North Sea Transition Authority Decarbonisation Project

REPORT

Decarbonisation of the North Sea Study Report **Vol 1**

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katoni ENGINEERING

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/2/	https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators	
/3/	https://dudgeonoffshorewind.co.uk/	
/4/	https://ember-climate.org/data/carbon-price-viewer/	
/5/	Renewables Generation Modelling Report	OGA201-D-001-Z-REP-0008
/6/	Platform Clustering Study	OGA201-D-001-Z-REP-0008
/7/	https://www.nstauthority.co.uk/media/7809/emissions-report_141021.pdf	Emissions Monitoring Report Date of publication: October 2021 Emissions Monitoring Report

ACRONYMS & ABBREVIATIONS

ABEX	Abandonment Expenditure
AC	Alternating Current
BEIS	Department for Business, Energy, and Industrial Strategy
CAPEX	Capital Expenditure
CNS	Central North Sea
COP	Cessation of Production
DC	Direct Current
EPC	Engineering, Procurement, and Construction
ETS	Emissions Trading Scheme
FPSO	Floating, Production, Storage, Offloading Vessel
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
MVAC	Medium Voltage Alternating Current
MVDC	Medium Voltage Direct Current
MW	Megawatt (unit of energy)
NSTA	North Sea Transition Authority
NUI	Normally Unattended Installation
OMF	Outer Moray Firth
OWA	Offshore Wind Array
OWF	Offshore Wind Farm
REBEX	Renewal Expenditure
SNS	Southern North Sea
UKCS	United Kingdom Continental Shelf

1. Foreword by Study Director, James Keachie

The kernels of this study were identified through our work with existing clients such as CNR, Dana Petroleum and Ithaca. During study work that was aimed at assessing the potential for electrification and emissions reduction, we found that common issues arose as we sought after standalone solutions.

A thorough understanding of the Brownfield Modifications and Power issues associated with operating assets allowed our team to develop the concept of our Main Hub and Sub Hubs to service individual platforms. The concepts in this document illustrate a design for an offshore electrical power network that would act as an interface between distributed sources of renewable power and Oil & Gas installations.

Importantly the concept also allows for the minimisation of equipment, modifications and infrastructure required on the assets themselves. Instead, control and safety equipment, as well as power transformation and distribution equipment, would be located on new, dedicated infrastructure. Furthermore, the design provides a large reduction in emissions in the most economical manner based on a range of study inputs.

The findings have been presented in this study with a range of inputs based on what we know today, with an eye on the future of technological development.

The aim of the research is to contribute to a debate about how the NSTA and partners in the UKCS with common interests can work together to reduce emissions while retaining assurance of production.

This study was designed, managed, and delivered by Katoni Engineering but we would like to thank the following partners:

SEVAN SSP | GE Power Conversion | TechnipFMC | CORE-POWER | SPC Network

"I would like to personally thank all the Operators who contributed significantly to this research and without whom we could not have provided a robust piece of research. I'd also like to thank the team at Katoni for their support and efforts through early 2022."

James Keachie of Katoni Engineering
Study Director and Head of Consulting

2. Executive Summary

The study which follows presents an industrialised approach to large scale electrification of the UKCS with a basin wide approach. The research has found that an economically viable solution could exist for full or partial electrification of the Central North Sea (CNS) which can in turn reduce emissions on platform by up to 78% and estimated CNS emissions by up to 50% (from 2.9 mmtCO2 pa to 1.45 mmtCO2 pa).

The concept to achieve these emissions reductions is based on creating an offshore 'island' grid without the requirement for connection to the UK national grid.

This offshore grid can be powered by a range of renewable sources although initially the assumption is that it would be powered by an 'efficient' offshore wind solution. In addition to providing reliability and reducing the risk of downtime for asset operators, thermal capacity in the form of highly efficient gas turbines would be available to the grid.

While the concept of an island grid is simple, the technical solutions required to make this work are complex but not insurmountable. Indeed, many of the technologies that we believe can be applied have already been proven in other industries and are working today.

The main challenges faced are therefore not related to brownfield modifications on assets, nor the creation of offshore infrastructure but are power / distribution related and security of supply.

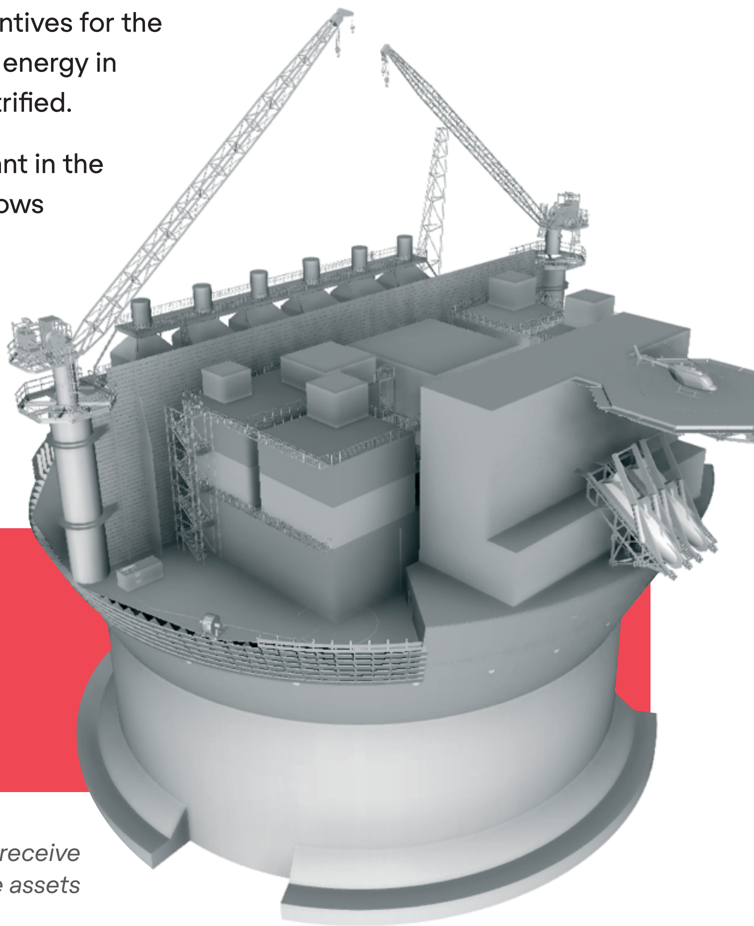
Economically the success of this concept is driven by gas and emissions costs. The cost of delivery is relatively modest and is comparable to oil and gas developments of this scale.

With the right economic regulation structure including incentives for the construction of the infrastructure and use of decarbonised energy in the fields it may be that large areas of the CNS can be electrified.

Katoni looks forward to continuing to be an active participant in the decarbonisation of the North Sea and believe this study shows that oil and gas production can sit alongside reduced emissions.

3D model of the proposed main hub that will receive and distribute renewable power to offshore assets.

For more detail please refer to the Technical Reports which are available at www.katoni.com/netzero



3D model of the proposed main hub that will receive and distribute renewable power to offshore assets

3. The big question and the challenges

What can be done to debcarbonise the UKCS and what role does electrification have in this?

Katoni has undertaken a range of studies for clients around the North Sea and had consistently found challenges associated with the operation of platforms and modifications required with almost all electrification concepts. Katoni and our clients were finding:

- Concerns over security of supply with renewable generation
- Significant challenges associated with receiving subsea power at an elevated voltage (suitable for efficient transmission)
- Challenges stepping that down power to match the working voltage of the platform.
- Free space and weight capacity constraints
- To provide security of supply, renewable sources will need to be distributed, diversified and over provisioned.
- How best to utilise electrical power on platforms

All of these issues or concerns were working against electrification proposals by increasing the scale and complexity of any receiving equipment making it less likely that an existing platform can accommodate it even with costly modifications.

However, in spite of these barriers there is a desire to find solutions from our clients.

3.1 The Hypothesis

We held the evidenced view that the biggest barrier to delivering electrification was either operational or modifications based. We hypothesised that with a reliable electrical power source that any platform could be electrified and therefore the challenge was creating a solution that any platform could 'plug into'. The obvious solution seemed to be one that:

- Removed the need for expensive and technically challenging modifications on platforms; and
- Could generate enough reliable power to ensure operational integrity / uptime was ensured

Our feedback and discussions with our Oil and Gas clients suggest the biggest technical challenge to overcome in achieving offshore electrification is the interface between distributed generation from renewable sources with the existing electrical power distribution systems on offshore installations.

It was our belief that it would be possible to design and specify an interface network that would sit between the renewable generation and the receiving Oil and Gas installations that require secure sources of lower emissions power. The network would be generation source agnostic to allow for maximum diversity of sources to be utilised.

Thanks to the NSTA £1m competition to develop concepts to answer this big question we, at Katoni, with partners were successful in an application to develop our **Main / Sub Hub Concept**.

3.2 Project Objective

In the Katoni submission to the NSTA the stated study objective was 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 key area of focus was evaluating a consumer driven technology solution

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.

3.3 What is the Solution?

Based on a Hub and Spoke model, it is anticipated that an individual system would comprise primarily of a floating Main Hub Substation (Main Hub) which could incorporate generation, transformation, storage, controls, and distribution.

