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Centralized power generation with carbon capture on decommissioned offshore petroleum platforms

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Abstract:

In this work, an offshore central power station is designed for supplying the electricity required during the lifetime of four identical productive floating, production, storage and offloading units (FPSO), aiming to increase the efficiency and alleviate the environmental burden that the business-as-usual utility systems are responsible for in offshore oil and gas activities. However, in face of the conflicting targets, intrinsic to offshore power generation systems (*e.g.* weight, area, cost and efficiency), along with prolonged offdesign operating conditions, a techno-economic assessment and optimization is necessary in order to determine the optimal configuration of power hub. By using a combined thermodynamic, environmental and economic analysis, together with space and weight allowance quantification, this work sheds light on the feasibility of offshore central power stations without or with carbon capture units and intended to be installed on decommissioned FPSOs, a novel proposal that reduces the initial investment cost. As a result, the advanced utility systems may provide higher overall power generation efficiencies (>35%) than existing simple cycle gas turbine (SCGT) configurations (about 30%), even at tenfold lower CO_2 emissions. Moreover, envisaging future carbon taxation scenarios, an incremental economic analysis has found that the advanced power generation systems may also economically outperform the conventional offshore power plants for moderate carbon taxations. Lastly, the effect of the peak of electricity demand on the initial investment cost and the overall exergy efficiency of the power hub are briefly discussed in light of the delay in entry of operation between FPSOs.

Keywords: Power hub, Optimization, Offdesign, Emissions, Economics

1. Introduction

Offshore petroleum extraction plays a strategic role in satisfying the world energy demand, considering that one-third of the global oil production comes from the sea [1]. This activity is particularly important in Brazil, where 96% of the petroleum production proceeds from maritime fields [2] and accounts for about 13% of its gross domestic product [2, 3]. However, despite its relevance to the national energy security and the remaining economic sectors, this industry still deals with technological gaps that may threaten its economic and environmental sustainability. Offshore petroleum production is an energy intensive process that demands a large amount of utilities, typically supplied by low-efficiency energy systems based on *N+1* simple cycle gas turbines (SCGT) with waste heat recovery units (WHRU). In fact, almost 3.4 million m^3 per day of natural gas are burnt in the existing FPSOs [4], with the corresponding volume of CO_2 emissions. Moreover, since these utility demands may undergo sharp variations over time due to the changing flow rate and composition of the fluids extracted, the cogeneration systems adopted mostly operate at offdesign conditions during the entire productive lifespan, even if multiple units are installed aiming to minimize the drop in efficiency.

Hitherto, space and weight budget along with other inherent constraints to existing FPSOs (*e.g.*, instability, electricity transportation, investment and risk) [5] have hampered the efforts to integrate more advanced (and bulkier) cogeneration plants, reportedly capable of increasing the overall cogeneration efficiency [6, 7]. Accordingly, if those constraints could be ingeniously resolved, an improved performance of the utility systems on existing FPSOs may help not only cutting down the utilities fuel consumption (*i.e.*, increased revenues from exported gas), but also mitigating the environmental impact. It also may reveal business opportunities in the transition to a low carbon matrix, in view of future scenarios of more stringent environmental regulations, commercial prospects for enhanced oil recovery (EOR) and implementation of carbon market [8, 9]. In this regard, in its 2020-2024 Business and Management Plan [10], Petrobras announced relevant targets for reducing its carbon intensity, aiming to reduce the emissions of the exploration and production activities by 32% (from 22 to 15 kg_{CO2e}/boe) between 2015 and 2025, whereas investments above US$150 million are expected for funding decarbonization projects. This trend is in agreement with a growing number of business initiatives within firms, in which the internal carbon price is used not only for planning purposes, but also for managing risk, in anticipation of the impact of increasing global environmental regulations on the operational results of the assets, designed to operate for decades [11].

Breakthrough approaches include electrification from shore (as for the North Sea oil fields in Norway) [12] and power hub concepts (composed of efficient combined cycles) for centralizing the electricity generation demanded by various FPSOs operating in the Brazilian pre-salt basin [13, 14]. Vidoza *et al.* [13] proposed a power hub without CCS unit in order to centralize the electricity generation demanded by various FPSOs. According to the authors, combined cycles with two levels of pressure, three gas turbines and one heat recovery steam generator (HRSG) hold the lowest investment cost and weight, whereas present a relatively high power generation efficiency of 53%. Moreover, the proposed hub may reduce the CO_2 emissions by 19%, compared to the business-as-usual configuration. However, the area occupied by the proposed configuration has not been estimated, thus, the possibility of installing the proposed hub on a decommissioned FPSO has not been considered. Freire and Oliveira Junior [15] proposed an alternative solution that considers the simultaneous power generation on the hub and the FPSOs, but no carbon capture and storage (CCS) unit was devised. Furthermore, unlike the previous research work, this proposal is aimed to settle on a decommissioned and adapted FPSO. This configuration reportedly increases the exergy efficiency by 9 points. An incremental techno-economic assessment including the sensitivity analysis to the carbon taxes showed that power hubs even without CCS unit could be not only technical, but also economically feasible depending on the carbon-taxed scenario adopted.

Only few studies focused on the design of centralized power stations that include post-combustion CCS unit, whereas none of them considered the use of decommissioned FPSOs to install the proposed hubs. Hetland et al. [16] suggested the integration of a CCS unit to a power hub (450 MW) in the denominated Sevan GTW concept. The CCS unit components were installed beneath the deck of the cylindrical platform to lower the gravity center of the assembly. This setup reportedly offers suitable operating conditions, despite the potential shortcomings that may arise from periodic oscillations and permanent tilting [17, 18]. Meanwhile, Roussanaly *et al.* [19] performed a techno-economic analysis of the so-called Clean Electricity Production from Offshore Natural Gas (CEPONG) concept (similar to that proposed by Hetland *et al.*), aimed to either decarbonize the onshore electricity mix or supply power for oil and gas production. As a result, the most attractive application of the concept is the decarbonization of the oil and gas industry. On the other hand, the import or export of electricity from or to the shore is not financially recommendable. Finally, Winden *et al*. [20, 21] designed an offshore power plant with carbon capture, called the Offshore Thermal Power Plant with CCS (OTPPC) concept (540 MW). In face of its cost-benefit performance, the electricity produced could be used to inject the CO_2 derived and captured in offshore and onshore applications.

Despite their relevance, the previous works did not report detailed thermodynamic or financial outcomes, or equipment specifications; thus, they cannot be easily reproduced. More recently, Flórez-Orrego *et al*. [22, 23] proposed a combined optimization of the dispatch and load distribution of a set of modular power units (MPUs) in a power hub with and without carbon capture and reinjection, in order to supply the time-varying power demands of four FPSOs. According to the authors, the fact that about half of the Brazilian FPSOs are nearing the end of its useful life renders the decommissioning and adaptation of a FPSO into a power hub an opportunity to integrate more efficient and environmentally friendly technologies in the offshore oil and gas sector. Indeed, a power hub would allow the optimization of its sizing and operating point, reducing the investment and operating costs, as well as the greenhouse gas emissions per unit of oil and gas produced. The weaknesses of the reviewed manuscripts is precisely that their authors have addressed only the thermodynamic aspects of including combined cycles and, seldom, carbon capture units; but none of them either realized or discussed the limitations of space and weight restrictions, or the need for optimizing both design and offdesign operating conditions. Economic evaluations considering carbon taxations and variation of CCS unit cost are also missing from those research works.

Certainly, new challenges may arise for companies that contemplate using more advanced energy technologies, such as the incremental costs associated to the adaptation of the hull, and the initial investment, operation and maintenance costs of the additional equipment. These circumstances render necessary to determine the trade-offs between the more efficient and more affordable alternatives available to supersede the conventional offshore cogeneration plants. Thus, in this work, a novel configuration of *power hub* without and with CCS unit is proposed to be installed on a decommissioned and adapted FPSO. The implementation is subject to the space and weight allowance, bearing in mind the fluctuations over time of the power demand of a set of four productive FPSOs. Four scenarios of centralized power stations are compared to the existing utility systems in the FPSOs. In this way, this study, first of its kind, sheds light on the feasibility of operating advanced power stations with carbon capture units. To this end, a thermo-economic evaluation for different scenarios that considers the specific cost of the carbon capture unit, the carbon tax and the interest rate (depreciation of money with time) is presented.

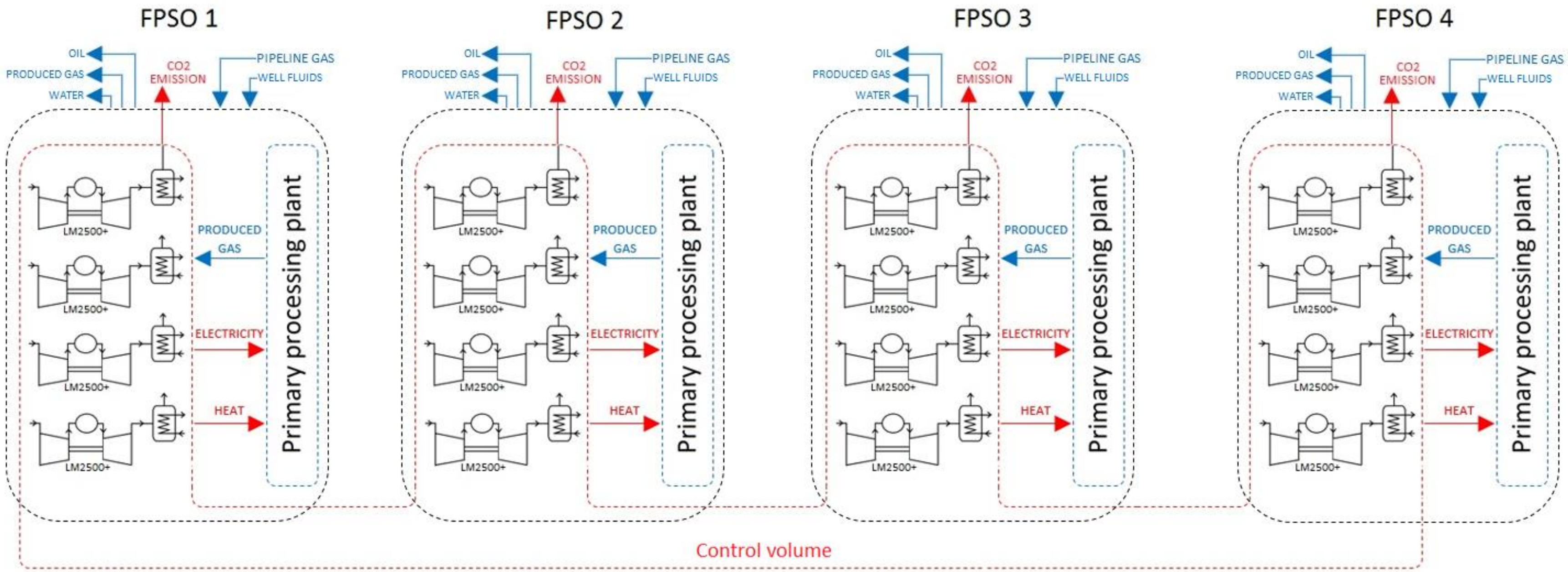
2. Offshore petroleum processing plants and utility systems

In this section, the characteristics of the productive FPSOs and the conventional utility systems, responsible for supplying the energy demands thereof, are presented. The modular power units (MPUs) that compose the power hub alternatives are also described. Finally, the challenges and opportunities for integrating offshore carbon capture and storage (CCS) units are briefly discussed.

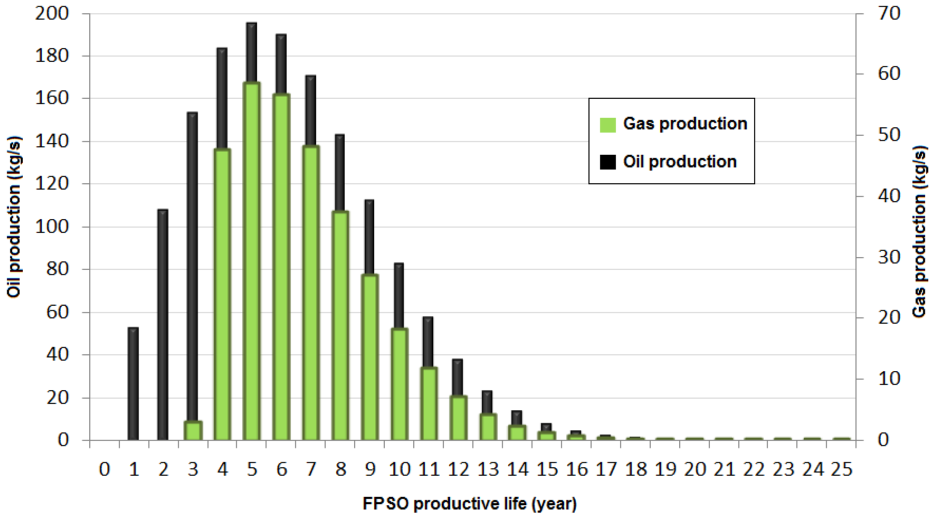
2.1. Characteristics of the productive FPSOs

The control volume adopted for performing the comparative incremental assessment encompasses the utility systems of four productive FPSOs (Fig. 1a). Each FPSO is capable of daily processing up to 150 thousand barrels of oil and 6 million Nm^3 of natural gas (Fig. 1b); as well as treating 20 thousand m^3 of produced water per day and storing around 1.6 million barrels of oil, which are periodically transported by a relief vessel to the coast [24]. The industrial processes occurring in the primary processing plants of each FPSO demand a large amount of utilities in the form of heat and power (Fig. 1c), typically supplied by four simple cycle gas turbine systems (LM2500+) equipped with WHRUs. The production process starts when each FPSO receives the petroleum via manifolds and risers (15-20 bar, 40-50°C) and preheats the mixture close to 80°C by using a pressurized hot water circuit (100-150°C), so as to facilitate its separation into oil, gas and water, along various separation stages. The oil is further degasified, conditioned and stored, and later offloaded to a shuttle tanker [25]; whereas the separated water is treated for residual oil removal and disposal. On the other hand, since the gaseous hydrocarbon from the well contains a significant amount of CO_2, it must be compressed up to the operating pressure of the membrane separation system (~50 bar), wherein CO_2 is largely removed [7]. Thereafter, the CO_2-rich gaseous stream produced must be reinjected, in order to comply with the environmental regulations; while the hydrocarbon-rich stream is dehydrated either to be exported (245 bar), reinjected (550 bar), used for gas-lift or partially consumed as fuel by primary movers of the pumps and compressors [26].

