100	3577.9
61.00	1.370	ACOM12		1.100	774.2
76.00	1.430	ACOM21		1.100	1024.8
91.50	1.480	ACOM22		1.100	2070.0
106.50	1.520	HELDCK		1.300	160.5
122.00	1.560	WINCH		1.500	772.0
137.00	1.600	LIFE		1.500	592.8
152.50	1.630	PROCESS		1.000	10748.9
167.50	1.670	HELDCK2		1.000	671.5
183.00	1.700	MOD2		1.000	3000.0
198.00	1.720	MOD3		1.000	5200.0
213.50	1.750				
228.50	1.770				
244.00	1.790				
259.00	1.800				51502.4

Sevan has some experience in how well these wind moment calculations match the results from wind tunnel tests on the units. According to this experience the macro gives conservative results compared to the wind tunnel tests.

The wind model is a table of surfaces. Each surface represents some structure exposed to the wind or underwater drag forces. Each surface is assigned a drag coefficient.

7.2.5 Regulatory basis, rules and regulations

According to the document, hydrostatic stability must comply with the following regulations:

1. UK HSE RR387 Edition 2005: Stability Research Report 387
2. DNV OS-C301 Edition January 2017: Stability and Watertight Integrity
3. MODU Code (IMO I810E) Edition 2010: Code for the Construction and Equipment of Mobile Offshore Drilling Units

7.2.6 HSE RR387

UK HSE RR387 Recommendations for Offshore Units, which basically is very similar to IMO MODU Code as well as class regulations for Mobile Offshore Units. For this regime, MAX KG Curves for the unit is developed. The RR387 Recommendations are valid throughout the complete service life of the unit.

7.2.7 DNV OS-C301

The class society DNV has based their offshore stability code DNV OS-C301 on the MODU Code, which is the universally accepted code for mobile offshore units like drilling rigs etc.

When the Sevan Concept was still new to the industry, DNV opted for a more conservative approach and required Sevan Units to conform to a 2-compartment damage scenario. This changed with the Dana Project when, following discussions with Sevan Marine and COSCO shipyard, DNV reverted to the original interpretation of the rules, requiring only one compartment to be damaged.

DNV OS-C301 requirements and criteria are covered by HSE RR387.

In addition, Sevan is checking 2 compartment MODU code damage using direct calculations.

7.2.8 IMO MODU Code

The MODU Code defines one-compartment damage scenarios. IMO MODU Code requirements and criteria are covered by HSE RR387. In addition, Sevan is checking 2 compartment MODU code damage using direct calculations.

7.2.9 Intact Stability Requirements

HSE RR387

The intact stability is ensured through establishing a KG Limit Curve satisfying the requirements of Chapter 2 Part 3 of the RR387. The Intact MAX KG Curve is established based on a wind speed of 100 knots, meaning it covers all modes of operation, including survival condition. The other modes of operation, with lower wind speed, would result in a higher curve of KG allowed, and is therefore omitted in the analysis.

RR387 Intact Stability Criteria:

1. The ratio of the area under the righting moment curve to that under the heeling moment curve should not be less than 1.4 for surface and self-elevating units. These areas should be measured from the upright position to an angle of heel, not exceeding either the angle of first down flooding or the second intercept of the wind heeling and righting moment curves, whichever is the lesser.
2. The range of positive stability to the second intercept for severe storm winds (i.e. at least 51.5 metres per second) should be at least 30°
3. The static angle of heel due to wind to 15° in any condition.
4. The metacentric height (GM) should be at least 0.3 metres for surface units.
5. The righting lever curve up to the angle of down flooding or the angle of maximum righting lever or 15°, whichever is the least, will need to be such that:
 $GZ \geq 0.5 GM \sin \theta$

IMO MODU Code

The intact stability regarding the MODU Code is analysed through a series of maximum allowable KG (VCG) calculations towards a set of intact stability criteria. As the Sevan unit is of a cylindrical hull shape, a spread of azimuth angles should be analysed. The following criteria are used to determine the limiting level of the KG for a spread of azimuth angles from 0° to 360° with a step of 18°.

The Intact Stability Criteria are:

1. The area under the righting moment curve to the second intercept or down flooding angle, whichever is less, should be not less than 40% in excess of the area under the wind heeling moment curve to the same limiting angle.
2. The righting moment curve should be positive over the entire range of angles from upright to the second intercept

In practice, HSE RR387 requirements are more stringent and therefore these requirements may be covered by HSE requirements.

Table 7-4 Intact Stability Calculation Methodology

Verification Type	As per Rules
Rule criteria	MODU/DNV OS-C301 HSE
Calculation methodology	Max VCG curves
Operational conditions	YES
IMR Conditions	YES*
Transit, Installation	YES*

* Will be checked in the next stage of the project.

7.2.10 Damage Stability requirements

Damage Stability is calculated according to HSE RR387 (covered MODU Code and DNV)

Following calculation methodologies applied to the various loading condition scenario:

Table 7-5 Damage stability methodology

Verification Type	As per Rules	SEVAN SSP Additional check
Rule criteria	MODU/DNVGL/HSE	MODU
Number of damaged compartments	1	2
Calculation methodology	Max VCG curves Empty Tanks Indirect calculations	Direct calculations on loading conditions
Operational conditions	YES	YES
IMR Conditions	YES*	YES*
Transit, Installation	YES*	YES*

* Will be checked in the next stage of the project.

Permeabilities applied in the damage stability calculations as per rules:

- Utility/Machinery spaces 0.85
- Liquid tanks 0.95
- Empty tanks and voids 0.95
- Accommodation spaces 0.95

HSE RR387

The damage stability is ensured through establishing a KG limit curve satisfying the requirements of Chapter 2 Parts 4, 5 and 6 of the UK HSE RR387.

Damaged KG limit curves are calculated for a draught range of 18-31 m and for an azimuth angle range of 0° to 180°, with a step of 18°. The 18° step is chosen to try to calculate in the direction of the damages, in order to cover the worst case, leading to the lowest allowable KG. As the routine searching for the minimum KG is looking in both directions of heel after damage, only 180° of the 360° perimeter need to be calculated.

The KG limit curve established for the damage condition is produced with a wind speed of 50 knots.

The unit should be able to withstand the following extents of flooding:

a) The flooding of any one watertight compartment, which for the purposes of calculation can be assumed to be free flooding. This is intended to provide a basic standard of watertight subdivision throughout those volumes upon which the buoyancy and stability of the unit depends, regardless of assumptions about the extent of damage (as in b)). It also affords some protection against flooding due to other causes (e.g. leakage or ballasting errors).

b) The flooding of those watertight compartments which are breached as a result of the extent of damage described below. In this case flooding may involve more than one compartment where a watertight boundary lies within the assumed zone of damage. Such damage is intended to represent that which could arise due to low energy collisions with attendant vessels and is associated only with operating and transit draughts (i.e. need not be considered during severe storm conditions or at intermediate draughts between minimum operating draught and maximum transit draught).

These two types of flooding may be assumed not to occur at the same time.

In addition, to satisfy the CLASS requirements (DNV-OS-C301 Ch. 5.5.1 2), any opening (through which progressive flooding may occur) below the final waterline shall be made watertight, and openings within 4 m above the final waterline shall be made weathertight.

Table 7-6 HSE RR387 Damage Dimensions

Damage	Length (Tangential)	Depth (Radial)	Height (Vertical)	Radial BH damaged
RR387	3.00	1.50	No limit	No

HSE RR387 Damage Stability Criteria:

1. Angle of heel after damage without wind heeling moment not more than 15 deg
2. Righting moment to reach at least equal to the wind moment up to 2nd intercept angle.
Both areas shall be calculated from the static angle of heel without wind.

IMO MODU Code

The damage stability analysis to MODU code is done by calculating a series of damages over a draught interval and at a series of azimuth angles. For each case the limiting value of KG is calculated towards a set of stability criteria.

All the damages are calculated for empty tanks before damage, meaning that in particular cases the results may be very conservative.

In addition, SEVAN SSP decided to check full 2-compartment damage with direct calculations meaning the damages will be applied on the set of loading conditions.

The dimensions of the damage are same as HSE RR387. The damage stability criteria are taken as per the MODU Code and from DNV OS C-301.

The criteria are as follows:

1. Angle of heel after damage including wind heeling moment not more than 17 deg
2. Righting moment to reach at least a value of twice the wind moment, both at the same angle
3. Minimum range of stability after damage not less than 7 deg

In addition, to satisfy the CLASS requirements (DNV-OS-C301 Ch. 5.5.1 2), any opening (through which progressive flooding may occur) below the final waterline shall be made watertight, and openings within 4 m above the final waterline shall be made weathertight. The wind heeling moments applied for the damage stability analysis are again generated by the wind-moment macro inside the NAPA software. The same wind model is used, and in line with the MODU Code a 50 knots wind velocity is used for damage stability.

7.2.11 Loading Condition

A one loading condition is developed as part of this study.

