Offshore power generation with carbon capture and storage to decarbonise mainland electricity and offshore oil and gas installations: A techno-economic analysis

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Abstract

This study investigates the techno-economic potential of offshore power generation from natural gas with carbon capture and storage to reduce the climate impact of mainland electricity and the offshore oil and gas industry. This potential is assessed through techno-economic assessments over two relevant cases ("floating" and "shallow water" cases) including comparison with relevant reference concepts.
In the base case evaluation, the offshore power plant concept toward decarbonising mainland electricity results in high costs (178 and 258 $/MWh respectively for the floating and shallow water cases) compared to a reference onshore power plant with carbon capture and storage (around 95 $/MWh). However, a stronger potential is identified for the concept toward decarbonising offshore oil and gas platforms as the concept results in costs more comparable with the reference electrification concept (137 compared to 133 $/MWh in the floating case and 207 compared to 166 $/MWh in the shallow water case).
Although the base cases show a limited potential for the offshore concept, the results show that with technological improvements (advanced capture technology, reuse of infrastructure…) and more suited case characteristics (development based on associated gas…), the offshore concept offers a significant potential for cost-efficiently decarbonising the offshore oil and gas industry, while a more moderate potential is foreseen for the decarbonisation of mainland electricity.

Keywords: Carbon Capture and Storage (CCS); Clean electricity; Offshore; Post-combustion capture; Techno-economic analysis.

Abbreviations: AC, alternating current; API, American Petroleum Institute; CCS, carbon capture and storage; CEPCI, chemical engineering plant cost index; CEPONG, clean electricity production from offshore natural gas; DC, direct current; DCC, direct contact cooler; DOGF, depleted oil and gas field; EBTF, European Benchmarking Task Force; ECPM, engineering, construction, and procurement management; EGR, enhanced gas recovery; EOR, enhanced oil recovery; EU ETS, European Union emissions Trading System; FEED, front-end engineering design; FPSO, floating, production, storage, and offloading; GT, gas turbine; HRSG, heat recovery steam generator; HVDC, high-voltage direct current; IEA, International Energy Agency; LNG, liquefied natural gas; MEA, monoethanolamine; LCOE, levelised cost of electricity; MMV, monitoring, measurement and verification; NGCC, natural gas combined cycle; SA, saline aquifer; ST, steam turbine; TEG, triethylene glycol; ZEP, zero emissions platform.

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1 Introduction

Global demand for natural gas is expected to increase to meet in particular future power and heat requirements, even under the International Energy Agency's (IEA) 2 °C scenario [1]. Although, renewable energy will play a large role in decarbonising the power sector, energy efficiency and carbon capture and storage (CCS) will still have significant contributions [1]. Indeed, a "100% renewable" scenario would result in a high stress in metal resources [2], challenges in integrating production intermittency with consumer needs over time, as well as require nearly 3.5 USD trillion more in investments [1].

Although power generation from natural gas has a lower carbon impact than coal-based power [3], CCS is still required to meet heat and power requirements based on natural gas in a carbon constrained world. However, producing electricity from natural gas with CCS is often regarded as an expensive measure [4, 5], especially due to the high capture costs associated with the electricity and heat consumption of the capture process [6, 7] and the cost of transporting CO_2 over long distances [8]. For example, the European Benchmarking Task Force [3] evaluated the cost of CO_2 captured from a gas-fired power plant based on monoethanol amine (MEA) and showed that the cost of electricity rises by 30% once CO_2 capture is included, leading to a capture cost of 48 €/$t_{CO2,avoided}$ (not including transport and storage). Moreover, the cost of retrofitting a CCS facility at the Kårstø onshore gas-fired power plant, located in western Norway, was estimated [9] to result in a capture cost of 85 €/$t_{CO2,captured}$.

Significant research efforts are under way to reduce the cost of CCS from natural gas-fired power plant [10, 11]. For solvent based CO_2 capture, which is the most mature technological option, strategies for cost reduction have mainly focused on reducing the energy penalty associated with regeneration, through novel solvent [12] and/or system optimisation [13], but also through novel configurations or units [14]. For example, Osagie et al. [15] illustrated that a reduction of 25% in reboiler duty could be achieved by considering 2-amino-2-methyl-1-propanol (AMP) instead of MEA as solvent. On the other hand, Herraiz et al. [16] showed that selective exhaust gas recirculation could decrease packing volume by more than 50% and the specific reboiler duty by up to 7%. Meanwhile, other studies have sought cost reduction opportunities through development of novel capture technologies. Several studies reported that these technologies could achieve significant reductions in CO_2 capture energy penalty [17]. Turi et al. [18] reported that a membrane-based process could lower the CO_2 capture energy penalty by up to 38%. Berstad et al. [19] reported that a calcium looping-based process could reduce the CO_2 capture energy penalty by up to 40% depending on the considered sorbent. However, when considering a complete techno-economic analysis, most of these novel concepts manage to achieve only limited cost reductions. Even though Turi et al. [18] indicated that membrane-based CO_2 capture could achieve a marginal cost reduction compared to MEA for CO_2 capture from an NGCC, Van Der Spek et al. [20] demonstrated that membrane-based capture would, in fact, result in a cost of electricity 10% higher compared to MEA. Van Der Spek et al. [21] concluded that electrical swing adsorption resulted in a cost increase of 13% compared to MEA.

An alternative strategy to reduce cost is to investigate new natural gas-to-power value chains potentially more suited to a carbon constrained world. A good illustration of this is the development of hydrogen value chains based on natural gas reforming, which would deliver a CO_2-free product that can be used to produce clean electricity and heat [22], or to support the decarbonisation of the transport sector [23, 24]. Another potentially interesting restructuring of the natural gas-to-power value chain would be to produce power from offshore natural gas with CCS directly offshore and export electricity to the targeted market instead of natural gas. This solution, which is the focus of the present study, may have potential for lowering costs compared to the conventional onshore power plant with CCS approach in several ways. It would provide an opportunity to run the power plant on otherwise non-commercial (stranded) natural gas, reduce the cost of CO_2 capture by using waste heat from the oil and gas production process [25], avoid the transport of natural gas and CO_2 over long distances [26], utilise the captured CO_2 for Enhanced Oil or Enhanced Gas Recovery (EOR/EGR) [27, 28]…

Furthermore, beyond its potential to supply clean power to support the decarbonisation of mainland electricity, offshore power generation with CCS could also be used to reduce the climate impact of

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offshore oil and gas activities. Indeed, although CO_2 emissions from offshore oil and gas activities make up only a small percentage of global anthropogenic CO_2 emissions, in certain countries (Norway, Saudi Arabia, Qatar, Iran, Brazil, United States, Mexico, United Kingdom…) they may represent a non-neglectable share of national CO_2 emissions. For example, 28% of Norway's CO_2 emissions are due to offshore oil and gas activities [29]. For such countries, this situation may lead to challenges to reach national obligations under the Paris Agreement, even if oil and gas companies are becoming eager to reduce the carbon footprint of offshore oil and gas operations [30]. Beyond CCS, two other strategies can be considered to reduce these CO_2 emissions. The first one is to radically change the way power and heat are generated on offshore platforms with concepts like "electrification" [31] or fuel switching (hydrogen and/or ammonia…). The second one is to maximise energy efficiency in order to reduce CO_2 emissions for a same power/heat production [25]. These two strategies were studied in the literature and showed some limitations. Electrification, for instance, demonstrated to be questionable under an economic point of view [32], while its global environmental impact is strongly affected by the method selected to take into account the emissions associated with power from shore [33]. On the other hand, the improvements achievable with energy efficiency measures are case specific [34, 35] and often require the utilisation of heavy waste-heat recovery systems[1] [25, 36] to achieve a limited reduction in CO_2 emissions (typically up 25%) [37]. Compared to these two options, carbon capture and storage can enable large CO_2 emissions reduction, typically 80-90%, without radical changes to the way oil and gas production facilities currently works.

While offshore acid gas (CO_2 and H_2S) removal from natural gas has been extensively studied [38, 39], only a few studies have focused on offshore power generation with CCS. Carranza Sanchez and De Oliveira [40] studied the exergy performance of the processes on an offshore primary petroleum processing plant with and without CO_2 capture. They concluded that implementing CCS produces a significant increment in the exergy destruction of the plant. For example, a reduction of 77% in CO_2 emissions resulted in a reduction of exergy efficiency of 2.8 points. Nord et al. [41] investigated three bottoming cycle configurations which could be integrated with conventional offshore power cycles[2] to meet the steam and power requirements of a CO_2 capture process. Based on power output and system weight, they concluded that a steam cycle with a back-pressure steam turbine would be the best strategy, as it would be able to provide all necessary steam and power, with margin, for the CO_2 capture and compression system. In addition, a few studies [42] have investigated the technical feasibility of certain capture technologies for offshore application. Hetland et al. [43] studied the design of a concept in which an offshore power plant burning natural gas was producing clean electricity, based on carbon capture and storage, to power five surrounding platforms (Kristin, Åsgard, Heidrun, Draugen, Njord), as well as for export to the mainland. Their study focuses on the design and integration of the CO_2 capture and conditioning process with the offshore power production platform. This study was the only one found to cover the entire offshore power plant with CCS. However, no techno-economic feasibility study of offshore electricity production from natural gas with CCS has yet been published, nor have the potential electricity markets (mainland and offshore oil and gas platforms) been compared.

This study therefore focuses on a techno-economic evaluation of a concept for Clean Electricity Production from Offshore Natural Gas (CEPONG) based on offshore power generation with CCS. The potential of this concept will be evaluated considering two targeted power markets: clean power supply aiming at decarbonising mainland electricity and clean power supply for decarbonising offshore oil and gas platforms. In both cases, the concept is also compared to suitable reference concepts in order to identify its cost-competitiveness. Finally, the potential of various measures to reduce the cost of the concept will be investigated, in order to better understand when the CEPONG concept could be cost-competitive.

The structure of this work is as follows. First, the CEPONG concept is introduced including selected cases, targeted markets and reference concepts. The technical and cost bases for the evaluation of the concept are then presented followed by the results of the design and cost evaluation, including

[1] Which is challenging in an offshore environment
[2] Traditionally based on a simple gas turbine cycle.

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comparisons to the reference concepts. Finally, the potential of different measures to reduce the cost of the concept is presented in order to provide a better understanding of when the CEPONG concept could be cost-competitive.

2 Description of concepts, markets and cases

2.1 CEPONG Concept

In the CEPONG concept, natural gas from a gas field or an offshore gas pipeline is received by the offshore platform. On the offshore platform, the natural gas is pre-treated if required[3] and converted to electricity that is exported by cable to the target power market(s). The exhaust flue gas from the gas power plant is sent through a CO_2 capture unit. The CO_2 is then sent for conditioning before being transported to a nearby CO_2 storage site, while the exhaust flue gas after CO_2 capture is vented. A schematic block diagram of the CEPONG concept is shown in Figure 1.

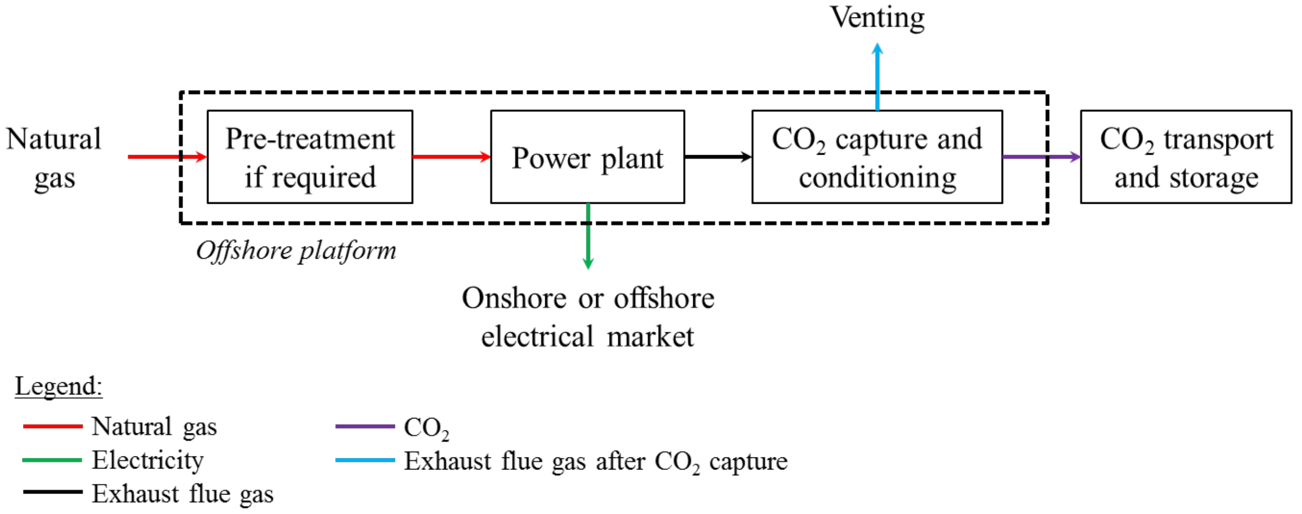

Figure 1: Schematic block diagram of the CEPONG concept

In this study, the CEPONG concept is designed and evaluated for two potential markets: 1) toward decarbonising mainland electricity 2) toward decarbonising offshore oil and gas platforms. For each of these markets, the CEPONG concept is compared to suitable reference concepts. These two markets and associated reference concepts are further detailed in section 2.2. In addition, two cases presented in section 2.3 are also considered. Figure 2 illustrates the different assessments performed for a given case.

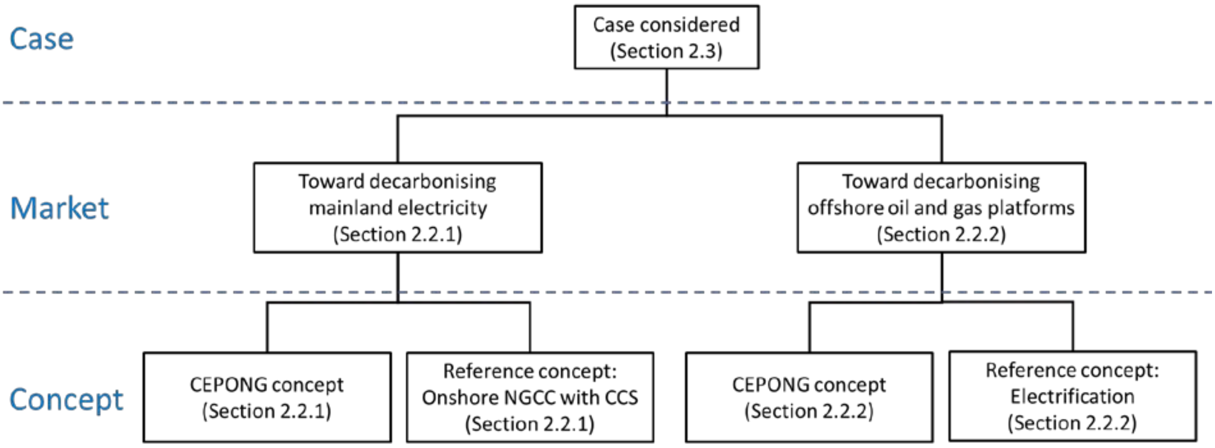

Figure 2: Illustration of the assessment performed for a given case

[3] This is the case if the natural gas contains H_2S or other components above the gas turbine specifications.

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2.2 Markets and reference concepts

The CEPONG concept has the potential to provide clean electricity to a variety of markets and clients. This section highlights the CEPONG concept for these two markets and the associated reference concepts.