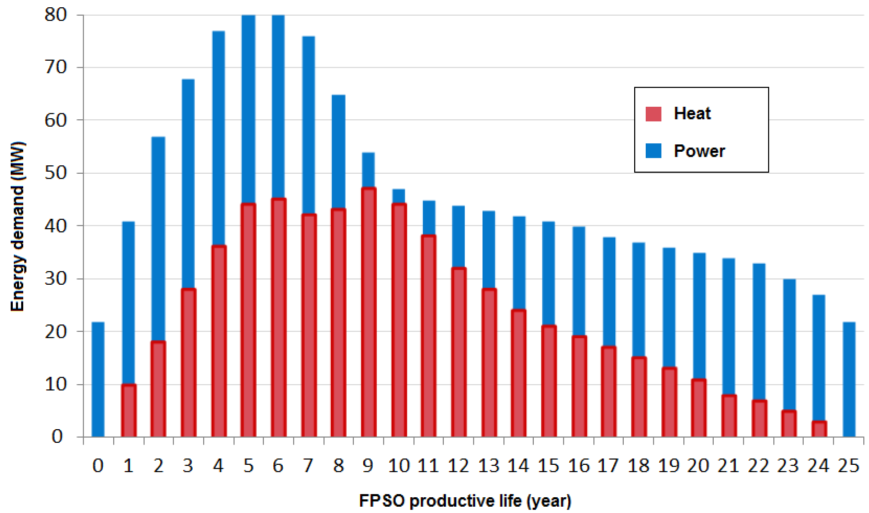
In this work, it is assumed that enough gas production allows for self-sustainable power generation between the 3rd and 15th years [27]; while, in the remaining years, the extracted gas fully bypasses the membrane separation system and, thus, import of fuel gas is required. In practice, the profiles of the energy demands of one typical FPSO, depicted in Fig. 1c, are difficult to predict with reasonable accuracy, as they depend not only on the performance of the topsides installed on the FPSO, but also on the changing flow rate and chemical composition of the fluids produced [28]. Consequently, the conventional utility system layout will generally become oversized and mostly runs at offdesign conditions throughout the project lifespan. In this context, the proposed power hub comes up with a solution not only to weight and space restrictions, but also to an inefficient cogeneration system on existing FPSOs.


FPSO 1
FPSO 2
FPSO 3
FPSO 4
OIL
PRODUCED GAS
WATER
CO2 EMISSION
PIPELINE GAS
WELL FLUIDS
LM2500+
PRODUCED GAS
ELECTRICITY
HEAT
Primary processing plant
Control volume

(a)


Gas production
Oil production
Oil production (kg/s)
Gas production (kg/s)
FPSO productive life (year)

(b)


Heat
Power
Energy demand (MW)
FPSO productive life (year)

(c)

Fig. 1. Four standalone FPSOs: (a) business-as-usual cogeneration and processing plants [15]; (b) production and (c) energy demands profiles [27].

The hull characteristics, such as available space, light weight, maximum load and minimum load, lifespan and others characteristics, used as physical constraints for the choice of the power hub components to be installed on the deck of a decommissioned and adapted FPSO, are shown in Fig. 2.

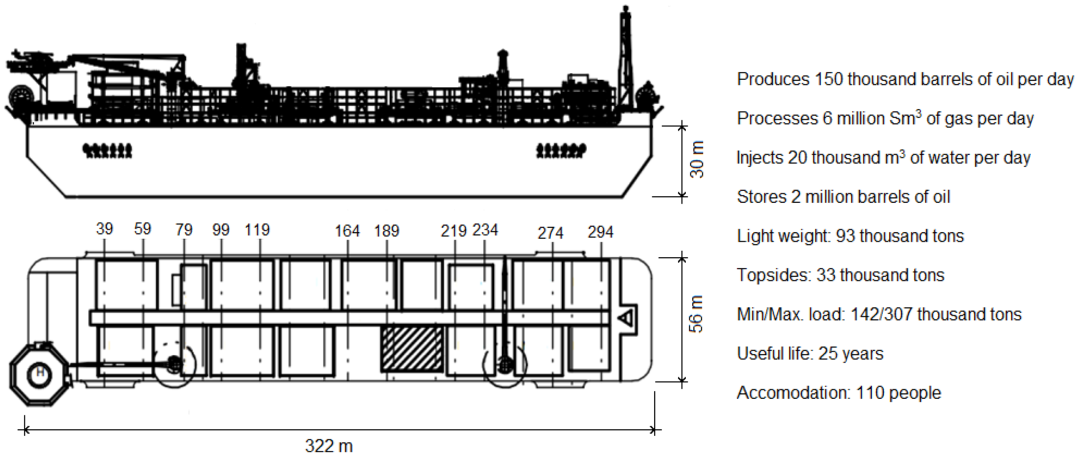


Fig. 2. Hull dimensions, light weight, maximum load and minimum weight load, lifespan and others characteristics of a typical FPSO [29].

The main reason of supplying four productive FPSOs relies on the constrained size of the reference decommissioned hull shown in Fig. 2. An increased number of served FPSOs could require a higher installed capacity in the hub, prohibitively increasing the footprint of the installed turbomachinery. This is in agreement with the maximum power reportedly generated in the offshore oil and gas applications (~500 MW). This fact, in turn, follows the typical demands of large FPSOs, reaching up to 80 MW at the peak of demand. Since it must be also considered the transmission losses, the need for reactive power supply, and the internal energy consumption for driving the CCS unit and other auxiliary systems; attending more than four FPSOs in the present scenario of production will exceed the design installed capacity and the space allowance. The assumption of the four identical energy demands profile is a simplifying hypothesis. For evaluation purposes, it is assumed that, for a giant oil field in the Santos basin, offshore the Brazilian coast, a series of identically designed FPSOs (called by Petrobras as “FPSOs replicantes” in portuguese) process comparable flow rates of petroleum with a similar composition.

Thus, the next sections describe the energy technologies, referred to as modular power units (MPUs), able to be combined in parallel with others of its kind in the power hub in order to supply the electricity required by four productive FPSOs. Thereafter, the dispatch optimization problem that guarantees the minimum fuel consumption is defined. Finally, it is worthy to notice that the thermodynamic target alone is not suitable for achieving realistic decision-making processes. Thus, economic and environmental indicators are also defined to compare the relative benefits and disadvantages of replacing the business-as-usual layout with a power hub concept under different scenarios of carbon taxation.

2.2. Parallel modular power units (MPUs) on the power hub

The concept of power hub emerges as an interesting alternative to supply the electricity to four productive FPSOs with identical energy demands, using more efficient and more environmentally friendly technologies. However, the design of centralized power stations comes up against several difficulties related to the definition of a universal power hub concept that is flexible enough and applicable to a variety of projects; not to mention the large number of available cogeneration alternatives, which have to work at the highest efficiency, even at prolonged offdesign operating conditions. Most gas turbine models are emissions-compliant only for partial loads ranging from 40 to 100% [30], and few for lower than 30% [31]. Thus, the operating conditions of the hub components must be wisely selected, so that a compromise between flexibility and operability can be obtained. Each power hub is considered as composed of a number of *modular power units* (MPUs) operating in parallel, each one contributing to the overall power output. This arrangement enhances the flexibility, since the load distribution amongst the various MPUs is adjustable. From independent simulations of each MPU, it could be possible to correlate their efficiency, weight, area and cost in terms of other operating conditions, as it will be discussed later, in order to establish a library of surrogated models, supported by the data available in specialized simulation software. In other words, it would not be necessary to know a priori a profile of production or energy demands to individually assess the performance of the different MPUs (or assemblies thereof). Moreover, since the power hub is now responsible for the power supply to the productive FPSOs, it would still be necessary to guarantee the inherent capacity of the oil production platforms to produce hot water *in situ*. This is achieved either using a battery of fired heaters (Fig. 3) or by preserving some of the original gas turbine systems of the conventional FPSOs, as in ref. [15].

In this way, four scenarios of centralized power stations, namely, four power hubs based on combined cycles either with one or two levels of pressure of steam injection, and either with or without integration of a CCS unit, are envisaged, in light of the four types of MPUs shown in Figs. 4a-d. Those technologies should generate a net amount of electricity to drive the processes on the productive FPSOs, regardless of the hub internal energy demands, such as the CO_2 desorption duty (if any). It is worthy to emphasize that the CCS units shown in Figs. 4b and d stand for the contribution of each MPU to the overall energy demands (*e.g.* desorption heat, and compression and pumping power) of the global CCS unit in the hub.

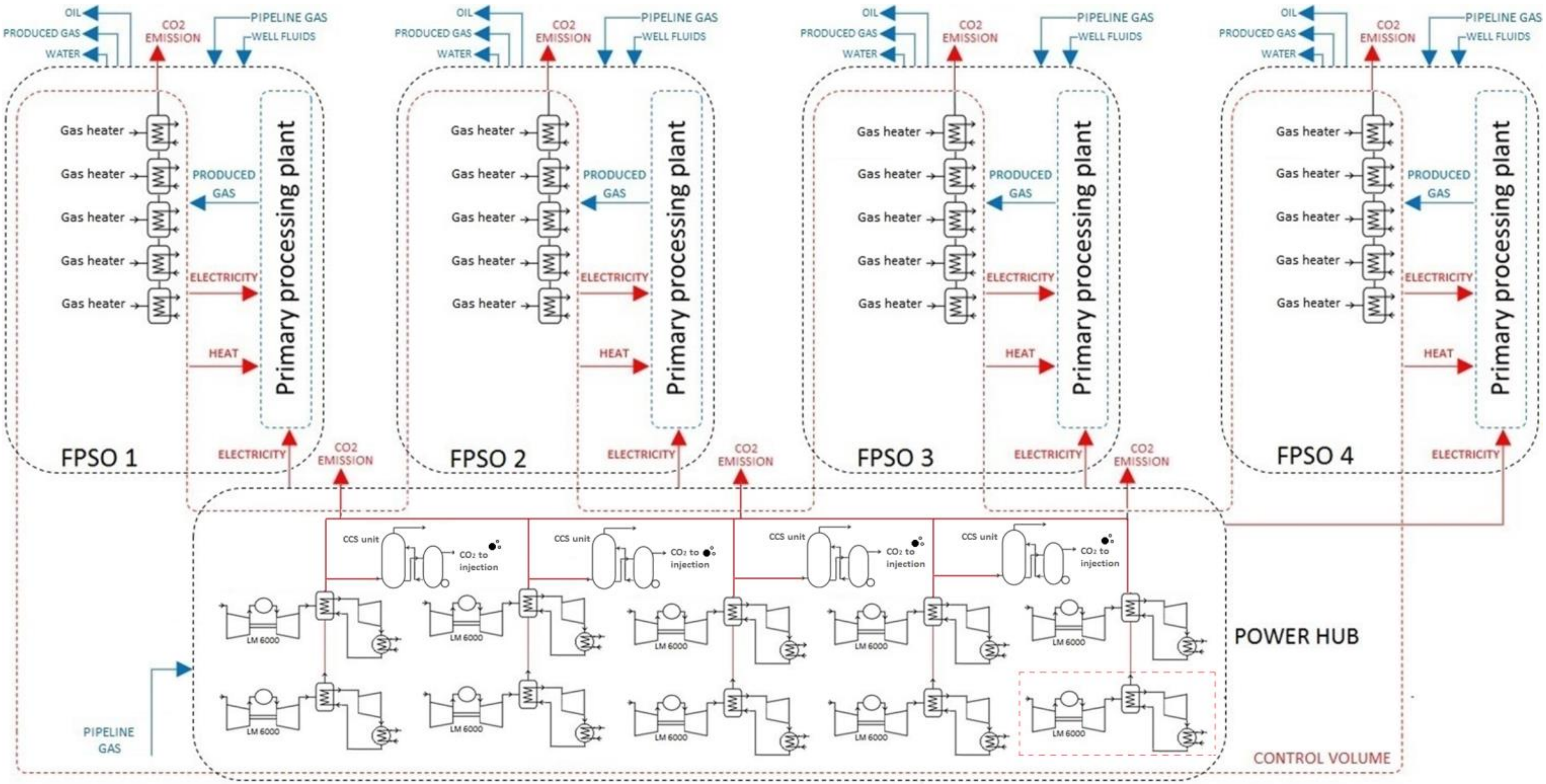
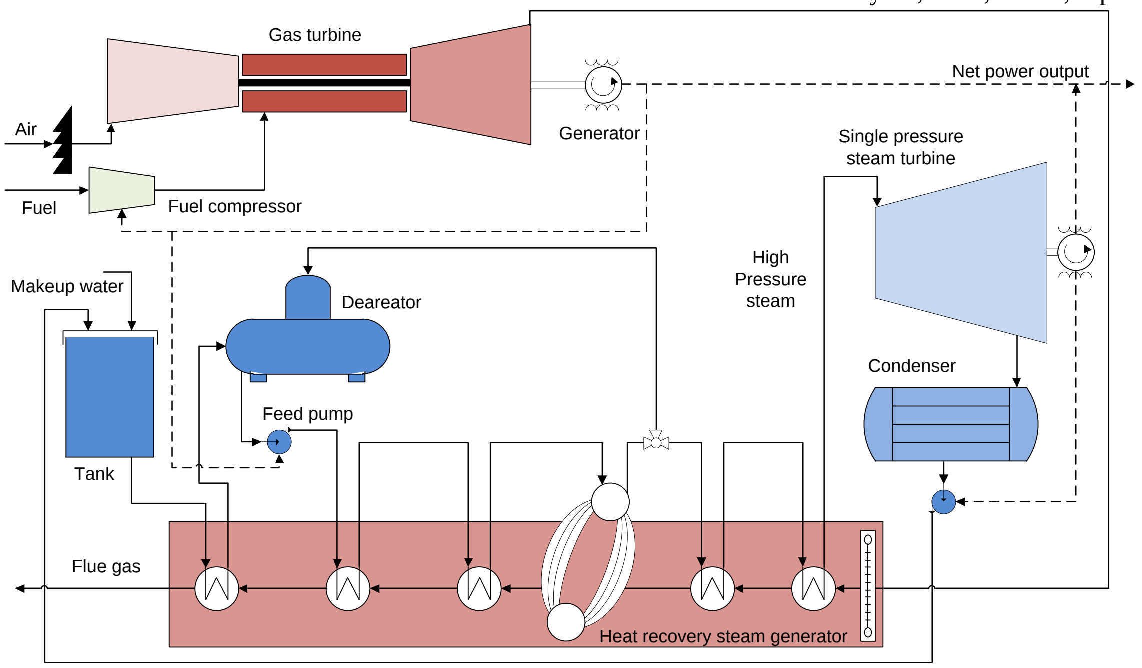
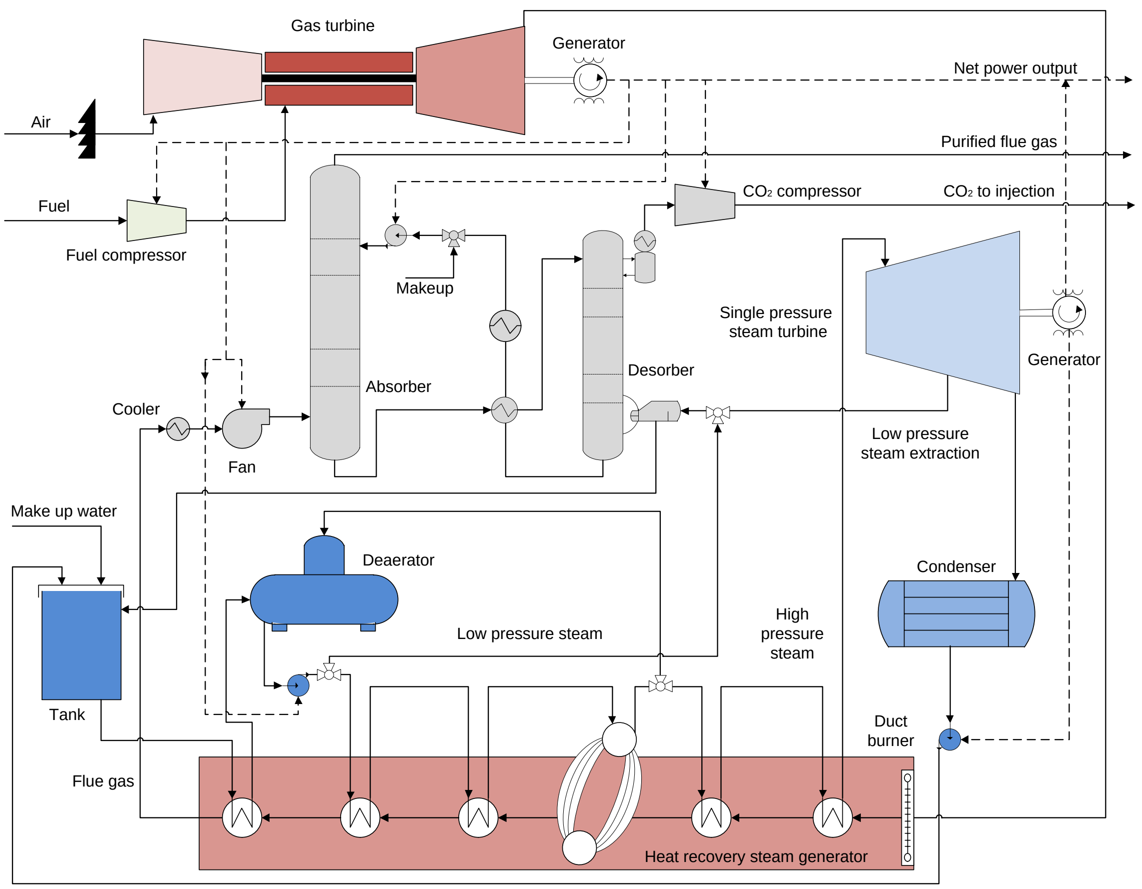