LD02D – Operational loading condition

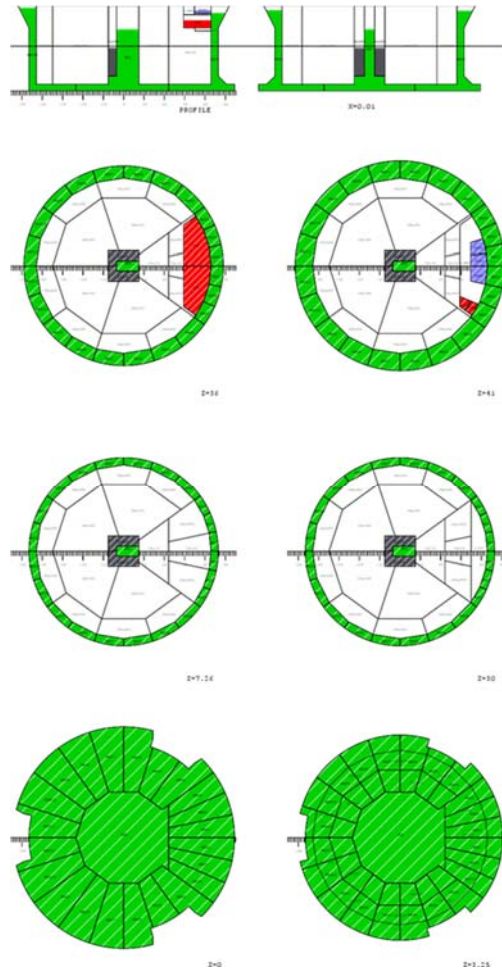
Tow-Out, Light Ballast Condition, Inspection, Maintenance and Repair conditions (IMR conditions) will be documented in the next stage of the project development.

The analysis is performed with a sea water density of 1.025.

The condition is listed below.

Table 7-7 Hydrostatics of the loading conditions

NAME	DESCRIPTION	DISPLACEMENT (t)	DEADWEIGHT (t)	DRAFT (m)	TRIM (m)	HEEL (deg.)	GM (m)	KGL (m)
LD02D	Operational condition	161793	86793	21.98	0.00	0.00	8.18	25.64



NAME	LOAD	MASS t	XM m	YM m	ZM m
Diesel Oil	DO	1710.0	35.228	-1.169	33.240
	FIXED	5158.0	0.000	0.000	24.352
Fresh Water	FW	230.0	38.700	1.108	39.072
Slop Tank	SLOP	2360.0	-0.647	0.000	14.160
Water Ballast	WB	77335.0	-0.874	0.023	14.633
Deadweight		86793.0	0.000	0.000	15.629

Lightweight		75000.0	0.000	0.000	36.770
Deadweight		86793.0	0.000	0.000	15.629
Total weight		161793.0	0.000	0.000	25.429

FLOATING POSITION

Draught moulded	21.981	m	KM	33.82	m
Trim	0.000	m	KG	25.43	m
Heel, PS=+	0.0	deg			
TA	21.981	m	GM0	8.39	m
TF	21.981	m	GMCORR	-0.21	m
Trimming moment	3	tonm	GM	8.18	m
AZIMUTH=0					

KGL = 25.639

NAME	LOAD	MASS t	FILL %	XM m	YM m	ZM m	FRSM tm	FRSML tm

CONTENTS=Diesel Oil (RHO=0.86)

DOP	DO	803.5	57.9	35.346	10.147	32.880	9152.22	2568.92
DOS	DO	803.5	57.9	35.346	-10.147	32.880	0.00	2568.92
DOSER	DO	51.5	57.3	35.222	-20.549	38.789	0.00	35.69
DOSET	DO	51.5	63.0	31.556	-18.265	38.917	0.00	29.29
SUBTOTAL	DO	1710.0		35.228	-1.169	33.240	9152.22	5202.83

CONTENTS= (RHO=1)

FLUID CONTENT	FIXED	1000.0	0.0	0.000	0.000	56.500	0.00	0.00
CREW	FIXED	300.0	0.0	0.000	0.000	58.500	0.00	0.00
MOORING CHAIN	FIXED	536.0	0.0	0.000	0.000	37.000	0.00	0.00
PROVISIO N & STORES	FIXED	300.0	0.0	0.000	0.000	58.500	0.00	0.00
MARINE GROWTH	FIXED	216.0	0.0	0.000	0.000	12.500	0.00	0.00
RISERS & CABLES	FIXED	1000.0	0.0	0.000	0.000	3.000	0.00	0.00
MOORING FORCE	FIXED	1500.0	0.0	0.000	0.000	3.000	0.00	0.00
LOST BUOYANCY	FIXED	306.0	0.0	0.000	0.000	13.000	0.00	0.00
SUBTOTAL	FIXED	5158.0		0.000	0.000	24.352	0.00	0.00

CONTENTS=Fresh Water (RHO=1)

POT1	FW	60.0	37.2	38.829	2.780	38.988	0.00	226.87
POT2	FW	60.0	35.2	38.400	8.843	38.951	0.00	188.78
SERV	FW	110.0	47.7	38.793	-4.022	39.183	0.00	312.27
SUBTOTAL	FW	230.0		38.700	1.108	39.072	0.00	727.92

CONTENTS=Slop Tank (RHO=1.025)

SLOPP	SLOP	1180.0	39.8	-0.647	4.559	14.160	286.82	1694.08
SLOPS	SLOP	1180.0	39.8	-0.647	-4.559	14.160	286.82	1694.08
SUBTOTAL	SLOP	2360.0		-0.647	0.000	14.160	573.65	3388.17

CONTENTS=Water Ballast (RHO=1.025)

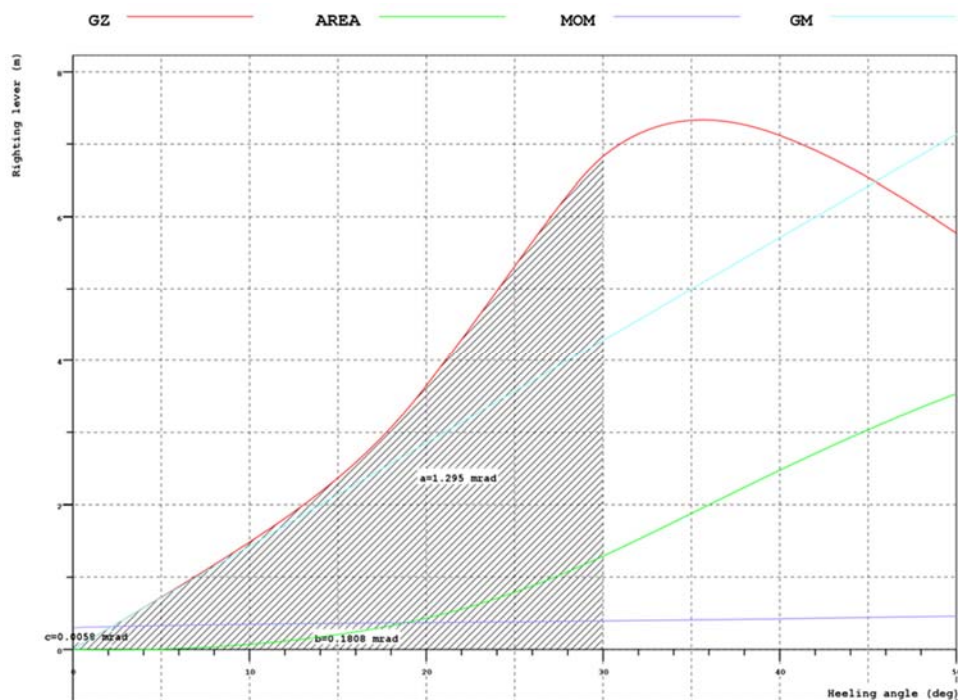
WBP1	WB	2267.2	88.4	43.155	4.535	13.978	561.75	321.68
WBP2	WB	2257.1	88.6	41.417	13.453	14.129	546.63	348.68
WBP3	WB	2230.3	88.9	38.018	21.937	14.477	517.05	396.75
WBP4	WB	3351.6	90.4	30.609	30.184	15.742	1343.32	1342.78

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WBP5	WB	3098.8	91.1	19.247	37.763	17.458	972.94	1840.63
WBP6	WB	3573.3	92.0	6.679	42.854	15.359	694.87	2096.78
WBP7	WB	3652.7	92.8	-6.799	42.955	15.356	723.85	2135.18
WBP8	WB	3682.9	93.5	-19.760	38.771	15.558	1027.37	1905.43
WBP9	WB	3708.1	94.2	-30.783	30.789	15.725	1496.85	1497.29
WBP10	WB	3726.2	94.6	-38.809	19.769	15.844	1965.10	1076.53
WBP11	WB	3357.1	95.1	-42.261	6.925	17.786	2288.80	845.01
WBS11	WB	3355.9	95.1	-42.259	-6.925	17.778	2286.20	843.06
WBS10	WB	3722.9	94.5	-38.807	-19.767	15.822	1960.38	1072.72
WBS9	WB	3702.9	94.0	-30.780	-30.786	15.691	1490.59	1490.98
WBS8	WB	3676.4	93.4	-19.757	-38.766	15.515	1020.12	1896.87
WBS7	WB	3645.5	92.6	-6.798	-42.948	15.308	716.26	2125.17
WBS6	WB	3566.2	91.8	6.678	-42.848	15.311	687.40	2086.75
WBS5	WB	3092.4	90.9	19.243	-37.755	17.412	966.00	1832.25
WBS4	WB	3346.5	90.3	30.606	-30.180	15.706	1336.84	1336.51
WBS3	WB	2226.6	88.7	38.014	-21.935	14.437	514.45	393.50
WBS2	WB	2254.8	88.5	41.415	-13.452	14.105	544.89	346.57
WBS1	WB	2266.1	88.4	43.154	-4.535	13.967	561.31	320.81
WBC	WB	7573.6	92.1	0.603	0.000	4.943	115.10	557.08
SUBTOTAL	WB	77335.0		-0.874	0.023	14.633	24338.0	28109.0
							7	3
TOTAL		86793.0		0.000	0.000	15.629	34063.9	37427.9
							4	4