2.2.1 Towards decarbonising mainland electricity

The European Union aims to cut greenhouse gas emissions to 80% below 1990 levels by 2050, and 40% by 2030. A significant proportion of these ambitious goals lies in the power generation sector, where nearly all emissions are expected to be eliminated by 2050. While a significant share of this reduction will be provided by renewables and nuclear power, fossil fuel power with CCS is a crucial component of the portfolio of solutions needed to realise this roadmap. In this case, the CEPONG concept is seen as an alternative gas-to-clean power value chain aiming at reducing the cost of the "traditional" onshore power generation with CCS. An onshore natural gas power plant with CCS is considered as a reference concept for the CEPONG concept.

For this market, the clean electricity produced by the CEPONG concept is exported to shore to contribute to the decarbonisation of mainland electricity. After offshore power generation with CCS, the electricity is exported via power cables to the European grid, as shown in Figure 3.

In terms of system boundaries, the CEPONG concept toward decarbonising mainland electricity and the associated reference concept start from the gas power plant until delivery to the power grid.

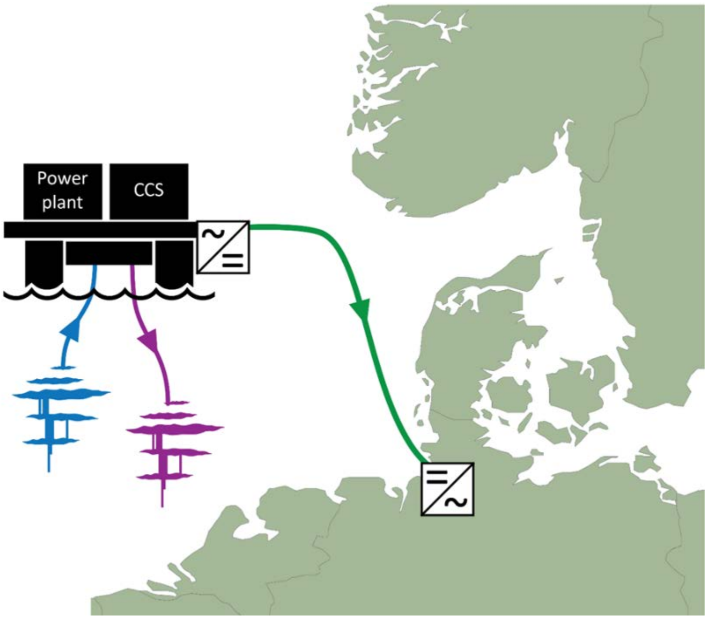

Figure 3: Schematic illustration of the CEPONG concept toward decarbonising mainland electricity

2.2.2 Towards decarbonising offshore oil and gas platforms

In countries with significant offshore oil and gas activities, a significant proportion of national CO_2 emissions take place offshore (for example, 28% in Norway). In order to reach their national CO_2 emissions reduction targets under the Paris Agreement, such countries can consider several strategies: energy efficiency measures [44], power supply from offshore wind [45], fuel switching to hydrogen [31], electrification [46], and the CEPONG concept. A brief description of the advantages and limitations of each of these options to decarbonise offshore oil and gas platforms is presented in Table 1. Among these, electrification is deemed as the most relevant one due to its acceptable costs, significant CO_2 abatement potential, and its recently shown feasibility on the Martin Linge oil and gas platform. In the electrification concept, clean power is purchased onshore and exported via electrical cables to a power hub as shown in Figure 4. Meanwhile, for this market, the CEPONG concept toward decarbonising offshore oil and gas platforms directly exports clean power to the target offshore installation.

In term of system boundaries, the CEPONG concept starts from the offshore power plant, and ends when the electricity is ready to be exported to the targeted offshore oil and gas platforms. Meanwhile, the electrification concept starts with the purchase of onshore electricity, and ends at the offshore power hub

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when the electricity is ready to be exported to the targeted offshore oil and gas platforms. In both cases, the final transport leg to targeted platforms is excluded.

Table 1: Advantages and limitations of each option to decarbonise offshore oil and gas platforms

Concept	Advantages	Limitations
Energy efficiency	Reduce fuel consumption and operating costs	Limited CO_2 emissions reduction (typically up to 25%) Require large and heavy waste heat recovery units
Power supply from offshore wind	Theoretically high emission reduction impact	Fluctuations in wind power limit the reduction potential
Fuel switching to hydrogen	Potential high CO_2 emissions reduction	Low maturity level Difficulties associated with hydrogen combustion NOx emissions Challenges with H_2/NH_3 offshore storage and transport logistic Lack of data available on cost performances
Electrification	Industrial experience Potential high CO_2 emissions reduction Cost	Cost highly dependent on transport distance and power capacity CO_2 emissions and cost reductions depend on purchased electricity characteristics
CEPONG concept	Can reduce CO_2 emissions by 90% Act as power hub Can valorise stranded/un-economic assets Cost	Less industrial experience Cost-competitiveness is case dependent

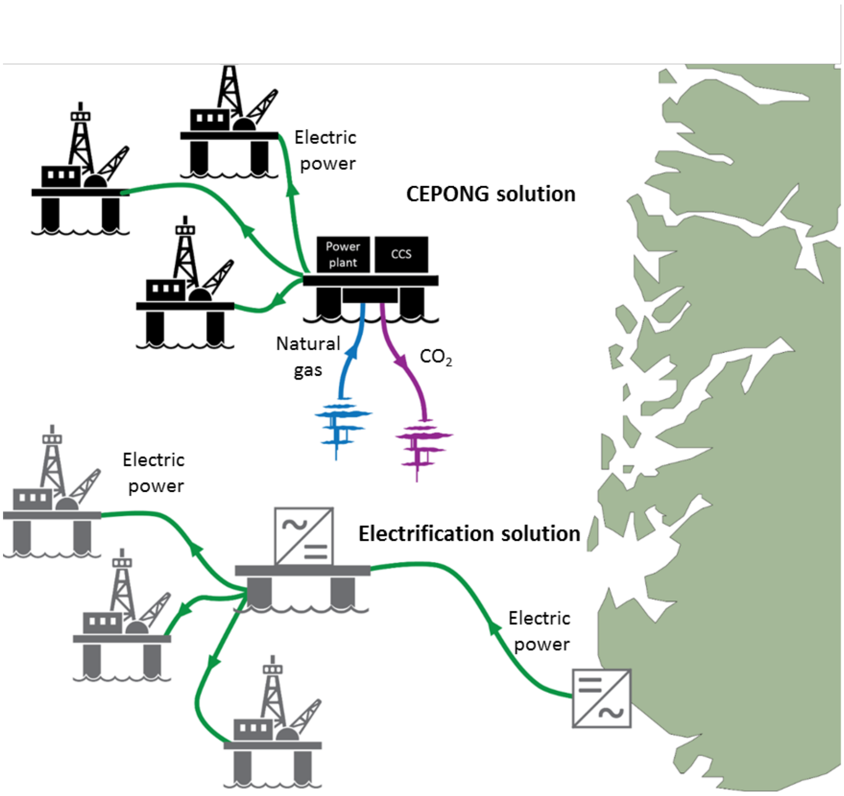

Figure 4: Schematic illustration of the CEPONG concept toward decarbonising offshore oil and gas platforms

2.3 Case studies

This study considers two cases for the CEPONG concept. The first is based on a large offshore power plant placed on a floating platform located on the Norwegian continental shelf. The second is based on a

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medium-size offshore power plant placed on a fixed platform on the Dutch continental shelf. Both these cases, further described in the sections below, were selected based on real potential prospects deemed suitable for the CEPONG concept.
For the sake of clarity throughout this work, the main text, including results and discussions sections, focuses on the first case, while the results of the second case are provided in Appendix A.

2.3.1 Floating case

The first case considers power generation on the Norwegian continental shelf at water depths greater than 100 m. As these depths are more suitable for floating platforms, this case is referred to as the "floating case".
In the floating case, natural gas is extracted from a rich gas pipeline located in the Troll region, on the Norwegian continental shelf, and with the characteristics presented in Table 2. The extracted gas is converted to electricity on an offshore floating platform located 200 km away from the Norwegian coast. The power plant is designed to produce around 650 MW with CCS and requires around 3.5 MM SM^3/day of gas from the rich gas pipeline. The CO_2 is assumed to be stored in a deep saline aquifer[4] 100 km distant from the platform. In the market toward decarbonising mainland electricity, the clean electricity produced by the concept is directly exported to Brunsbüttel (Germany) to reach the European grid. The transport distance is estimated to 750 km and the infrastructure is operated on a stand-alone basis.
In this case, the reference concept considered for the CEPONG concept toward decarbonising mainland electricity is based on a natural gas combined cycle (NGCC) with CCS as defined by the European Benchmarking Task Force (EBTF) [3]. Meanwhile, the reference concept for the CEPONG concept toward decarbonising offshore oil and gas platforms is based on electrification from the Norwegian coast. For consistency, the electrification concept is assumed to deliver the same power after the offshore power hub as the CEPONG concept. Furthermore, this offshore power hub is considered to have the same location as the CEPONG concept (200 km from Norwegian coast).

Table 2: Basic characteristics of the natural gas in each of the cases

	Floating case	Shallow water case
Inlet gas flow [MM Sm^3/d]	3.5	0.6
Extraction pressure [bar]	150	70
Gas composition [%vol]		
H_2O	0.06	-
N_2	1.15	0.5
CO_2	1.2	7.7
C1	89.95	91.7
C2	5.25	0.2
C3	1.69	Traces
iC4	0.25	Traces
nC4	0.35	Traces
iC5	0.05	Traces
nC5	0.05	Traces
Lower heating value [kJ/kg]	$4.72\ 10^4$	$4.03\ 10^4$
Higher heating value [kJ/kg]	$5.23\ 10^4$	$4.48\ 10^4$

2.3.2 Shallow water case

The second case considers power generation based on a real existing gas field prospect on the Dutch continental shelf with water depth around 40 m [47]. This case is thus located in shallow waters, which are more suitable to fixed platforms, and is referred as "shallow water case".
In the shallow water case, 0.6 MM SM^3/day of natural gas is considered to be extracted from a rich gas field and converted to electricity on an offshore fixed platform. Based on the gas intake and the gas

[4] It is worth noting that the captured CO_2 could be reinjected in the natural gas reservoir, however it would result in a significant CO_2 content increase in the produced natural gas over time. This increase would lower the power output of the power generation system as well as increase the sizes and costs of the CO_2 capture part of the concept. For these reasons, the combination of the concept with CO_2-enhanced gas recovery was not deemed as an attractive solution for the base case.

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characteristics of the considered prospect[5], shown in Table 2, the power plant is expected to result in a net power output with CCS around 130 MW. It is worth noting that in this case, the gas intake contains a significant proportion of CO_2 (around 7%)[6]. The captured CO_2 is expected to be stored in a deep saline aquifer, 10 km away from the platform. The platform is assumed to be located 140 km away from Den Helder (Netherlands), which is assumed to be the point of connection to the power grid.
In this case, the reference concepts are the same as for the floating concept, with the exception of the transport distance in the electrification concept. A cable length of 140 km based on a connection point at Den Helder is considered, while a delivered power identical to that of the offshore fixed platform is still targeted.

3 Methodology

3.1 Technical modelling

3.1.1 CEPONG concepts

3.1.1.1 Offshore power generation with CCS

The offshore power plant is based on a combined cycle configuration. This configuration combines multiple gas turbines (GT) and steam turbines (ST), where steam is generated by the waste heat from the GT exhaust in the Heat Recovery Steam Generators (HRSG). The GT fuel is natural gas after pre-treatment.
This work makes use of reactive absorption of CO_2 using monoethanol amine (MEA) as solvent as the end-of-pipe capture option for GT flue gases. The CO_2 capture section is shown in Figure 5 below. After the HRSG, the exhaust gas is cooled to 35 °C in a Direct Contact Cooler (DCC). The cooled gas is sent to a packed bed absorber where it is contacted with 30 wt% MEA solvent that is added to the top of the absorber. The flow rate of the solvent is adjusted to ensure the desired CO_2 capture ratio. The CO_2 lean exhaust leaving the top of the absorber contains MEA and other MEA degradation products. An amine water wash section at the top of the absorber removes MEA and other impurities by contacting it with cold water that is circulated. MEA with chemically bound CO_2 (also called rich solvent) from the absorber is preheated in a process heat exchanger called the lean/rich heat exchanger with hot solvent regenerated in the stripper (also called lean solvent) and sent to the stripper or regenerator where CO_2 is released, and solvent is regenerated. Heat is supplied for the regeneration process in the form of low pressure steam around 4 bar (with a condensing temperature of 140°C). The lean solvent is further cooled to 40 °C after the lean/rich heat exchanger and mixed with amine wash water prior to feeding it to the top of the absorber. The CO_2 released from the top of the regenerator contains mainly water and nitrogen as impurities. This stream is sent to a multi-stage compression process to compress the CO_2 product stream to 80 bar. The water is flashed out after the intercooling stages. To ensure a dry CO_2 stream suitable for transport, a dehydration step using Triethylene Glycol (TEG) is used after the third compression stage to reduce the water concentration to 10 ppm in the CO_2 product stream. After compression to 80 bar the CO_2 product is cooled with cooling water and then pumped to 110 bars.
The offshore power generation with CCS is modelled in HYSYS v9, and is designed following design standards for offshore oil and gas platform: size limitations, redundancy requirements, available space integration on the platform including height limitations. This leads to the following considerations:

- The gas and steam turbines are based on vendors input for well-proven and reliable machines for offshore power generation. In practice, this results in equipment size significantly smaller than for an onshore NGCC plant (for example, gas turbines of 54MW) and therefore in multiple units (for example, 10 gas turbine in the floating case) ;
- The CO_2 capture plant is design taking into account offshore practical constraints on equipment sizes to prevent flow maldistribution in columns due to tilting, to ensure platform stability, as well as redundancies. Hence, multiple absorbers and desorbers with diameters and heights lower

[5] It is worth noting that lower heating value (LHV) of a gas field is case specific. Although, gas prospects on the Dutch continental shelf may have higher LHV, the gas field considered in the shallow water case presents a LHV higher than the Groningen, onshore, gas field which is the largest gas field in both Netherlands and Europe.
[6] In the traditional natural gas value chain, it is worth noting that offshore acid gas removal would be required before the gas could be exported to shore.

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than typically obtained for onshore cases are selected. It is worth noting that these practical design criteria also have an impact on the performance of the process. Due to the shorter absorber columns, a CO_2 capture ratio of 82% was identified as optimal, while a specific reboiler duty higher than of a typical onshore design is obtained due to the lower desorber columns height.