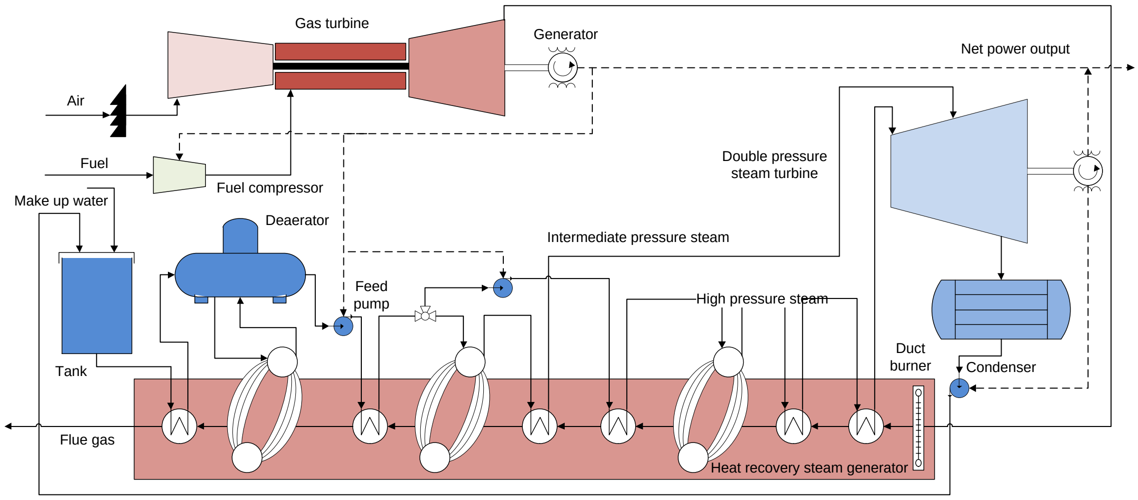
Fig. 3.Power hub conceived for supplying the electricity to four productive FPSOs with identical energy demands.



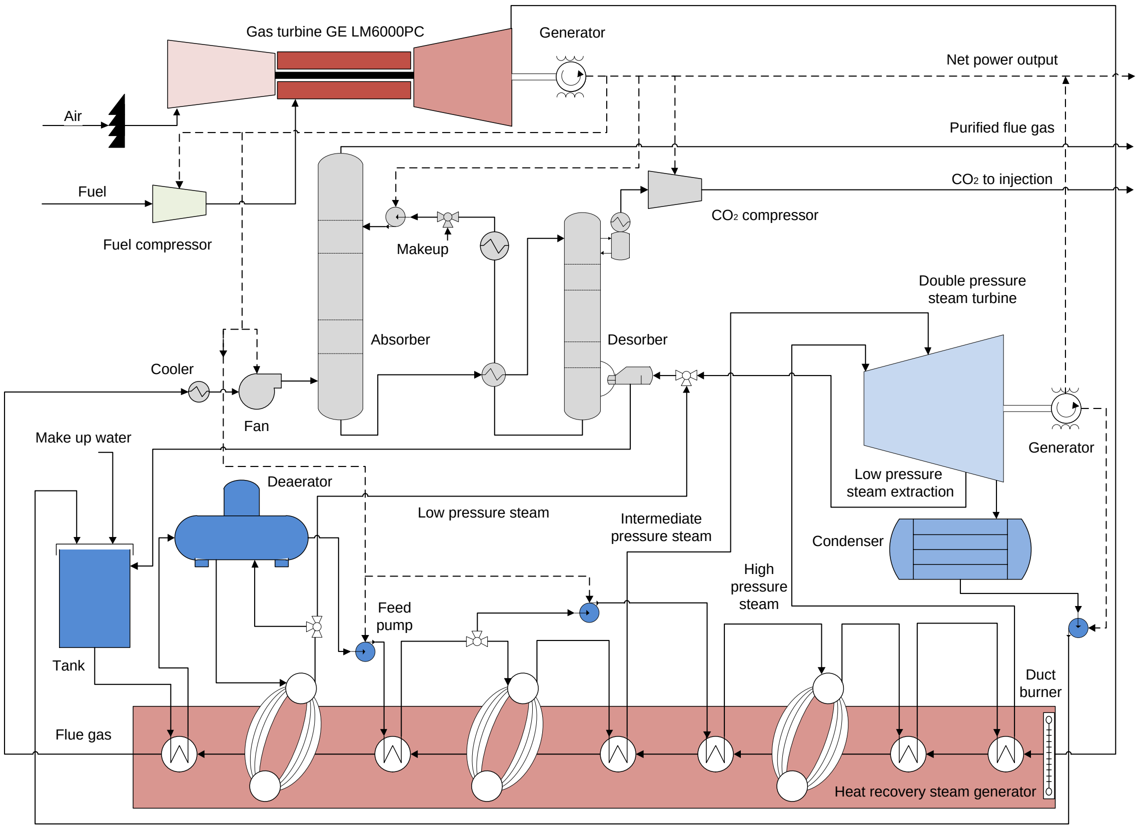
a) MPU type 1 (single pressure steam injection to steam turbine) without CCS unit.



b) MPU type 1 (single pressure steam injection to steam turbine) with CCS unit.



c) MPU type 2 (double pressure steam injection to steam turbine) without CCS unit.



d) MPU type 2 (double pressure steam injection to steam turbine) with CCS unit.

Fig. 4. Flowsheets of the MPUs considered for each power hub scenario.

The combined cycles shown in Figs.4a-b share some common characteristics, such as the use of a LM6000PC gas turbine system with heat recovery steam generator (HRSG) and supplementary firing system (*duct burner*), in case that the waste heat available does not satisfy the steam balance of the power hub. However, the corresponding steam cycles actually differ in the approach used to generate the steam required, either for power generation or as heating source for the CCS unit of the power hub. For instance, in the case of Fig. 4a, the condensing steam turbine is fed by superheated steam at a single level of pressure (HP); whereas in Fig. 4b, a fraction of low pressure

steam (LP) is extracted from the extraction-condensing turbine to supply the reboiler duty of the CCS unit. The remainder fraction is expanded to the condenser pressure to generate electricity. Differently from the previous ones, the MPUs shown in Figs.4c and d admit both high and intermediate (IP) pressure steam into the steam turbine, whereas an extraction from the LP section thereof makes up part of the process steam used in the CO_2 stripping process. Also, depending on the optimal operating condition, pressurized hot water or saturated steam can be also produced for adjusting the amount and properties of the steam required for carbon capture purposes. Clearly, the integration of a CCS unit sharply impacts the energy balance and the overall efficiency of the combined cycles [32, 33]. Hence, the operation parameters for the heat recovery steam generation system, the supplementary firing and the extraction-condensing steam turbine must be optimized. This strategy allows satisfying the energy demand of the CCS unit, while offsets its efficiency penalty and provides more flexibility to the MPUs.
On the other hand, the four scenarios of power hubs analyzed will also differ from each other in terms of the number of combined cycles (MPUs) installed, as the integration of a CCS unit will require an entire MPU only for supplying utilities to the CCS unit located in power hub. Moreover, for the sake of reliability, an arrangement of *N+1* MPUs in parallel is necessary, in which a set of *N* MPUs remain active and an additional module (+1) acts as redundancy, in the event of maintenance or unforeseen stops in the operation of any set [34]. Thus, as it will be shown, an arrangement of 8+1 and 9+1 combined cycles for the power hub configurations without and with a CCS unit, respectively, must be adopted. Moreover, since the power is supplied by the hub, the heating demand on each productive FPSO is guaranteed by a series of gas heaters (5x10 MW). The transmission system consists of transformers, submarine cables and reactive compensation units, which will be responsible for bringing the electricity generated in the power hub to each FPSO.

In the CCS process, the cooled flue gas is contacted in the absorption column with a selective solvent (MEA amine, 35%wt.) designed to remove up to 90% of CO_2 in the flue gas. The CO_2-rich solvent leaves the bottom of the column and it is preheated by exchanging heat with a stream of regenerated amine (93°C). The hot rich amine enters the desorption column, wherein steam is consumed (3.5-4 MJ/kgCO_2) to release the absorbed CO_2 [35]. The hot lean solvent is cooled and pumped back to restart the loop, while the CO_2 desorbed is released overhead, then conditioned and compressed for reinjection purposes. Noticeably, although pre-combustion carbon capture systems (> 12% mol CO_2) are relatively mature technologies [36], the applications of post-combustion CCS (< 7% mol) for gas power plants are still in development [37] or demonstration [38] stage. The reference considered in this work is the SSE's Peterhead gas power station (230 MW), with an estimated production of 3300 tCO_2/day (absorption column: diameter 11.8 m, height 53.3 m; desorption column: diameter 5.6 m, height 36.2 m) [39]. It is worthy to notice that, the height of a CCS system may alter the center of mass of a floating station, thus, some authors suggested that the stability of the arrangement can be improved by evenly distributing the total tower height into several columns and lowering their elevation on the hull [18, 19]. Modular configurations offer satisfactory operation in case of periodic column oscillations or even permanent inclinations (1% tilt tolerance), and the solvent distribution and fluid dynamics could be controlled by installing distributors and optimized packing [16]. Instability is not the only relevant consideration regarding the integration of a CCS unit. Large amount of low pressure steam (LP) may trigger steam turbine turn up mode and affect the exhaust nozzle operation, requiring throttling or sliding pressure control techniques to guarantee the steam conditions at the CO_2 desorption process, increasing the losses in the steam system [32, 33]. Moreover, multiple absorbers and one or more desorbers would be necessary depending on the number of emission sources. The process kinetics and specific steam consumption could be also modified if the solvent-to-gas ratio (L/G) is drastically changed. All in all, the definitive design of the CCS unit will depend on the overall flow rate and composition of the flue gas, the number of MPUs, the use of auxiliary firing and partial load of the MPUs.