Intact criteria LD02D

RCR	TEXT	REQ	ATTV	UNIT	STAT
MINGZ0	GZ>0	0.000	0.238		OK
UKHSE23B	Second Intercept	30.000	50.000	deg	OK
UKHSE23C	Angle of heel due to wind	15.000	2.197	deg	OK
UKHSE23D	Minimum GM	0.300	8.176	m	OK
UKHSE23E	Minimum GZ	0.039	2.369	m	OK
UKHSE23A	Area Ratio 1.4	1.400	7.911		OK



7.2.12 Maximum VCG curves

Based on relevant regulations and criteria maximum KG curves are developed for the unit. As has been the case for all Sevan units to date, we see that damage stability is critical for most of the draft range.

The combined maximum KG Curve is shown below:

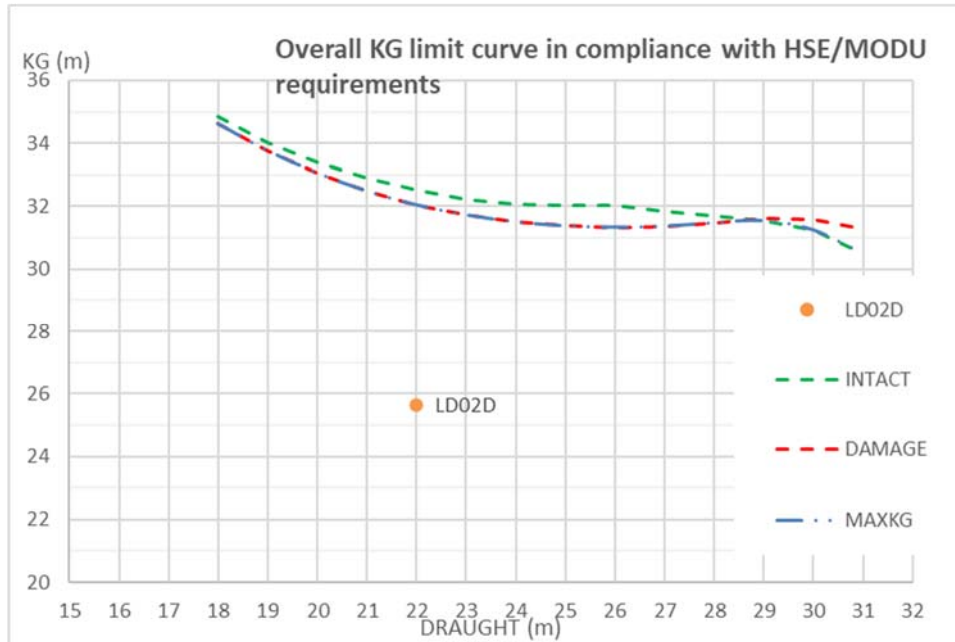


Figure 7-4 Combined VCG limit curve vs. loading condition

7.3 Sub hub

Based on weight input of topside equipment from Katoni a quick hull sizing activity has been performed. The hull size is given, based on a Sevan 300-unit size, but the exercise is carried out to establish basic input for both stability calculations and motions and mooring evaluations.

Table 7-6 NTE weight and VCG

Area	Weight [t]	VCG [m]
Process area	2,100	37.97
Main Deck area	1,500	33.50
Topside total	3,600	36.11
Hull	9,222	11.72
Platform Total	12,822	18.57
Weight reserves	2,178	37.97
NTE Weight	15,000	21.88

Explanation to the values used:

Process weight; based in input from Katoni

Utility Area: Estimate by Sevan. Cover weight of LQ & serviceblock below LQ

NAME	LOAD	MASS t	XM m	YM m	ZM m
	MASS	4170.0	0.000	0.000	20.217
Water Ballast	WB	20542.4	0.036	-0.037	9.838
Deadweight		24712.4	0.030	-0.030	11.589

Lightweight		15000.0	0.000	0.000	21.880
Deadweight		24712.4	0.030	-0.030	11.589
Total weight		39712.4	0.018	-0.019	15.476

FLOATING POSITION

Draught moulded	13.047	m	KM	22.73	m
Trim	0.000	m	KG	15.48	m
Heel, PS=+	0.0	deg			
TA	13.047	m	GM0	7.25	m
TF	13.047	m	GMCORR	-0.28	m
Trimming moment	1	tonm	GM	6.97	m
AZIMUTH=0					
KGL = 15.760					

NAME	LOAD	MASS t	FILL %	XM m	YM m	ZM m	FRSM tm	FRSML tm
CONTENTS= (RHO=1)								
FLUID	MASS	1000.0	0.0	0.000	0.000	41.500	0.00	0.00
CONTENT								
MOORING	MASS	1000.0	0.0	0.000	0.000	3.000	0.00	0.00
FORCE								
MOORING	MASS	400.0	0.0	0.000	0.000	22.000	0.00	0.00
CHAIN								
PROVISION	MASS	300.0	0.0	0.000	0.000	43.500	0.00	0.00
& STORES								
RISERS AND	MASS	1000.0	0.0	0.000	0.000	3.000	0.00	0.00
CABLES								
CREW	MASS	300.0	0.0	0.000	0.000	43.500	0.00	0.00
MARINE	MASS	50.0	0.0	0.000	0.000	12.500	0.00	0.00
GROWTH								
LOST	MASS	100.0	0.0	0.000	0.000	3.000	0.00	0.00
BUOYANCE								
POT WATER	MASS	10.0	0.0	0.000	0.000	49.000	0.00	0.00
SERVICE	MASS	10.0	0.0	0.000	0.000	49.000	0.00	0.00
WATER								
SUBTOTAL	MASS	4170.0		0.000	0.000	20.217	0.00	0.00

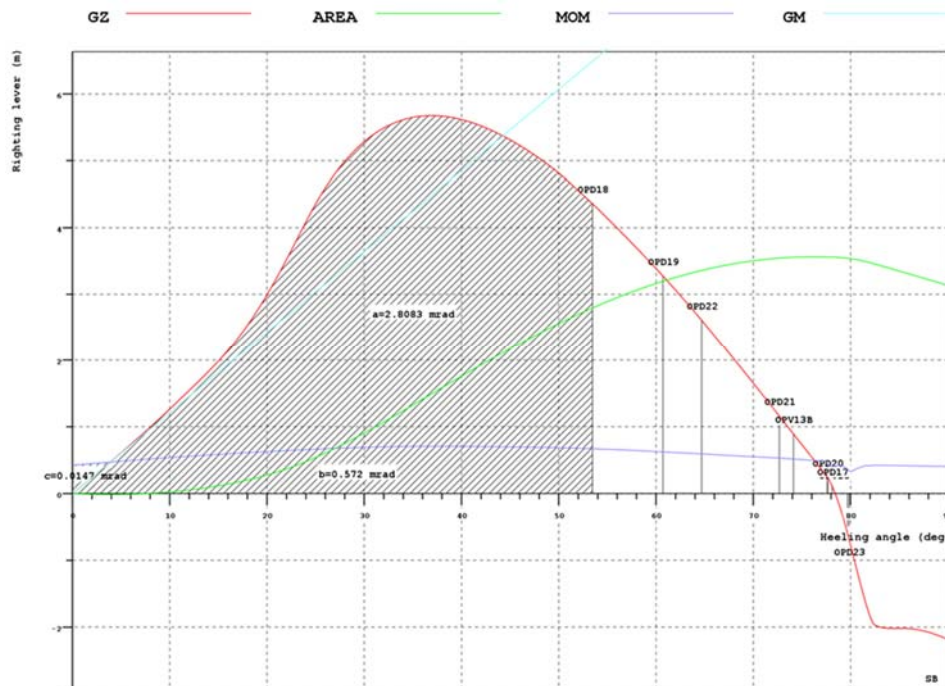
CONTENTS=Water Ballast (RHO=1.025)