From the Main Hub several smaller Sub-distribution Hubs (Sub Hubs) could be supplied with bulk electrical power. Equipment on the Sub Hub would then provide the final transformation and power regulation to provide suitable inputs to a number of individual Oil & Gas installations. The final cable run from the Sub Hub 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 was safe and reliable with the ability to reduce fault currents and harmonics to minimise upgrades or modifications being made to the Oil & Gas installation itself.

The Main Hub would incorporate sufficient conventional power generation and energy storage to provide a secure supply of electrical power to the Oil & Gas installations, even during times when power from renewables is insufficient.

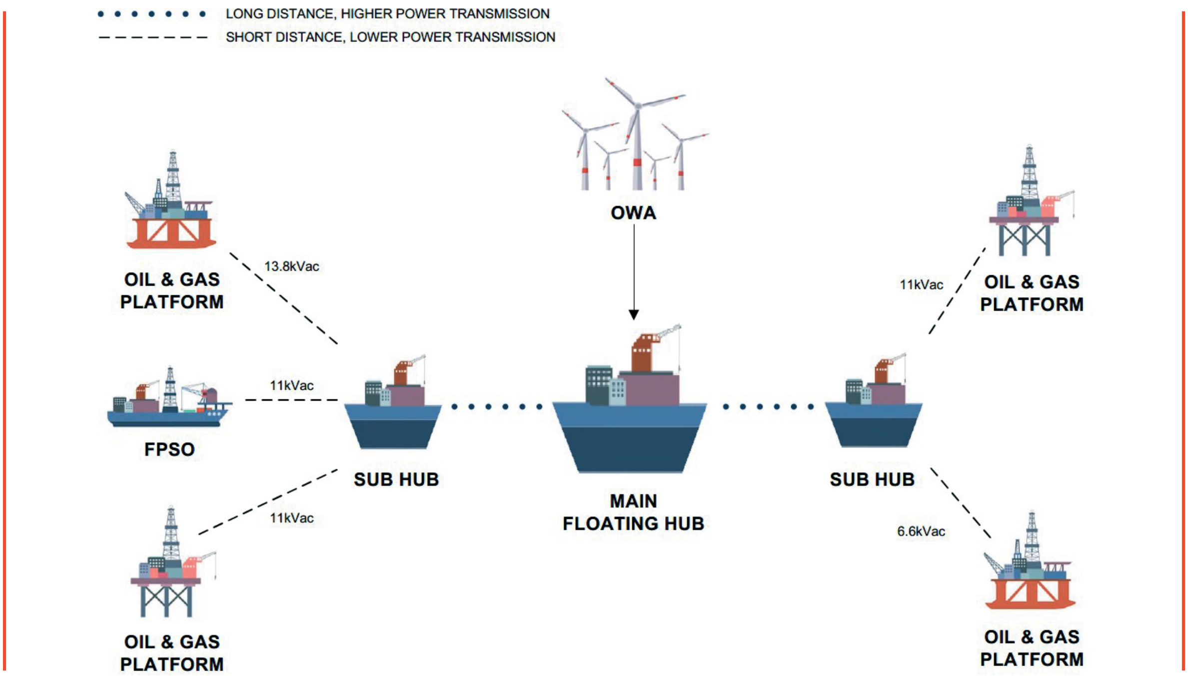


Figure 3-1 - Simplified Topology of Power Network

As shown in Figure 3-1 the system would comprise of:

- Offshore Wind Array (OWA)
- Floating Main Hub Substation (Main Hub)
  - OWA Receipt
  - Local Power Generation
  - Medium Voltage Direct Current (MVDC) Power Transmission
- Local Sub-Distribution Hubs (Sub Hubs)
  - MVDC Receipt
  - Medium Voltage Alternating Current (MVAC) Distribution

3.3.1 The Main Hub

The Main Hub is the key facilitator in distribution of power. The image below details the detailed concept which Katoni have developed for the Main Hub. This design carries all necessary equipment to distribute 450 to 500 MW of power and facilitates the interface between renewable energy sources, thermal power generation and transforms the power supply for high power, long distance transmission.

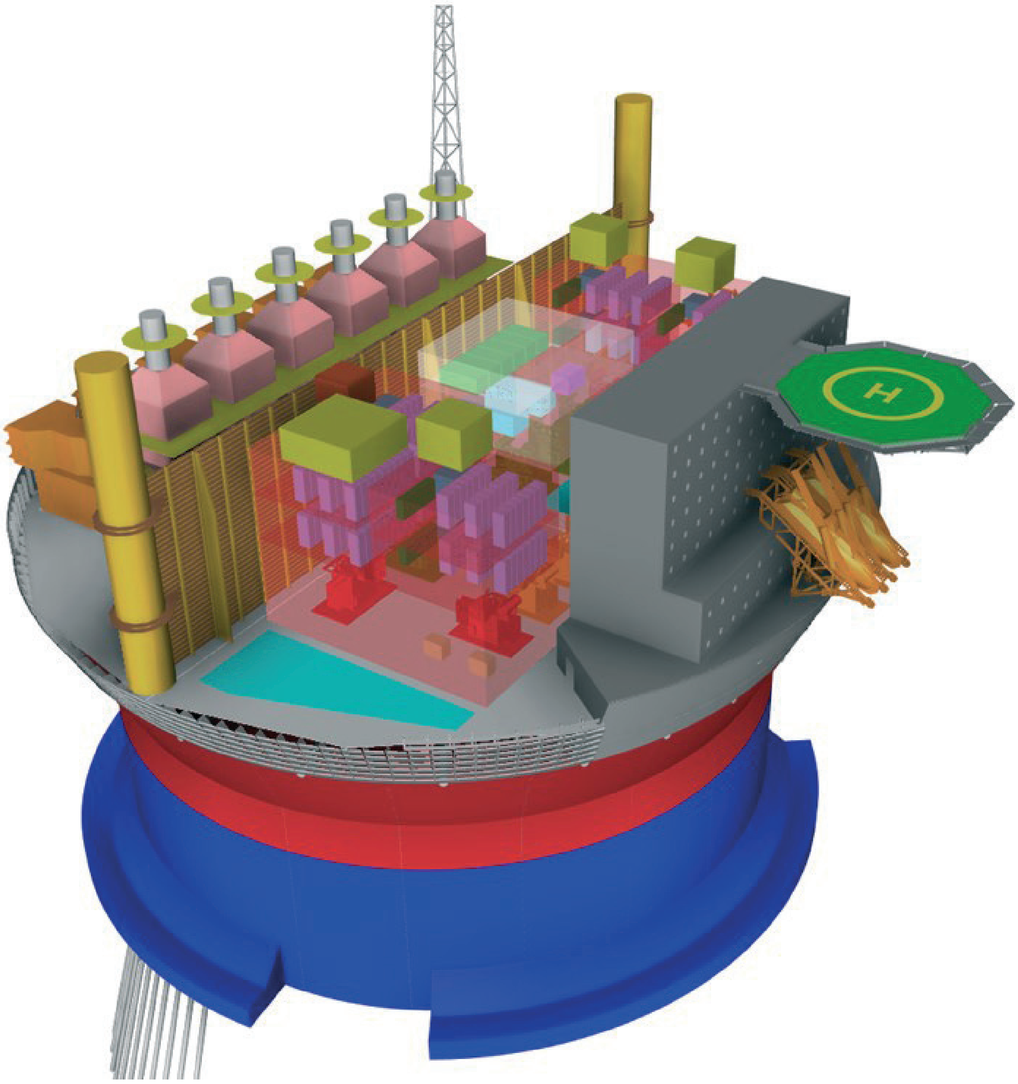


Figure 3-2 Main Hub Solution

The Main Hub Substation key details are:

- Based on a floating concept, in this case a Sevan 1000 (90m diameter hull)
- Renewable generation sources reception and control facilities (can act as substation for wind farm
- Include local generation and storage for security of supply (6 off Combined Cycle Gas Turbines)
- HV distribution via subsea cable to (multiple) Sub-distribution Hubs via MVDC transmission
- Has the potential to incorporate green storage technologies
- Repeatability of design to promote economies of scale to reduce cost of large electrical distribution equipment (i.e. multiple hubs built to satisfy different regional requirements)

3.3.2 The Sub Hubs

The Sub Hub acts as the critical interface to facilitate electrification. It acts as the interface for the power distribution system and transforms the power for use on oil and gas installations. Each Sub Hub will include all necessary equipment required to facilitate a "plug in" solution on the oil and gas asset. This will include voltage and frequency conversion, fault correction, any power compensation and distribution control.