3. Methods and tools

In this section, the tools used to calculate the thermodynamic properties of the substances; perform mass and energy balances; and estimate and compare the exergy, economic and environmental indicators, are defined. The proposed procedures for the multiobjective optimization (area, weight, efficiency and cost) of the process parameters of each MPU operating at nominal load, as well as for the optimal load distribution among the parallel MPUs in the hub, working at offdesign operating conditions, are also discussed. Moreover, since the primary processing plant is the same for all the scenarios, an incremental comparative assessment between the utility systems of the business-as-usual layout and the power hub setups is proposed. This procedure aims to estimate the marginal costs arising from the adoption of advanced solutions, by focusing on their relative economic feasibility against the conventional system when carbon-taxed scenarios are considered.

3.1. Process modeling

The thermodynamic properties of relevant streams, as well as the mass and energy balances of the power hub components are determined by using the suite of tools of Thermoflow® software. The GT PRO® tool creates the project for the combined cycles based on the thermodynamic criteria imposed by the user and on the assumptions for the specialized equipment, as well as on a list of candidate technologies suggested by the program. In this way, the program determines the base-case flowsheets and performs a preliminary sizing of the equipment. Next, the software reports detailed thermodynamic and economic parameters and other relevant results for decision-making at full load operating conditions. On the other hand, since the power cycles must be also evaluated at offdesign operating conditions, the GT MASTER® tool is executed using as input the results of GTPRO®. However, unlike the GTPRO® tool, in which the equipment and operating conditions and, thus, the size and cost of the components are freely varied, in the case of the GTMASTER® simulation, the cycle structure is fixed and only the offdesign operation is assessed.

In order to evaluate multiple operative scenarios, such as the load variation of the gas turbine, the levels of pressure and temperature of steam, the extent of supplementary firing, and so forth, two case study tools, namely ELINK® and MACRO®, integrated to the Thermoflow® software, are available. Those extensions allow for a greater flexibility to perform complementary calculations and post-calculations using the results of the mass and energy balances, as well as for generating graphs and reports about cost, weight and area occupied, along with other variables relevant to the design of the MPUs. Although MACRO and ELINK have similar functionalities, ELINK runs on Microsoft® Excel® and can be used to create a Thermoflow®-to-Matlab® interface via dedicated Excel® add-ins and VBA® routines, which turns out to be convenient for optimizing the operation of the MPUs in GTPRO® at nominal load.

Meanwhile, the CO_2 capture, compression and pumping systems have been simulated in Aspen® Hysys by using the Acid Gas® package (CO_2 capture) and the Benedict-Webb-Rubin equation of state (EoS) with Starling modifications (CO_2 compression), in order to determine the energy consumption and properties of the streams involved. The values obtained have been used as input to the Thermoflow® simulation (black box) of a CCS unit. Furthermore, in order to guarantee the minimum coolant flow rate and prevent the condenser choke, the upper and lower bounds of the exit pressure from the steam turbine may vary between 0.03 and 0.29 bar. Meanwhile, the maximum permissible temperature increment in the cooling water is set as 10 K. In light of these hypotheses, the standard Thermoflow® condenser model selects the condenser pressure in terms of variables such as (i) the hardware specification, (ii) the conditions at the last stage of the LP stage of the steam turbine, (iii) the thermal load, and (iv) the incoming coolant flow and temperature. The vapor fraction at the outlet of the steam turbine is kept at a minimum of 85%.

As it concerns the cost, occupied area and weight of the power generation components, those values are calculated by using the extensive libraries available in Thermoflow® software. However, since only few post-combustion CCS plants have been deployed at large commercial scale (>200 MW), available data reported in the literature has been used for estimating and validating some plant characteristics, such as size, specific energy consumption and economic parameters [16, 38, 39]. Finally, the characteristics of submarine cables, transformers, reactive compensation, mobilization and demobilization, and cable freight are based on [40, 41].

3.2. Performance indicators

Due to the existence of diametrically opposite targets for the conventional cogeneration systems and the power hub layouts, several performance indicators must be used to rationally compare all the configurations studied. The average annual exergy efficiency of the cogeneration systems, defined in Eq. 1, aims to assess the ability to convert the chemical exergy of the fuel ($m_{fuel} b_{fuel}^{CH}$) into the useful power (W_{net}) and heat exergy (B^Q) used in the primary processing plants of the productive FPSOs.

$$\eta_{ex} = \frac{W_{net} + B^Q}{m_{fuel} b_{fuel}^{CH}} \tag{1}$$

The net cumulative CO_2 emissions are calculated based on the mean annual thermodynamic performance and the carbon capture rate over the lifespan of the project. Meanwhile, an incremental approach is used to economically evaluate the attractiveness of the more advanced configurations (Fig. 3) with respect to the conventional setup (Fig. 1), based on the incremental net present value (INPV, Eq. 2), the incremental internal rate of return (IIRR) and the modified incremental internal rate of return (MIIRR, Eq. 3) [42]:

$$INPV = \sum_{n=1}^{N} \frac{\left[(R-C)_{n,option\ B}\right] - \left[(R-C)_{n,option\ A}\right]}{(1+i)^n} \tag{2}$$

where $(R-C)$ is the net cash flow (*i.e.* revenues minus expenses) for each of the several (N) yearly periods (n), calculated for a certain configuration B, that is compared with a reference configuration A; and i is the average interest rate.

The IIRR is the rate that turns the INPV null, whereas the MIIRR is calculated based on the future value (FV) of positive cash flows at the cost of capital rate and the present value (PV) of the negative cash flows at the financing cost [42]. The calculation of the MIIRR, defined in Eq.3, aims to solve the problems of the IIRR, such as being only valid if all the cash flows of the project are reapplied at the same rate of return as that of the project that generated them, especially when IRR is relatively high. This is usually an unrealistic scenario and a more likely situation is that the funds are reinvested at a rate closer to the firm's cost of capital (*i.e.* the required return necessary to make a capital budgeting project).

$$MIIRR = \sqrt[N]{\frac{FV(\text{positive cash flows} \times \text{cost of capital})}{PV(\text{initial outlays} \times \text{financing cost})}} - 1 \tag{3}$$

Finally, Table 1 summarizes the main parameters used in the calculation of the incremental financial performance indicators. The variable and fixed operation & maintenance (O&M) costs have been adopted depending on the characteristic of the power technology considered [43, 44]. The power hub hull cost is assumed as a representative cost for conversion [45]. An owner’s cost factor of 1.6 is applied to the acquisition costs to reflect not only the purchase cost, but also the direct and indirect costs due to transportation, installation, startup and contingencies. The total capital investment is divided between the first (60%) and second (40%) years. A decommissioning cost of 5% of the overall CAPEX is assumed. Additionally, it is considered that each platform enters in operation with a delay of one year from the entry of the previous platform. Transmission costs estimates have been adapted from data of offshore wind farms, due to the lack of open information for the ultra-deep waters case [40].

Table 1. Main parameters used in the calculation of the incremental financial performance indicators for the conventional and power hub-based scenarios.

Process parameter	***Conventional***	***Combined cycle***	***Combined cycle w/ CCS***
Number and reference of MPUs installed	4 FPSOs each equipped with 3+1 Siemens gas turbines SGTA35 & WHRUs	8+1 GE LM6000 in combined cycle & 4+1 fired heaters on each productive FPSO	9+1 GE LM6000 in combined cycle & 4+1 fired heaters on each productive FPSO
Fuel gas lower heating value LHV (kJ/kg)	47644	47644	47644
Fuel gas price (USD/GJ)	5.0	5.0	5.0
Electrical transmission losses (%)	8.0	8.0	8.0
Variable operation and maintenance costs (USD/kWh)	0.002	0.004	0.006
Fixed operation and maintenance costs (USD/kW-y)	11.0	19.0	27.0

3.3. Optimization problem definition and solution framework

The multiobjective optimization of each MPU shown in Figs. 4a-b, when operating at nominal load, considers the simultaneous minimization of the specific cost (USD/kW), weight (kg/kW) and area (m^2/kW) per unit of power generated, and the maximization of the efficiency (%). The efficiency is normally expected to be directly and inversely proportional to the capital cost and the atmospheric emissions, respectively. However, due to the adoption of a CCS unit, the relationship between cost, thermodynamic performance and net amount of CO_2 emissions is not straightforward. In fact, these relationships end up in conflicting objectives, such as a reduced initial investment *vs.* a minimum environmental burden *vs.* a high efficiency technology.

The operation of each type of MPU can be characterized by (*i*) the properties of the working fluids (pressure, temperature, composition and flow rate); (*ii*) the characteristics of the specialized equipment, such as rotodynamic machinery and heat recovery steam generators; (*iii*) the contribution to the steam and power consumption of the CO_2 capture process in the hub (if it applies); and (*iv*) the need for supplementary firing. Since the characteristics of the topping cycle (gas turbine) are set by the manufacturer database, in this work, the optimization variables are the pressure of the high pressure (HP) steam injected to the steam turbine ($25<x_1<60$ bar) and the corresponding HP steam superheating temperature ($350<x_2<550$ ° C). Regarding the MPUs with two levels of steam generation, additional optimization variables are considered, namely the intermediate (IP) level of pressure ($20<x_3<35$ bar) and the corresponding superheating temperature of the steam fed to the turbine ($200<x_4<500$ ° C). As it concerns the power hub with CCS unit, the amount of steam extracted from the extraction-condensing steam turbine ($8<x_5<12$ kg/s) is also considered as a decision variable. The CO_2 desorption duty and specific steam consumption is limited to 3.6-4 MJ/kg [46]. This variable bounding relaxes an equality constrain and facilitates the convergence of the multiobjective optimization problem. At the same time, it allows for solutions that enable the generation of saturated steam directly by the recovery boiler to make up part of the steam demand of the CCS unit. In this way, less steam is injected into the turbine; thus, avoiding the excess power generation in offshore power stations, which lack of net electricity import from or export to the shore.

Figure 5 summarizes the procedure for optimizing each type of MPU working at nominal load, as well as for defining the optimal load distribution between the parallel MPUs installed on a power hub operating at offdesign conditions. This procedure relies on the integration of Thermoflow® and Excel® via Matlab®. The function *gamultiobj* (non-surrogate genetic algorithm for multiobjective optimization) of Matlab® OptimTool is used to generate a 4D Pareto front. The search for the solution is monitored according to termination and convergence criteria, including average distance between individuals and average dispersion, among others. Obtaining a solution using the genetic algorithm may take from hours to days, depending on the processing capacity and the number of optimization variables, as well as the search parameters (population, mutation, crossing, etc.), Also due to the impossibility of performing parallel simulations using Matlab®-GTPRO® connection, for every iteration it takes more time to completely converge before restarting the search process. After the optimization of the process parameters is achieved, the 4D Pareto front of non-dominated optimal solutions is built for each MPU. Other relevant information of non-optimal setups can be determined to outline the general behavior of the energy conversion systems.

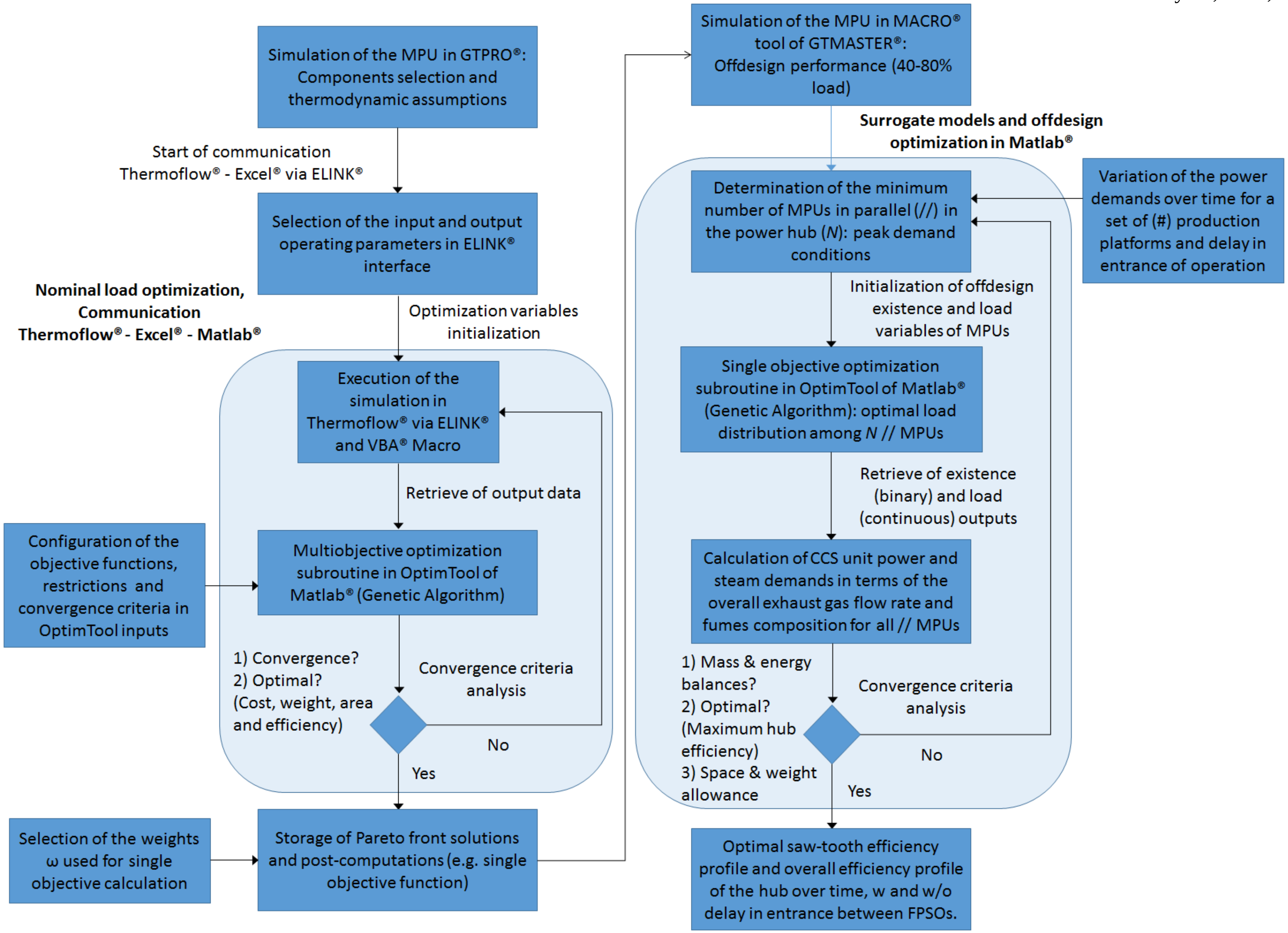


Fig. 5. General procedure for the simulation, communication (Thermoflow® -Matlab® -Excel®) and optimization (OptimTool®) of each MPU operating at nominal load and when operating in parallel at offdesign conditions in a power hub with or without CCS unit.

