A Multi-year Planning Model for Low-carbon Transitions of Offshore Oil and Gas Platforms

Jiangyi Huang[1*], Alena Lohrmann[1], Anna Peecock[2], Fabian Heymann[1],
Til Kristian Vrana[3], Juha Kiviluoma[4], and Russell McKenna[1,5]
[1]Chair of Energy System Analysis, ETH Zürich, Zürich, Switzerland
[2]School of Engineering, University of Aberdeen, Aberdeen, United Kingdom
[3]Equinor, Trondheim, Norway
[4]Nodal-Tools Ltd., Helsinki, Finland
[5]Laboratory for Energy Systems Analysis, Paul Scherrer Institute PSI, Villigen PSI, Switzerland
[*]Corresponding author: jiahuang@ethz.ch

***Abstract*—Offshore oil and gas (O&G) assets provide unique opportunities for low-carbon energy transition in the coming decades, including decarbonising the O&G platform operations and repurposing existing infrastructure for clean energy uptake. However, modelling the long-term transition at offshore O&G platform level remains currently under-examined. This study proposes a multi-year planning model of individual offshore O&G platforms for exploring low-carbon transition pathways. The case-agnostic model optimises investments and operations by minimising total system costs, accounting for energy-related expenditures and revenues from onshore markets. We apply the model to a synthetic platform, considering onshore market prices for O&G, electricity, hydrogen (H_2) and carbon emissions. Technology integration encompasses power from shore, offshore wind, and green and blue H_2, with offshore-specific multipliers applied to the associated costs. Results demonstrate the ability of the model to evaluate strategies for the offshore O&G low-carbon transition, highlighting key opportunities and challenges at an individual platform level.**

***Index Terms*—Hydrogen energy; Multi-year investment planning; Offshore energy transition; Offshore oil and gas; Offshore wind energy.**

I. INTRODUCTION

Low-carbon energy transition in the offshore oil and gas (O&G) sector has gained increasing interest [1]–[3] amid concerns over the growing number of ageing facilities and the need for rapid decarbonisation. Individual offshore O&G platforms can be of up to several hundred MW of energy demand [4]. Typically relying on onsite gas turbines [5], offshore O&G operation *per se* is carbon-intensive [6], to which electrification by low-carbon energy sources would bring immediate decarbonisation. Particularly in the North Sea, where abundant offshore wind resources [7] and a strong offshore petroleum sector co-exist, a growing number of O&G infrastructures will face costly decommissioning in the coming decades [3]. Simultaneously, North Sea countries are facing pressure to strengthen energy supply security, while meeting ambitious climate goals. In this context, low-carbon offshore O&G transitions to harness offshore wind power (OWP) present a unique opportunity.

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Decarbonising platform operation and repurposing offshore O&G installations for low-carbon energy production and transport are two key transition ways for the offshore O&G sector. Energy for platform operations is supplied either by power from shore (PFS) [8], offshore wind turbines (OffWTs) installed in the platform vicinity [9], or a hybrid of both [10], [11]. The generated OWP can utilise hydrogen (H_2) produced via water electrolysis (green H_2) for energy storage [12] to smooth its output intermittency. Where structural integrity allows, existing offshore O&G infrastructures can be repurposed into OWP hubs [13] or green H_2 plants powered by OWP [14], and associated gas pipelines may be retrofitted for H_2 transport [15]. In addition, onsite carbon capture and storage (CCS) can decarbonise the platform operation. When combined with effective carbon storage, steam methane reforming (SMR) converts reservoir natural gas into blue H_2, allowing for low-carbon exploitation of offshore fossil resources.