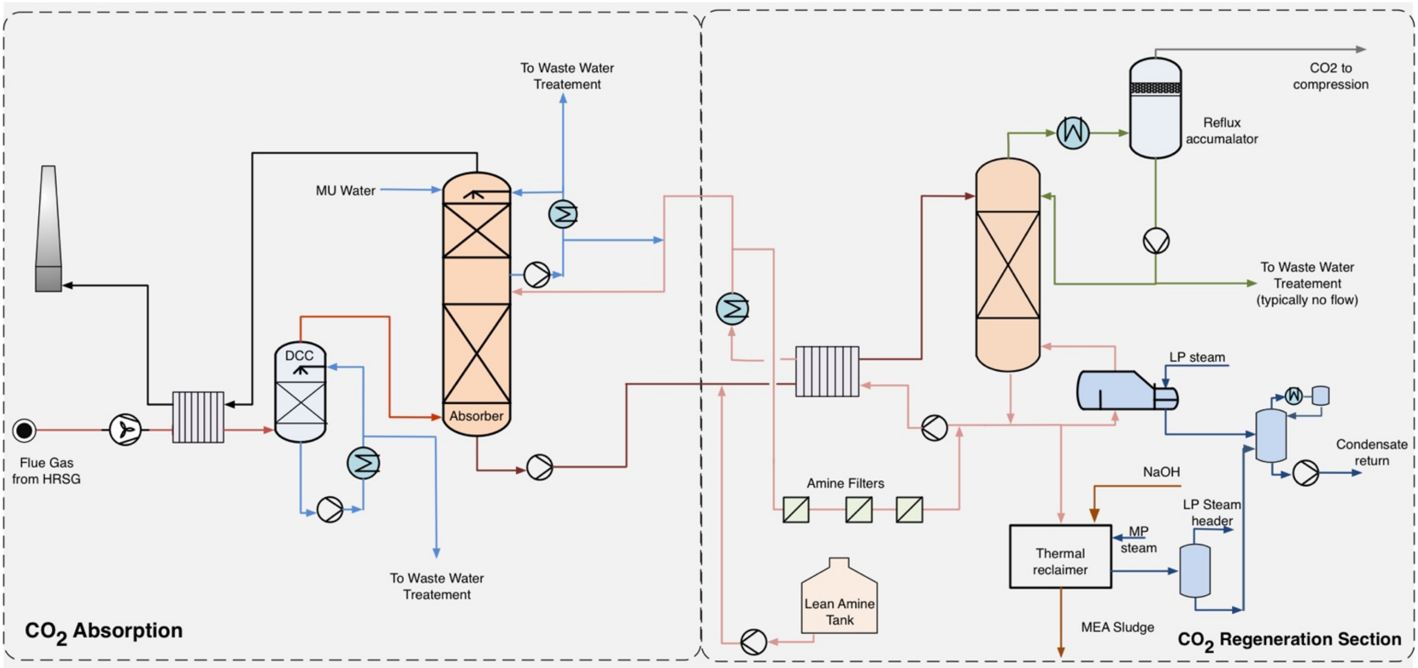

Figure 5: Process flow diagram of post-combustion CO_2 capture using MEA as solvent

In the floating concept, the offshore floating platform hull is designed to accommodate the required topside equipment (power plant system, CO_2 capture system, electric installation, utility systems), weight and area. The layout of the offshore power production platform with CO_2 capture and compression is shown in Figure 6 for the floating case. The power plant is arranged on main and process decks and consists mainly of 10 large pre- fabricated modules like the gas turbine packages including electrical generators, the HRSGs and combustion exhaust systems. In principle, these components are arranged in two rows each with 5 gas turbine packages and associated equipment to minimise the space demand. Then the hull is designed "around" these components later. The two steam turbine driven electrical generators are located adjacent to the gas turbine packages. The CO_2 capture equipment is arranged in centre of the hull below the gas turbine packages and as low as possible due to the high absorber and desorber columns, and to locate some of the heavy equipment low to obtain best possible platform stability.

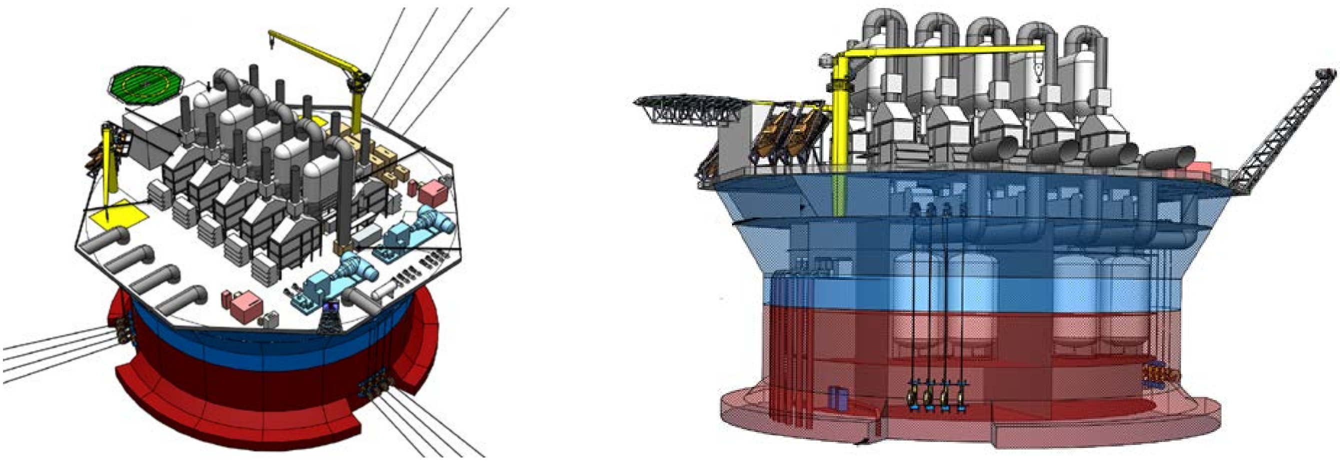

Figure 6: Layout of the offshore power production platform with CCS in the CEPONG concept in the floating case (a) deck views (b) lateral view

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3.1.1.2 CO_2 transport and CO_2 storage

After CO_2 capture and conditioning on the platform, the CO_2 is transported to the seabed via a flexible riser before being further transported to a nearby CO_2 storage site for injection, as shown in Figure 6.
CO_2 transport is assessed using the iCCS CO_2 value chain tool developed by SINTEF Energy Research [48, 49]. Due to prohibitive subsea pumping costs, no reboosting is considered along the offshore pipeline, and the pressure drops must therefore be limited in order to keep the outlet pressure above 60 bar [4]. Based on the flowrate and transport distance, the pipeline diameter is optimised to minimise the cost of the transport infrastructure. The pipeline designs are based on the minimum wall thickness required [50] and following the American Petroleum Institute (API) specification 5L standard [51]. The pressure drop is calculated using the Fanning equation [52].
The technical modeling of the CO_2 storage is performed using the CO_2 storage module of the iCCS value chain tool [48, 53]. The storage module is based on the Zero Emission Platform (ZEP) report on CO_2 storage in depleted oil and gas fields (DOGF) and deep saline aquifers (SA) [54] and extended to include CO_2-EOR storage [53]. In this study, CO_2 is assumed to be stored in an offshore deep saline aquifer. The storage infrastructure modelling assumes an annual maximum well injection rate of 0.8 Mt_{CO2}/y/well [54]. More details on key assumptions in the CO_2 transport and storage modelling can be found in previously published studies [49, 53].

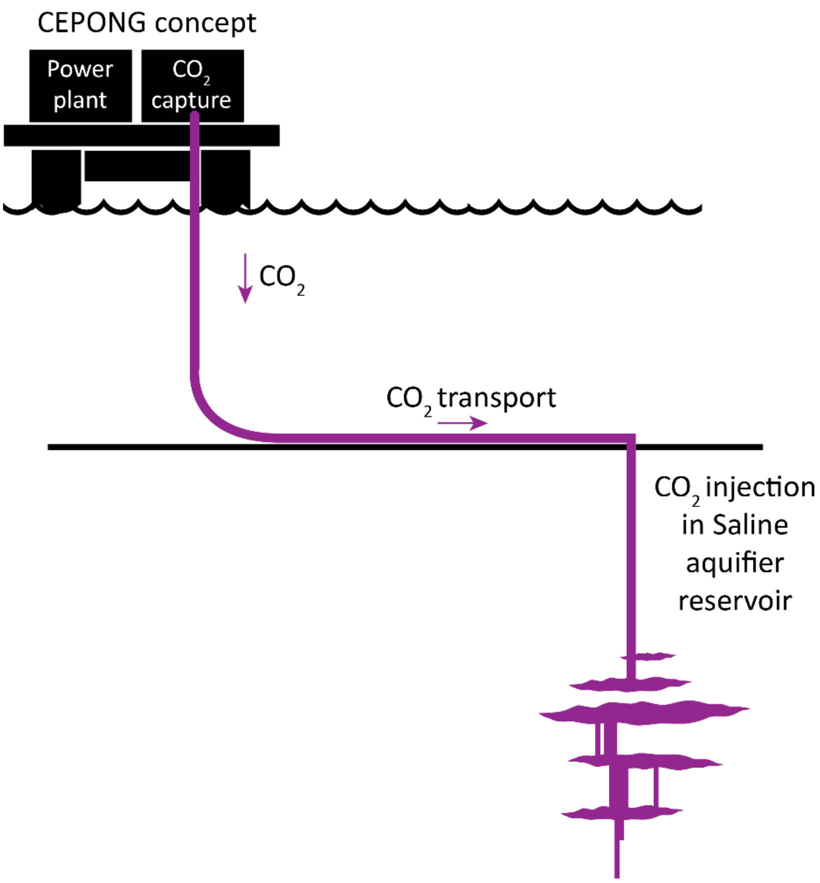

Figure 7: Schematic design of the transport and storage of CO_2 in the CEPONG concept

3.1.1.3 Power export to mainland

Based on the distances and capacities modelled here, the power export to mainland is assumed to take place via high-voltage direct current cables (HVDC) [55]. The power export to mainland can thus be divided into three elements as shown in Figure 7: 1) an AC/DC convertor located on the CEPONG platform 2) a HVDC cable circuit[7] to transport the power from the platform to the mainland 3) a DC/AC convertor located onshore that reconverts the power to match European grid conditions. Here, these

[7] A HVDC cable circuit refers to a pair of HVDC cables (minus and plus) which form a symmetric monopole.

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infrastructures are considered to be dedicated to the CEPONG concept, although economies of scale could be gained through joint infrastructure with, for example, offshore wind or the development of an European offshore power grid [56, 57].
While each of the AC/DC and DC/AC converters are assumed to result in power losses of 1% [58], the power losses through the HVDC cables are calculated based on the cable cross-section and length, as well as the current intensity as shown in Equation 1 [58]. Finally, the cable characteristics (voltage, cross-section area, capacity) are optimised to minimise the cost of the electricity delivered to shore, taking into account both costs and power losses through the power export system.

$$P_{\text{Cable losses}} = 2\ R'' \cdot \frac{L \cdot I_{\text{cable}}^2}{A_{\text{cable}}} \qquad (1)$$

where
$P_{\text{Cable losses}}$: power losses through the HVDC cables in MW
R'': is the resistance of copper and assumed to be equal to 21.4 $\Omega.km.mm^{-2}$ based on an operating temperature of 90 ºC [58]
L: is the cable length in km
A: is the cable cross-section in mm^2
I: is the current intensity in kA

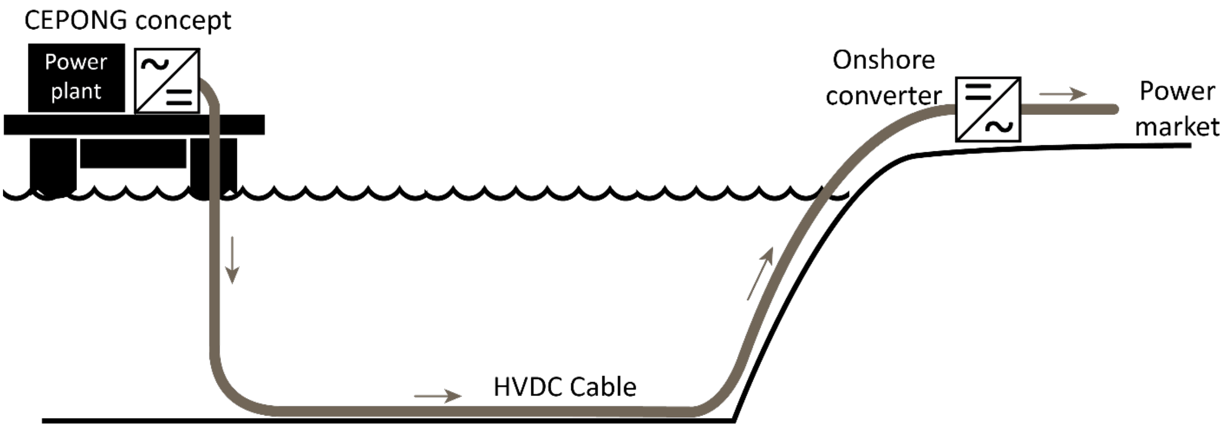

Figure 8: Schematic design of electrical export to the onshore power market in the CEPONG concept toward decarbonising mainland electricity

3.1.2 Reference concepts

As discussed previously, two reference concepts have been established in order to provide standpoints for the CEPONG concept. Onshore power generation with CCS is treated as the reference point for the CEPONG concept producing clean power to decarbonise mainland electricity. Meanwhile, the electrification concept is the reference point for the CEPONG concept producing clean power to decarbonise offshore oil and gas platforms.

3.1.2.1 Onshore power generation with CCS

Here, CCS from a NGCC as defined in the EBTF report [3] is considered. Without CCS, the NGCC plant has a net power output of 830 MWe with a thermal efficiency of 58.3%, and emits 2.18 $MtCO_2$/y. The NGCC plant is assumed to be located in the Netherlands by the coast, and CO_2 capture is assumed to be based on a MEA-based absorption process with a CO_2 capture ratio of 90%. Two storage options are considered to reflect the dependency of transport costs to the storage location. In the first option, CO_2 is assumed to be transported to an offshore deep saline aquifer on the Dutch continental shelf about 200 km from the power plant. In the second option, the CO_2 is assumed to be transported to an offshore deep saline aquifer, on the Norwegian continental shelf, located about 750 km from the power plant. Based on the capacity and distances evaluated [8], an offshore pipeline is selected as the transport mode in the first storage option, while shipping with direct injection is assumed in the second. In both options, the CO_2 storage characteristics are assumed to be identical to those used in the CEPONG concept.

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While the technical characteristics of the NGCC without capture are extracted from the EBTF report, the CCS chain is assessed using the iCCS CO_2 value chain tool modules for MEA-based CO_2 capture [7, 49], CO_2 transport by offshore pipeline or ships [8, 49], and CO_2 storage [49, 53]. Indeed, while the EBTF provides representative technical and cost performances of an NGCC plant, literature has proven that the costs associated with the CO_2 capture part of the process were underestimated [21, 59].