The 4D Pareto front represent the best configurations of each MPU operating at nominal load. In order to determine their performance at offdesign operating conditions, weight factors ω are attributed to each normalized target (weight, cost, area and efficiency), so that an equivalent single objective function, Eq. 4, can be defined. In this work, ω_{cost} = 0.4, ω_{weight} = 0.1, ω_{area} = 0.1, and $\omega_{efficiency}$ = 0.4 are selected. The index *i* stands for the several non-dominated optimal solutions in the Pareto front for each type of MPU.

$$Max\left\{\frac{\|efficiency_i\|\times\omega_{efficiency}}{\|weight_i\|*\omega_{weight}\times\|cost_i\|*\omega_{cost}\times\|area_i\|*\omega_{area}}\right\} \quad (4)$$

Thereafter, based on the optimal configurations, worked out by using the single objective function, Eq.4, the variation of the power generated, the efficiency and other process parameters of each MPU can be correlated in terms of its load in the form of metamodels built upon analytic response surfaces. These functions are, in turn, used to outline the hub *saw-tooth plot* (*i.e.* the profile of overall efficiency *vs.* power generation of the hub), which represents the maximum obtainable efficiency through the optimal combination of parallel MPUs. In fact, this plot corresponds to the solution of the problem of minimum hub fuel consumption given in terms of the dispatch (binary, on/off) and load (continue, 40-80%) variables of each MPU. Finally, based on the profile of overall power demand of the four identical FPSOs, as well as on the saw-tooth plot, it can be calculated the profile of optimal electricity generation efficiency for every year of the hub lifespan. In practice, the use of a CCS unit can be enabled or disabled depending on the hub load and other process operating conditions (severe weather, FPSOs production rate, etc.). Finally, the selected setups can be compared in terms the footprint, weight, initial investment and exergy efficiency.

4. Results and discussion

The main results related to the optimization of the MPUs operating at nominal and offdesign conditions in the power hub are discussed, together with the aspects related to the compliance with space and weight constraints. An incremental comparative assessment in terms of thermodynamic, environmental and economic indicators is also presented. Finally, the effect of delay in entrance of operation between platforms is briefly discussed.

4.1. Determination of optimal MPU designs operating at nominal load

After the multi-objective optimization of the MPUs shown in the Figs.4a-d operating at full load is performed, those results are represented as non-dominated solutions in the Pareto front displayed in Fig. 6 (area axis is not shown). Meanwhile, Table 2 summarizes the results of the optimal process variables for the scenarios studied, namely, four power hubs composed of similar MPUs of each type shown in Figs. 4a-d. Solutions with relatively higher superheating temperatures (450°C) and moderate levels of pressure (25-40 bar) of HP steam are favoured over high pressure configurations (above 60 bar). Meanwhile, relatively low superheating temperatures (240°C) and pressures (25 bar) are preferable for IP steam conditions.

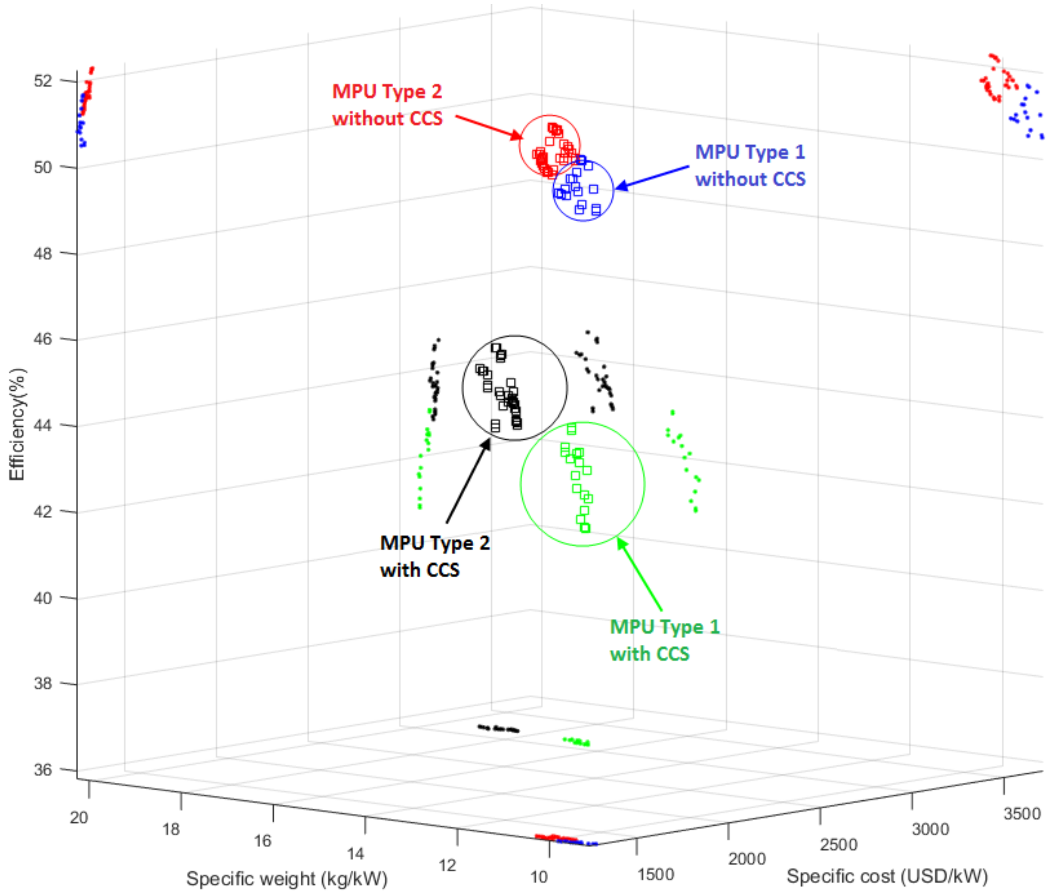


Fig. 6. Pareto front resultant of the four dimensional multi-objective optimization (area axis is not shown) of the MPUs shown in Figs.4a-d, when operating at nominal load conditions.

Bearing in mind the power demand of each productive FPSO (Fig. 1c) and assuming one year of delay in entry of operation between one FPSO and the next, the cumulative peak power demand may reach up to 320 MW. However, this value only accounts for the net power consumption of the four productive FPSOs; thus, an additional electricity generation capacity is still required, so that the internal power hub demands, including those arisen from the operation of the CCS unit, are satisfied. Furthermore, it is important to notice that the gas turbine systems of the MPUs operate at a maximum (*safe-point*) load of 80%. This value represents a practical, safety and reliability limit, as it is assumed that a gas turbine operating at maximum load (100%) could not withstand a sudden increase of load arisen from startup of compressors and motors or any other unanticipated overload. A power factor is usually applied to the generator capacity to indicate what the risk factor should be in such overloads. Consequently, the minimum number of MPUs required must also consider the derated power generation capacity thereof. In this way, the gross power generation required, along with the idle MPU that acts as redundancy, defines the power hub installed capacity; whereas the actual energy delivered to the processing plants defines the net power generation shown in Table 2. It is noteworthy that, except for the additional equipment required to generate the steam for CO_2 desorption purposes and the CCS unit itself, all the power hub scenarios are analogous. Thus, these results can be used to assess the effect of the integration of a CCS unit on the overall performance and elucidate the trade-offs between offshore utility systems, considering not only thermodynamic, but also economic and environmental targets, subject to severe space and weight constraints.

Table 2. Optimal process variables, weight and occupied area, and economic results of the different power hubs with and without CCS unit operating at nominal load.

Process parameter	***Scenario 1***	***Scenario 2***	***Scenario 3***	***Scenario 4***
Number (*N+1*) and type of MPUs used in the hub	10 MPU#1	10 MPU#2	9 MPU#1	9 MPU#2
Power hub installed capacity (kW)	490,350	509,139	483,152	486,715
Power hub net generation (kW)	340,239	353,562	344,965	347,128
Carbon capture unit installed	***Yes***	***Yes***	***No***	***No***
Bottoming cycle characteristics				
Low pressure steam to reboiler (bar/°C)	4/143	4/143	-	-
Intermediate pressure steam (bar/°C)	-	25/240	-	25/230
High pressure steam (bar/°C)	25/447	41/445	25/420	35/447
MPUs components (purchase cost × N) (kUSD)[4]	416,877	448,099	374,409	405,274
a) Gas turbine	164,031	164,031	147,628	147,628
b) Steam turbine	48,370	48,928	48,522	52,451
c) Heat recovery steam generator	29,994	43,366	19,899	32,715
d) Condenser	2,105	2,722	3,468	3,654
e) Fuel gas compressor	15,449	15,449	13,904	13,904
f) Continuous emissions monitoring system	3,840	3,840	3,456	3,456
g) Distributed control system	1,884	1,950	1,813	1,894
h) Transmission voltage equipment	13,430	13,916	12,950	13,522
i) Generating voltage equipment	3,013	3,104	2,872	2,978
j) Others[1]	15,898	19,937	14,877	18,777
k) Mechanical	46,678	55,509	38,496	43,421
l) Electrical assembly and wiring	14,209	16,206	13,299	15,235
m) Engineering and plant startup	57,976	59,142	53,225	55,639
MPUs components (owner's cost × N) (kUSD)[4]	**667,003**	**716,959**	**599,054**	**648,439**
+ CCS investment cost (kUSD)[2]	735,524	763,708	0	0
+ Power hub hull cost (kUSD)	50,000	50,000	50,000	50,000
+ Submarine transmission cable (× 4) cost (kUSD)[3]	17,176	17,176	17,176	17,176
= Hub topsides overall investment cost (kUSD)[4]	**1,469,703**	**1,547,844**	**666,230**	**715,615**
Hub topsides specific investment cost (USD/kW)[5]	2,997	3,040	1,379	1,470
+ Fired water heaters cost (× 5) × 4 FPSOs (kUSD)	15,136	15,136	15,136	15,136
= Utility system overall investment cost (kUSD)[4]	**1,484,839**	**1,562,979**	**681,365**	**730,751**
Utility plant specific investment cost (USD/kW)[5]	*3,028*	*3,070*	*1,410*	*1,501*
Hub topsides area occupied (m^2)	**4399.9**	**4651.1**	**2668.94**	**2829.7**
Hub topsides specific area occupied (m^2/kW)[5]	0.008973	0.009135	0.005524	0.005814
Hub topsides weight (t)	**7689.5**	**8694.7**	**4215.9**	**4948.4**
Hub topsides specific weight (kg/kW)[5]	15.7	17.1	8.7	10.2

1. "Others" include pumps, tanks, cranes, medium/low voltage equipment, general instrumentation, miscellaneous; and mechanical costs include onsite transportation and rigging, equipment erection and assembly, piping and steel; 2. CCS unit cost: 1,500 USD/kW includes owner's cost multiplication factor of 1.6; 3.Submarine cable cost: 226 kUSD/km; 4. Overall owner's cost to purchase cost ratio set as 1.6; 5. Calculated per unit of installed power generation capacity.

Although the specific cost of the CCS unit, initially assumed as 1500 USD/kW [47], may drastically affect the economics of the power generation systems (see Table 2); depending on the adopted scenario of carbon taxation, this apparently unfavourable circumstance could be countervailed by contemplating other forms of revenues. For instance, the use of enhanced oil recovery (EOR) for improved petroleum extraction, and the public-private partnerships and government subventions may also play an important role, as it has been already demonstrated in similar applications at commercial scale [38]. As for the stability issues, the equipment on the FPSOs is always subject to accelerations associated with the vessel movements. Unlike other specialized equipment, such as rotating machines, exchangers and vessels; the separation components are, in particular, more susceptible to the ship movements, due to secondary flows, interfaces and dispersion issues [17]. Positioning those components parallel to the longitudinal axis of the FPSO could mitigate the effect. Other challenges in the implementation of CCS systems may be the need for fresh water (partially resolved by the condensation of water contained in the flue gases) [18], the cooling of the exhaust gases from the turbine (by quenching or direct mixing), the supply of makeup amine (due to dragging with the purified flue gas) and the purification and control of the solvent composition, as well as the conditioning of the CO_2 to be injected [16]. Finally, from the data reported in Table 2, it is possible to determine other operating parameters, and these data can be analytically correlated in order to generate response functions that characterize the metamodels used in the optimization of the load distribution between the parallel MPUs.

On the other hand, Fig. 7 shows the schematics of the space availability on the deck of a ship adapted to operate as a power hub. It is important to notice that, the distribution of the power generation systems and the CCS components are only illustrative and a detailed stability analysis of the ship is still required [22]. The relevance of Fig. 7 lies rather on the evidence of the available space and weight allowance on the deck of a typical FPSO, susceptible to be decommissioned and adapted to a centralized power station, such as that devised in this work.