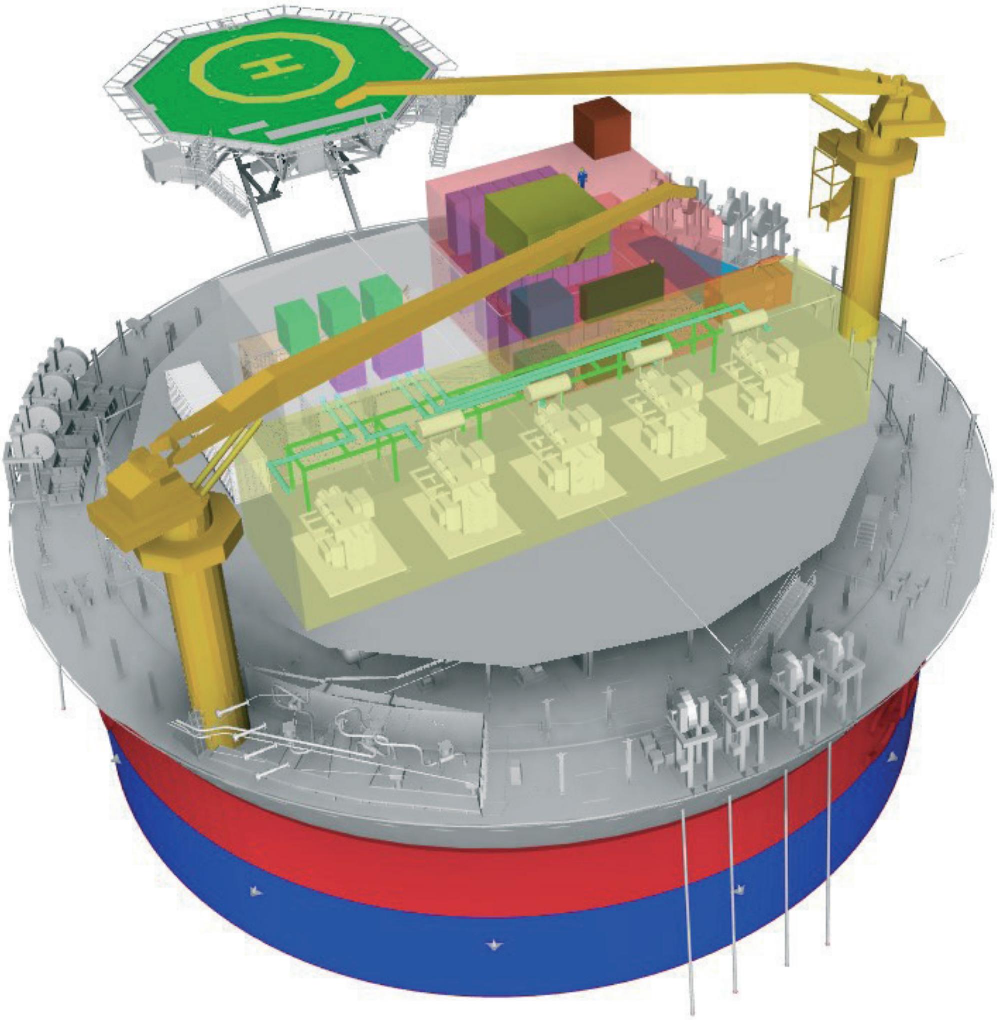


Figure 3-3 Sub Hub Solution

This is an example of one of the local Sub-Distribution Hubs:

- Smaller hubs located close to existing Oil and Gas infrastructure allowing for efficient transmission over a short distance at a voltage level matching the platforms in the vicinity
- Based on Sevan 300 unit, however jack-up alternative option depending on water depth
- Would receive power from the Main Floating Hub via subsea cable
- Contain appropriate transformation and conversion equipment to meet local platform requirements, e.g. 6.6kV, 11kV, 13.6kV or 33kV

4. Project Overview

4.1 Asset Evaluation and Selection

Assets were evaluated to determine their applicability for full or partial electrification based on the following:

- Power Requirements
- Geographical Location
- Existing Asset Infrastructure

Cessation of Production (COP) date was excluded from the basis of the study based on electrification of the North Sea potentially changing the strategy of assets lifetime. Additionally, assets may benefit during the decommissioning phase from having reliable, low carbon power available to support Plug & Abandon and make-safe operations which can often last for 4 to 5 years.

4.1.1 Asset Data

Katoni 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 evaluated were:

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

4.1.2 International Boundaries

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

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

Cross border assets were not considered in the Clustering Assessment.

4.2 Study Boundaries

Input to the system was considered based on either:

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

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

[1] The economic analysis assumes the power source is exogenous and so if in future a better or cheaper source of power can be found this would have advantages to the concept.

5. Technical Solution

The topography of the system is outlined in Figure 3-1. The purpose of the system is to transmit relatively large quantities of power over long distances from a centralised power hub (the Main Hub).

This section provides a deeper technical briefing on the how renewable and supplementary (thermal) power is generated and then transmitted to Sub-Hubs and then on to platforms. Importantly this section explores cabling and transmission voltages.

5.1 Power Generation

5.1.1 Renewables Input

Renewables input to the Main Hub has been based on Offshore Wind Arrays, an increasingly common technology in the North Sea. However, based on the system design, any alternative or complementary renewable source could also be linked into the Main Hub via MVAC cabling, utilising voltages anywhere from 11kV upwards.

Wind power was considered as the primary renewable generation source based on its Technical Readiness Level, but as additional renewable sources mature and can be utilised at scale, then these technologies can also be incorporated. Systems such as wave and tidal power could become key inputs in the future and would be viewed as complementary to wind systems, acting to further reduce reliance on thermal power generation.

5.1.2 Supplementary Power System

Supplementary power provided by multiple combined cycle gas turbines (CCGTs) was considered necessary to support power generation from wind to compensate for low wind speed periods.

The key reason that a supplementary power system was used rather than reliance on existing on platform power generation for this concept is:

1. To promote higher efficiencies by centralising and utilising combined cycle. Utilising the power generation in this configuration could achieve up to 55% efficiency.
2. To minimise platform modifications and reduce the high maintenance burden of platform power generation systems. By removing the requirement for on platform power generation, the generator incoming switchgear can be repurposed for subsea power import connections.

Early in the study, the concept of using a power sharing arrangement between platforms using existing power generation equipment was dismissed. Centralising power generation efficiency and emissions reduction potential was considered paramount to the overall concept.

5.2 Power Transmission

5.2.1 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).

There are two main technological approaches to this challenge – transmitting at a high voltage alternating current (HVAC) or a medium/high voltage direct current (MVDC or HVDC). The choice of using AC or DC transmission typically comes down to cable length and power transmitted. DC typically suits projects with higher power demands and/or longer distances and HVDC is the defacto standard technology used for bulk power interconnectors between countries.

MVDC is an emerging technology, already prevalent in onshore industries such as rail, and being considered for offshore and subsea applications. In MVDC the DC link operates at a lower voltage (typically below +/-150kV) which reduces the cost and size of the power electronics and the DC cables.

The use of power electronics eliminates the need for costly reactive compensation for long submarine links which are a feature of HVAC transmission systems offshore. Power electronics also provide better control over power quality than simple AC transmission.

Additionally, a DC link requires fewer cables than HVAC. When routing substantial amounts of subsea infrastructure, such as being nominated by this concept, the costs of HVAC cabling vs MVDC cabling was estimated to be between 40 to 50% higher.

The disadvantage of DC transmission is the requirement for power electronic conversion equipment at each end of the link. If MVDC was used to power a platform directly the conversion equipment would need to be located on the platform itself. In this concept the MVDC equipment is located on the Sub Hub, which outputs the required AC power for the connected assets and so removes much of the burden of topsides modifications.

5.2.2 Low Power Transmission

5.2.2.1 CNS/OMF

The final electrical connection between the Sub Hub and the CNS/OMF assets themselves is a relatively low power (<40MW in most cases), short distance connection which more readily suits itself to Medium Voltage Alternating Current (MVAC).

As the project aim was to deliver power at the asset's native voltage this meant transmission voltages of 3.3kV, 6.6kV, 11kV, 13.8kV or 33kV based on the spread of assets considered.

More importantly the project aim was to minimise the requirement for modifications to the Oil & Gas assets themselves. If a different transmission technology was used (either a higher AC voltage, or a DC conversion) then additional equipment (for example transformers, switchgear and power electronics) would be required which would take up substantial real estate on assets that typically have little capacity for expansion.

For the lower asset voltages, particularly 6.6kV and below, this meant the distance the asset could be from the Sub Hub was very limited. In these cases, it may be recommended to investigate installing a new topsides 11 kV or 33kV switchboard, or alternatively the use of subsea transformer technology which itself is maturing. This is discussed further in the Platform Modification Section of the Volume 2 Report.

5.2.2.2 SNS

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 50 kW. 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. This shift to renewable technology enables assets to become NUI on a more permanent basis.

The concept for the SNS is to power the gas gathering platforms in a similar way as the CNS/OMF as these are high demand assets. For other lower demand platforms, it was considered that from each Sub Hub a MVAC radial or ring circuit would be created to power a number of platforms in the vicinity of the Sub Hub. The wellhead platforms, which are all Low Voltage, would require a containerised switchgear and transformer solution to receive power from the distribution circuit.

6. Minimising Brownfield Modifications

The core goal for this study has been to design a system which can interface as simply to platforms as possible. Removing the complexity in redesign and fundamentally to removing barriers to electrification.

The principal in this concept is to remove the requirement for any on asset power transformation including:

- Changes to voltage
- Changes to frequency
- Changes to phase
- Changes to current
- Requirement for reactive power compensation
- Power management from a large network

Facilitating any of these requirements on an asset will require significant modifications and investment due to the size and weight of equipment required to achieve this.

A 66 kV to 11 kV 50 MVa transformer weights approximately 120 tonnes and is a 7m x 5m x 5m cuboid. Very few platforms could easily incorporate an item of this size, and this is only one of many pieces of equipment required.