Multi-year planning models are critical to realising the offshore O&G transition, for which investment planning needs to span both operating and post-decommissioning phases of offshore O&G platforms. However, existing modelling on individual platforms mainly contains operation planning under presumed low-carbon configurations (e.g. [16]–[18]), omitting multi-year investment planning. While [19] and [20] adopted multi-year planning models to explore long-term transition opportunities for offshore O&G in the North Sea, offshore O&G transition was modelled from a multi-nation energy system perspective, neglecting direct influence on individual platforms. In reality, whether a platform benefits from adopting low-carbon alternative technologies would determine its role in the overall energy transition pathway. An energy planning model for the low-carbon offshore O&G transition of individual platforms would therefore be of strategic value for cost-effective transitions.

This study thus aims to develop a novel multi-year energy planning model for low-carbon transitions of offshore O&G platforms with platform-level techno-economic operational details. Specifically, the developed model allows asset repurposing in addition to capacity expansion and decommissioning of a petroleum field and explicitly represents its continuous expenditure on reservoir recovery. The model development is followed by applying it to a synthetic North Sea O&G platform to demonstrate the capability of the methodology in assessing low-carbon transition strategies and the influence of onshore market prices of crude oil, natural gas, electricity, carbon emission and H_2. Although our model is applied within the North Sea context, the methodology is context-agnostic and can thus be transferred to similar offshore platform architectures.

This paper is organised as follows. Section II presents the modelling methodology. Section III provides a model instance for demonstration. Section IV concludes by summarising the research and the limitations.

II. METHODOLOGY

A. *Energy System of Offshore O&G Platform*

Regarding low-carbon offshore O&G transitions, a platform energy system comprises (1) existing energy-related facilities for conventional hydrocarbon production, processing and export, and (2) alternative low-carbon technologies for operational decarbonisation and asset repurposing. In this study, an offshore O&G platform refers to a set of offshore installations that form an independent O&G production and export unit.

Fig. 1 presents an archetypal platform energy system with candidate low-carbon technologies. The system explicitly captures the reservoir well-stream, energy product export to shore, and CCS service for onshore systems. Conventional hydrocarbon production consumes electricity and heat for well-stream processing and personnel living, typically supplied by onsite gas turbines consuming *in situ* natural gas [5] and producing carbon emissions. Heat demand can be of different temperature ranges for diverse industrial processes [21] and residential needs. Alternative low-carbon technologies include PFS, OffWT, electric boilers, H_2 conversion and storage, SMR, and CCS. Having these technologies installed could transform the onsite energy balance profile and the export product and service. For instance, CCS consumes electricity and can provide bankable carbon injection.

B. *Transition Problem Description*

The low-carbon transition model considers investment and operations of both conventional O&G production and alternative low-carbon technologies on an offshore O&G platform. In addition to expenditures needed to maintain production activity, there is an upfront cost for reservoir exploration and development before the platform production starts. Typically financed by loans, this cost accounts for approximately 50% of the total expenditure of an O&G project [22]. Repayment of the loan plus interest continues during the platform production phase. As a result, offshore O&G platform operation aims for stable and continuous reservoir exploitation to maximise profitability. While these economic considerations are beyond the scope of this study, we assume the modelled platform pursues profit maximisation, i.e. revenues from selling energy products and services onshore minus all investment and operational expenditures.