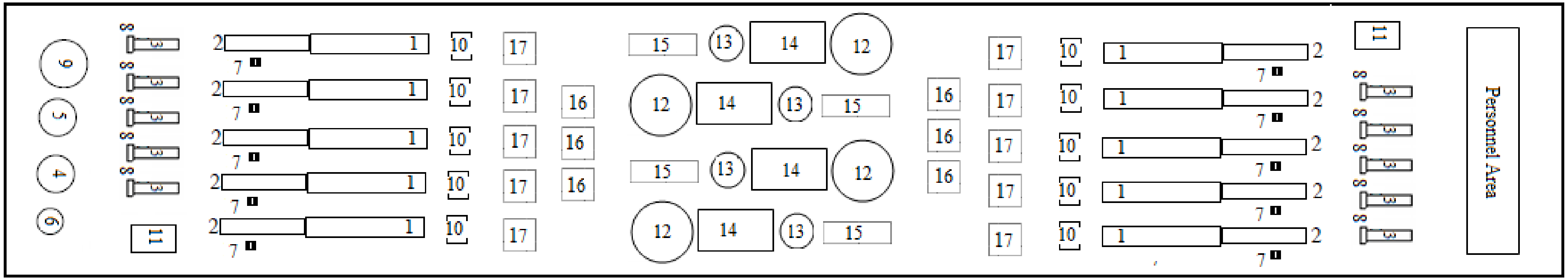


Fig. 7. Schematics of the footprint availability on the deck of a typical FPSO after decommissioned and adapted for power hub services, estimated by using the PEACE® tool of Thermoflow®: 1. Gas turbine package; 2. Heat recovery steam generator; 3. Steam turbine package; 4.Demineralized water tank; 5. Raw water tank; 6. Neutralized water tank; 7. Feed pumps; 8. Condenser; 9. Fire protection tank; 10. Gas turbine transformer; 11.Steam turbine transformer; 12.Absorbers; 13. Desorbers; 14. CCS unit auxiliaries; 15. CO_2 compressors; 16. Flue gas fans; 17.Flue gas coolers.

4.2. Optimal load distribution between identical parallel MPUs

Figure 8 shows the hub net power generation efficiency, calculated as a function of the net power throughput for the different scenarios reported in Table 2. The average electricity generation efficiencies of the power hub designs without a CCS unit are naturally higher due to the absence of the energy intensive steam and power demands of the CCS unit. However, it is also clear that those outstanding efficiencies only come at the expense of an accentuated environmental impact, as it will be discussed in more detail. The *saw-tooth* plots, characteristic to each power hub configuration, are used to estimate the variation of the efficiency of the utility systems over the time, based on the overall energy demands of four identical productive FPSOs, as it is shown in Fig. 9.

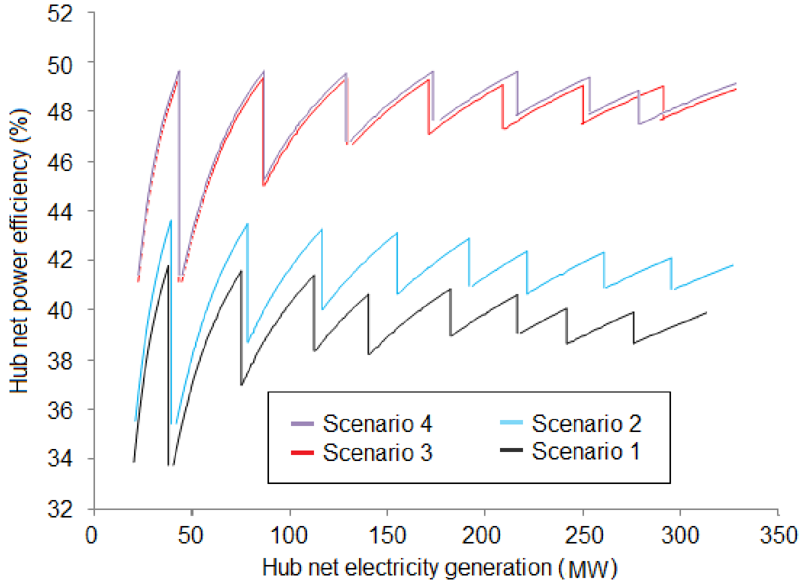


Fig. 8.Hub net power generation efficiency as a function of the hub net power throughput. The saw-tooth profiles are characteristic to each power hub design.

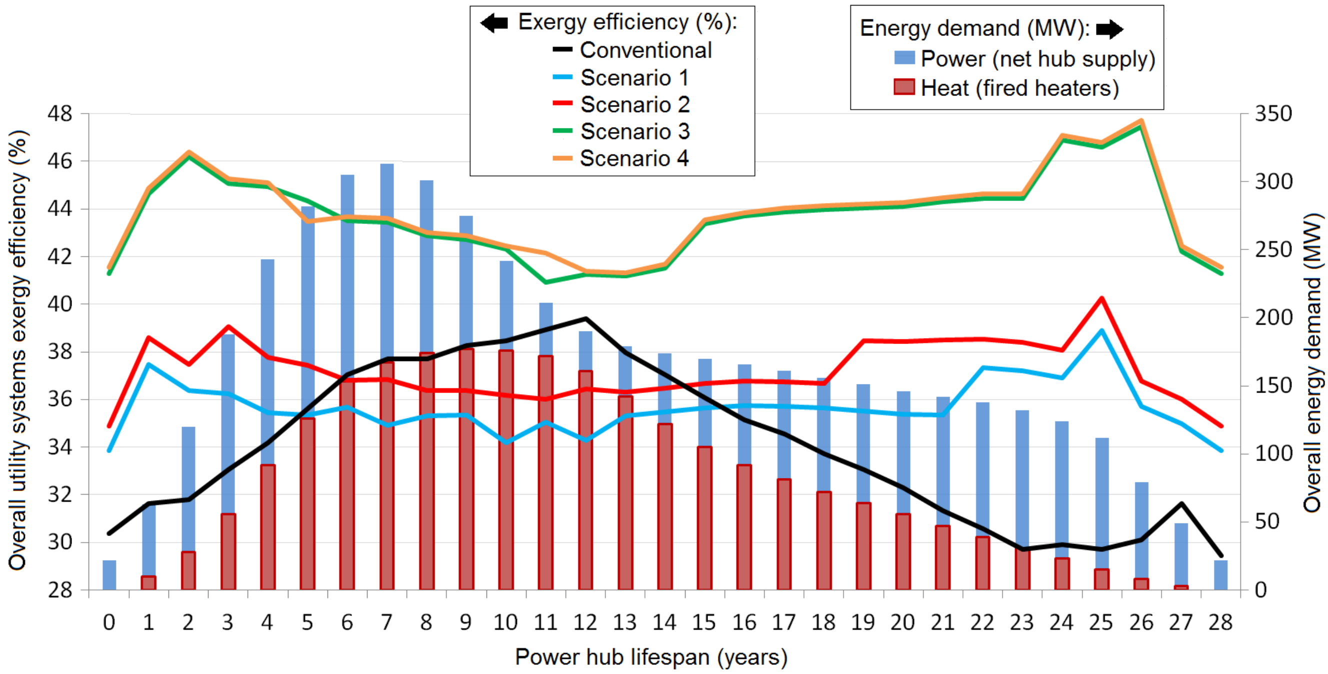


Fig. 9. Yearly variation of the overall exergy efficiency for each utility system serving four productive FPSOs.

Due to the offdesign optimization of the load distribution, represented by the *saw-tooth* profiles, the mean lifespan exergy efficiency of each scenario shown in Fig. 9 is expectedly higher than that achieved if an even distribution of loads among all the parallel MPUs were implemented. Actually, although the adoption of an even load could be considered as a simpler approach for the load distribution problem, this option is not only a suboptimal solution in terms of fuel utilization, but also it could infringe the minimum load and, thus, the environmental regulations [34, 48]. It must be also observed that the overall exergy efficiencies of the utility systems in the different scenarios of power hubs (Fig. 9) are somehow lower than the net power generation efficiencies of the power hub, shown in Fig. 8. This is a consequence of (*i*) the use of fired heaters for satisfying the heating demand of the primary separation process on each productive FPSO; and (*ii*) the additional fuel consumption in the flue gas purification and CO_2 injection steps in the case of the power hubs with a CCS unit.

From Fig. 9, it can be also seen that, except for the period of the hub lifespan in which the highest heating demands occurs (6^{th} -14^{th} years), the power hub configurations outperform the conventional utility system in terms of exergy efficiency (Conventional: 34%; Scenario #1: 35.7%; #2: 37.2%; #3: 43.7% and #4:43.9% in average). In fact, even at the expense of intensive fuel consumption in the FPSO fired heaters, the power hubs without CCS unit still present the highest exergy efficiency, followed by the power hubs equipped with a CCS unit, emphasizing the advantages of the power hub concepts, at least in regard to this thermodynamic indicator. A more subtle outcome from Fig. 9 is that, the power hub concepts without a CCS unit show almost the same performance over the time, regardless of the levels of steam pressure adopted (one or two). Thus, the final selection between those alternatives will likely favor the simplest, lightest and most affordable layout. However, this is not the case when a CCS unit is integrated. Notably, when an emissions abatement technology is envisaged, the selection of a bottoming cycle with two levels of pressure may increase up to 2 percentage points the overall utility system efficiency, compared with the single pressure steam network. Additionally, since the higher the exergy efficiency, the lower the fuel consumption; the advantage is twofold for the most efficient configurations. First, they increase the amount of gas exportable to the shore and, second, they partially reduce the average annual atmospheric emissions arisen from the utility systems, as it is shown in Fig. 10. In Table 3, both the mean lifespan CO_2 emission rate and the net cumulative CO_2 emitted by the conventional layout are also compared with those ones of the power hubs without and with CCS unit.

Table 3. Mean lifespan CO_2 emission rate and net cumulative CO_2 emissions for the various utility systems.

Parameter	***Conventional***	***Scenario 1***	***Scenario 2***	***Scenario 3***	***Scenario 4***
Mean lifespan CO_2 emissions (kg/s)	31.0	7.5	7.3	25.1	25.0
Net cumulative CO_2 emissions (t)	28,326,422	6,827,416	6,713,069	22,987,912	22,906,865

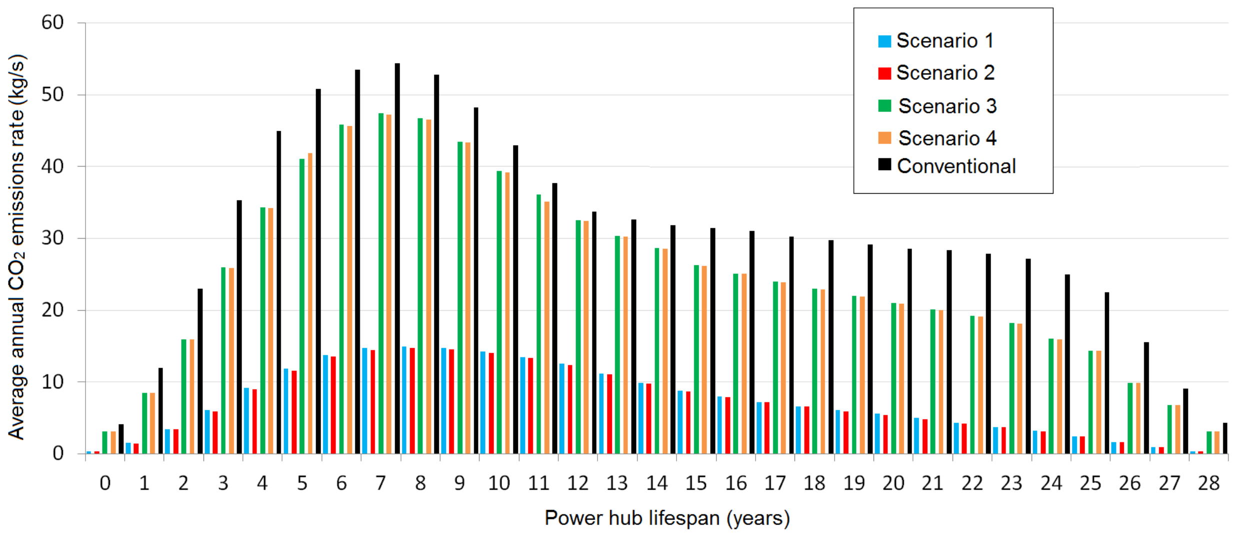


Fig. 10. Yearly variation of the CO_2 emissions rates for the different scenarios of utility systems over the productive life of the hub.

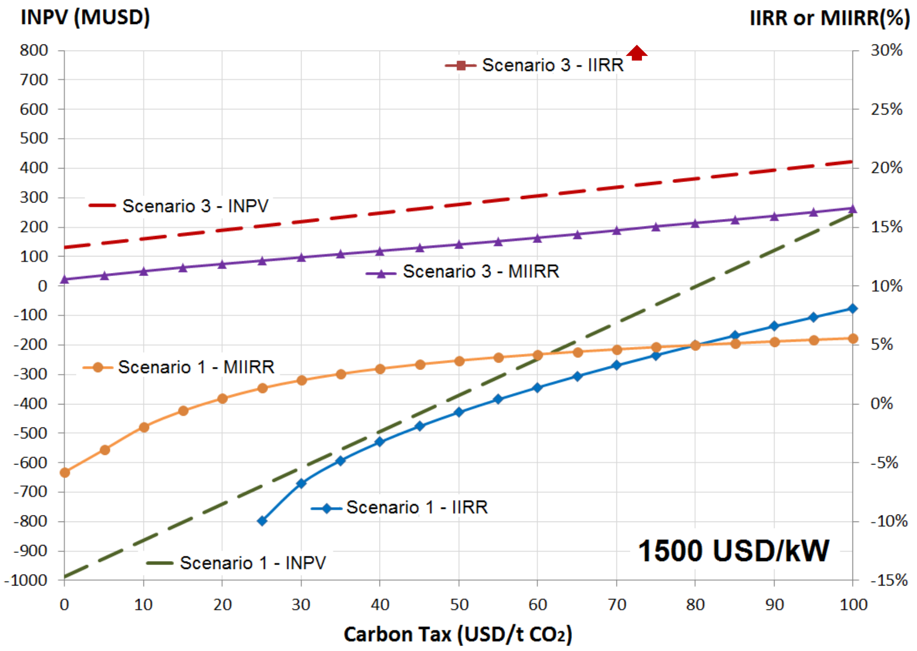
4.3. Incremental financial analysis

The advanced utility systems based on power hub concepts are expectedly bulkier and costlier, since they integrate a larger number of complex power generation technologies, such as combined cycles and CCS units. However, misleading conclusions may be obtained if their apparent disadvantages are not economically weighed in light of the growing awareness of the need for more cost-efficient and environmentally friendly utility systems in offshore oil and gas production facilities. To this end, in the following incremental financial analysis, some hypothetical scenarios are considered, in which carbon taxes are gradually implemented (0-100 USD/t_{CO2}) and mature post-combustion carbon capture technologies are developed at commercial scale (500-1500 USD/kW) [49-53]. Clearly, the reduction of the risk and the widespread use of those technologies will be a natural consequence of gain of maturity, substantial governmental subventions, public-private partnerships, and enhanced oil recovery applications [38].