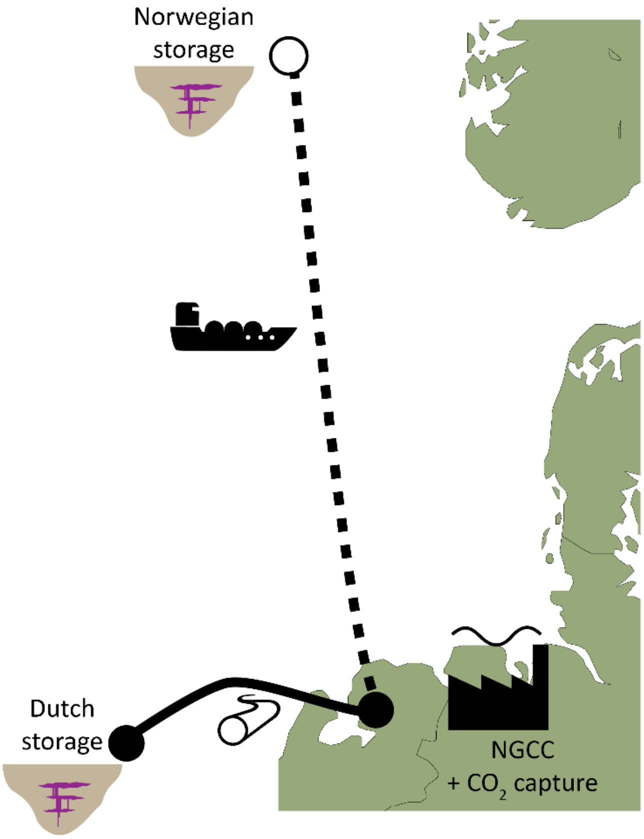

Figure 9: Illustration of considered infrastructure geographical locations for the reference onshore NGCC with CCS

3.1.2.2 Electrification

In the electrification concept, power is purchased onshore and transported to an offshore power hub. Based on the case distances and capacities, the electrification concept is assumed to rely on an HVDC transport. The electricity purchased is first converted from AC to DC before being transported via a HVDC cable circuit to the offshore power hub. On the offshore power hub, the current is then converted from DC to AC before being exported to the nearby targeted offshore infrastructure. As schematic representation of the electrification concept is presented in Figure 9. As in the CEPONG concept (section 3.1.1.3), the power transport infrastructures for the electrification concept are assumed to be dedicated and are optimised to minimise the levelised cost of electricity delivered at the offshore power hub.

When discussing electrification of offshore oil and gas platforms, it is important to understand which source will actually power the electrification. Here, electrification powered by renewable is assumed, however it is important to note that this may differ in practice [33].

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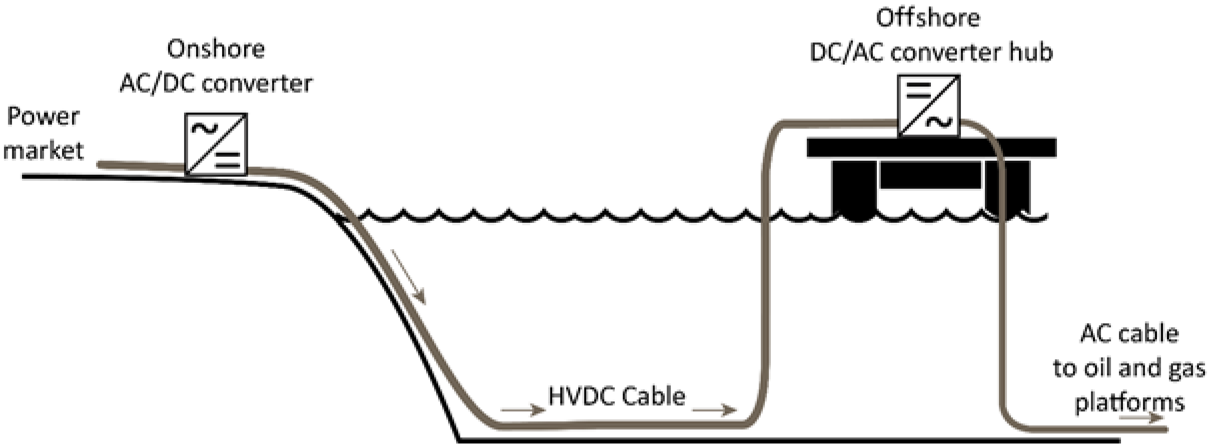

Figure 10: Schematic design of power import in the reference electrification concept

3.2 Cost evaluation

Various cost estimation methods are used for the evaluation of the CEPONG and reference concepts as discussed in the following sections. Investment and operating costs are given in US dollar[8] 2015 prices. In instances in which cost data are not available directly in 2015 prices, costs have been updated using the IHS-CERA indexes [60] for offshore infrastructures, the Chemical Engineering Plant Cost Index (CEPCI) [61] for onshore infrastructures, and inflation [62] for utilities. Meanwhile, costs not directly available in US dollar are converted considering the following exchange rates: 1.11 USD/Euro and 8.93 NOK/Euro [63].

It is important to note that the costs presented here do not reflect the development and demonstration costs that typically occur during early deployments.

Finally, the targeted investment estimates accuracy corresponds to an AACE Class 4 estimate (-15% to +40%).

3.2.1 CEPONG concept

3.2.1.1 Offshore power generation with CCS

The investment costs evaluation of the offshore power plant with CCS is evaluated based on a cost methodology specific to offshore estimates. In this approach, the weights of equipment modules and construction steel[9] are estimated and then multiplied by individual cost per ton for the different elements based on previous projects and recent quotations from shipyards in the Far East[10] for similar construction work. Transportation costs are then evaluated based on experience from similar transportations considering a transport from a shipyard in the Far East to Europe on a heavy lifting vessel. The costs of installation and hook-up at the field are based on experience from similar installations. Engineering, procurement and construction costs are based on estimated manpower for conceptual design, FEED (Front-End Engineering Design), detailed design, procurement, and the construction phases of the concept implementation. Investment costs take into account project contingencies (15% of installed cost) and ECPM (Engineering, Construction, and Procurement Management mark-up) costs.

The operating costs are divided into manning, operations, and fuel. The manning is estimated based on estimated onshore and offshore crews. The operating costs take into account stand-by and supply vessels, turbine and marine services, consumption and disposal of chemicals, and miscellaneous[11] costs. The costs associated with natural consumption are based on estimated natural gas intake and a natural gas value of

[8] US dollar is here selected as currency, despite the European location, as it is the typical currency for upstream Oil and Gas related activities.

[9] Including hull, support structures, piping and piping support bulk materiel, cable and cable tray bulk material and access material (ladders, walkways, stairs etc.).

[10] Procurement from Far East was selected based on experience from engineering contractors for similar type of infrastructures.

[11] Including painting, hospital services and material, inspections by third parties, flag & class if applicable, marine department services, communication, warehouse services, mobilisation, base, insurance, assistance, other indirect.

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6 \$/GJ. Finally, penalty costs for offshore CO_2 emissions are considered[12]: 55.9 \$/t_{CO2} in the floating case based on a Norwegian location, and 5.9 \$/t_{CO2} for the shallow water case based on a Dutch location [64].

3.2.1.2 CO_2 transport and CO_2 storage

The costs of the CO_2 transport and storage part of the CEPONG concept are assessed using the iCCS tool [48, 49]. While more details on the corresponding cost assumptions can be found in previous studies [49, 65], the following paragraphs provide an overview.

For the offshore pipeline transport, the investment costs are evaluated assuming an investment of 64,000 €$_{2015}$/inch/km[13] based on the EU FP7 CO_2Europipe project [66]. This cost, adapted to a North-West European concept, is based on a maximum operating pressure of 200 bar for offshore transport. In addition, the cost of the pipeline riser is based on a reference cost of 7 M€$_{2015}$[14] for a 1 MtCO_2/y [67] and scaled up, assuming that costs are linear with the pipeline diameter. The annual pipeline fixed operating costs are assumed to be an annual cost per kilometer, independent of the pipeline diameter and equal to 6,700 €$_{2015}$/km/y [66].

Regarding the CO_2 storage stage, the costs model considered [49, 53] is based on the ZEP report [54] and thus consists of six components which include all the phases in the lifetime of an SA- or DOGF-based CO_2 storage project: 1) Pre-Financial Investment Decision, 2) Platform, 3) Injection wells, 4) Operating, 5) Monitoring, Measurement and Verification (MMV) 6) Close-down. For an offshore SA, the cost evaluation considers a cost per well of 21.4 M€/well and a liability cost of 1 €/$t_{CO2,stored}$.

3.2.1.3 Power export to mainland

The investment cost model of the power export to mainland is based on data from National Grid's Ten Year Electricity Statement 2015 [68]. The HVDC cables investment cost is a function of the designed transmission power and the cable length as shown in Eq. 2 below, while the investment cost for each converter is a function of the designed transmission power as shown in Eq. 3. As space and weight were specifically allocated for the offshore electrical converter when designing the offshore platform, only the cost of an onshore electrical converter is considered here to avoid accounting twice for the integration with the offshore platform. A summary of the cost-scaling parameters used to evaluate cables and converters investment costs is shown in Table 3.

Meanwhile, the annual operating cost of the converters and electrical export are assumed to represent 2% of the investments, with an upper bound of 5 M€/y for the cable, based on industrial recommendations.

$$\mathrm{I_{cable}} = \mathrm{P_{cable\ inlet}} \cdot \mathrm{L} \cdot \mathrm{B_{dp}} + \mathrm{L} \cdot \mathrm{B_d} + \mathrm{B_0} \qquad (2)$$

$$\mathrm{I_{converters}} = 2 \cdot \left(\mathrm{P_{trans}} \cdot \mathrm{C_p^L} + \mathrm{C_0^L}\right) \qquad (3)$$

where

- L is the length of the export cable
- $\mathrm{P_{trans}}$ is the designed transmission power
- B_{dp}, B_d, B_0, $\mathrm{C_p^L}$, and $\mathrm{C_0^L}$ are the cost parameters for scaling of cable and converters investment costs presented in Table 3

Table 3: Cost parameters for scaling of cable and converters investment cost

Parameter	Value	Unit	Related item
B_{dp}	0.47	k€/(km.MW)	HVDC Cables
B_d	680	k€/km	HVDC Cables

[12] While the Dutch continental shelf located case considers a penalty based on 2015 levels of the European Union Emissions Trading System (EU ETS), the Norwegian continental shelf case includes both the EU ETS cost and CO_2 emission tax applied to offshore oil and gas activities in Norway.

[13] 75,000 €$_{2010}$/"/km. As an indication, the pipeline investment cost given by the EU FP7 CO_2Europipe project shows that an offshore pipeline will be 50% more expensive than an onshore pipeline of the same length and diameter.

[14] 900 M¥$_{2012}$, assuming a well-head depth 500 m below the surface.

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B_0	5 000	k€	HVDC Cables
C_p^L	118.3	k€/MW	Onshore converter
C_0^L	20 280	k€	Onshore converter
C_p^S	758	k€/MW	Offshore converter (including platform)
C_0^S	129 900	k€	Offshore converter (including platform)

3.2.2 Reference concepts

3.2.2.1 Onshore gas power generation with CCS

While the costs of the onshore gas power plant without CO_2 capture are extracted from EBTF [3], the cost assessments of carbon capture, transport and storage chains are based on the iCCS tool [48, 69]. A summary is presented here, while more details can be found in previous studies [8, 49]. A penalty cost for CO_2 emissions of 5.9 $/t$_{CO2}$ is assumed, based on current EU ETS levels [64].
The cost of the onshore gas power plant is based on a bottom-up approach for the investment cost while operating costs are based on estimated maintenance, labour and utilities costs. Here, a gas cost of 7 $/GJ [3] is considered to reflect the additional cost of gas transport compared to the CEPONG concept.
The MEA-based CO_2 capture investment costs are evaluated based on a factor estimation method. In this approach, the direct costs of equipment in suitably selected materials are evaluated using Aspen Process Economic Analyzer® and then multiplied by an indirect cost factor to obtain the investment costs. Meanwhile, fixed operating costs are evaluated as a set percentage of the investment cost and variable operating costs are based on estimated utilities consumption and utilities cost.
For the shipping transport, the investment and operating costs of ships are determined based on their effective capacity, as shown in Table 4 [70] and a fuel cost of 370 $/t$_{fuel}$, while the costs of unloading process equipment are based on a factor method.
Finally, offshore pipeline transport and CO_2 storage are evaluated following the same cost methodology as described in section 3.1.1.2.

Table 4: Ship investment and fixed operating cost [70, 71]

Ship size [t$_{CO2}$]	Total investment cost [M€$_{2009}$/ship]	Annual ship fixed operating cost [M€$_{2009}$ /y/ship]	Fuel consumption [g$_{fuel}$/t$_{CO2}$/km]
7,300	30.8	1.8	6.84
10,900	34.0	1.9	6.67
16,400	38.8	2.1	6.42

3.2.2.2 Electrification

For the reference electrification concept, the infrastructure cost evaluation follows the same approach as for the evaluation of the electrical export costs in the CEPONG concept. Based on the National Grid's Ten-Year Electricity Statement 2015 [68], the HVDC cables investment cost is evaluated as a function of the designed transmission power and the cable length, as shown in Eq. 2, while the investment cost for each converter is a function of the designed transmission power as shown in Eq. 4. It is important to note that Eq. 4 differs from Eq. 3 as, here, the investment costs of a dedicated offshore platform for the DC/AC converter must be included.
Regarding the operating costs, the annual costs of the converters and electrical export follow the same methodology as for the power export of the CEPONG concept. Finally, as discussed in section 2.2.2, the electrification is assumed to be powered by renewable electricity with the following characteristics: a cost of 100 $/MWh and no climate impact [72].

$$I_{converters} = \left(P_{trans} \cdot C_p^L + C_0^L\right) + \left(P_{trans} \cdot C_p^S + C_0^S\right) \qquad (4)$$

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Where

- P_{trans} is the designed transmission power
- C_p^L, C_0^L, C_p^S, and C_0^S are the cost parameters for scaling of cable and converters investment costs presented in Table 3

3.3 Key performance indicators

The levelised cost of electricity (LCOE) is used here as key performance indicators in order to compare the CEPONG concepts with the reference concepts.

The LCOE [$/MWh] measures the unit cost of electricity generation of a plant with and without CO_2 capture. It approximates the average discounted electricity price over the project duration that would be required to generate an income that matches the net present value of the capital and operating costs of the project. It is equal to the annualised costs divided by the annualised net electricity production [3].

$$\text{Levelised cost of electricity} = \frac{\text{Annualized investment} + \text{Annual OPEX}}{\text{Annual net electricity output}} \quad (2)$$

The LCOE is calculated considering a discount rate of 8%, an economic lifetime of 25 years, and an average yearly utilisation rate of 85% [3]. The investment costs also assume that construction is spread over a three-year period (with 40/30/30 annual allocations) [3]. Finally, annualised investments take into account commissioning/start-up, decommissioning/provision costs and owner costs.

In addition to the LCOE estimates obtained for the CEPONG and references concepts, sensitivity analyses will also be performed with the following ranges:

- Investment costs: -15% and +40% (based on the estimated CAPEX uncertainty);
- Operating costs, overall costs, power losses, etc: -40% and +40%;
- Discount rate: 4 and 12%;
- Project duration: 10 and 40 years
- Utilisation rate: 60% and 90%.

4 Results

4.1 Technical performances of the offshore platform with CCS

The gas turbine selected for power generation on the platform are offshore gas turbines with a rating of 54 MWe. The CO_2 capture plant consists of five absorbers and two desorbers/regenerators. The net power available after CO_2 capture and conditioning is 638.4 MWe. It is worth noting that, due to the constraints associated with offshore design, the CEPONG concept results in a specific reboiler duty for the CO_2 capture process around 7% higher than the ones typically obtained for an onshore design [3].

An overview of the results of the offshore platform with CO_2 capture and compression is given in Table 5.