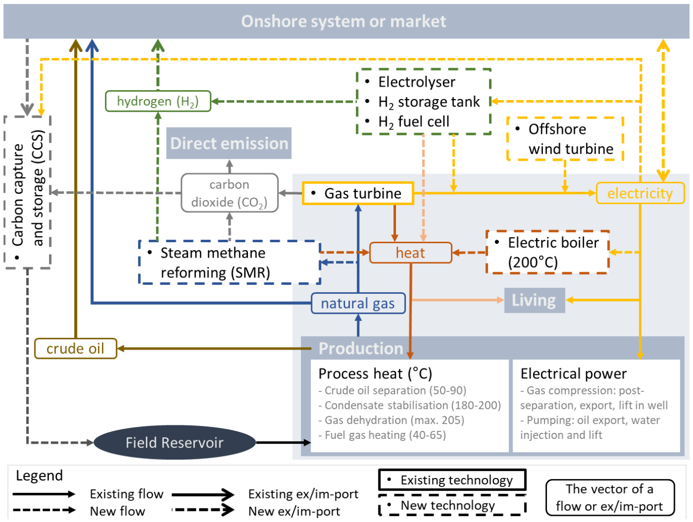

Fig. 1. The energy system of an offshore O&G platform and alternative low-carbon technologies. The "Existing" technologies and flows represent the initial configuration of a platform under conventional O&G operation. And the "New" features represent low-carbon transition options in which the platform can invest. Specifically, heat flows differ in two categories: high-temperature (dark orange) process heat, and low-temperature (light orange) process and personnel living.

For conventional O&G operations, one fundamental operational decision is the continuous expenditure on reservoir recovery to maintain well-stream production. After the primary recovery of a reservoir, well-stream capacity would decline without investing in further recovery measures (Fig. 2). Platform operators may stop investing in reservoir recovery to decommission before the plan. During its operational lifetime, O&G output is bounded by the invested well-stream capacity, determining the export quantity to the onshore market via existing pipelines and onsite electricity and heat demand. Gas turbines supply the energy demand as well as an operating reserve. When a gas turbine reaches the end of its operating lifetime, the platform decides whether to invest in new ones.

Electrification encompasses investment and operational decisions in (1) power cables connecting onshore power supply (PFS import), (2) dedicated OffWTs in the platform vicinity and the OWP output, (3) electric boilers for heat supply, and (4) electrolyser, storage tank and fuel cell for smoothing OWP output variation using H_2. Costs for PFS import are subject to the quantity and onshore electricity prices. OWP output is subject to *in situ* wind resource availability and installed capacity. Alternatively, platform operators may invest in CCS that injects CO_2 in depleted reservoirs, which adds to electricity demand. Decisions on these decarbonisation measures remain available during the platform's operational period until its decommissioning.

Infrastructure repurposing involves investments and operations during the operational and post-decommissioning phases of the modelled platform. Platform operators may invest in SMR and CCS to produce blue H_2 from indigenous natural gas. Platform operators may bid for surrounding marine areas

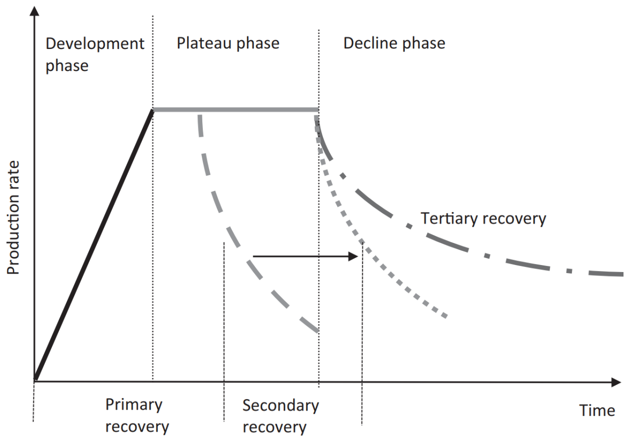

Fig. 2. Typical recovery phases of an O&G reservoir [23]. Developed O&G reservoirs invest in secondary recovery to maintain production rate, and tertiary recovery to alleviate the inevitable rate decline.

to build utility-scale offshore wind farms and power cables to export OWP to the onshore system, leading to repurposing the platform into an OWP hub. In addition, investment in H_2 conversion and storage technologies is available. Exporting the green H_2 requires investment in new H_2 pipelines or retrofitting existing gas pipelines.

C. Model description

The transition problem is modelled in mixed-integer linear programming (MILP) formulations using the open-source framework `SpineOpt.jl` [24]. This section outlines the key formulations, in terms of their main functionality, employed to develop the proposed multi-year planning model for the low-carbon transition of O&G offshore platforms. Details on the mathematical definitions can be found in Appendix-A.