The concept developed for this study involves running pre-conditioned power to each platform from a small distribution facility. This facility will provide all of the:

- Changes to voltage
- Changes to frequency
- Changes to phase
- Changes to current
- Reactive power compensation
- Power management from a large network

> Essentially the concept provides each asset with a direct replacement for onboard power generation.

The system is designed to simply disconnect existing power generation and feed a high availability supply direct into the existing electrical distribution system, via the previous power generation connections. As most platforms have multiple power generators due to sparing requirements, this offers the ability to run multiple cables allowing larger amounts of power to be distributed than a single cable solution. This also offers some protection from full interruption to supply from failure of a subsea cable, or on asset switchgear.

This allows for minimal on asset expenditure to introduce this power into platforms. The true costs of brownfield modifications associated this concept will be dependent on consumers appetite for electrification and changes made to the process to best exploit the new power source available. Modifications could include:

- Electrification of direct drive generators
- Electrification of heat
- Implementation of fired boilers
- Investment in gas export routes

The suitability of these modifications will be required to be assessed on an asset by asset basis, based on detailed analysis conducted by the operators. This concept is designed to deliver the foundations for these decisions to be made.

7. Energy Mix

7.1 Power Demand

For the base case deployment of the infrastructure in the Central North Sea it is considered 19 assets can be fully or partially electrified. The basis for this is considered as:

The base electrical demand of these 19 assets is considered to be approximately 330 MW, and from work carried out during the study on obtaining information from operators it is actually considered that electrical demand provided by on asset generation is closer to 285 MW for power generation.

In addition to on platform power generation the following is considered as a general basis to interpret actual absorbed power requirements for mechanically driven equipment.

- Generalised 2 × 50% design for direct drive equipment
- Reduction in gas compression requirements due to mature fields
- More efficient electrical drives vs mechanical drives. (less mechanical losses)
- Of the assets installed direct drive equipment power capacity a total 40% has been utilised as the actual demand used by direct drives.

From the total installed capacity of these assets mechanical drives it is considered there is an additional 135 MW of required demand .

In short it is considered that the 420 MW of power provided would provide near full electrification of all targeted assets, in combination with increased operating efficiency. One area this may not cover is full process heating offset. Process heat has not been included in the electrical demand assessments as quality data for process heating requirements is not readily available, and from the assets considered very few of them have operational waste heat recovery systems.

7.2 Power Generation

The study details analysis of 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 was evaluated to characterise the operating efficiency of the system, determine the backup power requirements needed from conventional power generation and was utilised to compareinstalled cost of wind power vs installed conventional power generation.

The modelling evaluated the optimum balance of wind power and conventional power generation 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.

The Dudgeon wind farm located off the East Coast of the UK was utilised as the basis of all analysis conducted. This wind farm is a larger scale of offshore wind, utilising the same or similar wind turbines as Hywind, the first full-scale floating offshore wind development. The average capacity factor[2] for Dudgeon is 48%.

[2] Capacity factor is a ratio of the actual electrical energy output over a given period of time to the maximum possible electrical energy output over that same period. Wind farms are a variable source of electrical energy due to the fluctuating nature of wind and so capacity factors are lower than for conventional thermal power plants.

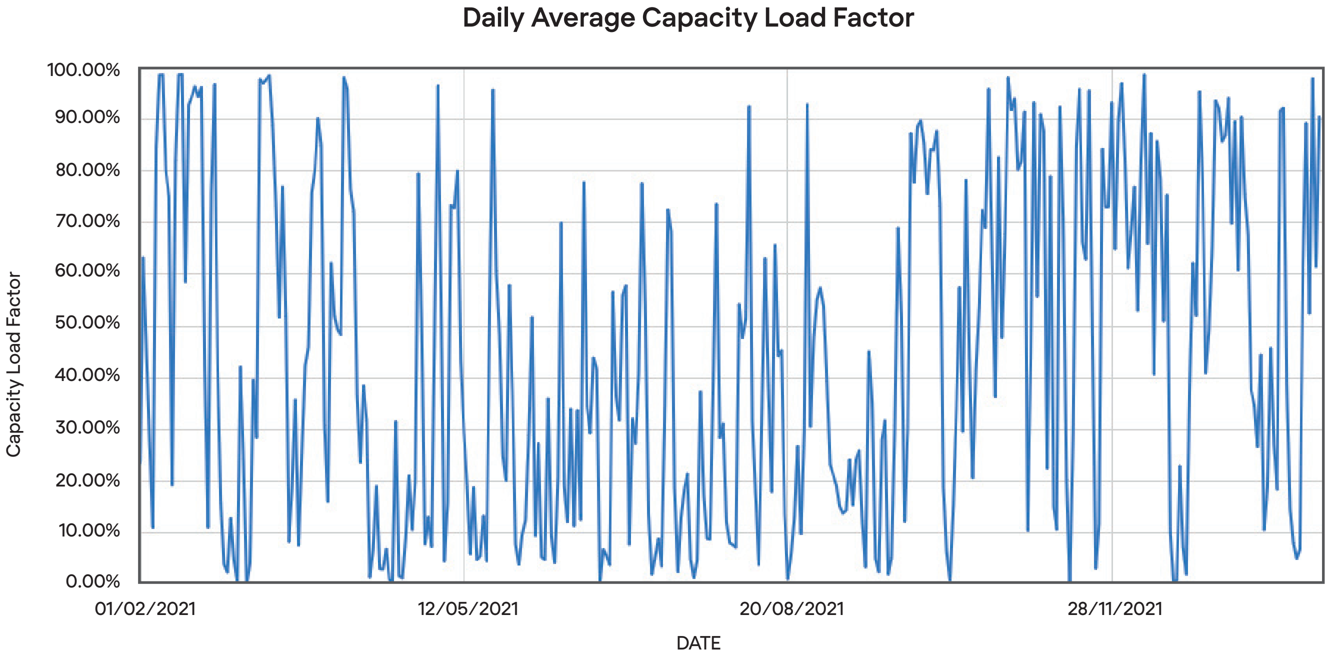


Figure 7-1 Daily Average Capacity Load Factor (Feb-21 to Feb-22)

Figure 7-1 demonstrates the yearly daily average load factor. This demonstrates that the output of the 400 MW offshore 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 7-1 Dudgeon Load Factor

Table 7-1 summarises statistical analysis which has been conducted on the Dudgeon wind farm output. All data was obtained from the Elexon BMRS portal. This data can be interpreted as 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 was calculated based on the total number of instances output at a specified load factor. As can be seen, the wind farm is outputting close to maximum 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 7-2 was critical to performing the secondary generation power analysis and therefore calculating the OPEX cost for the system per annum. The information contained in Table 7-2 demonstrates how critical having a dispatchable power generation system is, i.e. gas turbines for this concept.

The calculated demand for power for the assets captured by the CNS system was estimated to be 418.5 MW.

Four wind farm designs were 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 7-2 Wind Farm Designs

All analysis was conducted utilising /2/:

- Wind farm costs £3.5m/MW /3/.
- Low – 60p/therm (May 17th 2021)
- Normal – 90p/therm (Sep 20th 2021)
- High – 150p/therm (Dec 6th 2021)

Current gas prices were not considered to be representative of future gas prices due to the ongoing Ukraine Conflict and other external factors at the time of writing.

Additional analysis was conducted building in the market price of UK Emissions Trading Scheme (ETS) of £60/tonne of CO_2 emitted (November 17th 2021) /4/ (also the average cost over the previous 12 month period).

When incorporating ETS, the profiles for combined cycle operation shown in Figure 7-2 demonstrate 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 based on the simplistic analysis model utilised for this analysis. More detailed analysis is presented in Section 10.

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.