Table 5: Performance and design results of the power plant with CO_2 capture and compression in the floating case

Section	Item	Value
Gas in-take	Thermal input [MW_{th}]	1361
Power production process	Number of gas turbines [-]	10
	Number of steam turbines [-]	2
	Net power output without CO_2 capture [MW]	733
	Exhaust flue gas flow [t/h]	1348
	CO_2 concentration in exhaust flue gas [$\%_{mol}$]	3.65
CO_2 capture process	Captured CO_2 flow [kg/s]	62.7
	CO_2 captured ratio [%]	82
	Number of absorbers [-]	5
	Absorber diameter [-]	11.3

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	Absorber height [-]	21.2
	Number of desorbers [-]	2
	Desorber diameter [-]	8.1
	Desorber height [-]	8.4
	Specific reboiler duty [GJ/tCO_2]	4.24
	Net power output with CO_2 capture [MW]	638
Platform	Hull diameter [m]	94
	Hull height [m]	51
	Total topside weight [t]	42900
	Share allocated to Power plant [%]	63%
	Share allocated to CO_2 capture and conditioning [%]	37%

Finally, the energy performances throughout the different stages of the CEPONG concept toward decarbonising mainland electricity and toward decarbonising offshore oil and gas platforms are summarised in Table 6. In both market scenarios, the evaluations result in a net power output of the power plant without CCS of 733 MW. Once CCS included, the net power output drop by 95 MW due to the high energy consumption of the MEA-based CO_2 capture and conditioning process. The CEPONG concept toward decarbonising offshore oil and gas platforms leads to a net power output of 638 MW before local power dispatch. Finally, once the power losses in the electrical converters and cable are taken into account, the CEPONG concept toward decarbonising of mainland electricity delivers 596 MW to the European grid's hypothetical connection point in Brunsbüttel.

Table 6: Powers throughout the CEPONG concept

	CEPONG concept toward decarbonising mainland electricity	CEPONG concept toward decarbonising offshore oil and gas platforms
Thermal input (MW_{th})	**1,361.3**	**1,361.3**
Net power output of the power plant without CCS (MWe)	**733.4**	**733.4**
Power losses associated with CCS (MWe)	95	95
Net power output of the power plant with CCS (MWe)	**638.4**	**638.4**
Net power delivered by the concept (MWe)	**596**	**638.4**
Climate impact of electricity (kg_{CO2}/MWh)	96.7	90.2

4.2 Cost performances and comparison with the reference concept

4.2.1 CEPONG concept toward decarbonising mainland electricity

The LCOE breakdown of the CEPONG concept toward decarbonising mainland electricity is compared to reference onshore gas power plants with CCS in Figure 11. The two transport and storage options evaluated, for the reference concept, reflect the impact of storage location on cost: Dutch Continental Shelf-based storage (Option 1) and Norwegian Continental Shelf-based storage (Option 2).
The cost evaluation of the CEPONG concept results in LCOEs of 142 and 178 $/MWh (equivalent to 128 and 160 €/MWh) respectively without and with CCS. In the CEPONG concept with CCS, the power plant accounts for around 45% of the LCOE (25% for fuel costs and 20% for investments and non-fuel operating costs). The CCS part, including associated power losses, represents 31% of the LCOE, while the power export accounts for 20%. Finally, the cost related to the remaining CO_2 emissions to the atmosphere accounts for 2% of the LCOE.
When comparing the CEPONG concept with and without CCS, the evaluation shows that the increase is very closely linked to the CO_2 capture and conditioning costs and associated power loss. Indeed, the investment and non-power related operating costs of the CO_2 capture account for 45% of the cost increase, while the power losses associated with CO_2 capture and conditioning represent 40%. Finally, the remaining increase is linked to CO_2 transport (5%) and storage (10%) costs.
Based on these elements, the CEPONG concept toward decarbonising mainland electricity results in an LCOE which is almost twice that of the reference onshore gas power plant with CCS (94-97 $/MWh, equivalent to 85-87 €/MWh, depending on the storage option). This large increase can be explained by the higher investment and operating costs of the offshore installation and operation as well as the

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additional costs of the power transmission system. Although this increase is slightly tempered by a reduction in the gas cost considered in the offshore case, this benefit does not appear to compensate the cost increase in other parts of the concept. However, it is important to note that there is an inherent uncertainty regarding the gas cost that should be considered for the cost evaluation of the concept, as this parameter is very case-specific. Admittedly, even with a gas cost of 0 \$/GJ for the CEPONG concept, further improvements would still be required for the CEPONG concept to reach the cost of the reference onshore power plant with CCS.

This trend is confirmed by the sensitivity analysis presented in Figure 12. Indeed, none of the parameters considered results in a cost decrease strong enough to enable the CEPONG concept toward decarbonising mainland electricity to reach electricity cost lower than the reference onshore NGCC plant with CCS (storage option 1). However, a low gas cost for the CEPONG concept combined with, for example, several technological improvements could result in a cost-competitive CEPONG concept toward decarbonising mainland electricity.

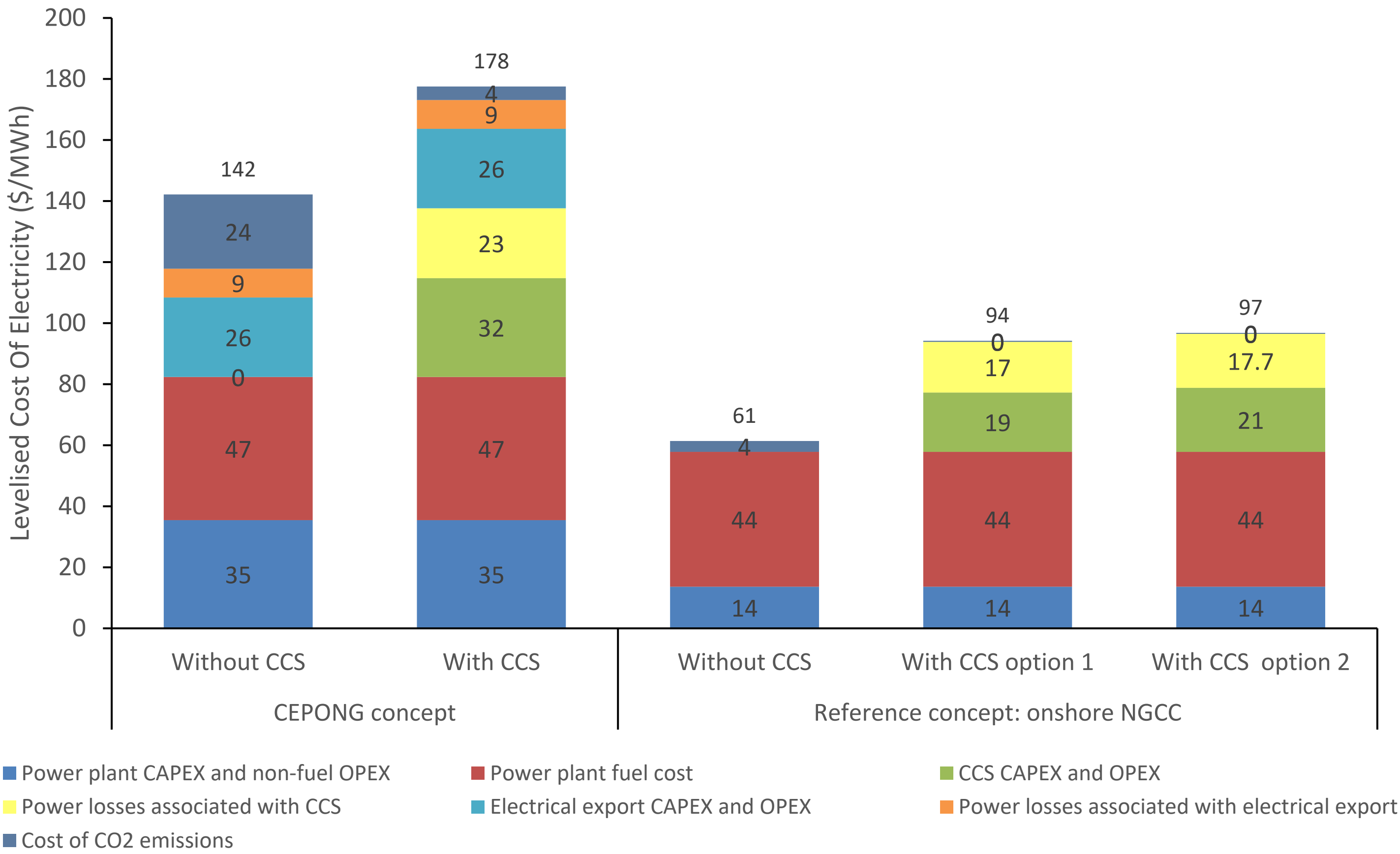

Figure 11: Comparison of LCOE of the CEPONG concept and the reference onshore NGCC with CCS concept in the floating case

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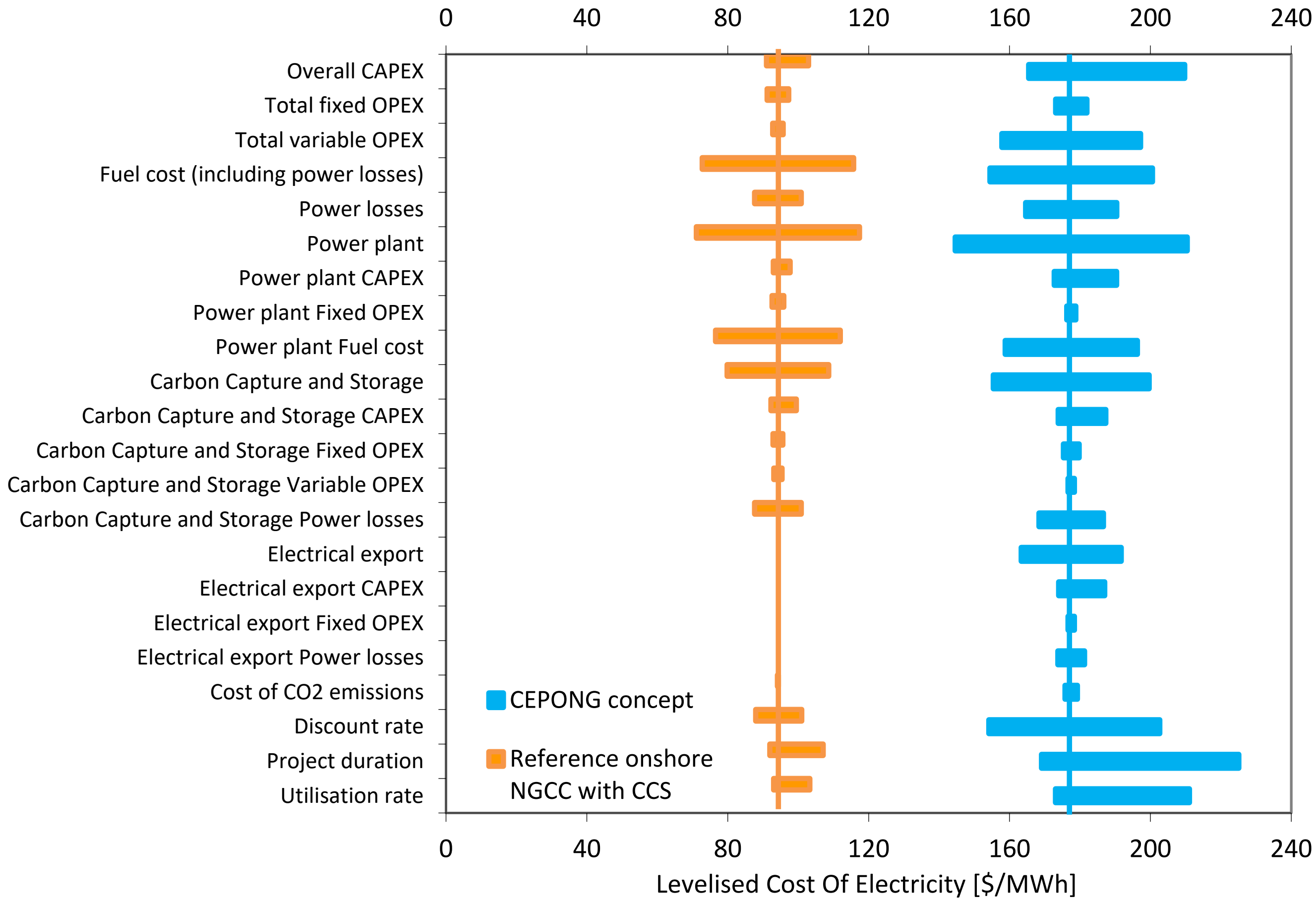

Figure 12: Sensitivity analysis on the LCOEs of the CEPONG concept toward decarbonising mainland electricity and the reference onshore NGCC plant with CCS (storage option 1) in the floating case

4.2.2 CEPONG concept toward decarbonising offshore oil and gas platforms

The LCOE breakdowns of the CEPONG concept toward decarbonising offshore oil and gas platforms are compared to the reference electrification concept in Figure 13. The evaluation of the CEPONG concept toward decarbonising offshore oil and gas platforms results in LCOEs of 107 and 137 $/MWh (equivalent to 96 and 123 €/MWh) respectively without and with CCS.

Although similar trends are observed, lower costs are obtained compared to the CEPONG concept toward decarbonising mainland electricity as there is no electrical export system to shore. This, indeed, significantly reduces the concept costs and energy losses caused by the long transport distance involved. In the CEPONG concept with CCS, the costs of the power plant including fuel cost thus represent 60% of the LCOE (82 $/MWh) while CCS is responsible for 37% of the LCOE (50 $/MWh). The cost of the CEPONG floating concept is therefore only slightly higher (5%) than the reference concept, which considers electrification powered by renewables (133 $/MWh equivalent to 118 €/MWh).

These elements suggest a significant potential for the CEPONG concept toward decarbonising offshore oil and gas platforms, particularly when potential cost reduction opportunities in the CEPONG concept are taken into account. Indeed, as shown in the sensitivity analyses presented in Figure 14, many of the considered parameter variations can result in a CEPONG concept toward decarbonising offshore oil and gas more cost-efficient than the reference electrification concept.

Furthermore, it is important to note that the costs of the electrification concept are highly dependent on transport distance and capacity, as well as the characteristics (cost and climate impact) of the electricity considered to power electrification. Indeed, as Figure 13 shows, the LCOE of the electrification concept are highly impacted by both transport distance and capacity, particularly when considering power deliveries below 500 MW. As a result, the CEPONG concept would outperform, in term of LCOE, electrification for transport distances greater than 225 and 125 km when considering power deliveries of

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500 and 350 MW, respectively. Furthermore, while this study assumes that electrification is powered by renewable resources, it is also important to note that this assumption may vary significantly depending on the geographical location considered, which may limit the abatement potential of this measure. Finally, in countries in which renewable power is not the main source of electricity, extensive electrification may offset efforts to reduce the climate impact of onshore electricity through new renewable deployments [32, 33].