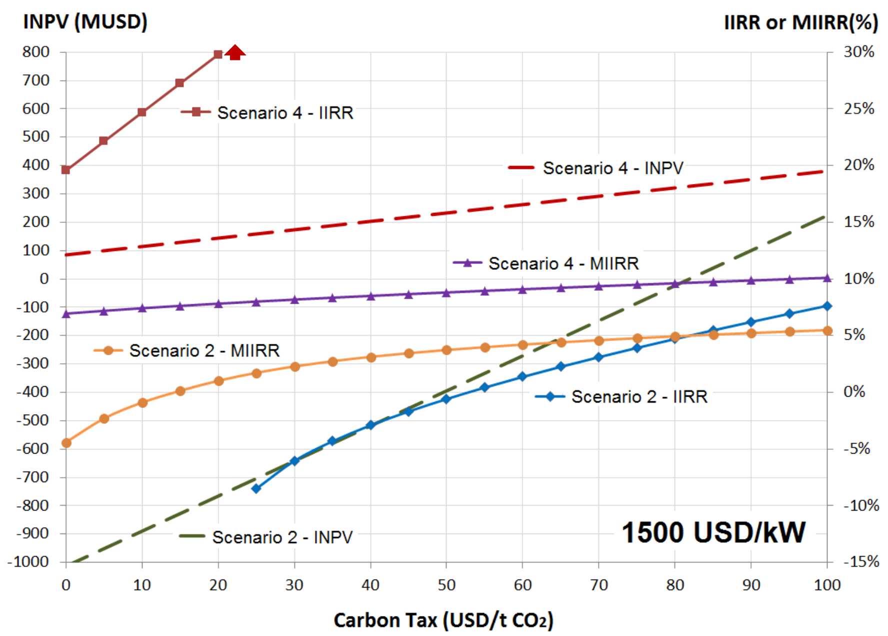
Figures 11a-b show the variation of the INPV, IIRR and MIIRR as a function of the carbon tax, when the specific cost of the CCS unit is set as 1,500 USD/kW and the interest rate is fixed to i = 5%. It must be noticed that, in some figures, the calculated IIRR is out of the plot scope, since it is abnormally high, well above 60% or even as high as 700%. It occurs due to the high attractiveness of the scenarios without CCS unit, regardless of the carbon tax. Since the IIRR has an extremely large value, a red arrow pointing to very large numbers in Figs. 11 and 12 is used instead. The calculation of the MIIRR aims to solve the problems of the IIRR, such as being only valid if all the cash flows of the project are reapplied at the same rate of return as that of the project that generated them, especially when IRR is relatively high. This is usually an unrealistic scenario and a more likely situation is that the funds are reinvested at a rate closer to the firm's cost of capital.

As it can be seen from Figs. 11a-b, for the hypothesis adopted, only the power hubs without CCS unit (Scenarios 3 and 4) always present positive INPVs and MIIRR values, which increase proportionally to the increment in the carbon taxation. Strikingly, despite the higher costs of the double pressure steam generation in the Scenario 4, both scenarios perform similarly, with the Scenario 3 holding a slightly higher INPV due to the simpler steam network configuration. These results highlight not only the prominent thermodynamic and environmental benefits, but also the economic advantage of the power hubs without CCS over the conventional utility system. In fact, an increased efficiency leads to more gas available for exportation and also to reduced CO_2 emissions. Consequently, the project revenues increase, shifting the financial indicators to more attractive figures, if compared to the more environmentally friendly Scenarios 1 and 2. Noteworthily, the MIIRR of the scenario 3 is always higher than the MIIRR of the scenario 4, which is partially explained by a reduced initial investment cost of the former setup, even if both designs achieve similar thermodynamic and environmental performances.

On the other hand, the power hubs equipped with a CCS unit present a relatively unfavorable INPV, at least for carbon taxes below ~80-85 USD/t_{CO2}. In fact, for those configurations, the MIIRR is negative for carbon taxes below 15-18 USD/t_{CO2}; which are much higher than those adopted by some regional economies [54]. In summary, in light of the current hypotheses, the power hub configurations without CCS unit also outperform the counterparts with a CCS unit, in terms of the reduction of the project outlays, insofar as the actual environmental burden is understood as a collateral consequence that can be simply paid off. In this regard, it is not surprising that the power hubs without CCS unit are more efficient and cheaper, but the spotlight here is on the actual effect of the externality, as the emissions trade systems are still under development and the pollution impacts on the society are still difficult to quantify with precision. Thus, although the environmental burden may remain to be considered as simply payable, the truly problem of the emitted CO_2 will have to be eventually tackled and the means to mitigate the mentioned impact have to be worked out, regardless of the monetary penalty. In this context, mid-to-high carbon taxations (>80 USD/t_{CO2}) may bring cleaner offshore central power stations a step closer to reality. This is in agreement with the High-Level Commission on Carbon Prices, which suggested that a global CO_2 price of 40-80 USD/t_{CO2} would be needed in 2020 [55] and a price of 50-100 USD/t_{CO2} by 2030 [56], in order to be consistent with the 2°C target in the Paris Agreement. Also, the Carbon Pricing Corridors initiative projected that price levels of 30-100 USD/t_{CO2} will be necessary to decarbonize the power sector by 2030 [57]. For this reason, suitable carbon taxes and mature post-combustion carbon capture systems should start being introduced at commercial scale.



(a)

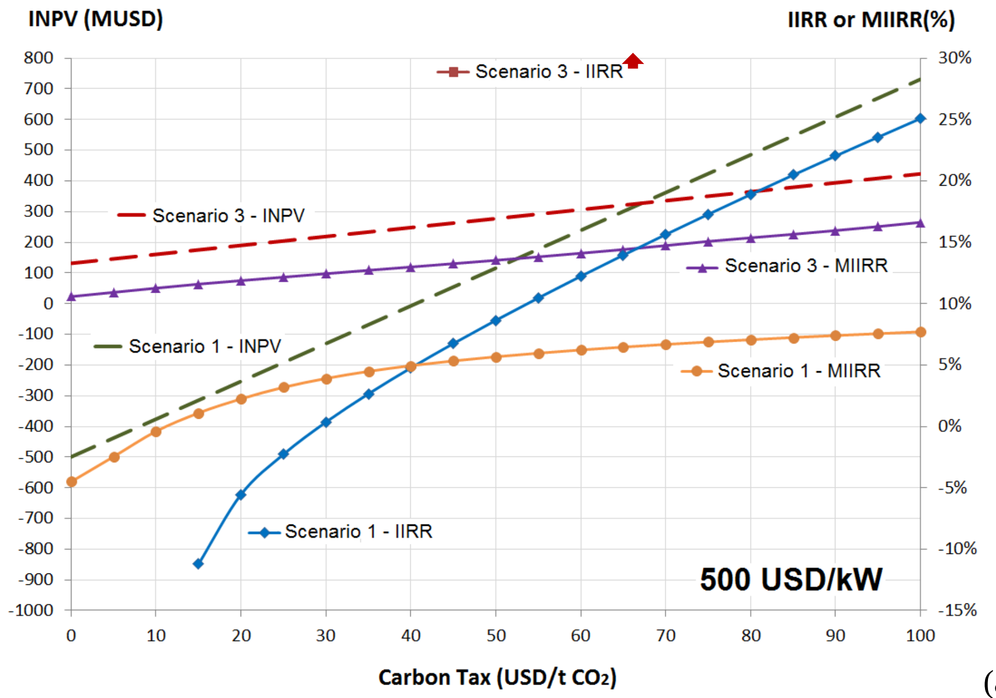


(b)

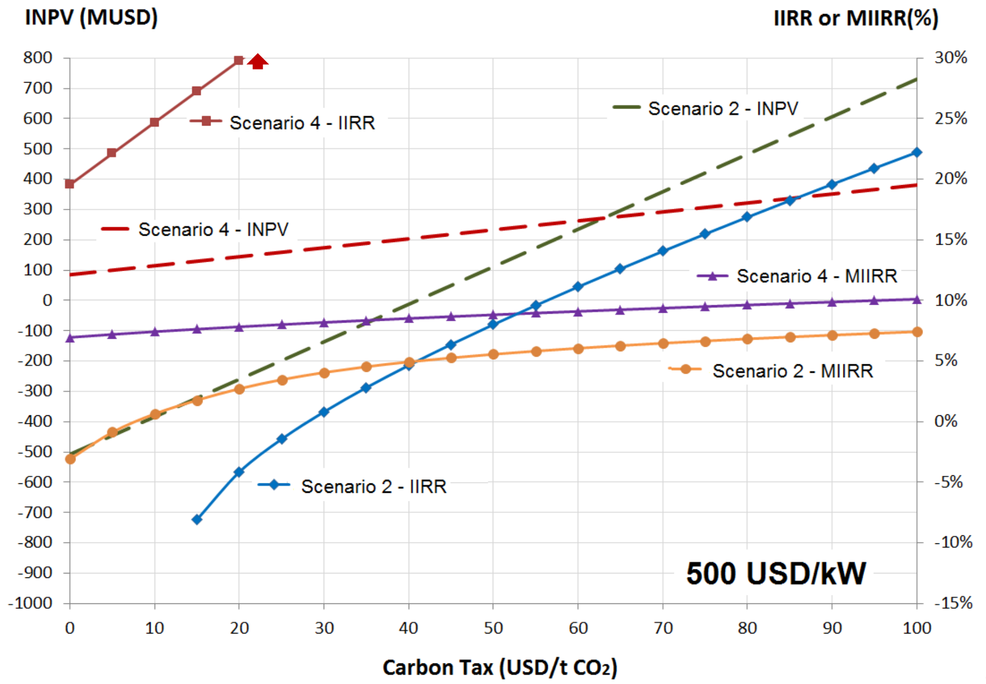
Fig. 11. INPV, IIRR and MIIRR as function of the carbon tax for (a) scenarios 1 and 3 and (b) scenarios 2 and 4 (interest rate i=5%, CCS unit specific cost: 1500 USD/kW).

Accordingly, it would be also interesting to assess the effect that a drop in the cost and investment risk of the integration of a CCS unit may have on the economic indicators. Confluence of several factors, such as (*i*) equipment maturation; (*ii*) economies of scale and extensive deployment of large scale commercial CCS units (> 400 MW); (*iii*) more stringent regulatory commitments pointing towards the decarbonization of the oil and gas industry; as well as (*iv*) attractive fiscal incentives and international cooperation may boost the development of CO_2 capture and storage [18, 52]. This scenario is not unrealistic, considering that by 2040, more than two thousand large-scale CCS facilities would be necessary to reach sustainable development goals and to comply with the Paris agreement, as stated by the International Energy Agency [58]. In practice, the successful cases of integration of commercial CCS units to onshore and offshore power generation systems have thrived in business environments either restricted by carbon taxation policies or motivated by ostensive technology development, in order to augment the oil recovery in mature field rigs [9, 59]. For instance, the Norwegian innovative carbon emissions tax, introduced in 1991, helped to build the business case of CCS at Sleipner. As for the offshore oil and gas sector in Norway, the CO_2 taxes and the quota price under emissions trading systems is currently around 60 USD per t_{CO2} [60]. The economic advantages of the project can be recognized bearing in mind that an equivalent of more than one million tons of CO_2 per year has been injected since 1996. Meanwhile, despite the fact that in Brazil, differently from neighbor countries such as Chile and Colombia, there is not an implemented CO_2 taxation framework, Petrobras has already injected more than 10 million t_{CO2} between 2008 and 2018, and the company estimates an accumulated reinjection of CO_2 of about 40 million t_{CO2} by 2025, highlighting its compromise to decarbonize its exploration and production activities [61].

Accordingly, if a radical cost reduction of the CCS technology is achieved, the economic indicators, especially the INPV, could show a striking shift to higher and more attractive revenues, even at a relatively low carbon tax of 40 USD/t_{CO2}. It can be seen from Figs.12a-b and contrasted with Figs. 11a-b. The MIIRR and the IIRR also present important variations, although the former seem to better represent the more realistic scenario, as it corrects the assumption of reinvesting all the lifespan revenues of the project at a relatively high IIRR. Notably, for a future scenario of lower specific cost of the CCS unit, as the carbon tax increases, the power hubs equipped with a carbon capture unit become ever more competitive vis-à-vis the power hub counterparts without a CCS unit. Actually, when the carbon tax reaches values between 60 and 70 USD/tCO_2, the power hub scenarios 1 and 2 start to outperform both the conventional utility system and the power hubs without CCS unit (scenarios 3 and 4), in terms of the incremental financial indicators. Nevertheless, the MIIRRs of the latter configurations are always higher (10-17% in scenario 3; 7-10% in scenario 4) than the more environmentally friendly setups (<7% in both scenarios 1 and 2). The drop in the MIIRR from Scenario 3 to Scenario 4 is again owed to the increase of the initial investment of the latter configuration. This fact once again emphasizes the advantages of the single pressure steam networks over the double pressure-based one, especially in the absence of a carbon abatement technology. This is not the same case if the Scenarios 1 and 2 are considered. Indeed, the Scenario 1 requires a larger carbon tax (11 USD/t_{CO2}) in order to turn its MIIRR positive, compared to the more efficient Scenario 2 (8 USD/t_{CO2}), despite its reduced initial investment.



(a)



(b)

Fig. 12. INPV, IIRR and MIIRR as function of the carbon tax for (a) scenarios 1 and 3 and (b) scenarios 2 and 4 (interest rate i=5%, CCS unit specific cost: 500 USD/kW).