The objective function minimises a total system cost accounting for investment and operational decisions of the modelled platform system, subject to four main categories of constraints in respect of Appendix-A5.

(1) Constraints on investment decisions, including decommissioning and repurposing, on the technologies and assets pertaining to the modelled offshore platform.
(2) Constraints for balancing energy or commodity flows where storage operation is applicable.
(3) Constraints on the operation of transmission technologies, such as power cables and O&G pipelines.
(4) Constraints on the operation of generation or conversion technologies, such as wind turbines or gas turbines, where the formulation can take operating reserves into account.

To encode the export revenues of O&G and carbon emissions, of which the delivery quantity is formulated under flow variables, the platform model uses the negation of O&G price and CO_2 tax values to define respective cost parameters. With this setup, the objective function corresponds to maximising the platform's profitability. Reservoir recovery is explicitly modelled as endogenous investment decisions in the capacity of the well-stream. `SpineOpt.jl` allows timeseries input for the capacity and the cost parameters, enabling the model to capture the variations in well-stream availability and recovery expenditure.

III. DEMONSTRATION CASE

A. Model Specification and Input Data

Based on open data, we apply the proposed model to a synthetic offshore O&G platform as a demonstrative case. Ekofisk is the prototype of the synthetic platform. According to [25], this offshore O&G field is located in the centre of the North Sea on Norway's flank, 200 km from Stavanger, equipped with a 356 km oil pipeline to the UK and a 443 km gas pipeline to Germany. Regarding petroleum output capacity, Ekofisk is a medium-large O&G field and platform among its North Sea peers.

Table I shows the fundamental profile of the modelled synthetic platform. The O&G output capacity and the associated investment, which represent reservoir recovery at different phases, originate from Ekofisk historical records [26] under the assumption of 65% reservoir well-stream being oil and the rest being gas according to [18]. The onsite electricity and heat demand are estimated by multiplying the specific electricity and heat consumption per reservoir well-stream [18] by the platform output capacity.

TABLE I
BASIC PLATFORM OPERATIONAL INFORMATION PER INVESTMENT PERIOD.

Period	***Oil***^{a} ***(GW)***	***Gas***^{a} ***(GW)***	***Investment (BEUR)***	***Electricity***^{b} ***(MW)***	***Heat***^{b} ***(MW)***
2025-30	15.3	8.2	1.05	57.7	24.3
2030-35	12.6	6.8	2.31	57.7	20.7
2035-40	6.9	3.7	4.20	57.7	13.0
2040-45	4.6	2.5	1.68	57.7	9.9
2045-50	4.6	2.5	1.68	57.7	9.9
2050-55	2.3	1.2	0.92	44.3	6.8
2055-60	0	0	0	0	0
2060-65	0	0	0	0	0

[a] Investable output capacity.
[b] Demands account for living consumption.

In this demonstrative case, we model a horizon of 40 years spanning from 2025 to 2065, with the reservoir scheduled to decommission in 2055. The last decade (2055-2065) represents the duration of cases where the platform repurposing extends its original lifetime. As an initial configuration, the platform already has three gas turbines operating for its onsite power and heat supply. We assume that these generators were installed before the modelling horizon and will retire in 2035, but are replaceable during the first decade. Investment decisions are in a five-year resolution associated with one operation day of a four-hour resolution per investment period.

Accounting for the technologies discussed in Section II, we enclose low-carbon offshore O&G transition strategies for the synthetic platform in four scenarios (Table II). Scenario *BaseOperation* represents regular operations of conventional O&G production on the modelled platform. Scenario *RepurpBlueH2* contains electrification with OWP. In scenario

ElectrifyOffWT, H_2 only serves for onsite energy storage to smooth the variation of OWP output. In contrast, the platform may export H_2 onshore in the *RepurpGreens* scenario.

TABLE II

SYSTEM CONFIGURATION SCENARIOS OF TRANSITION OPTIONS.