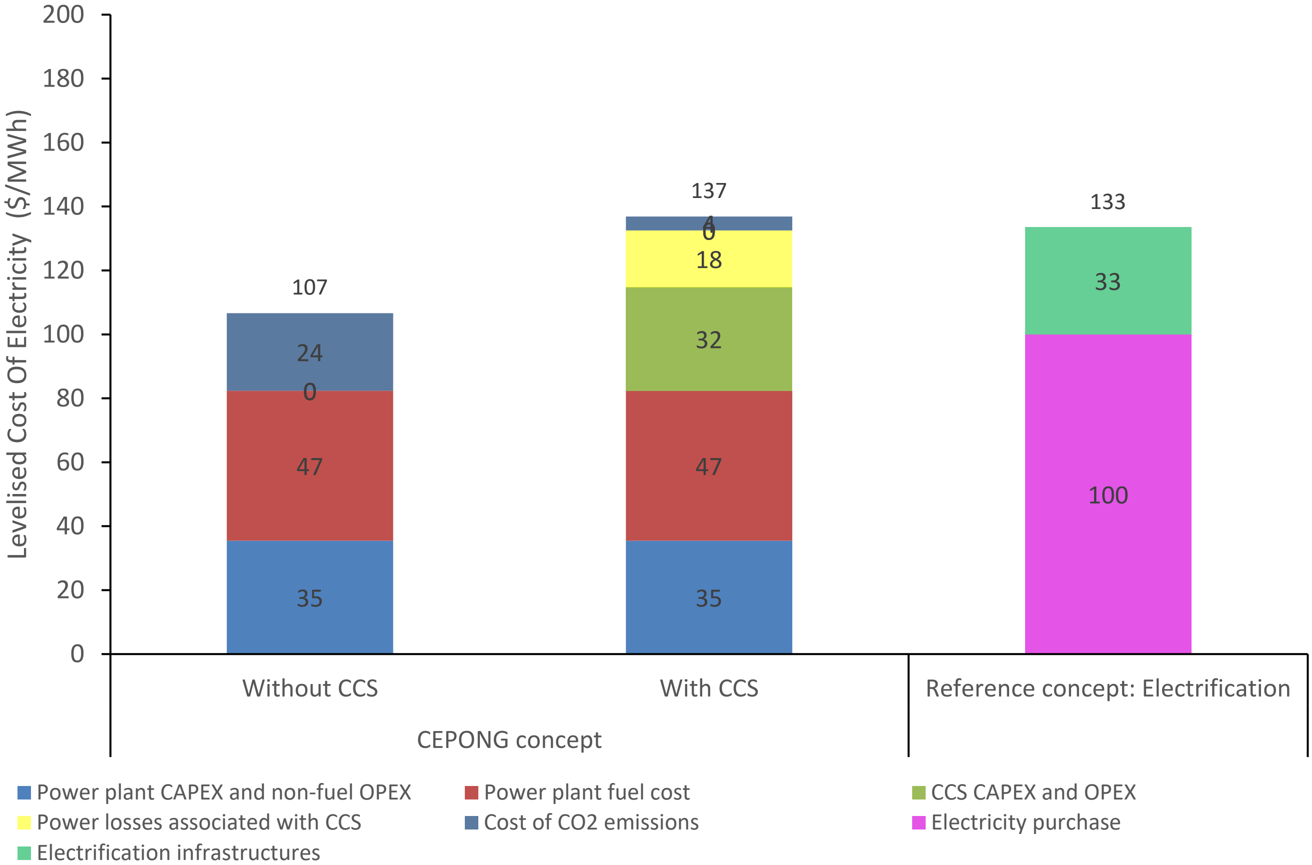

Figure 13: Comparison of LCOEs of the CEPONG concept toward decarbonising offshore oil and gas platforms and the reference electrification concept in the floating case

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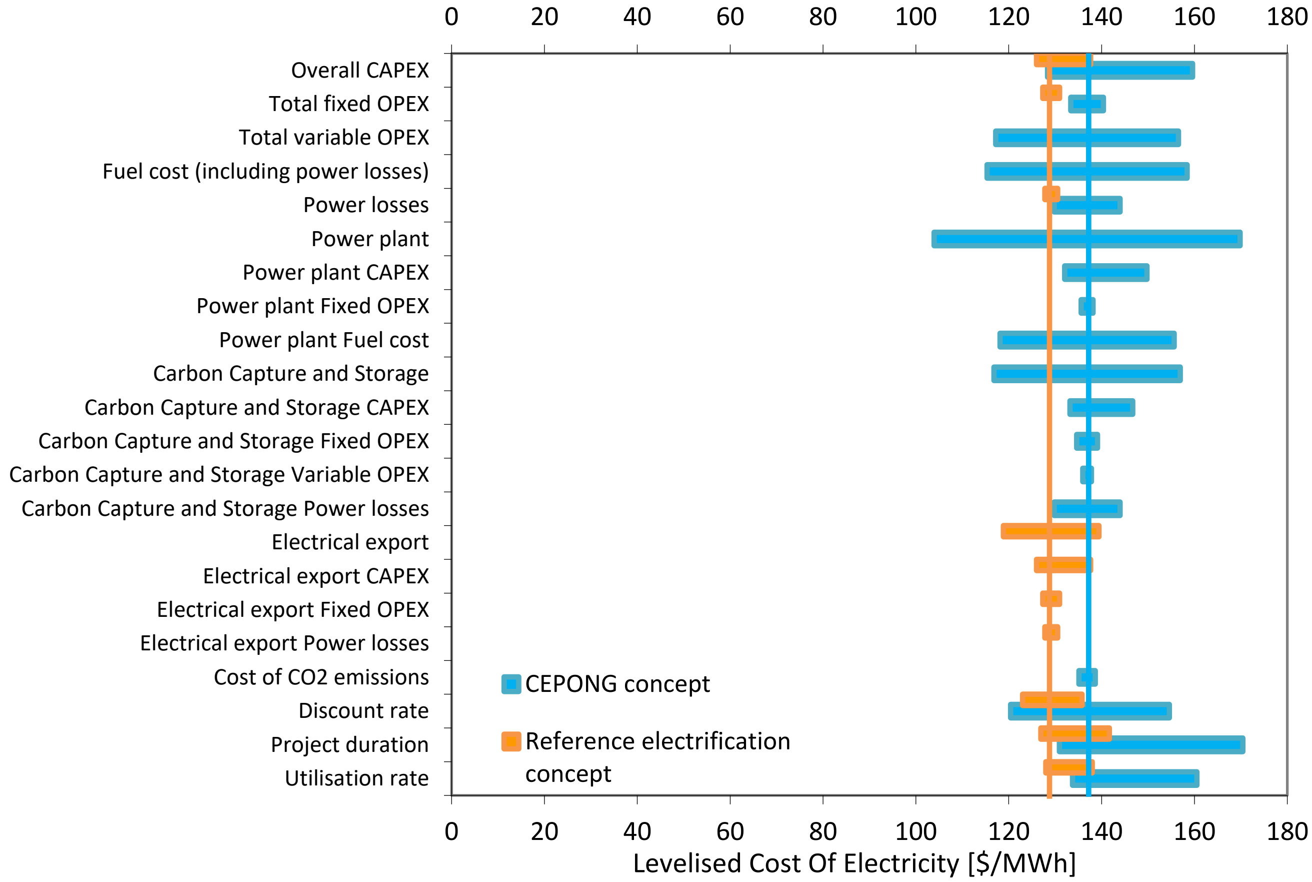

Figure 14: Sensitivity analysis on the LCOEs of the CEPONG concept toward decarbonising offshore oil and gas platforms and the reference electrification concept in the floating case

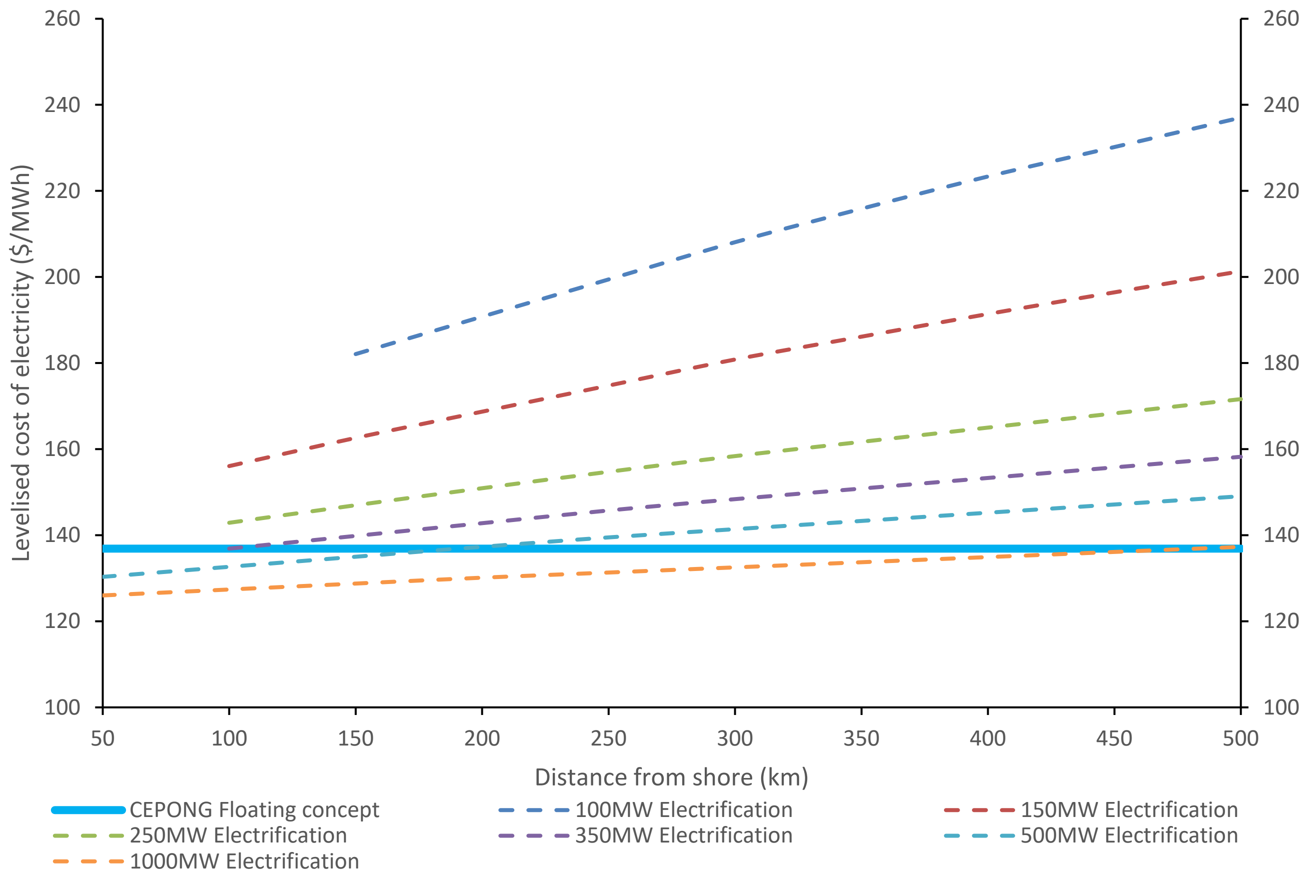

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Figure 15: Impact of the capacity and transport distance on the comparison of the CEPONG concept toward decarbonising offshore oil and gas platforms and the reference electrification concept in term of LCOE for the floating case

5 Discussions

In order to better understand the potential of the CEPONG concept, further analyses to identify the benefits of key potential technological improvements as well as the impact of case specific characteristics are considered. Here, 7 potential means of reducing the cost of the concept compared to the base case, through specific technological improvements and more attractive case specific characteristics, are presented and subsequently discussed. These focus on the following areas: improved offshore power plant, improved capture technology, reuse of existing infrastructure and relaxed design criteria, better storage integration opportunities, improved electric power export, and value/cost of natural gas. Based on system evaluations and literature reviews, the potential impact of each mean on the LCOE of the concept was evaluated individually as shown in Figure 15 and Figure 16.

The first interesting technological mean of improving the concept cost is to use gas turbines with higher efficiency than those considered in the base case design. In fact, a design based on the most efficient gas turbine available on the market could lead to gas turbine efficiencies of 42.7% [73] while the base case gas turbines efficiency is 39.1%. This would result in an LCOE decrease of 6.2 and 6.9 % for the concept delivering power to, respectively, mainland and offshore oil and gas platforms.

Regarding CO_2 capture technologies [17], an alternative case considering a 40% reduction in capture and conditioning energy penalty and a 20% reduction in investments and non-fuel operating costs is investigated. Although other capture technologies than solvent could reach these targets, it is worth noting that recent solvent developments have displayed a promising potential to reduce both energy and cost penalties [74]. Based on the assumed capture improvements, this alternative case results in an LCOE decrease of 10.4% for the concept delivering power to mainland, and 12.2% for the concept delivering power to offshore platforms.

The final technological improvement selected for the offshore platform is the potential development of the concept in connection with re-use of existing oil and gas infrastructures. Indeed, the re-use of existing platforms could simultaneously reduce decommissioning costs and the cost of the CEPONG platform, although inspection and repair program of the considered existing offshore asset is to be expected. The alternative case considered here corresponds to re-use of an existing FPSO unit (floating production, storage and offloading) as floating assets are deemed to be easier and more efficient to re-use, as well as being most relevant for deployment in the North Sea. This alternative case also considers optimisation of the construction through modularisation and time reduction of an expensive yard requirement. Based on these elements, this alternative could produce reductions in LCOE of 8.5 for the concept delivering power to mainland, and 10.2% for the concept delivering power to offshore platforms.

Another interesting way of reducing the costs of the concept is better integration with CO_2 storage. An alternative case that combine CO_2 storage with enhanced oil recovery (EOR) are also selected. This envisages an EOR response to the CO_2 injection of 1.53 bbt/$t_{CO2,imported}$ in average over the injection life time[15] [53]. Based on an oil value of 50$/bbl [53], the evaluation shows that the concept delivering power to mainland will result in a decrease in LCOE of 14.7% while a decrease of 17.9% is observed for a delivery to offshore oil and gas platforms. This especially emphasizes the significant potential of integration with CO_2 EOR, and possibly CO_2-EGR, to reduce the costs of the CEPONG concept.

Beyond technological improvements, case characteristics can also have a significant impact on the cost performances of the CEPONG concept. As one of the key characteristics for the development of the concept is the gas cost, two relevant scenarios related to gas cost are considered. The first scenario aims to represent a development of the CEPONG concept based on unprocessed gas or in connection to a dedicated field. It considers a gas cost of 3.4 $/GJ corresponding to the median of the subsea cost estimates

[15] It is worth noting that the amount of CO_2 imported to the CO_2 EOR storage is expected to decrease over time to maintain a constant injection despite the increasing reservoir CO_2 production with time. Thus, a buffer saline aquifer is considered for the remaining CO_2 captured from the CEPONG concept.