Finally, the heat map given in Table A1 in Appendix 1 summarizes the effect of the simultaneous variation of the interest rate *i*, the carbon tax and the cost of the CCS unit on the INPV. As expected, for a given scenario of specific cost of the CCS unit, the increment of the carbon taxation is favorable to the integration of a CCS unit in terms of INPV. More interestingly, for a particular carbon tax, the interest rate considered plays a fundamental role on the attractiveness of those systems. For middle to stringent carbon taxations (40-100 USD/t_{CO2}), there exists a so-called Fischer interception, which defines the maximum interest rate for which the CCS-based power hub setups start to outperform the conventional design, consistent with the incremental financial approach suggested. As a result, at very low carbon taxes (5 USD/t_{CO2}), such as those typically found in the regional economies [54], even a radical reduction of the capital expenditure of a CCS unit would not be enough to shift the INPV of the power hub designs with carbon abatement technologies to more attractive figures. Meanwhile, at moderate carbon taxations, such as those imposed by Norway and Finland (~40-60 USD/t_{CO2}) [54], the integration of relatively inexpensive CCS units (~500 USD/t_{CO2}) starts to bring about better INPV values. Finally, relatively higher CCS unit costs (>1500 USD/t_{CO2}), partially owed to incipient technology deployment and risk perception, will keep hampering the adoption of post-combustion carbon capture technologies on offshore power hubs in terms of INPV. Actually, the use of CCS technologies in offshore power hubs would be seemingly profitable only if governmental subventions and stimulation of CCS industries; low interest rates (<5%); as well as mid-to-severe carbon taxes (80-100 USD/t_{CO2}) are implemented. In the meantime, the scenarios of power hubs without CCS units (scenarios 3 and 4) may come up as interesting solutions to the technological gaps and the environmental burden of the offshore oil and gas industry.

4.4. Effect of the delay in entry of operation

In the previous discussions, the delay in entry of operation between one productive FPSO and the next one has been invariably set as one year. However, as it has been mentioned in the Methods and tools section, the increase of this delay may help not only:

(*i*) reducing the initial investment, due to a reduction of the number of MPUs that, otherwise, would be installed exclusively for satisfying the peak of the electricity demand of the four productive FPSOs; but also,

(*ii*) flattening the referred peak and, consequently, reducing the time during which each MPU operate at offdesign conditions.

Thus, in this section, the implications of the increase of the delay in entry of operation in the initial investment and the lifespan efficiency are briefly discussed for a specific case study. Figure 13 shows the yearly average exergy efficiency and the net amount of electricity that must be supplied by a power hub equipped with 9+1 identical MPUs and a CCS unit (scenario 1), when a delay in entry of operation of *six years* is assumed. Notably, the peak of the power demand is reduced by almost 30% in comparison to the peak evidenced in Fig. 9, in which a delay in entry of operation of one year was adopted. Meanwhile, Table 4 summarizes the effect of the variation of the delay in entrance of operation on the maximum number of required MPUs, as well as on the mean lifespan power hub exergy efficiency for the two scenarios involving a CCS unit. As it can be seen, the mean lifespan power hub efficiency remains almost invariable, regardless of the number of MPUs installed, as a consequence of the offdesign optimization achieved (*i.e.* the sawtooth plots). For a delay in entry of operation of more than two years, the required installed capacity and its associated investment costs could be cutdown proportionally to the change of that variable. In this way, an excessive number of idle power units, only required for attending the peak demand that occurs in a short interval of the whole lifespan of the hub, could be avoided.

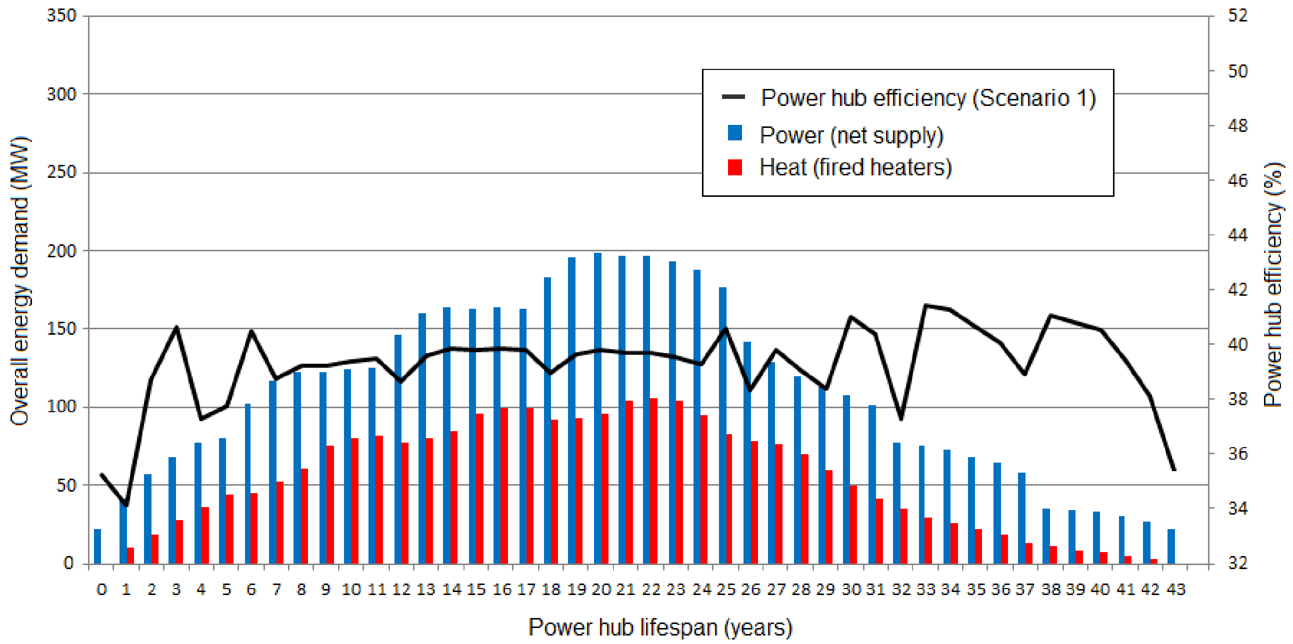


Fig. 13. Net power generation and yearly average efficiency of the power hub (Scenario 1) when operating with a delay in entry of operation of six years between productive FPSOs.

In practice, very long delays would not be attractive for companies aiming to increase their net present revenues. Thus, evidently, there will be a trade-off associated to the main company targets and to the opportunity costs of the oil and gas not produced yet, as a result of the depreciation of the value of money with time. This undergoing analysis will be presented in future works.

Table 4. Effect of the variation of the delay in entry of operation between productive platforms on the maximum number of MPUs required and the mean lifespan power hub efficiency.

	Delay in entry of operation (years)					
Power hub design	**0**	**1**	**2**	**4**	**6**	**8**
Scenario 1 *N+1* MPUs	9(+1)	9(+1)	8(+1)	7(+1)	6(+1)	5(+1)
[Mean lifespan power hub efficiency (%)]	[39.7]	[39.1]	[38.9]	[39.4]	[39.3]	[39.4]
Scenario 2 *N+1* MPUs	9(+1)	8(+1)	8(+1)	6(+1)	6(+1)	4(+1)
[Mean lifespan power hub efficiency (%)]	[41.6]	[41.1]	[40.8]	[41.1]	[41.1]	[41.1]

5. Conclusions

Limited weight and space budget on existing FPSOs restrain the electricity generation to low-efficiency energy systems, which hampers the efforts to radically abate the environmental impact produced. Meanwhile, since half of the Brazilians FPSOs are close to the end of their productive lifespan and will need to be decommissioned soon, the adaptation of those vessels into centralized power stations may partially overcome the restrictions on existing FPSOs. In this regard, the power hub concept emerges as an interesting alternative to supply the power required by a set of four FPSOs by using more efficient and environmentally friendly, as well as affordable energy technologies, envisioning an hypothetical scenario of increased environmental regulations of oil and gas industry. Although power hubs may effectively increase the thermodynamic and environmental performance of the offshore utility systems, many challenges are still brought to companies that contemplate using those technologies, mostly due to the incremental costs associated. Accordingly, a comparative financial incremental analysis has been performed to shed light on the potential benefits of the central power stations. They include (*i*) the optimization of sizing and dispatch processes, which in turn may help (*ii*) reducing the amount of fuel consumption, (*iii*) augmenting the revenues with gas exportation and (*iv*) cutting down the investment and operating cost, as well as (*v*) the atmospheric emissions per unit of petroleum extracted. This methodology is in agreement with the recent practices that aim to include the costs of the environmental impact in the evaluation of future projects. Moreover, the introduction of carbon taxes may encourage the development and diminish the financial risks associated to breakthrough technologies, such as post-combustion CCS units, thus, revealing new business opportunities to decarbonize the petroleum extraction activities. As a result, the more advanced power generation systems may provide higher overall performances (about 40%) than the existing configuration (about 30%), even at one-fourth of the CO_2 emissions. Notwithstanding, the initial investment costs of the CCS units remain the main drawback, difficult to circumvent without the cooperation of governmental subsidies and risk investors, and aggravated by the lack of suitable carbon taxation frameworks. Finally, the delay in entry of operation may also help mitigating the high initial investment cost, although its opportunity cost must still be studied.

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Nomenclature

Latin Symbols

b – specific exergy [kJ/kg]

B – exergy flow rare [kW]

C – expenses [USD]

i – interest rate [%]

m – *mass flow rate* [kg/s]

n – number of years [y]

N – number of non-redundant modular power units [-]

R – revenues [USD]

W – power [kW]

ω – decision weight [-]

x – *decision variable* [-]

η – efficiency [%]

Subscripts

1,...,5 – decision variable number

ex – exergy

fuel – fuel consumption

net – net power generation

Superscripts

Q – exergy of heat

CH – chemical exergy

n – year

Acronyms

boe – *barrels of oil equivalent*

CAPEX – *capital expenditures*

CCS – *carbon capture and storage unit*

CEPONG – *Clean Electricity Production from Offshore Natural Gas concept*

EOR – *enhanced oil recovery*

FPSO – *floating, production, storage and offloading unit*

FV – *future value*

GE – *General Electric brand*

HP – *high pressure*

HRSG – *heat recovery steam generator*

INPV – *incremental net present value*

IP – *intermediate pressure*

IIRR – *incremental internal rate of return*

LHV – *lower heating value*

LP – *low pressure*

MEA – *methyl ethanolamine*
MIIRR – *modified incremental internal rate of return*
MPU – *modular power unit*
OTPPC – *Offshore Thermal Power Plant with CCS concept*
PV – *present value*
SCGT – *simple cycle gas turbine*
VBA – *Visual Basic for Applications*
WHRU – *waste heat recovery unit*

Appendix 1

Table A1. Effect of the variation of the interest rate i, the carbon taxation and the cost of the CCS unit on the INPV (in MUSD).

		Scenario 1									***Scenario 2***									***Scenario 3***			***Scenario 4***		
		10 MPU type 1 + CCS unit									10 MPU type 2 + CCS unit									9 MPU type 1			9 MPU type 2		
CCS cost (USD/kW) →		500			1000			1500			500			1000			1500			0			0		
Carbtax (USD/tCO$_2$) →		5	40	100	5	40	100	5	40	100	5	40	100	5	40	100	5	40	100	5	40	100	5	40	100
	0%	-522	230	1520	-779	-27	1263	-1037	-284	1006	-499	257	1554	-767	-10	1287	-1034	-278	1019	278	465	786	232	422	747
	1%	-501	164	1304	-754	-89	1051	-1007	-342	797	-486	183	1328	-749	-81	1065	-1012	-344	802	241	404	683	195	360	644
	2%	-482	109	1123	-732	-141	873	-982	-391	623	-474	120	1140	-734	-139	880	-994	-399	620	210	353	599	164	309	559
	3%	-465	64	971	-713	-184	723	-960	-431	476	-464	68	980	-721	-189	723	-978	-446	466	185	312	530	138	267	488
	4%	-451	25	842	-696	-220	596	-941	-465	351	-454	25	845	-709	-230	591	-964	-485	336	164	277	472	117	233	430
	5%	-438	-7	732	-681	-250	488	-925	-494	245	-446	-12	730	-698	-265	477	-951	-518	225	146	248	423	100	203	381
	6%	-426	-34	637	-668	-276	395	-910	-518	154	-438	-44	631	-689	-295	380	-940	-546	129	132	224	382	85	179	339
	7%	-416	-58	556	-656	-298	316	-897	-539	75	-431	-71	546	-681	-321	297	-930	-570	47	119	203	348	73	158	304
	8%	-406	-78	486	-646	-317	247	-885	-556	7	-425	-94	472	-673	-343	224	-921	-591	-24	109	186	318	62	140	274
	9%	-398	-95	424	-636	-333	186	-874	-571	-52	-419	-114	408	-666	-361	161	-913	-609	-86	100	171	293	53	125	249
***i* (%)**	10%	-390	-110	371	-627	-347	134	-864	-584	-103	-413	-132	352	-660	-378	106	-906	-624	-141	92	158	271	45	112	226
	11%	-383	-123	324	-619	-359	88	-855	-595	-148	-408	-147	302	-654	-392	57	-899	-637	-188	85	146	251	39	101	207
	12%	-376	-134	282	-612	-369	47	-847	-604	-188	-404	-160	258	-648	-404	14	-892	-648	-230	79	136	235	33	91	190
	13%	-371	-144	245	-605	-378	11	-839	-612	-224	-400	-172	219	-643	-415	-24	-886	-658	-267	74	128	220	28	82	175
	14%	-365	-153	212	-599	-386	-22	-832	-619	-255	-396	-182	184	-638	-424	-58	-880	-667	-300	69	120	207	23	74	162
	15%	-360	-160	182	-593	-393	-50	-825	-626	-283	-392	-191	153	-634	-433	-88	-875	-674	-330	65	113	195	19	67	150
	16%	-355	-167	155	-587	-399	-76	-819	-631	-308	-389	-199	125	-629	-440	-116	-870	-681	-356	62	107	185	16	61	140
	17%	-351	-173	131	-582	-404	-100	-813	-636	-331	-386	-207	100	-625	-447	-140	-865	-687	-380	58	101	175	12	56	130
	18%	-347	-179	110	-578	-409	-121	-808	-640	-351	-383	-213	77	-622	-453	-162	-861	-692	-402	55	96	166	9	51	121
	19%	-344	-184	90	-573	-413	-140	-803	-643	-369	-380	-219	56	-618	-458	-183	-857	-696	-421	53	92	159	7	46	114
	20%	-340	-188	72	-569	-417	-157	-798	-646	-386	-377	-225	37	-615	-462	-201	-853	-700	-439	50	88	152	4	42	107

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