RWBT3P	WB	1721.0	98.0	6.786	25.326	9.877	289.72	1598.89
RWBT6P	WB	1700.7	98.0	-25.314	6.726	9.838	1589.86	284.59
RWBT5S	WB	1720.7	98.0	-18.541	-18.540	9.879	946.97	949.17
RWBT4P	WB	1721.0	98.0	-6.786	25.326	9.877	289.72	1598.89
RWBT1S	WB	1703.1	97.0	25.290	-6.776	9.708	1572.91	276.99
RWBT1P	WB	1720.7	98.0	25.326	6.786	9.878	1609.66	289.48
RWBT3S	WB	1721.0	98.0	6.786	-25.326	9.877	289.72	1608.65
RWBT2P	WB	1720.7	98.0	18.541	18.540	9.879	946.97	944.90
RWBT6S	WB	1720.7	98.0	-25.326	-6.786	9.878	1603.78	289.99
RWBT2S	WB	1703.1	97.0	18.514	-18.514	9.708	935.38	922.55
RWBT4S	WB	1721.0	98.0	-6.786	-25.326	9.877	289.72	1608.64
RWBT5P	WB	1668.9	98.0	-18.468	18.504	9.773	926.28	929.27
SUBTOTAL	WB	20542.4		0.036	-0.037	9.838	11290.69	11302.01
TOTAL		24712.4		0.030	-0.030	11.589	11290.69	11302.01

Intact criteria LD02D

Loading condition: OPERATIONAL CONDITION

RCR	TEXT	REQ	ATTN	UNIT	STAT
MINGZ0	GZ>0	0.000	0.298		OK
RR387B	Second Intercept	30.000	76.269	deg	OK
RR387C	Angle of heel due to wind	15.000	3.892	deg	OK
RR387D	Minimum GM	0.300	6.965	m	OK
RR387E	Minimum GZ	0.000	0.113	m	OK
RR387A	Area Ratio 1.4	1.400	5.762		OK



7.3.2 Maximum VCG curves

Based on relevant regulations and criteria maximum KG curves are developed for the unit. As has been the case for all Sevan units to date, we see that damage stability is critical for most of the draft range.

The combined maximum KG Curve is shown below:

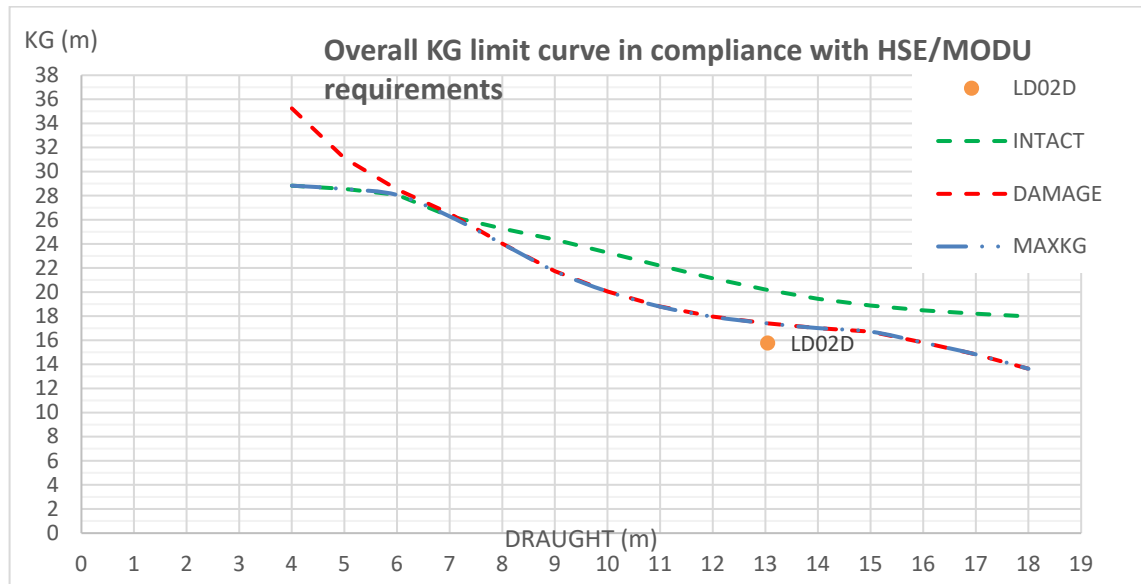


Figure 7-5 Combined VCG limit curve vs. loading condition

7.4 Hull optimization

This study makes use of the 300-hull and the 1000-hull. These designs have proven to be successfully as FPSO's. The design combines excellent motion characteristics in combination with a large storage volume and high deck load capacity. When not used as an FPSO the large internal volume is unused, the total weight of the unit is significantly reduced resulting in the units having large excess buoyancy. To achieve satisfactory performance, the surplus buoyancy needs to be compensated by increasing the ballast water.

Next phase of the decarbonization study should include hull optimization exercise changing hulls to Small Waterplane Area Circular Hull design (SWACH). These designs have a large moonpool adapted to the reduced deck load, while at the same time providing the same deck area. The SWACH design has improved motion performance compared to the traditional hulls due to the reduced waterplane area.

Another option that can be pursued is to move some of the deck modules to inside the hull.

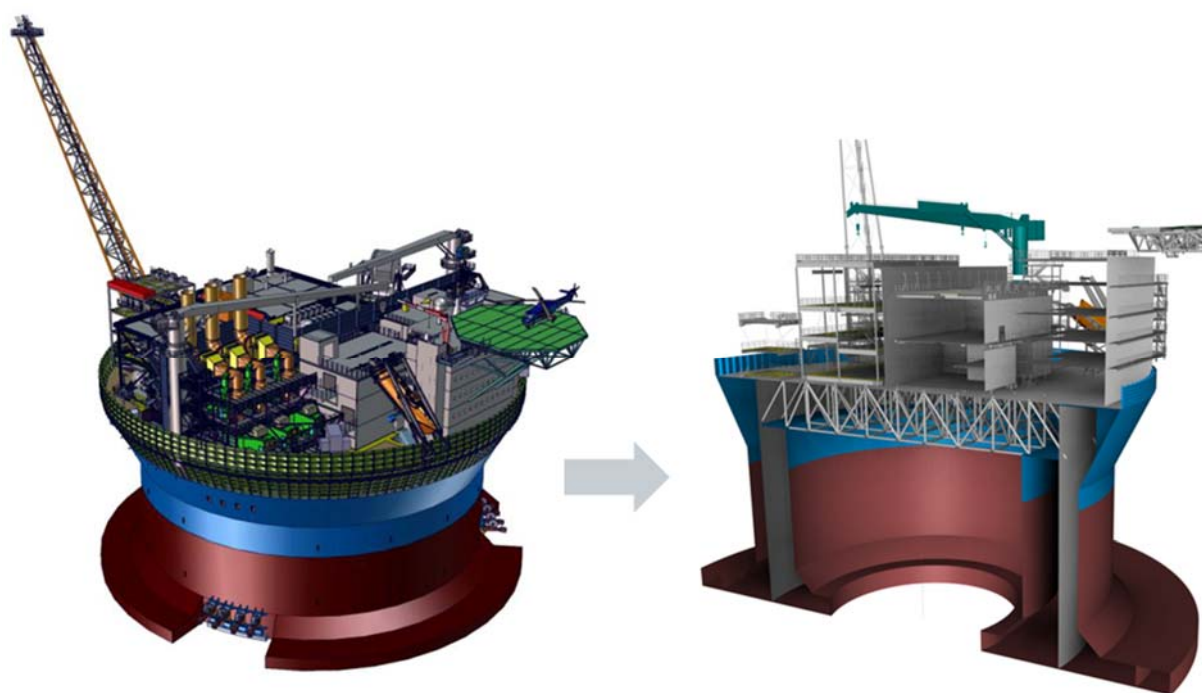


Figure 7- 6 Small Waterplane Area Circular Hull6

8 MARINE AND UTILITY SYSTEMS

8.1 Main Hub

The main hubs are large floating units which will be permanently manned. The accommodation will be fully equipped with all facilities for the crew. This includes single and double cabins, galley, laundry, storage etc. There will also be space for storage, workshops, gym facilities, communication central, and control room.

The marine system includes ballast system, sea water lift, freshwater system, diesel system, sewage treatment, drain system etc. to support the onboard accommodation, power generation and power export.

Primary means of access to the unit will be by helicopter. A helideck including facilities for fueling the helicopter will be included. Helideck complies with CAP 437.

Lifeboats, escape chute w/rafts and fast rescue boat are provided.

Equipment for power generation, transformation and distribution are placed on main deck level and on process deck level. A large fire wall divides the process deck in one hazardous area and one safe area.

The large gas driven turbines for power generation with their gas fuel import and safety system are placed on the hazardous side.

On the safe side electrical equipment for power transformation, switchboards, and utilities for power export to the sub hubs are located. This is arranged in large modules with up to 3 levels.

I-tubes through the hull and up to hang-off at main deck level are arranged for each power cable and riser. The I-tubes for the power cables are located near the center of the hull.

Cooling water for cooling of transformers will be provided from the seawater lift system. Modules can either be naturally ventilated or be connected to the HVAC system.

Two large deck cranes are located on each side of the hull for material handling on the unit at lifting on and off the platform. The cranes are hydraulic operated powered by a common HPU dedicated for the cranes, the mooring winches, and the bunker stations.

An extensive gas detection, fire and smoke detection and extinguishing system covering all modules and compartments will be installed. Fire extinguishing systems will include water mist system, foam system and inergen system adapted to the equipment in each room and module.

Refer to Main Equipment List for Main Hub.