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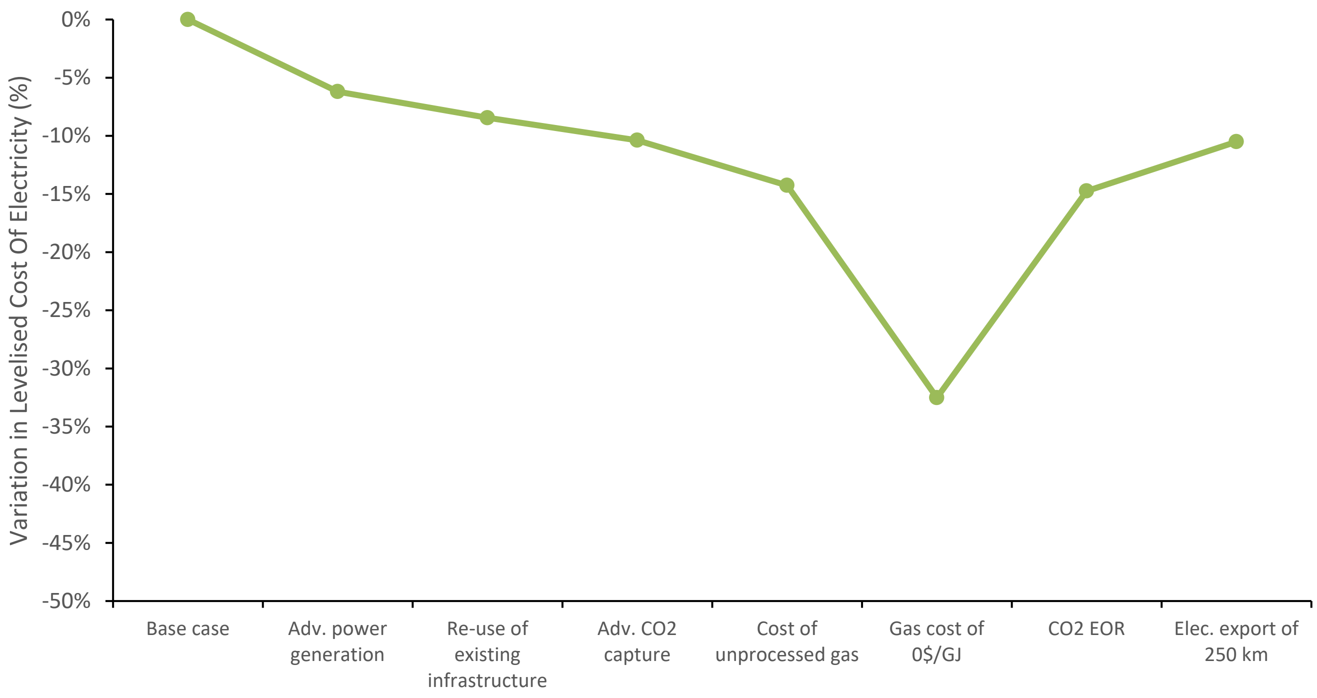
(drilling, pipeline and subsea) of 27 future gas field developments located in the North Sea and delivering unprocessed natural gas. The evaluation shows a strong cost reduction potential (14.3-17.3% in LCOE depending on the targeted market). The second gas cost scenario explores implementation of the CEPONG concept based on associated gas from oil production field(s) without access to a gas transport infrastructure. This scenario is thus relevant for development of oil and gas fields "far" from shore, like for example in the Castberg region in the Barents Sea. Indeed, in such cases, handling the associated gas could in fact represent a heavy cost burden for the oil production platform[16]. Considering a gas cost for the concept of 0 \$/GJ to reflect the little gas valorisation opportunities, this scenario results in LCOE reductions of 32.5% for the concept delivering power to mainland, and respectively 39.4% for the concept delivering power to offshore platforms. The significant cost reduction opportunities observed through these two gas cost scenarios demonstrate the importance of this case-specific parameter to achieve a cost-competitive CEPONG concept.
Furthermore, for the CEPONG concept toward decarbonising mainland electricity, significant cost reduction opportunities in the electrical export might be obtained in some cases. This is investigated through a case considering an implementation of the CEPONG concept 250 km away from the targeted mainland market (vs. 750 km in the base case) to reflect the potential implementation of the concept nearer to market. For the "250 km" alternative case, the evaluations lead to reductions in LCOE of 10.5% for the concept delivering power to mainland.

Although these measures will not be able to individually enable a cost-competitive CEPONG concept, combinations of them can lead to a competitive concept. Based on the individually cost reduction reached and the sensitivity analyses presented in section 4, the CEPONG concept is deemed to have a significant potential to cost-effectively decarbonise the offshore oil and gas industry. Indeed, with an advanced CO_2 capture technology, the CEPONG concept would already outperform the reference electrification concept. Furthermore, the CEPONG concept is expected to result in significant cost reduction compared to electrification if several of the above technological improvements and more attractive case characteristics can be reached together. Meanwhile, a more moderate potential is foreseen for the concept decarbonising toward mainland electricity as many of the potential improvements for the CEPONG concept would also benefit to the reference NGCC plant with CCS. However, in any case, the results underline the importance of both the case characteristics and technological solutions for the development of a cost-competitive concept.



[16] Due to investment and operating costs required to handle the associated gas.

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Figure 16: Summary of the individual impacts of selected measures to reduce the cost of the CEPONG concept to decarbonise mainland electricity in the floating case

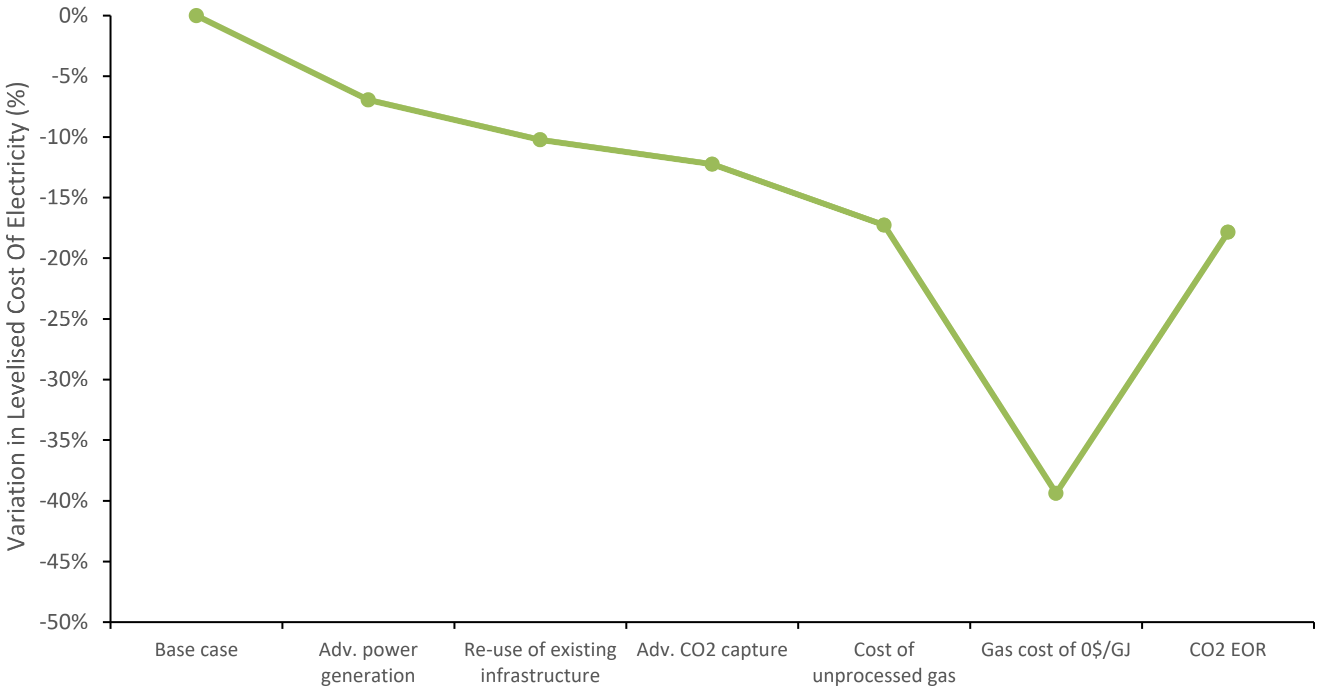

Figure 17: Summary of the individual impacts of selected measures to reduce the cost of the CEPONG concept to decarbonise offshore oil and gas platforms in the floating case

6 Conclusions

While power generation with carbon capture and storage from offshore natural gas is expected to play a significant role in decarbonising the global energy mix, further reductions in the cost of natural gas to clean power value chain is required to reach competitiveness with other clean energy technologies. Thus, the potential for offshore power generation from natural gas with carbon capture and storage to supply clean power to decarbonise mainland electricity and offshore oil and gas platforms was investigated. This potential was evaluated through techno-economic assessments of the "Clean Electricity Production from Offshore Natural Gas" (CEPONG) concept for both potential markets (decarbonising mainland electricity and decarbonising offshore oil and gas platforms) through two relevant cases and comparisons with suitable reference concepts. In the base cases, the CEPONG concept toward decarbonising mainland electricity results in costs significantly larger than the reference onshore gas-fired power plant with carbon capture and storage. In fact, while the reference onshore gas-fired power plant with carbon capture and storage leads to an electricity cost of around 94-97 \$/MWh depending on the storage scenario considered, the CEPONG concept results in costs of electricity of 178 and 258 \$/MWh in the floating and shallow water cases respectively. However, the CEPONG concept toward decarbonising offshore platforms leads to costs that are more similar to the reference concept of electrification through import of power from mainland. In fact, while the electrification concept leads to electricity costs of 133 and 166 \$/MWh in the floating and shallow water cases, the CEPONG concept results in electricity costs of 137 and 207 \$/MWh in the floating and shallow water cases respectively.

Although the base cases show a limited potential for the proposed concept, further analyses show that a stronger potential can be achieved through potential technological improvements (advanced power generation and CO_2 capture technologies, reuse of existing infrastructure …) and more suitable case characteristics (development of the concept in connection with unprocessed or stranded gas, long distances to mainland …). Taking these elements into account, the proposed concept is deemed to have a significant potential to cost-effectively decarbonise the offshore oil and gas industry, while a more moderate potential exists for the concept toward decarbonising mainland electricity.

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7 Appendix A: Results for the shallow water case

A summary of the results of the technical modelling of the CEPONG concept is presented in Table 7 while the layout of the offshore platform is presented in Figure 18. The energy performances throughout the different stages of the CEPONG concept toward decarbonising mainland electricity and toward decarbonising offshore oil and gas platforms are summarised in Table 8.

Table 7: Performance and design results of the power plant with CO_2 capture and compression in the shallow water case

Section	Item	Value
Gas in-take	Thermal input [MW_{th}]	288
Power production process	Number of gas turbines [-]	3
	Number of steam turbines [-]	1
	Net power output without CO_2 capture [MW]	155
	Exhaust flue gas flow [t/h]	423
	CO_2 concentration in exhaust flue gas [$\%_{mol}$]	2.86
CO_2 capture process	Captured CO_2 flow [kg/s]	15.7
	CO_2 captured ratio [%]	82
	Number of absorbers [-]	2
	Absorber diameter [-]	8.6
	Absorber height [-]	27
	Number of desorbers [-]	1
	Desorber diameter [-]	5.6
	Desorber height [-]	10
	Specific reboiler duty [GJ/tCO_2]	4.33

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	Net power output with CO_2 capture [MW]	130
Platform	Hull diameter [m]	80
	Hull height [m]	38
	Total topside weight [t]	28800
	Share allocated to Power plant [%]	61%
	Share allocated to CO_2 capture and conditioning [%]	39%

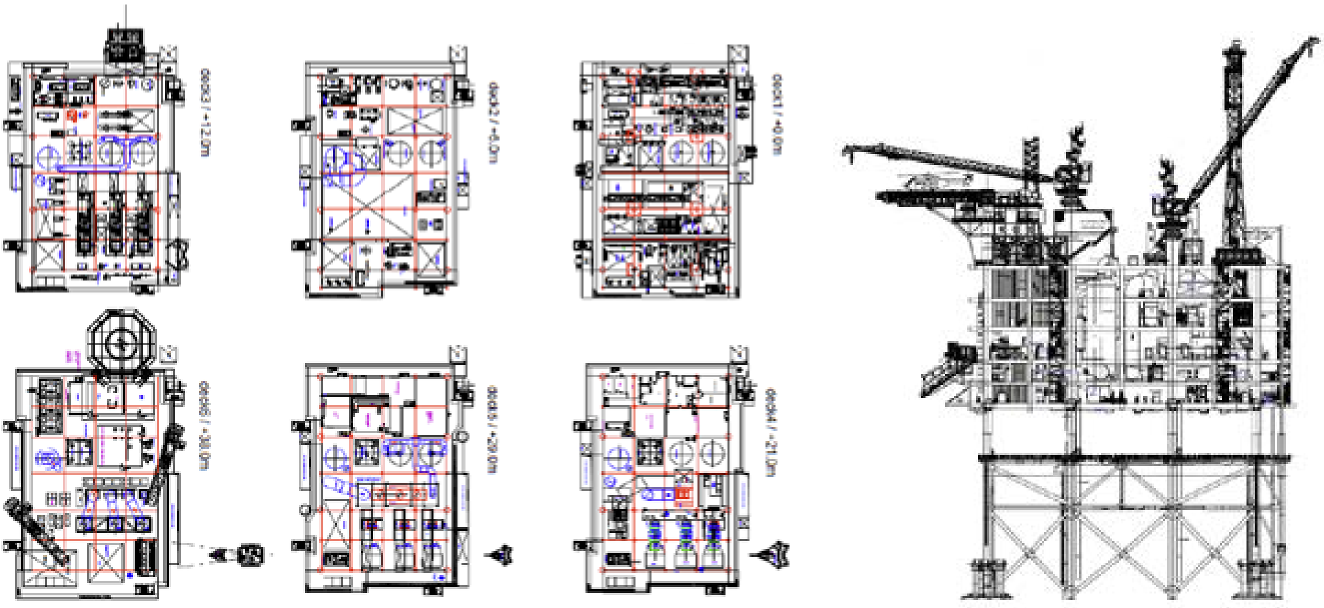

Figure 18: Layout of the offshore power production platform with CCS in the CEPONG concept in the shallow water case (a) deck views (b) lateral view

Table 8: Powers throughout the CEPONG concept in the shallow water case

	CEPONG concept toward decarbonising mainland electricity	CEPONG concept toward decarbonising offshore oil and gas platforms
Thermal input (MW_{th})	**288.0**	**288.0**
Net power output of the power plant without CCS (MWe)	**155**	**155**
Power losses associated with CCS (MWe)	25	25
Net power output of the power plant with CCS (MWe)	**130**	**130**
Power losses associated with electrical export (MWe)	5.7	-
Net power delivered by the concept (MWe)	**124.3**	**130.0**
Climate impact of electricity (kg_{CO2}/MWh)	100.2	95.9

The results of the cost evaluation and comparisons with reference concepts are presented in Figure 19 for the CEPONG concept toward decarbonising mainland electricity and in Figure 20 for the CEPONG concept toward decarbonising offshore oil and gas platforms. Overall, similar trends as in the floating case are obtained, although higher costs are observed for the CEPONG concept. These higher concept costs are especially due to the small scale of the power infrastructure in this case, as well as the lower synergy achievable when integrating a large CO_2 capture system in fixed platform rather than in a floating platform. Indeed, in the case of floating platform, many large equipment can be placed inside the hull reducing the overall weight of the platform.
The sensitivity analyses presented in Figure 12 and Figure 14 show similar trends than in the floating concept. Indeed, while a few improvements can enable a cost-competitive CEPONG concept decarbonising offshore oil and gas platforms, the CEPONG concept toward decarbonising mainland electricity will need strong cost reduction from several parts of the concept to reach the level of the reference concept.