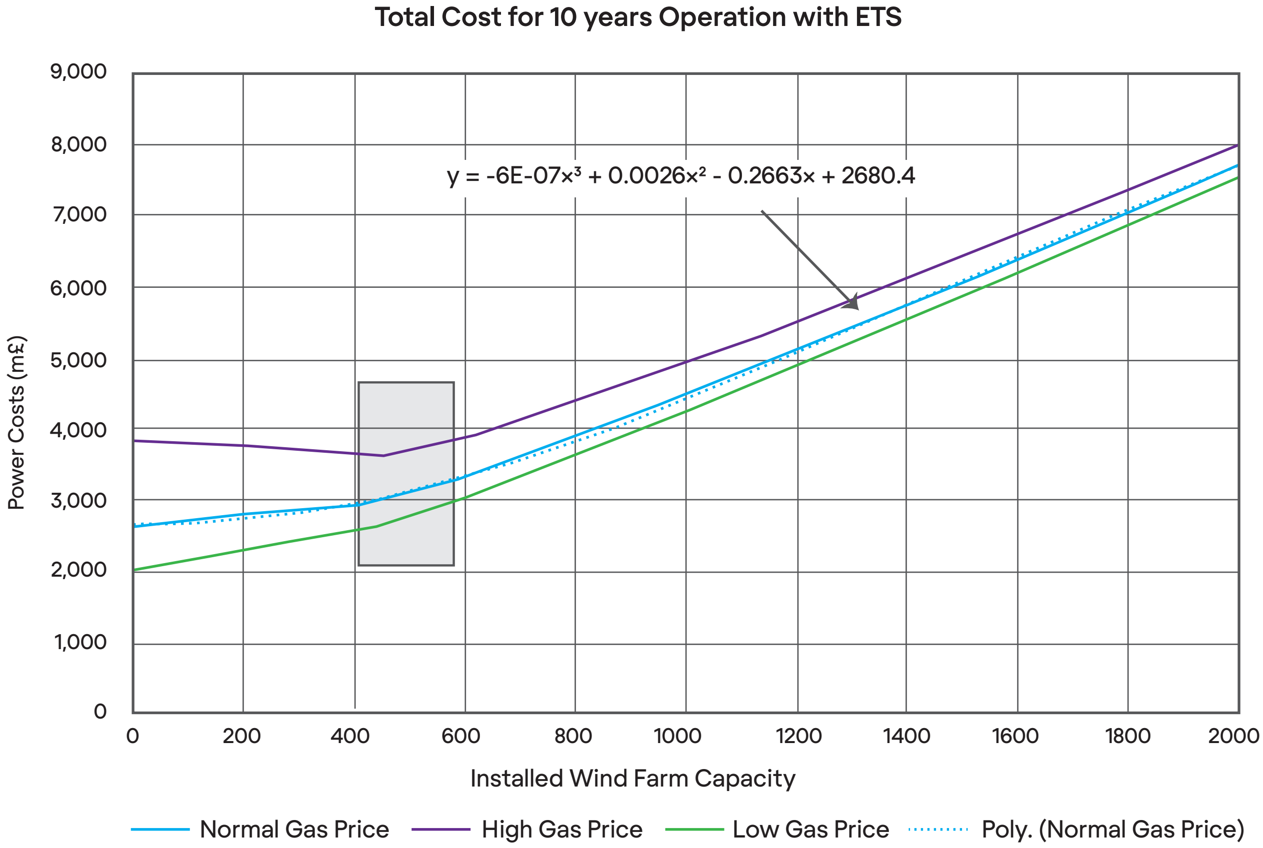


Figure 7-2 Project Energy Costs (10 Years) with ETS 420 MW Demand Combined Cycle

The ETS costs used are the average from the 19th of May 2021 to 7th of March 2022. The peak ETS cost during this time was £88 / tonne of CO_2 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.

If a continuity-based power supply was adopted, i.e. wind farm tied into the National Grid, then the analysis conducted in this section is not relevant. The costs for imported gas and ETS will not be applicable and the costs for normalised wind will be over a much longer duration, not the 10 years considered by this modelling.

8. Emissions Reduction

Three cases were modelled – a P_{95}, $P_{Optimised}$ and "Platform Generation".

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 P95 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 Report /5/.

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 significantly higher than the base power demand. This was viewed as a sensitivity which, based on fuel gas price and ETS, could be cost neutral to install /5/.

Both systems were compared against a total power demand of 418.5 MW which is based on the base CNS cluster identified from the Platform Clustering Study /6/.

The cases are summarised in Table 8-1 - Modelled Cases Summary.

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 8-1 Modelled Cases Summary

A sensitivity case with CCGTs only and no wind energy was also analysed for comparison.

8.1 Results

The results of modelling the three systems are summarised in Table 8-2.

Case	Fuel Gas Consumption (ktonnes per year)	CO2 Emissions (mmtCO2pa)	Emissions Reduction Relative to Platform Generation	Emissions Reduction mmtCO2pa
Platform Generation	1,157	2.89	-	0
P_{95}	297	0.741	74%	2.15
$P_{Optimised}$	239	0.598	79%	2.3
Sensitivity	529	1.323	55%	1.6

Table 8-2 Case Modelling Results

Table 8-2 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)	CO2 Emissions (mmtCO2pa)	Emissions Reduction Relative to Full OMF + CNS	Emissions Reduction mmtCO2pa
Full OMF + CNS	640	1,768	4.42	-	0
P_{95}	640	1,006	2.51	43 %	1.91
$P_{Optimised}$	640	931	2.33	47 %	2.09
Sensitivity	640	1,140	2.85	36 %	1.57

Table 8-3 CNS + OMF 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, a significant reduction in emissions can be achieved. This is based on the base case clustering to minimise infrastructure, i.e. 1-off 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 8-3 will be achieved.

A similar analysis was conducted on just the CNS region excluding the OMF assets which are not within the envelope of the Main Hub.

Case	Power Requirements (MW)	Fuel Gas Consumption (ktonnes per year)	CO2 Emissions (mmtCO2pa)	Emissions Reduction Relative to Full OMF + CNS	Emissions Reduction mmtCO2pa
Full CNS	530	1,464	3.66	-	0.00
P_{95}	530	702	1.75	52%	1.91
$P_{Optimised}$	530	627	1.57	57%	2.09
Sensitivity	530	836	2.09	43%	1.57

Table 8-4 CNS Only Emissions Reduction

It should be noted the full CNS emissions per annum is an ideal target at a generation efficiency of 25%. In practice this is as low as 10-14% on some assets.

The NSTA Emissions Monitoring Report /7/ identifies that approximately 12 mmtCO2/pa is reportedly released across all oil and gas production. Using this as a basis, it would suggest that the "Full CNS" emissions are likely closer to 5 mmtCO2/pa for this asset group, meaning an emissions reduction of 3.5 mmtCO2/pa.

9. Asset Clustering

Asset clustering is a key technical driver of the proposed concept.

The analysis was used to determine the proposed location of the Main Hub and Sub Hubs whilst minimising the total number of Hubs and subsea cables required to facilitate electrification of assets in a cluster.

The purpose of completing the asset clustering was to understand the technical feasibility of powering offshore Oil & Gas assets via the proposed Main and Sub Hub arrangement.

The objective of the assessment was to maximise the number of assets that could be electrified using the minimum amount of infrastructure.

The clustering assessment used a scaled method of transmission voltage, platform demand & assets' geographical location to determine efficient clustering of assets and subsequent location for the Main Hub and associated 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 that could be transmitted through a 1000mm2 copper cable. These circles were plotted to demonstrate the maximum distance a Sub Hub would have to be located from an asset to allow electrification. Although this simplifies cable capacity it was determined that volt drop remains the key determining factor for submarine cables, even if charging capacity and other issues are considered.

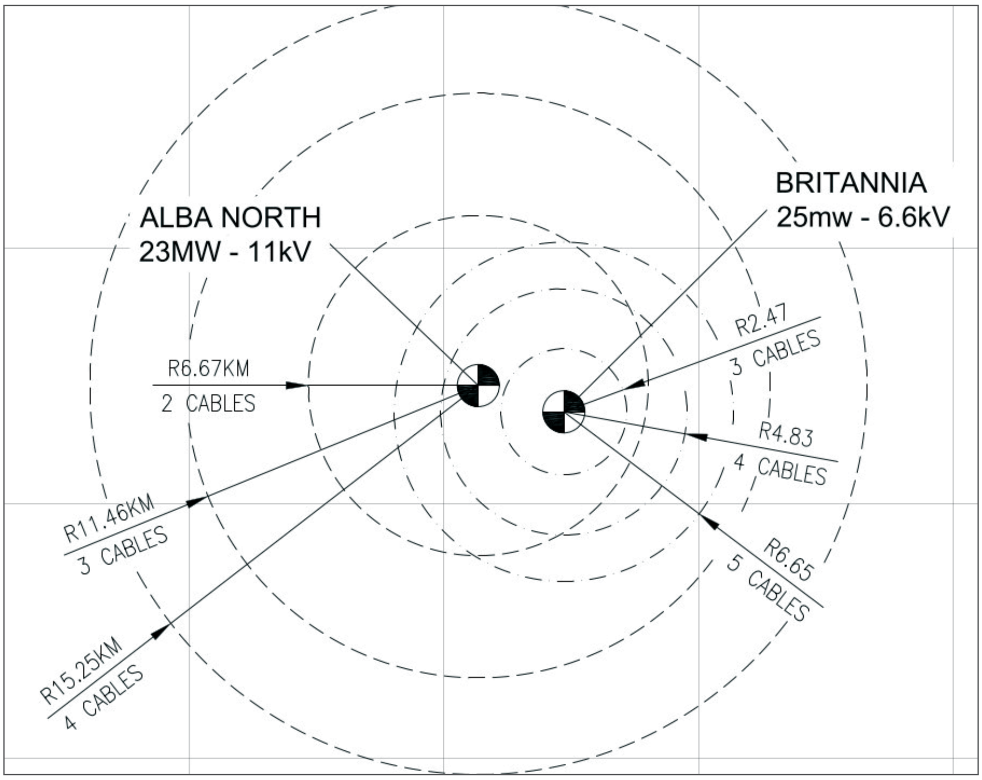


Figure 9-1 Example of Platform Distribution Zones

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 good candidates for electrification using this concept.

Utilising this methodology, the infrastructure maps shown in the following sections were generated to support the concept development.

9.1 Main Hubs

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

9.2 Central North Sea

The base case for the Central North Sea was to locate 1-off Main Hub and 4-off Sub Hubs capable of providing power to multiple assets. Figure 9-2 indicate the proposed locations.