8.2 Sub hub

The sub hubs will be unmanned units, with an emergency overnight accommodation for 4-6 persons only. Compared to the main hub's full accommodation the facilities onboard the sub hubs will be very limited, no separate cabins, simple facilities for toilet, shower and galley. The emergency overnight cabin will be located below main deck level inside the hull.

Power supply to the sub hubs is branched off from the power supplied from the main hub. Separate distribution board are included for powering the systems onboard the unit. In addition, an emergency diesel generator will be installed onboard. The generator is self-contained with its own diesel fuel system.

The sub hubs will be equipped with ballast system to ballast them to the correct operational draft after installation on the location. Pump room with valves and piping system for the ballast system is located inside the hull.

Since the ballast system is inactive in operation, the ballast pumps can serve as seawater lift pumps for heating/cooling purposes.

I-tubes through the hull and up to hang-off at main deck level are arranged for each power cable. The I-tubes for the power cables are located near the center of the hull.

HVAC for the emergency overnight accommodation and other compartments will be provided.

The electrical transformers are placed in separate containers. It is assumed that natural ventilation will provide sufficient cooling. Forced ventilation can be provided by expanding the HVAC system.

Two cranes for internal material handling and lifting on and off the sub hub is included. The hydraulic power is provided from an HPU shared with the mooring winches.

An automatic fire detection and extinguishing system covering all modules and compartments will be installed. Fire extinguish system will include water mist system, foam system and inergen system adapted to the equipment in each room.

There is no bunker hose reel for importing fresh water or diesel fuel. All liquids are supplied via vessel delivered TOTE tanks.

Primary means of access to the unit will be by helicopter. A helideck is provided. The helideck complies with CAP 437. The sub-hubs will not have helifuel facilities.

Since the unit is unmanned, with only smaller crews visiting for inspection, maintenance, and repairs, permanently installed lifeboats are not required.

Rafts and *Donut personal controlled descent device* will be provided onboard for emergency disembarking from the sub hub.

Refer to Main Equipment List for Sub Hub.

9 LAYOUT AND ARRANGEMENTS

9.1 Main Hub

The accommodation is located in the forward end of the unit. Accommodation unit contains cabins, galley, laundry, offices, control room, storage etc. Below the accommodation and stretching into the hull is the service block. The service block gives space to utility systems required for the accommodation, HVAC system, and firefighting skids.

The helicopter deck with facilities is located on top of the accommodation.

Two large cranes cover all material handling in and out of the unit. One crane is located on port side and one on starboard side.

Lifeboats are located near the accommodation unit.

Main deck contains 3 clusters of mooring winches, riser bay areas where power export cables and gas fuel riser are hung-off.

On main deck safe and dry space are allocated to hydraulic power units. Space is also allocated to smaller modules part of the power generation and export system.

A large fire wall divides the process deck in one hazardous area and one safe area, leaving the large gas driven turbines with their gas fuel import, metering station and safety system are placed on the hazardous side, while on the safe side the electrical equipment for power transformation, switchboards, and utilities for power export to the sub hubs are located.

Bunkering stations and diesel generators are also located on safe side of the process deck.

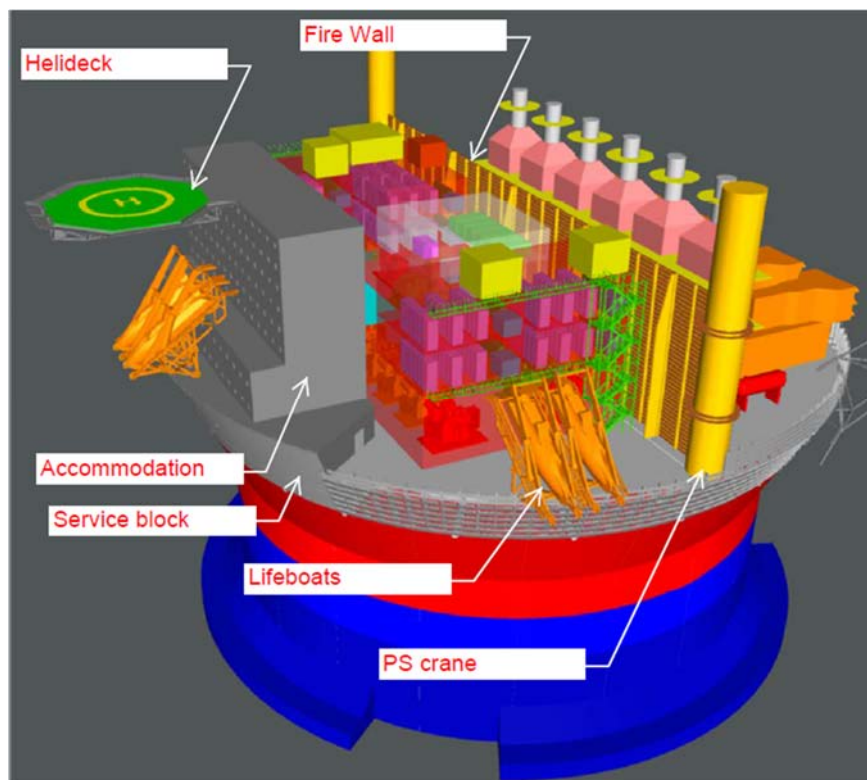


Figure 9-1 Main Hub

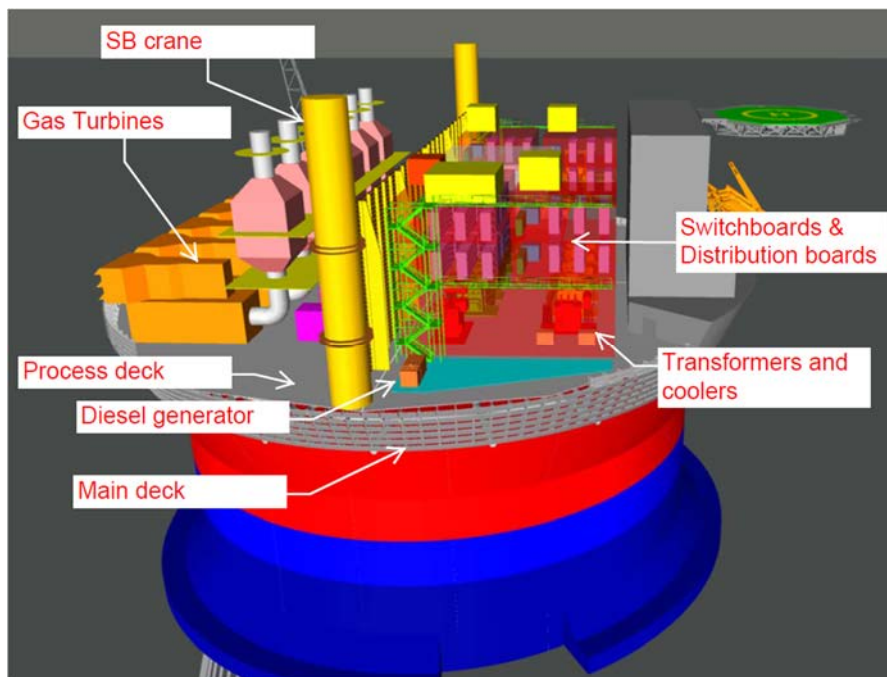


Figure 9-2 Main hub

Refer to Navis model for details related to platform layout.

9.2 Sub Hub

The facilities for electrical power import and export on the sub hubs will be arranged on two levels on process deck. This includes switchboards, distribution boards and transformers.

Since the sub hubs are unmanned, there is no accommodation unit onboard, only an emergency overnight accommodation located on main deck. The facilities in here are limited.

In dry and safe area on the main deck utility systems required for HVAC system and firefighting skids are placed. Pumps for ballast and sea water lift are placed inside the hull.

Two cranes covers all material handling in and out of the unit. One crane is located on the port side and one on the starboard side of the unit.

The unit is equipped with two lifeboats. However, as the sub hubs are unmanned consideration can be made to replace the lifeboats with rafts and *Donut personal controlled descent device*.

Main deck contains 3 clusters of mooring winches, riser bay areas where cables for power export and power import are hung-off. Main deck also includes safe and dry space for the hydraulic power unit for operation of the winches and the crane.

The helicopter deck with facilities is located on top of the process deck.