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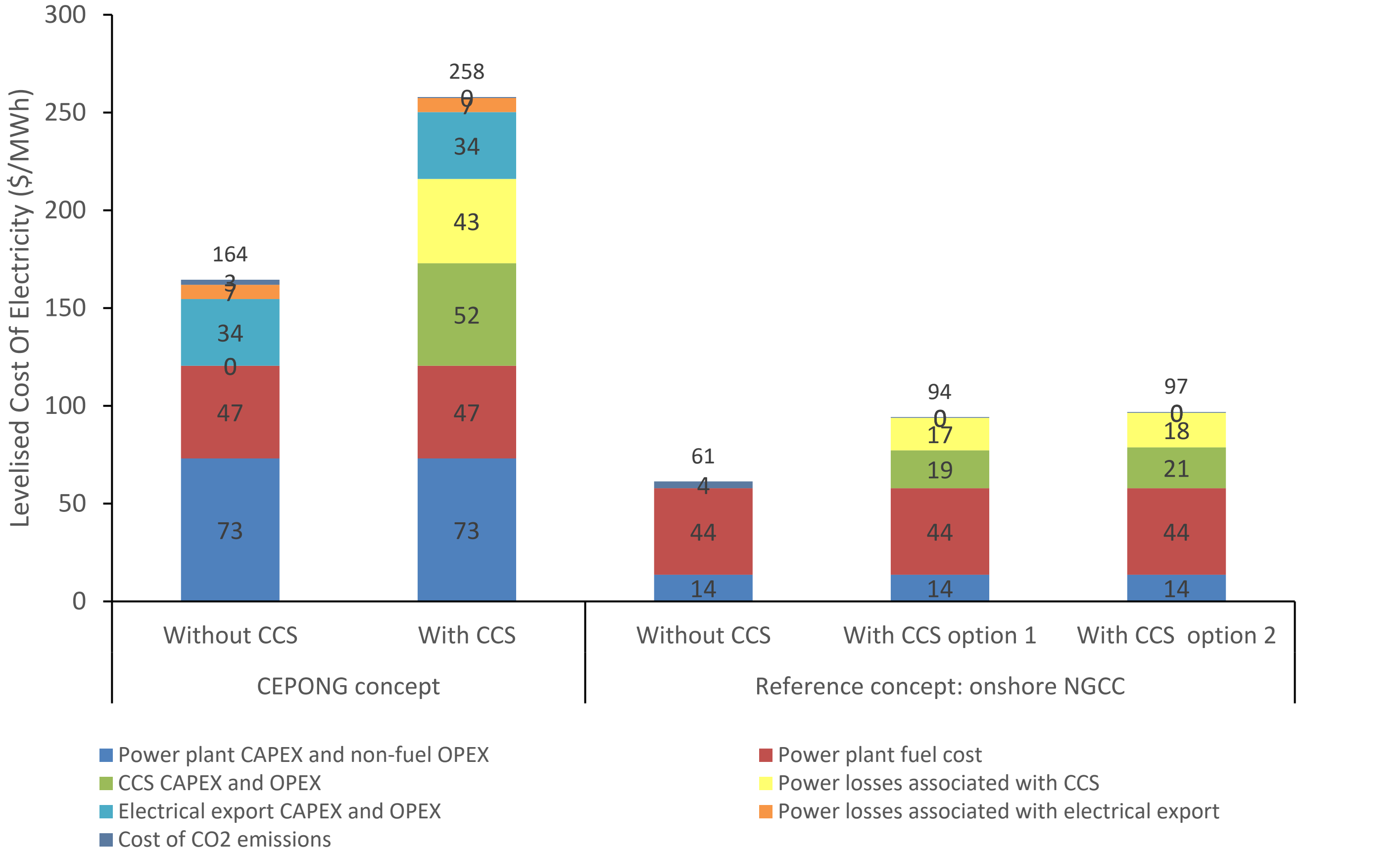

Figure 19: Comparison of LCOEs of the CEPONG concept and the reference onshore NGCC with CCS concept in the shallow water case

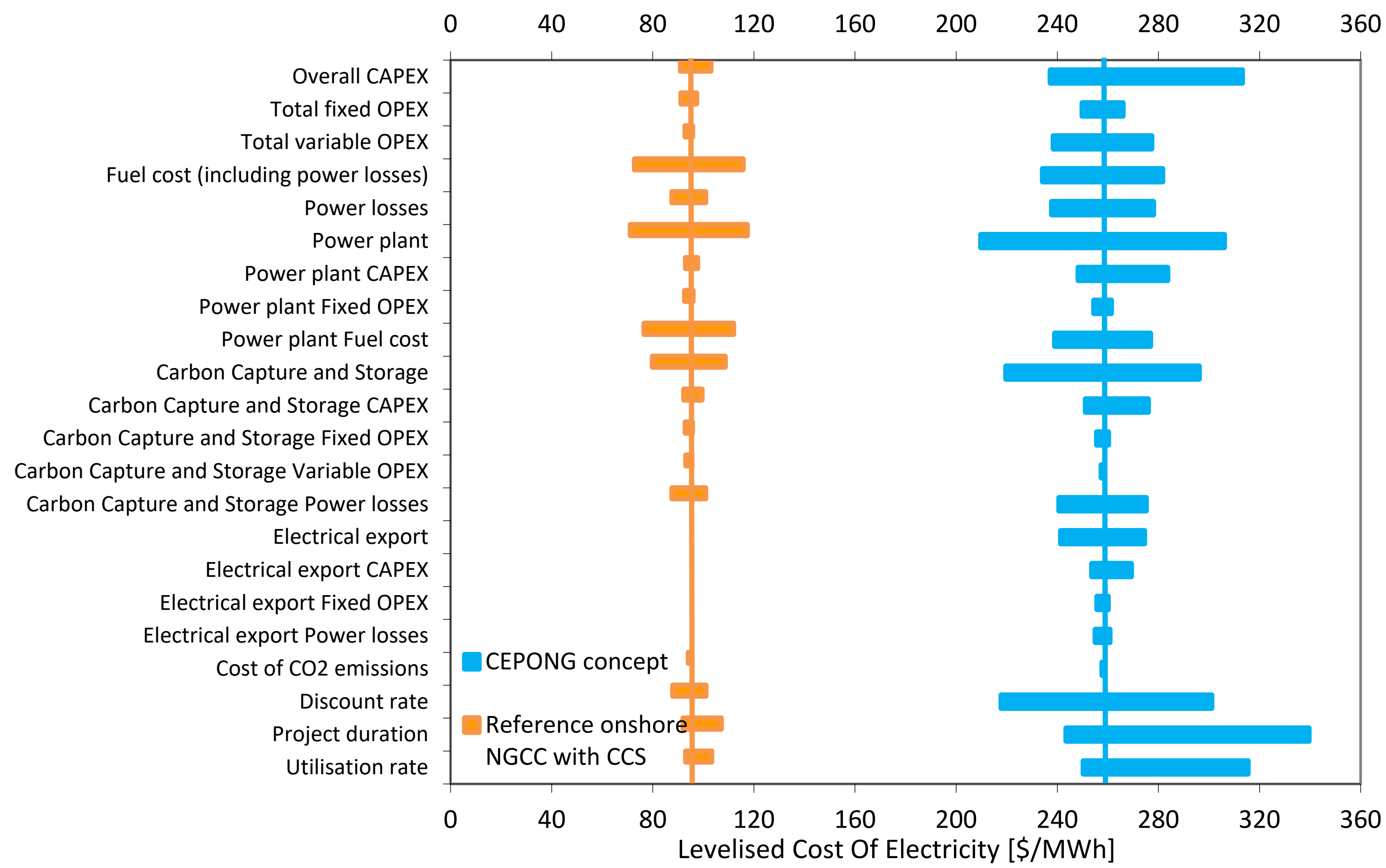

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Figure 20: Sensitivity analysis on the LCOEs of the CEPONG concept toward decarbonising mainland electricity and the reference onshore NGCC plant with CCS (storage option 1) in the floating case

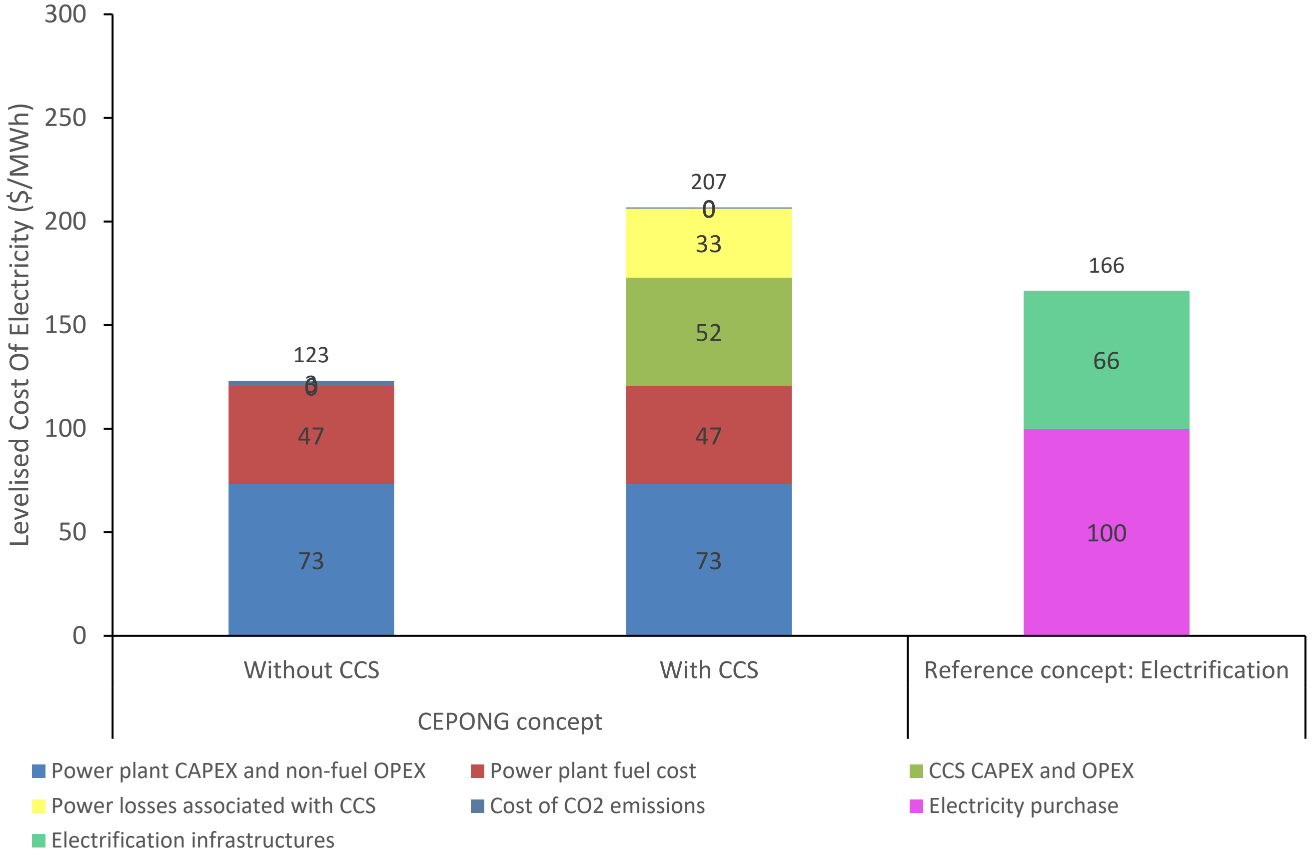

Figure 21: Comparison of LCOEs of the CEPONG concept toward decarbonising offshore oil and gas platforms and the reference electrification concept in the shallow water case

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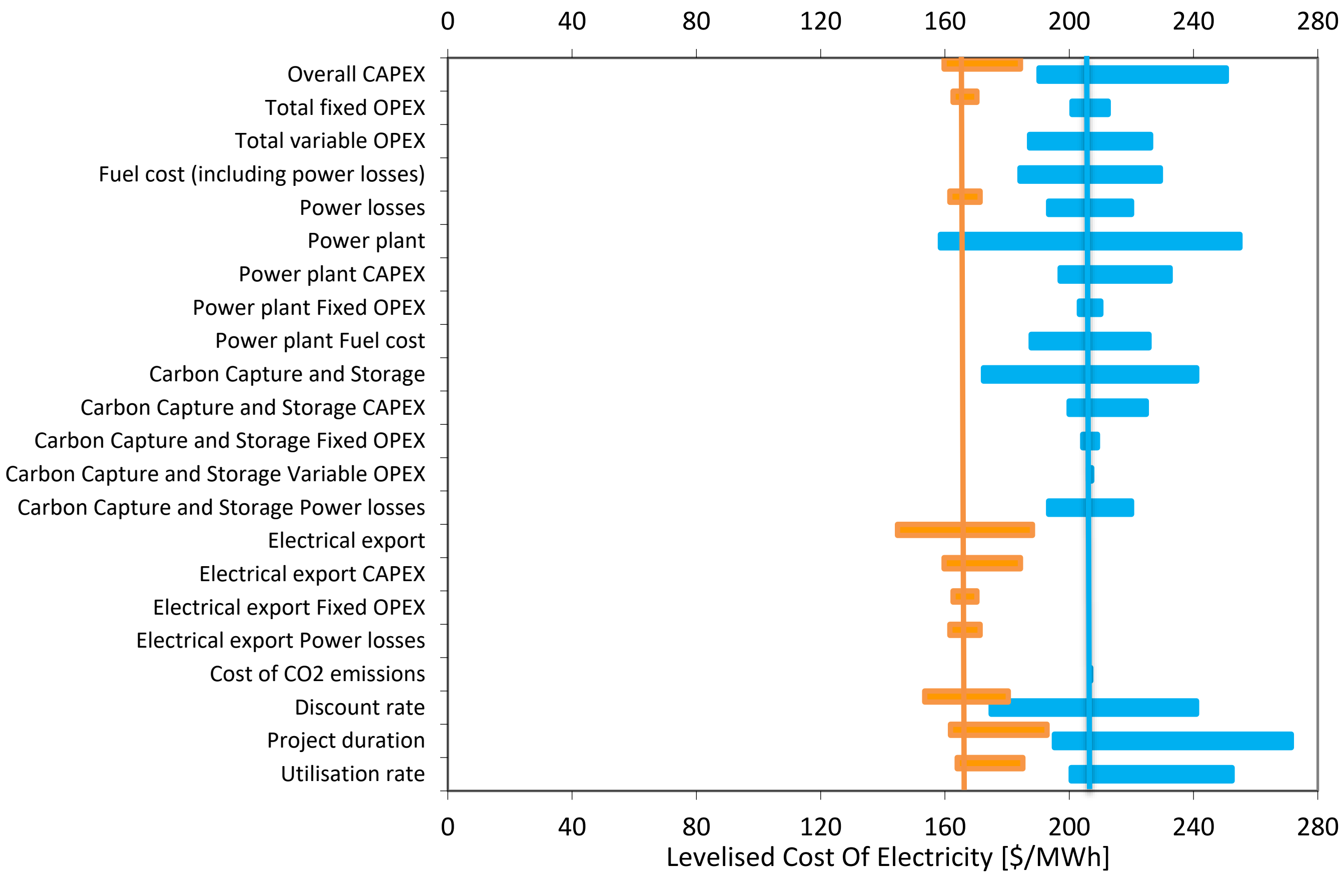

Figure 22: Sensitivity analysis on the LCOEs of the CEPONG concept toward decarbonising offshore oil and gas platforms and the reference electrification concept in the floating case

Similarly to section 5, potential cost reductions achievable through the selected 7 means considered are presented in Table 9. Similar trends as for the floating case are obtained although differences can be observed due to variation in the cost breakdown. In conclusion, although the CEPONG concept toward decarbonising oil and gas platforms still have a strong potential in the shallow water case, the concept toward decarbonising mainland has a limited potential, even with the cost potential reduction, due to the high cost in the base case.

Table 9: Summary of LCOE individual cost reduction potential of the measuresfor the CEPONG concept in the shallow water case

	Toward decarbonising mainland	Toward decarbonising oil and gas platforms
Ad. Power Generation	7.3%	8.3%
Re-use of existing infrastructure.	11.8%	14.1%
Advanced CO_2 capture	12.4%	14.6%
Cost of unprocessed gas	10.1%	12.0%
Gas cost of 0 $/GJ	22.9%	27.3%
CO_2 storage associated with EOR	12.0%	14.3%
Shared electrical export	7.7%	-

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