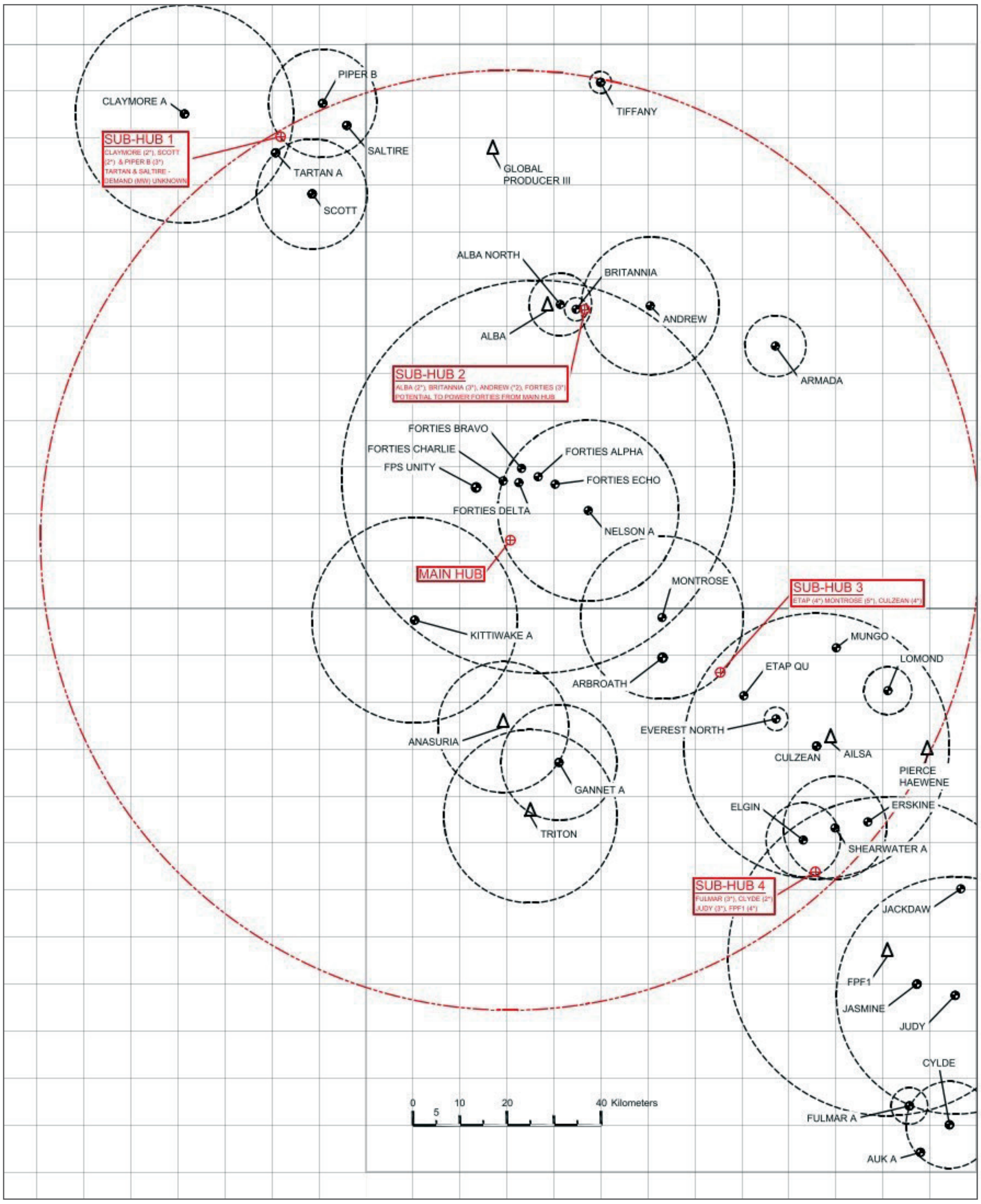


Figure 9-2: CNS – Base Case

9.3 CNS with Outer Moray Firth Expansion

An alternative layout of infrastructure was reviewed to include several Outer Moray Firth assets, namely the Buzzard, Golden Eagle & Captain Assets. Initial reviews indicated that utilising 1-off Main Hub was not feasible due to the geographical location and power demands of the OMF Assets. To meet the increased OMF demands, an additional Main Hub and associated Sub Hubs would be required. A proposed layout of the infrastructure is shown in Figure 9-3. A benefit of this alternative layout is that additional CNS assets which were previously more than 100km away from the Main Hub, can now be included.

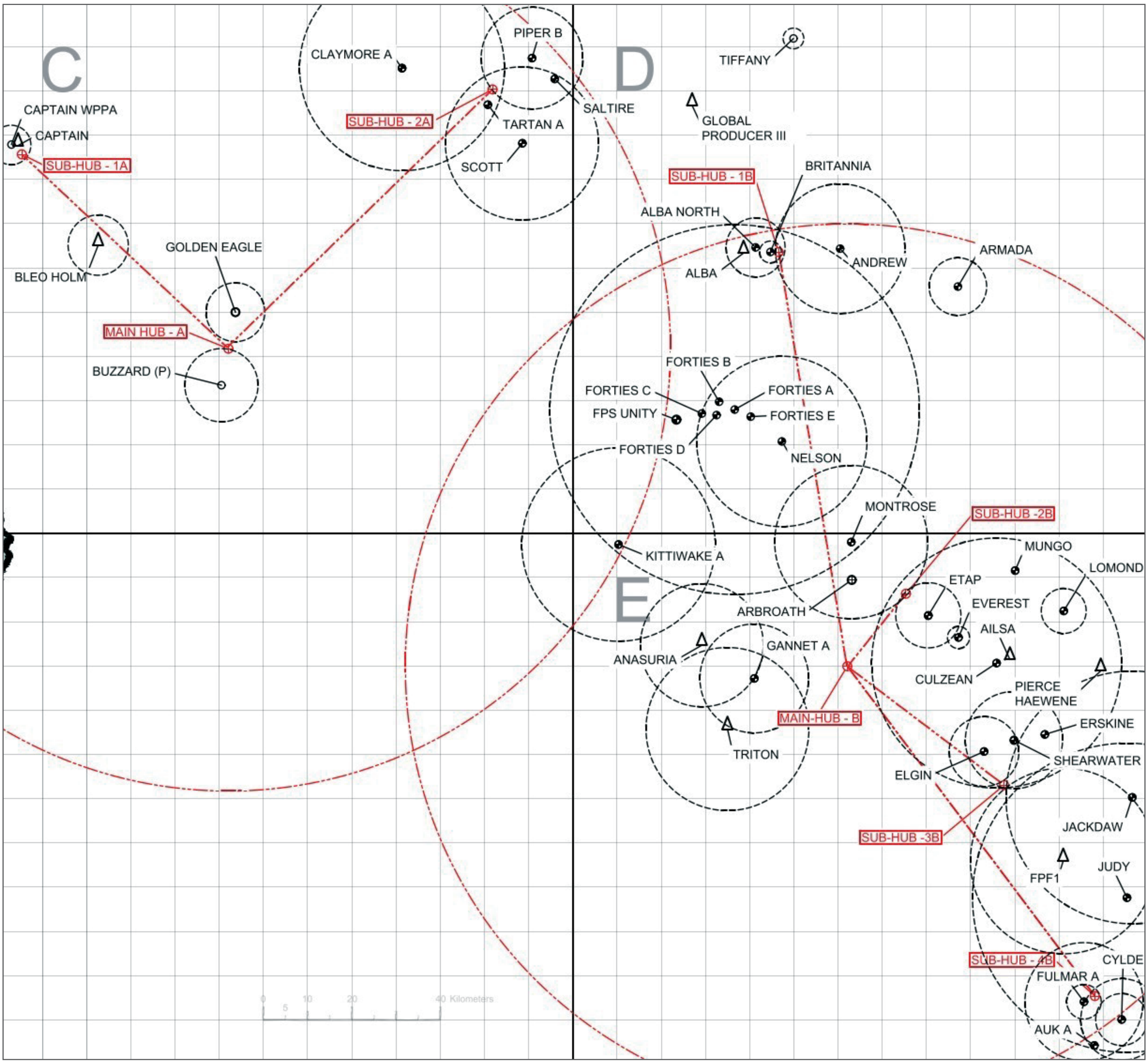


Figure 9-3: OMF & CNS Alternative Option

9.3.1 CNS - Wind Farm Locations

Data from Marine Scotland's 'Sectoral Marine Plan for Offshore Wind for Innovation & Targeted Oil & Gas Decarbonisation (INTOG)' report was overlaid onto the Clustering Maps. This information highlights areas where potential wind projects targeting Oil & Gas decarbonisation of greater than 100MW output are being considered. Such projects would be ideal candidates for input to a Main Hub.