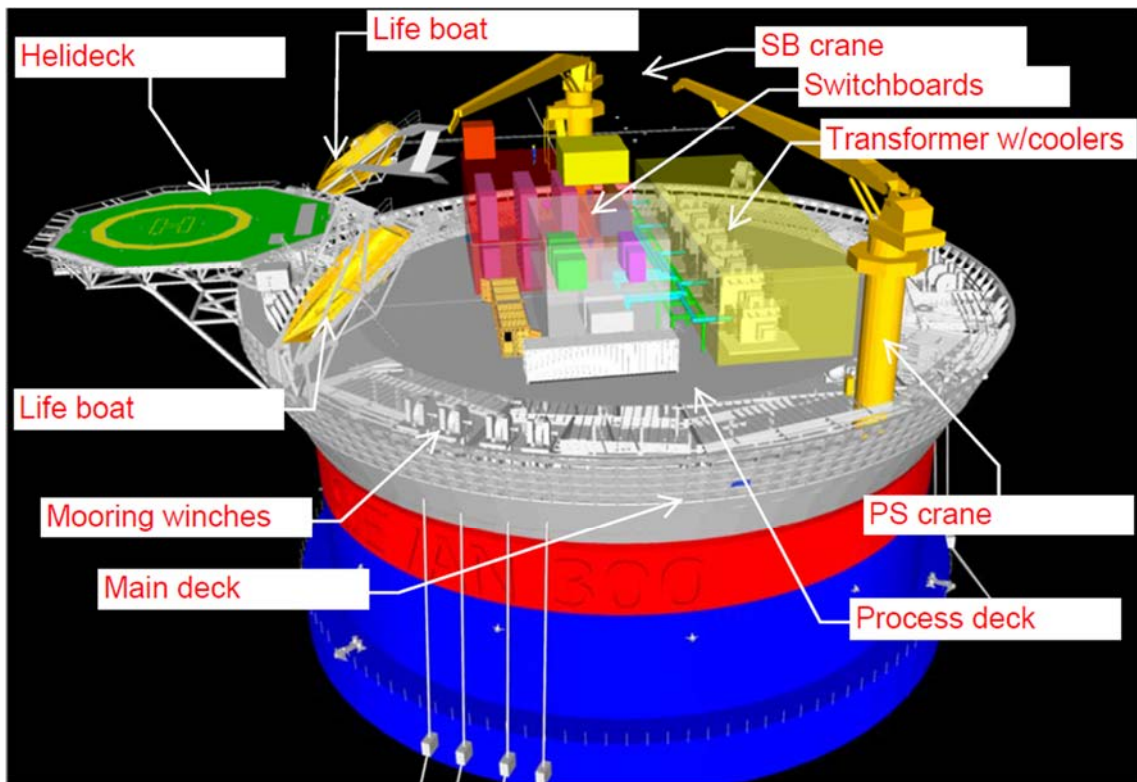


Figure 9-3 Sub hub

Refer to Navis model for details related to platform layout.

10 COST ESTIMATE

The enclosed cost estimate has been prepared based on Sevan SSP's standard cost estimation procedure. The work is defined as Screening/Concept Evaluation study and is thus defined as a class A estimate with an accuracy in the range of -40% to +60%.

The cost estimate is based on fabrication being carried out at a Far East yard.

The cost estimate cover EPC of the Marine Equipped Hull and Mooring System.

Marine Equipped Hull

Includes (if relevant):

- Hull
- LQ (if manned)
- Helideck
- Lifeboats
- Cranes
- Marine Systems
- Mooring Equipment (on vessel)

Excludes:

- Process Modules
- Power Generation
- Utility Systems
- Flare

Main Mooring System Components (off-vessel)

- Anchor
- Bottom chain
- Top chain
- Polyester line

11 APPENDIX A – SUMMARY METOCEAN DATA NEARBY FIELDS

Shelley:

WINDS	1/12-Year	1-Year	10-Year	50-Year	100-Year
<i>Wind Speeds at 10m asl [m/s]</i>					
V (1-hr)	24.7	28.7	31.9	34.0	34.8
V (10-min)	26.9	31.5	35.2	37.7	38.6
V (1-min)	29.8	35.2	39.5	42.4	43.6
Gust (3-sec)	33.6	39.9	45.1	48.6	50.0
WAVES	1/12-Year	1-Year	10-Year	50-Year	100-Year
<i>Wave Heights [m]</i>					
Hs (3-hr)	8.1	10.3	12.0	13.2	13.7
Hmax (3-hr)	15.3	19.1	22.3	24.5	25.4
<i>Crest Elevation [m]</i>					
<i>Wave Periods [s]</i>					
Tz (lower)	8.2	9.2	10.0	10.5	10.7
Tz (central)	9.1	10.3	11.1	11.6	11.9
Tz (upper)	10.7	12.0	13.0	13.7	13.9
Tp (lower)	11.0	12.3	13.3	14.0	14.2
Tp (central)	12.3	13.8	15.0	15.7	16.0
Tp (upper)	13.7	15.4	16.7	17.5	17.8
Tass (lower)	11.0	12.3	13.3	14.0	14.2
Tass (central)	12.3	13.8	15.0	15.7	16.0
Tass (upper)	13.7	15.4	16.7	17.5	17.8
CURRENTS	Mean Spring	1-Year	10-Year	50-Year	100-Year
<i>Total Current Profile [m/s]</i>					
Depth Mean	0.32	0.68	0.79	0.87	0.90
1m Above Sea Bed	0.20	0.42	0.49	0.54	0.56
SURGE LEVELS		1-Year	10-Year	50-Year	100-Year
<i>Positive Surge Levels (MSL) [m]</i>		0.58	0.79	0.94	1.00
<i>Negative Surge Levels (MSL) [m]</i>		-0.46	-0.59	-0.68	-0.72
EXTREME TOTAL LEVEL		100-Year		10,000-Year	
<i>Crest+Tide+Surge (Sea Bed) [m]</i>		111.1		115.1	
<i>Crest+Tide+Surge (LAT) [m]</i>		16.13		20.13	
<i>Crest+Tide+Surge (MSL) [m]</i>		15.21		19.21	
TEMPERAURES		DESIGN		DESIGN	
<i>Air Temperatures [°C]</i>	Minimum	-8.2		Maximum	24.8
<i>Sea Surface Temperatures [°C]</i>	Minimum	2.0		Maximum	19.7
<i>Sea Bed Temperatures [°C]</i>	Minimum	5.6		Maximum	10.6

TIDAL LEVELS	Tidal parameters do not vary with return period
<i>Tidal Height (LAT) [m]</i>	
HAT	1.81
MHWS	1.52
MHWN	1.19
MSL	0.92
MLWN	0.65
MLWS	0.32
LAT	0.00

Chestnut:

WINDS		1/12-Year	1-Year	10-Year	50-Year	100-Year
<i>Wind Speeds at 10m asl [m/s]</i>						
V (1-hr)		25.4	29.5	32.8	34.8	35.7
V (10-min)		27.7	32.4	36.3	38.6	39.7
V (1-min)		30.8	36.2	40.8	43.6	44.8
Gust (3-sec)		34.7	41.2	46.6	50.0	51.5
WAVES		1/12-Year	1-Year	10-Year	50-Year	100-Year
<i>Wave Heights [m]</i>						
Hs (3-hr)		8.1	10.1	11.9	13.1	13.6
Hmax (3-hr)		15.1	18.9	22.1	24.2	25.1
Crest Elevation [m]		8.33	9.64	12.10	13.62	14.27
<i>Wave Periods [s]</i>						
Tz (lower)		8.2	9.2	10.0	10.4	10.6
Tz (central)		9.1	10.2	11.1	11.6	11.8
Tz (upper)		10.7	12.0	13.0	13.6	13.8
Tp (lower)		10.9	12.2	13.3	13.9	14.2
Tp (central)		12.3	13.8	14.9	15.6	15.9
Tp (upper)		13.6	15.3	16.6	17.4	17.7
Tass (lower)		10.9	12.2	13.3	13.9	14.2
Tass (central)		12.3	13.8	14.9	15.6	15.9
Tass (upper)		13.6	15.3	16.6	17.4	17.7
CURRENTS		Mean Spring	1-Year	10-Year	50-Year	100-Year
<i>Total Current Profile [m/s]</i>						
Depth Mean		0.32	0.68	0.79	0.87	0.90
1m Above Sea Bed		0.19	0.41	0.47	0.52	0.54
SURGE LEVELS			1-Year	10-Year	50-Year	100-Year
<i>Positive Surge Levels (MSL) [m]</i>			0.66	0.81	0.94	1.00
<i>Negative Surge Levels (MSL) [m]</i>			-0.48	-0.59	-0.68	-0.72
EXTREME TOTAL LEVEL			100-Year		10,000-Year	
<i>Crest+Tide+Surge (Sea Bed) [m]</i>			138.72		142.91	
<i>Crest+Tide+Surge (LAT) [m]</i>			16.12		20.31	
<i>Crest+Tide+Surge (MSL) [m]</i>			15.26		19.45	
TEMPERAURES			DESIGN		DESIGN	
<i>Air Temperatures [°C]</i>		Minimum	-8.2		Maximum	24.8
<i>Sea Surface Temperatures [°C]</i>		Minimum	2.0		Maximum	19.7
<i>Sea Bed Temperatures [°C]</i>		Minimum	5.6		Maximum	10.6
TIDAL LEVELS		Tidal parameters do not vary with return period				
<i>Tidal Height (LAT) [m]</i>						
HAT				1.68		
MHWS				1.45		
MHWN				1.14		
MSL				0.86		
MLWN				0.58		
MLWS				0.26		
LAT				0.00		

Huntington:

WINDS		1/12-Year	1-Year	10-Year	50-Year	100-Year
<i>Wind Speeds at 10m asl [m/s]</i>						
V (1-hr)		24.7	28.7	31.9	34.0	34.8
V (10-min)		26.9	31.5	35.2	37.7	38.6
V (1-min)		29.8	35.2	39.5	42.4	43.6
Gust (3-sec)		33.6	39.9	45.1	48.6	50.0
WAVES		1/12-Year	1-Year	10-Year	50-Year	100-Year
<i>Wave Heights [m]</i>						
Hs (3-hr)		8.1	10.3	12.0	13.2	13.7
Hmax (3-hr)		15.3	19.1	22.3	24.5	25.4
Crest Elevation [m]		-	9.5	12.0	13.6	14.3
<i>Wave Periods [s]</i>						
Tz (lower)		8.2	9.2	10.0	10.5	10.7
Tz (central)		9.1	10.3	11.1	11.6	11.9
Tz (upper)		10.7	12.0	13.0	13.7	13.9
Tp (lower), Tass (lower)		11.0	12.3	13.3	14.0	14.2
Tp (central), Tass (central)		12.3	13.8	15.0	15.7	16.0
Tp (upper), Tass (upper)		13.7	15.4	16.7	17.5	17.8
CURRENTS		Mean Spring	1-Year	10-Year	50-Year	100-Year
<i>Total Current Profile [m/s]</i>						
Depth Mean		0.34	0.59	0.67	0.73	0.76
0.9m Above Sea Bed		0.20	0.34	0.39	0.43	0.44
SURGE LEVELS			1-Year	10-Year	50-Year	100-Year
<i>Positive Surge Levels (MSL) [m]</i>			0.72	0.93	1.08	1.14
<i>Negative Surge Levels (MSL) [m]</i>			-0.52	-0.67	-0.78	-0.82
EXTREME TOTAL LEVEL			100-Year		10,000-Year	
<i>Crest+Tide+Surge (Sea Bed) [m]</i>			106.1		110.1	
<i>Crest+Tide+Surge (LAT) [m]</i>			16.06		20.06	
<i>Crest+Tide+Surge (MSL) [m]</i>			15.32		19.32	
TEMPERAURES			DESIGN		DESIGN	
<i>Air Temperatures [°C]</i>		Minimum	-8.2		Maximum	24.8
<i>Sea Surface Temperatures [°C]</i>		Minimum	2.0		Maximum	19.7
<i>Sea Bed Temperatures [°C]</i>		Minimum	5.6		Maximum	10.6

TIDAL LEVELS		Tidal parameters do not vary with return period	
<i>Tidal Height (LAT) [m]</i>			
HAT		1.42	
MHWS		1.27	
MHWN		1.00	
MSL		0.74	
MLWN		0.47	
MLWS		0.18	
LAT		0.00	

28.21 Further Information on Submarine Cable Installations

Document Title	Source
Review of Cabling Techniques and Environmental Effects Applicable to the Offshore Wind Farm Industry, 2008	BERR (Department for Business Enterprise and Regulatory Reform)
Cable Burial Risk Assessment Methodology – Guidance for the Preparation of Cable Burial Depth of Lowering Specification, 2015	The Carbon Trust – Document CTC835
Technical Brochure 379: Update of Service Experience of HV Underground and Submarine Cable Systems, 2009	CIGRE
Technical Brochure 398: Third-party damage to Underground and Submarine Cable Systems, 2009	CIGRE
Technical Brochure 415: Test Procedures for HV Transition Joints and for Rated Voltages 30kV (Um = 36kV) up to 500kV (Um = 550kV), 2010	CIGRE
Technical Brochure 483: Guidelines for the Design and Construction of AC Offshore Substations and Wind Power Plants, 2011	CIGRE
Technical Brochure 490: Recommendations for Testing of Long AC Submarine Cables with Extruded Insulation for System Voltage Above 30 (36) to 500 (550) kV, 2012	CIGRE
Technical Brochure 496: Recommendations or Testing DC Extruded Cable Systems for Power Transmission at a Rated Voltage of up to 500kV, 2012	CIGRE
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Technical Brochure 623: Recommendations for Mechanical Testing of Submarine Cables, 2015	CIGRE
Sharing Lessons Learned and Good Practice in Offshore Transmission: A Report for 'The Crown Estate', 2014	DNV-GL
Subsea Power Cables in Shallow Water for Renewable Energy Applications, 2014	DNV-GL – Document DNV-RP-J301
Recommendation 1-14A: Recovery of Out of Service Cables	International Cable Protection Committee (ICPC)
Recommendation 2-11B: Cable Routing and Reporting Criteria	International Cable Protection Committee (ICPC)
Recommendation 3-10C: Telecommunications Cable and Oil Pipeline/Power Cables Crossing Criteria	International Cable Protection Committee (ICPC)
Recommendation 4-8C: Coordination Procedures for Repair Operations Near in-service Cable Systems	International Cable Protection Committee (ICPC)
Recommendation 6-10A: Actions for Effective Cable Protection (Post-Installation)	International Cable Protection Committee (ICPC)
Recommendation 7-6D: Offshore Civil Engineering Work in the Vicinity of Active Submarine Cable Systems	International Cable Protection Committee (ICPC)
Recommendation 8-9A: Procedure to be Followed Whilst Offshore Seismic Survey Work is Undertaken in the Vicinity of Active Submarine Cable Systems	International Cable Protection Committee (ICPC)
Recommendation 9-5B: Minimum Technical Requirements for a Desktop Study	International Cable Protection Committee (ICPC)
Recommendation 10-4A: The Minimum Requirements for Load and Lay Reporting and Charting	International Cable Protection Committee (ICPC)
Recommendation 13-2C: The Proximity of Offshore Renewable Wind Energy Installations and Submarine Cable Infrastructure in National Waters	International Cable Protection Committee (ICPC)
Recommendation 14-2A: Basic Power Safety Procedures that are to be Followed by Marine Repair Operators and Terminal Station Personnel During Subsea Cable Repair Activities	International Cable Protection Committee (ICPC)

Document Title	Source
Recommendation 15-2: Procedure to be Followed Whilst Marine Aggregate Extraction, Dredging or Mining is Undertaking in the Vicinity of Active Submarine Cable Systems	International Cable Protection Committee (ICPC)
Recommendation 16-1A: Considerations for Marking Submarine Cables	International Cable Protection Committee (ICPC)
Recommendation 18-1A: Minimum Technical Requirements for the Acquisition and Reporting of Submarine Cable Route Surveys	International Cable Protection Committee (ICPC)
Power Cables with Extruded Insulation and Their Accessories for Rated Voltages Above 30kV (Um = 36kV) up to 150kV (Um = 170kV) – Test Methods and Requirements, 2020	International Electro-Technical Commission – Document 60840 Edition 5
Power Cables with Extruded Insulation and Their Accessories for Rated Voltages Above 150kV (Um = 170kV) up to 500kV (Um = 500kV) – Test Methods and Requirements	International Electro-Technical Commission – Document 62067 Edition 2
Guidance Notes for Planning and Execution of a Geophysics and Geotechnical Ground Investigation for Offshore Renewable Energy Developments, 2014	Offshore Site Investigation and Geotechnical Committee (OSIG)
Guidelines on Best Environmental Practice (BEP) in Cable Laying and Operation, 2012	OSPAR Commission
Procedure for Subsea Cable Route Selection, 2004	Scottish and Southern Energy
Guideline 6: The Proximity of Offshore Renewable Energy Installations and Submarine Cable Infrastructure in UK Waters, 2016	Subsea Cables Uk (Now European Subsea Cables Association – ESCA)
Guideline 8: Submarine Cable Decommissioning, 2016	Subsea Cables Uk (Now European Subsea Cables Association – ESCA)
Guideline 14: Power Cable Installation, 2018	Subsea Cables Uk (Now European Subsea Cables Association – ESCA)
Guideline 15: Power and Renewable Energy Cable Repair, 2018	Subsea Cables Uk (Now European Subsea Cables Association – ESCA)
Guideline 17: Testing of AC and DC Subsea Power Cables, 2016	Subsea Cables Uk (Now European Subsea Cables Association – ESCA)
Export Transmission Cables for Offshore Renewable Installations: Principle of Cable Routing and Spacing, 2012	The Crown Estate
Export Transmission Cables for Offshore Renewable Installations: Guideline for Leasing of Export Cable Routes/Corridors, 2012	The Crown Estate
Submarine Cables and Offshore Renewable Energy Installations Proximity Study, 2012	The Crown Estate