Technology	*Base Operation*	*Electrify PFS*	*Electrify OffWT*	*Repurp BlueH2*	*Repurp Greens*
GT	✓	✓	✓	✓	✓
PipeGas	✓	✓	✓	✓	✓
PipeOil	✓	✓	✓	✓	✓
ElecBoiler		✓	✓	✓	✓
ElecCable		✓			✓
OffWT			✓	✓	✓
PipeCO2				✓	
CCS				✓	
SMR				✓	
PipeH2^{a}				✓	✓
Electrolyser			✓		✓
H2FC			✓		✓
H2tank			✓		✓

[a] GT: gas turbine, FC: fuel cell.

[b] Demands account for living consumption.

[c] Include the new built and retrofitting from existing gas pipelines.

Table III presents the primary techno-economic features of technologies in consideration based on the sources given next. Note that the techno-economic data usually represents onshore implementation, especially for the conventional technologies such as gas turbine, O&G pipelines and electric boiler. When these technologies are installed and operated offshore, the distant logistics and more severe erosion in the sea could significantly add to their costs. To the authors' best knowledge, no literature has quantified this difference. Hence, based on the authors' expertise in the North Sea O&G industry, we assume that the offshore investment and operational costs are five times the onshore value under appropriate cost categories.

Reference [28] is the main source of Table III. Specifically, [29] and [30] provide most techno-economic data for electricity generation (including electrolysers and fuel cells) and industrial process heat supply. We use the method and values of [31] to calculate the offshore power cable costs. For other energy transmission technologies, we derive the costs from [32] by linearly adapting the given values to the distance of respective ashore transmission lines of the synthetic platform. The costs for SMR are found in [33], and its conversion efficiency is from [34].

Table IV summarises the market prices used in the model simulation. The prices are expected to roughly represent the present situation in Europe, except for the H_2 price (equivalent to 2 EUR/kg) that represents one recognised break-even cost for green H_2.

B. Results

Fig. 3 presents the model results of installed capacity, with Fig. 4 in Appendix-B showing the annual production level of the installed technologies. Compared with the *BaseOperation* scenario that represents conventional gas-turbine-dependent operation, all transition scenarios reduce the installation and use of gas turbines over the platform operating period. In the *ElectrifyPFS* scenario, a gas turbine remains over the platform operating period, with the electric boiler substituting part of the heat supply. Similarly, no other scenarios have replaced all gas turbines in the first decade despite the offshore multiplier applied to the investment and fixed operational costs, which is largely owed to the demand for a stable heat supply for the platform operation.

Fig. 5 presents the model results of the total system cost decomposed into revenues and expenditures. In the *ElectrifyPFS* scenario, the increase in expenditure gets paid off by its revenue expansion bringing a 0.5 BEUR net increase, thanks to the savings in onsite consumption of natural gas for more export. This outcome could be sensitive to the relative value between natural gas and electricity prices. According to [35], PFS could become economically unfavourable if electricity prices become high. The *ElectrifyOffWT* scenario preserves the same revenue expansion that benefits from saving

TABLE III

MAIN TECHNO-ECONOMIC INPUT DATA.