Figure 9-4: CNS Base Case – INTOG Overlay

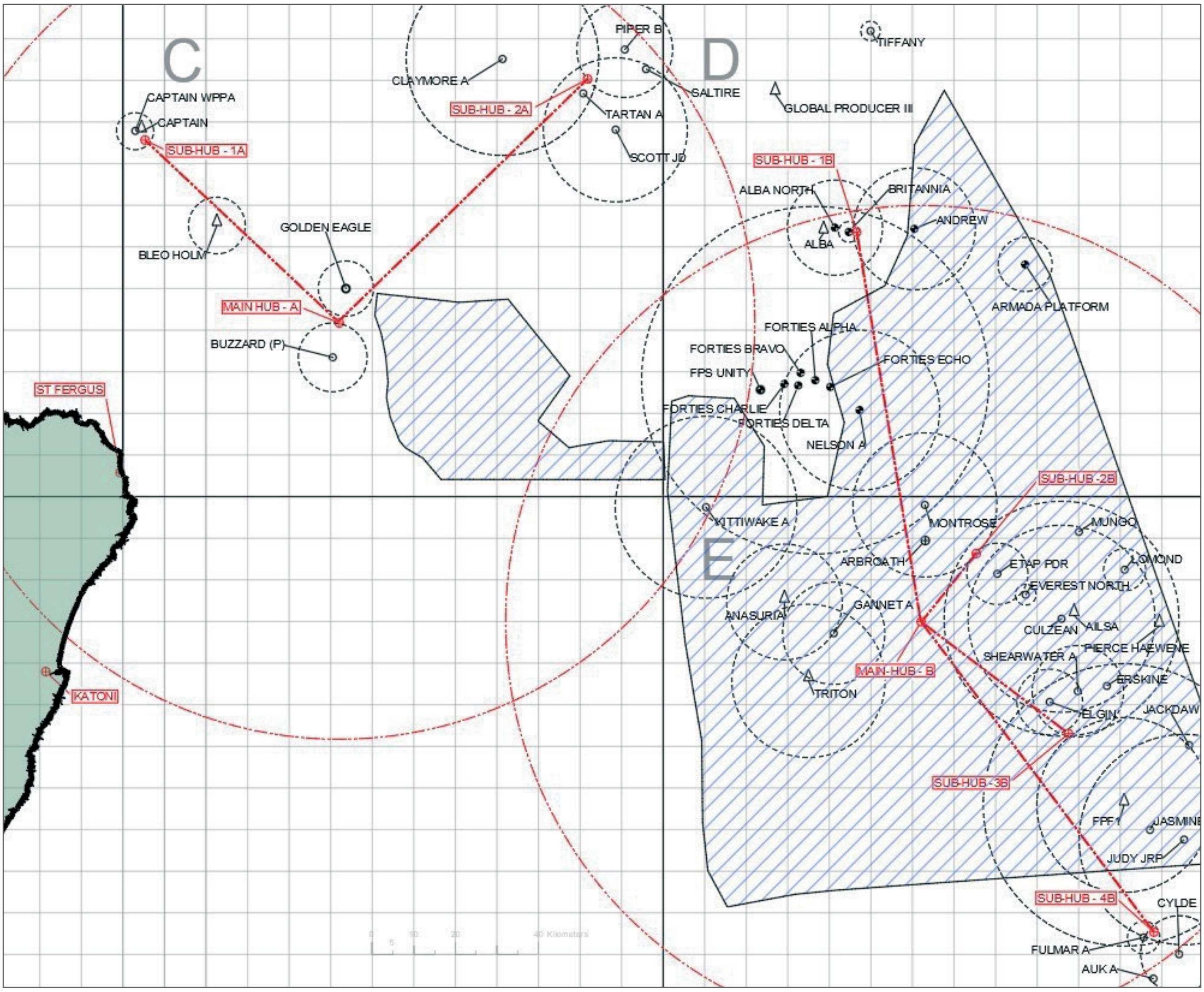


Figure 9-5: CNS Alternative option – INTOG Overlay

9.4 Southern North Sea

Due to the different characteristics of the SNS when compared with the CNS and OMF regions, a different clustering approach has been taken to account for the high numbers of platforms each with lower power and voltage requirements. Rather than distributing to individual platforms directly from the Sub Hub, the philosophy for the SNS is to power multiple platforms from a common High Voltage supply routed through the clusters with topsides transformers and switchgear used to step down to the low voltage required by the platform. This would enable 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) targeted when considering the location of Sub Hubs. Standalone assets with large demand (e.g., Cygnus) were also included.

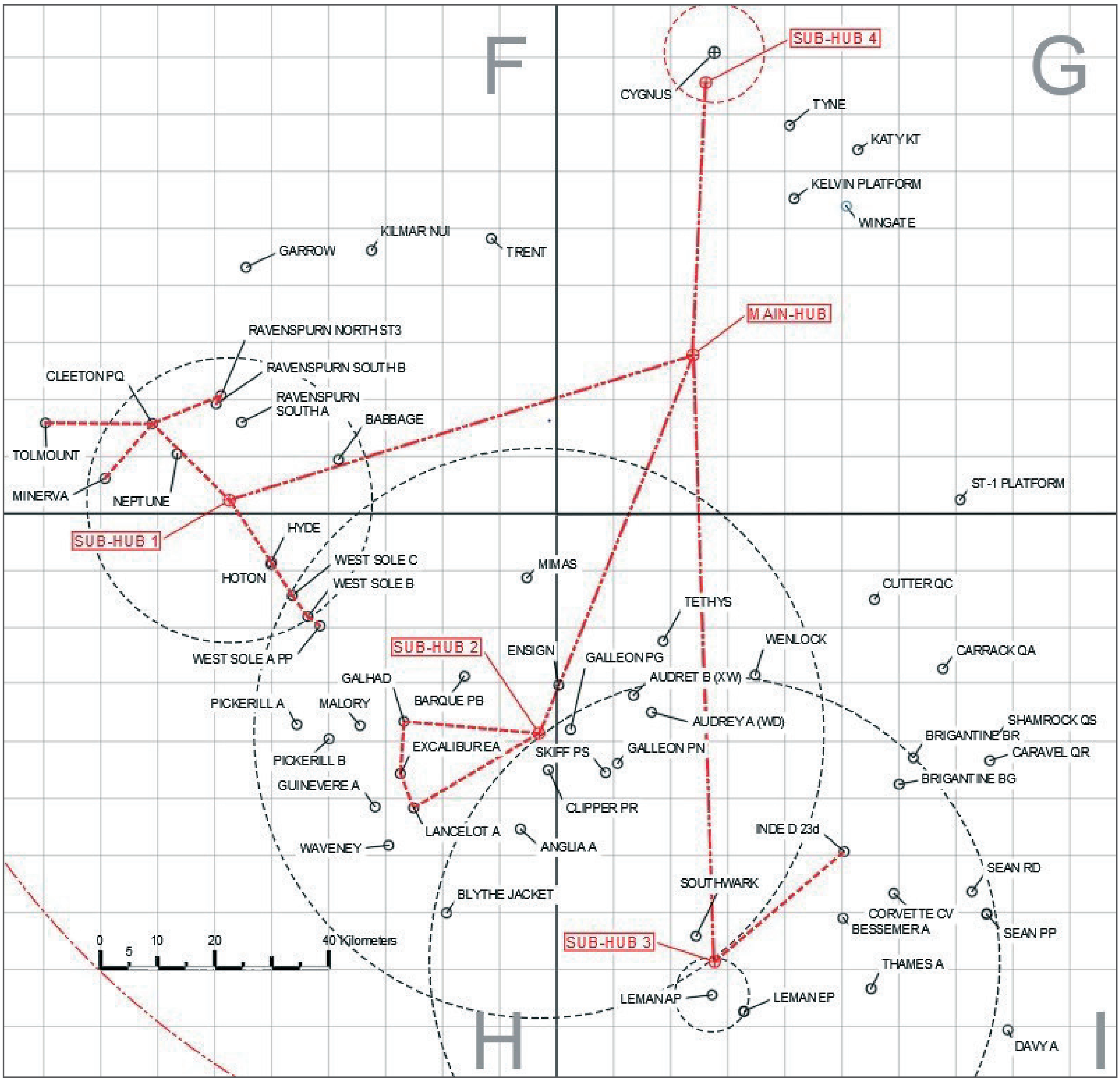


Figure 9-6: SNS Base Case

9.5 SNS – Wind Farm Locations

Data from the Department for Business, Energy & Industrial Strategy (BEIS) report 'Review of Consented Offshore Wind Farms in the Southern North Sea Harbor Porpoise SAC' /1/ report was overlaid onto the SNS Clustering Map, highlighting the proximity of offshore wind sites to the Hub locations, notably wind site 25; Hornsea 3. As with the CNS region, such a development could be a key input into an SNS Main Hub.

Figure 9-7: SNS with Wind Farm Overlay

10. Cost Models

Katoni Engineering as part of this study work developed a bespoke economic model in partnership with SPC Network. This model was 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 as 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 were developed and provided. However, regulatory analysis was not a major driver of this research given other workstreams being managed by the NSTA.

10.1 Philosophy

The economic cost of distribution and supply of low-carbon electricity in the UKCS can be considered conceptually as the unit 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 was taken to allow Katoni 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' allowed Katoni to provide a price which is realistic at today's prices. However, any future improvements in technology, or access to easier low carbon generation in the future, would provide upsides to the analysis.

This approach to model the economic cost of electricity supplied by non-carbon generation formed the "Base Case". However, in order to estimate the net economic costs of non-carbon generation Katoni also needed 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 formed the net economic cost of decarbonisation.

The Counterfactual

The Counterfactual case assesses what would happen if nothing was changed i.e. the Status Quo. Katoni has assessed this against the 'Base Technical Case' to allow us to assess the difference between an intervention or doing nothing.

The modelling approach calculated 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 the Department of Business, Energy and Industrial Strategy ("BEIS") in its publication "Cost of Electricity Generation", August 2020.

The model covered the CNS and SNS areas, since these are expected to be the areas with greatest potential benefit, and are the main subjects of this study.