28.22 Cost of Energy Determination - Data and Results Table

Asset Number	Total Power Demand (MW)	Uptime Factored Total Power Demand (MW)	Total Energy Demand (MW)	Uptime factored Total Energy Demand (MW)	Estimated Fuel Gas Consumption (kg/s)	Cost of Fuel - High (£MM/Yr)	Cost of Fuel - Medium (£MM/Yr)	Cost of Fuel - Low (£MM/Yr)	Cost of Fuel - Feb 2022 (£MM/Yr)	CO ₂ Emissions (tonne/Yr)	Total ETS Cost (£MM/Yr)	Reported OPEX (£MM/Yr)	Normalised OPEX (£MM/Yr)	CAPEX (£MM/Yr)	GT life extension / replacement Cost (£MM)	Gas Deficiency Year	Is Waste Heat Recovery used?	Energy Cost - High (£/MWh)	Energy Cost - Medium (£/MWh)	Energy Cost - Low (£/MWh)	Energy Cost - Feb 2022 (£/MWh)	Energy Cost - Fuel Only - High (£/MWh)	Energy Cost - Fuel Only - Medium (£/MWh)	Energy Cost - Fuel Only - Low (£/MWh)
1	35.0	31.5	42.0	37.8	2.72	56.5	33.9	22.6	67.8	214091.4	12.8	1.9	1.9	0.4	0.0	2014	Y	216.4	148.2	114.1	250.6	170.6	102.4	68.3
2	12.0	10.8	12.0	10.8	0.93	19.4	11.6	7.7	23.2	73402.8	0.0	0.5	0.5	0.2	37.0	2020	N	251.7	169.8	128.8	292.7	204.8	122.9	81.9
3	25.1	22.6	25.1	22.6	1.95	40.5	24.3	16.2	48.6	153534.1	9.2	0.0	1.9	0.0	0.0	2022	N	261.1	179.2	138.3	302.1	204.8	122.9	81.9
4	14.7	13.2	14.7	13.2	1.14	23.7	14.2	9.5	28.4	89734.9	0.0	0.0	1.9	0.0	0.0	2021	N	221.5	139.6	98.7	262.5	204.8	122.9	81.9
5	60.0	54.0	73.0	65.7	4.66	96.9	58.1	38.7	116.2	367013.8	22.0	3.6	3.6	3.5	0.0	2025	Y	218.9	151.6	117.9	252.6	168.3	101.0	67.3
6	30.0	27.0	38.5	34.7	2.33	48.4	29.1	19.4	58.1	183506.9	11.0	1.8	1.8	2.5	0.0	2022	Y	210.0	146.1	114.2	241.9	159.6	95.7	63.8
7	5.0	4.5	6.0	5.4	0.39	8.1	4.8	3.2	9.7	30584.5	0.0	1.1	1.1	0.9	0.0	2024	Y	213.5	145.2	111.1	247.6	170.6	102.4	68.3
8	28.0	25.2	33.6	30.2	2.17	45.2	27.1	18.1	54.2	171273.1	10.3	2.0	2.0	0.0	0.0	2021	Y	216.9	148.7	114.5	251.1	170.6	102.4	68.3
9	14.5	13.1	17.4	15.7	1.13	23.4	14.0	9.4	28.1	88695.0	0.0	6.4	6.4	0.0	0.0	2040	Y	217.5	149.3	115.1	251.6	170.6	102.4	68.3
10	21.0	18.9	21.0	18.9	1.63	33.9	20.3	13.6	40.7	128454.8	7.7	1.2	1.2	0.0	0.0	2021	N	258.7	176.8	135.9	299.7	204.8	122.9	81.9
11	4.0	3.6	4.8	4.3	0.31	6.5	3.9	2.6	7.7	24467.6	0.0	0.0	1.9	0.0	12.0	2040	Y	253.6	185.3	151.2	287.7	170.6	102.4	68.3
12	31.6	28.4	43.6	39.2	2.45	51.0	30.6	20.4	61.2	193293.9	11.6	2.0	2.0	0.2	21.6	2040	Y	194.8	135.5	105.8	224.5	148.4	89.1	59.4
13	31.0	27.9	31.0	27.9	2.41	50.0	30.0	20.0	60.1	189623.8	11.4	3.3	3.3	0.0	18.0	2040	N	272.2	190.3	149.3	313.2	204.8	122.9	81.9
14	21.5	19.4	26.5	23.9	1.67	34.7	20.8	13.9	41.7	131513.3	7.9	2.0	2.0	0.2	12.0	2040	Y	220.2	153.7	120.5	253.4	166.1	99.7	66.5
15	36.4	32.8	36.4	32.8	2.82	58.8	35.3	23.5	70.5	222655.0	13.4	1.8	1.8	0.3	7.2	2040	N	261.2	179.3	138.4	302.2	204.8	122.9	81.9
16	59.5	53.6	69.5	62.6	4.62	96.1	57.6	38.4	115.3	363955.3	21.8	0.0	1.9	0.0	3.0	2040	Y	219.3	149.1	114.1	254.3	175.3	105.2	70.1
17	2.2	2.0	2.2	2.0	0.17	3.6	2.1	1.4	4.3	13457.2	0.0	0.2	0.2	0.1	2.0	2021	N	230.7	148.8	107.9	271.7	204.8	122.9	81.9
18	11.0	9.9	11.0	9.9	0.85	17.8	10.7	7.1	21.3	67285.9	0.0	0.5	0.5	0.0	2.0	2023	N	212.8	130.9	90.0	253.8	204.8	122.9	81.9
19	7.0	6.3	7.0	6.3	0.54	11.3	6.8	4.5	13.6	42818.3	0.0	0.6	0.6	0.1	0.0	2021	N	218.2	136.3	95.3	259.1	204.8	122.9	81.9
Average	23.7	21.3	27.1	24.4	1.8	38.2	22.9	15.3	45.8	144703	7.3	1.94	1.9	0.4	6.0	2028.2	-	230.0	156.0	119.0	267.0	184.9	111.0	74.0
Installation High	60.0	54.0	73.0	65.7	4.7	96.9	58.1	38.7	116.2	367014	22.0	6.4	6.4	3.5	37.0	2040.0	-	272.2	190.3	151.2	313.2	204.8	122.9	81.9
Installation Low	2.2	2.0	2.2	2.0	0.2	3.6	2.1	1.4	4.3	13457	0.0	0.0	0.2	0.0	0.0	2014.0	-	194.8	130.9	90.0	224.5	148.4	89.1	59.4

Average GT Efficiency25 %

Gas LHV46.4 MJ/kg

Gas Price (High)150 p/Therm51.2 £/MWh

Gas Price (Medium)90 p/Therm30.7 £/MWh

Gas Price (Low)60 p/Therm20.5 £/MWh

Gas Price (Feb 2022)180 p/Therm61.4 £/MWh

kg CO₂ per kg Gas2.5

ETS Clearing Price60 £/tonne

Uptime90 %



29. Supporting Documents

Document Number	Revision	Title
Layout Drawings – Main Hub		
OGA201-D-001-L-GAD-0001	B1	Main Hub - General Arrangement - Plot Plan
OGA201-D-001-L-GAD-0002	B1	Main Hub - General Arrangement - Isometric View - Sheet 1
OGA201-D-001-L-GAD-0003	B1	Main Hub - General Arrangement - Isometric View - Sheet 2
OGA201-D-001-L-GAD-0004	B1	Main Hub - General Arrangement - Isometric View - Sheet 3
OGA201-D-001-L-GAD-0005	B1	Main Hub - General Arrangement - Isometric View - Sheet 4
OGA201-D-001-L-LAD-0001	B1	Main Hub - Layout - Transformer Module
OGA201-D-001-L-LAD-0002	B1	Main Hub - Layout - 100MW Conversion Module
OGA201-D-001-L-LAD-0003	B1	Main Hub - Layout - 200MW Conversion Module
OGA201-D-001-L-LAD-0004	B1	Main Hub - Layout - Switchboard Module
OGA201-D-001-L-LAD-0005	B1	Main Hub - Layout - Combined Cycle Gas Turbines
Layout Drawings – Sub Hub		
OGA201-D-002-L-GAD-0001	B1	Sub Hub - General Arrangement - Plot Plan
OGA201-D-002-L-GAD-0002	B1	Sub Hub - General Arrangement - Isometric View - Sheet 1
OGA201-D-002-L-GAD-0003	B1	Sub Hub - General Arrangement - Isometric View - Sheet 2
OGA201-D-002-L-GAD-0004	B1	Sub Hub - General Arrangement - Isometric View - Sheet 3
OGA201-D-002-L-GAD-0005	B1	Sub Hub - General Arrangement - Isometric View - Sheet 4
OGA201-D-002-L-LAD-0001	B1	Sub Hub - Layout - Transformer Module
OGA201-D-002-L-LAD-0002	B1	Sub Hub - Layout - 200/100MW Conversion Module
OGA201-D-002-L-LAD-0003	B1	Sub Hub - Layout - Switchboard Module
Electrical Single Line Diagrams		
OGA201-D-001-E-SLD-0001	B1	MVDC Arrangement Overview Single Line Diagram
OGA201-D-001-E-SLD-0002	B1	MVDC Arrangement Main Hub Single Line Diagram
OGA201-D-001-E-SLD-0003	B1	MVDC Arrangement Sub Hub 1 Single Line Diagram
OGA201-D-001-E-SLD-0004	B1	MVDC Arrangement Sub Hub 2 Single Line Diagram
OGA201-D-001-E-SLD-0005	B1	MVDC Arrangement Sub Hub 3 Single Line Diagram
OGA201-D-001-E-SLD-0006	B1	MVDC Arrangement Sub Hub 4 Single Line Diagram
3D Models		
OGA201-D-001-L-MOD-0001	A1	Main Hub 3D Navisworks Layout Model
OGA201-D-002-L-MOD-0001	A1	Sub Hub 3D Navisworks Layout Model
Electrical Power System Models		
OGA201-D-001-E-MOD-0001	B1	CNS Cluster DIgSILENT Model
OGA201-D-001-E-MOD-0002	B1	SNS Cluster DIgSILENT Model