10.2 Basis

The modelling assumed that existing asset-based gas turbine generators (in the Counterfactual Case) were 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 supplementary CCGT generating capacity to cover periods of unavailability of wind sourced generation. It was assumed that the supplementary, centralised thermal generation capacity provided 53% of demand annually.
- High voltage cables connecting to Sub Hubs.
- Medium voltage cables connecting to the individual platforms.

The Base Case model cost components included:

- 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;
- REBEX (renewal expenditure) of the assets over the period;
- ABEX (abandonment costs);

The economic analysis for the base case also included tax liability for the hypothetical company that builds, operates and receives revenue compensation for the assets. We 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 fuel gas for the turbines;
- Cost of CO_2 emissions under the UK Emissions Trading Scheme ("ETS");
- OPEX of the gas turbines;
- REBEX (renewal expenditure) of the gas turbines;

Katoni have not included an assessment of ABEX (Decommissioning costs) as field decommissioning happens in each option regardless, so is a net zero impact.

Katoni 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 included 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 CO_2 emissions. However, this can be more efficiently generated in one location (the Hub) therefore reducing gas costs and emissions.

10.3 Further assumptions

Table 10-1 summarises the input factors considered, and specific values used in the central scenario.

Counterfactual Gas Turbine OPEX		
Total OPEX	19 × £2.5m/year/platform	20 × £1m/year/platform + 6 × £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
CO_2 emissions: Base Case	38,026 tonnes/year/platform	12,596 tonnes/year/platform
CO_2 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 CO_2 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, 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 10-1 Model assumptions

10.4 CNS and SNS Assumptions

Table 10-2 summarises more detailed basin specific data for the CNS and SNS. The points of note in the table are:

- Higher sub-hub costings in the SNS due to the need for more infrastructure to services the number of assets in that area
- Higher modification costs in the CNS due to the nature of the assets / platforms in that region
- The SNS has a larger number of, on average, smaller platforms, and a lower demand for electricity overall, this has an overall negative impact on the economic outcomes of the proposals in this area. This is because a larger infrastructure build cost is spread over a smaller volume of delivered electricity.

Inputs	CNS	SNS
Base Case Infrastructure costs		
Number of 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

Table 10-2 Basin assumptions

10.4.1 Platform Modification Summary CNS

Platform modifications have been estimated at £390 million. This is based on an asset modification characterisation assessment, full details of which are included in the Volume 2 Report /5/.

The assessment looked to rank each platform in relation to complexity to utilise an external power source and attribute a cost to the types of modifications which would be required on each installation. These topsides modifications do not include any costs for cables or cable reception facilities out with topsides cabling to the topsides termination point. These costs are considered in the cable laying costs.

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

Table 10-3 Outcome of Platform Characterisation Assessment

- **Type A** assets are essentially plug and play, costs attributed to topsides modifications are £5m for these assets. Work completed show this is feasible for some installations
- **Type B** assets require more modifications, this could be change out of a direct drive GT or installation of new electrical distribution equipment, or other similar modifications. We have considered £25m per asset for this.
- **Type C** assets require more modifications, this could be installation of a new export riser to a nearby platform, or tackling heat and direct drive equipment. This has been estimated based on £50m worth of modifications to these assets.
- **Type D** assets require more modifications, this could be a combination of significant electrical modifications, direct drive replacement and potential gas export route modifications.
- **Type E** assets are considered as unfeasible to electrify.

10.5 Findings

Table 10-4, Table 10-6 and Table 10-8 display the model results for the central scenario, and a number of sensitivities. Given the diversity of economic outcomes in the two regions being assessed the data has been presented in aggregate and separately.

In short, the spread and type of assets in the SNS do not lend themselves to positive economic outcomes for the concept presented. However, there appears to be a stronger case for the concept in the CNS even when input assumptions are put under stress / tested for sensitivity purposes.

10.5.1 Findings CNS

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. 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 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 non-carbon generation: x 1.5	£212	£227	£0.9 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

Table 10-4 CNS Cost of Distributed Power (£/MWh, 2022 price level)

The data also shows that when a range of sensitivity tests are undertaken positive economic outcomes still appear to be achieved, these are summarised below:

Marginal economic benefit

- 20% capex overrun
  (on top of existing optimism bias of 20%)
- 2 year project delay
- Cost of wind (non-carbon energy) rises by 50%
- Cost of equity increases by 1%

Significant economic benefit

- Gas prices are twice base level £109.34 M/Wh
- ETS costs double
- Cost of wind (non-carbon energy) halves

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. The case for the CNS remains positive even if the price of gas was to be lower by 25% or the cost of CO_2 emissions were to be rise by 2% p.a. (rather than 5% p.a. in the central case), breakeven tests are shown below.

	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%

Table 10-5 Breakeven levels of key assumptions

10.5.2 Findings SNS

The findings in the SNS are all together different from those in the CNS. As previously stated this is due to geography and the nature of assets in this part of the UKCS.

	Base Case (£/MWh)	Counterfactual Case Case (£/MWh)	Cumulative Discounted Economic Net Benefit to 2040
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 non-carbon generation: x 1.5	£367	£235	-£3.5 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

Table 10-6 SNS Cost of Distributed Power (£/ MWh, 2022 price level)

All scenarios lead to negative economic outcomes. Indeed a breakeven point would require an unexpected or large change in primary drivers of the economics namely Gas or ETS pricing. While the analysis is at early concept stage it appears that a development of this nature in the SNS is not viable.

The case for the SNS remains negative even if the price of gas were to be higher by 46% or the cost of CO_2 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 to a negative level for the SNS to break even, this is shown below.

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

Table 10-7 Breakeven levels of key assumptions

10.5.3 Combined CNS and SNS Findings

Drawing together UKCS regions the table below summarises the impact of the concept. In terms of technical delivery each region is independent and unless there is a strong economic or probably environmental driver then the previous analysis on CNS and SNS separately operating is more valuable.

The table below provides a summary of a basin wide assessment which shows viability is only likely if an operator delivered the full scheme with higher Gas and / or ETS prices being in place.

	Base Case (£/MWh)	Counterfactual Case Case (£/MWh)	Cumulative Discounted Economic Net Benefit to 2040
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 non-carbon generation: x 1.5	£261	£229	-£2.7 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 10-8 Combined CNS and SNS Cost of Distributed Power (£/MWh, 2022 price level)

The modelling in a dual region approach does not compound risk on delivery which is likely to be significant given that more than twice the infrastructure delivery is required i.e. this would place significant stress on market capacity.

Breakeven analysis again demonstrates economic viability issues for a basin wide solution with a requirement for the cost of wind generation would need to fall by 95% for the combined CNS and SNS to breakeven.

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 10-9 Breakeven levels of key assumptions

10.6 Economic Modelling Conclusion

The findings 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 considered as marginal, however, this uses historic gas and emissions pricing which may not prevail. These are the major drivers of a net economic benefit. Table 10-4 details the key relationship between ETS and project benefit.

However, the analysis shows there may be a case for localised investment in the CNS with a range of potential economic upsides even using different sensitivity tests.

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 impact on the economic outcomes, but we know that major projects can 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 Cessation of Production (COP) dates for individual platforms as well as market testing for infrastructure delivery.

11. Key Findings

The maximum transmission distance between the Main Hub and Sub Hubs was set at approximately 100 km based on utilising Medium Voltage Direct Current transmission technology. The main platform voltage has a major impact on achievable transmission distance from the Sub Hubs. These two factors had a significant influence on the selected locations for the Main Hubs and Sub Hubs and the Oil & Gas assets which could be feasibly supplied with electrical power.

Due to the variable nature of wind energy production, the supplementary thermal power generation capacity provided on the Main Hub must at least match the overall power demand to ensure that a stable electricity supply can be provided.

The use of hydrogen as an energy storage solution for tapping into surplus wind energy production was found to have limited potential benefits and is not commercially viable for this project, at this time. Alternative storage technologies such as chemical battery should be explored in more detail, as having some energy storage throughout the network would benefit the resilience of the network and the ability to respond to rapidly changing supply and demand conditions.

Though the project's aim was to minimise modifications to existing Oil & Gas assets to receive subsea power, it was found that at least minor modifications will be required in all cases. Due to the energy usage offshore there are some cases where more significant modifications will be required if full electrification is to be achieved. It was also found that the supply of subsea power opens up opportunities for further emissions reduction by reviewing existing processes and considering new and alternative technologies.

Maximum potential emissions reductions, associated with asset power generation, up to approximately 75% are possible. When this reduction in emissions of the evaluated platforms is applied to the CNS/OMF basin, the emissions reductions were estimated to be approximately 43%. This reduction accounted for platforms which have not been tied into the system being added based on a typical emissions profile vs power requirements assuming a 25% efficiency.

The economic model estimated a net economic benefit for implementation of the Decarbonisation Project in the CNS; however, a net economic loss was estimated for the SNS and for the combined CNS and SNS. This is due to the smaller number of larger (in terms of power requirements) platforms, requiring less investment per MWh. Regulatory intervention may be necessary to make the economic case viable for the combined CNS and SNS as capital costs are unlikely to reduce significantly. Gas and ETS costs were also found to be significant drivers of the economics.

Cooperation or levered participation is critical - this is a basin wide concept, and the economics rely on economies of scale.

12. 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, if marginal, solution for electrifying the assets identified in the CNS/OMF region.

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