Technology	*Cap.*	*INV*	*VOM*	*FOM*	*Eff.*	*LT*
(electricity, heat, O&G)	*MW (output)*	*EUR /kW*	*EUR /MWh*	*EUR /MW/h*	-	*year*
GT	26×3	3500^{a}	5.1	10.6^{a}	39%	25
PipeGas	10000	NA	3.38^{a}	NA	100%	35
PipeOil	20000	NA	0.75^{a}	NA	100%	NA
ElecBoiler	50	500^{a}	2.6^{a}	0.63^{a}	98.5%	25
ElecCable	4000	3021	0.36	NA	92%	20
OffWT	7000^{b} 380^{b}	2893	3.9	7.2	ts^{c}	30
H2FC	100	1170	0	6.7	50%	10
(electricity)	*MW (input)*	*EUR /kW*	*EUR /MWh*	*EUR /MW/h*	-	*year*
Electrolyser	4000	950	0	4.3	58%	25
(H_2)	*MW (output)*	*EUR /kW*	*EUR /MWh*	*EUR /MW/h*	-	*year*
PipeH2new	10000	120	1.082	NA	97%	50
PipeH2retro	10000	96	1.082	NA	97%	50
H2tank^{e}	800	100	0	0.06	88%	25
SMR	10000	0.75M	0	3.85	80%	30
(CO_2)	*tph (output)*	*EUR /tph*	*EUR /tonCO$_2$*	*EUR /tph/h*	-	*year*
PipeCO2	320	10M	0	0.68	100%	50
CCS	600	2.16M	7.5	1.6	0.014^{d}	30

Cap.: maximum investable capacity, INV: investment,
VOM: variable operational and maintenance (O&N) cost,
FOM: fixed O&M cost, Eff.: efficiency,
LT: lifetime, tph: tonCO_2/h, NA: not applicable.

[a] adjusted according to the cost assumption for offshore implementation.

[b] 7000 in scenario *RepurpGreens*, 380 for other scenarios having OffWT.

[c] ts: timeseries capacity factor, obtained from [27].

[d] MWh-e/tonCO_2.

[e] MWh H_2 storage capacity.

TABLE IV

ONSHORE MARKET PRICES OF ENERGY, COMMODITY AND SERVICES

Crude oil	*Natural gas*	*H_2 export*	Electricity		Carbon	
			export	*import*	*emission*	*injection*
EUR/MWh					*EUR/tonCO$_2$*	
-37	-35	-51	-78	87	82	-100

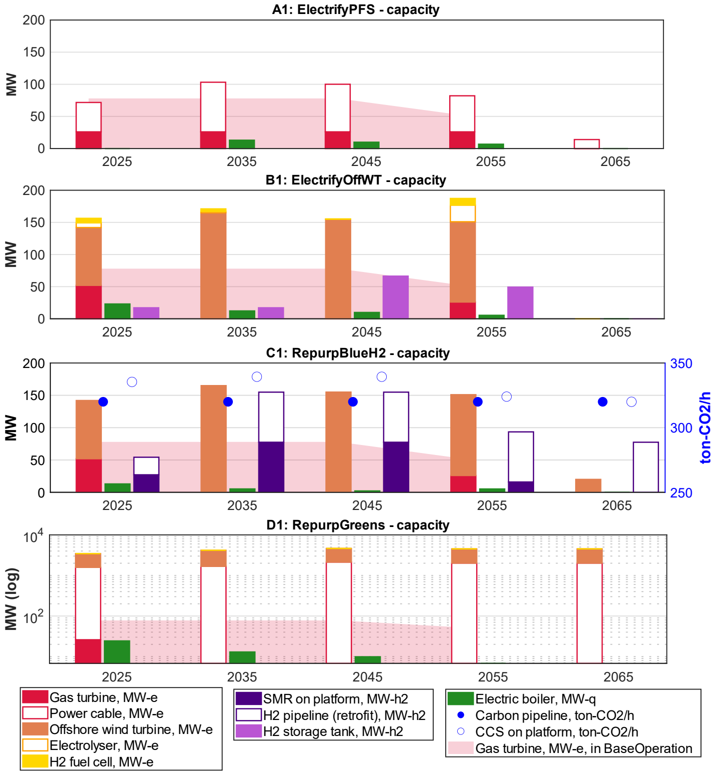

Fig. 3. Results of the modelled platform system: technology capacity installations per decade. The first bar in each year is for electricity (in MW-e), the second for heat (in MW-q), and the third for H_2 (in MW-h2). The light-red-shadow area represents gas turbine capacity under conventional O&G platform operation denoted by the *BaseOperation* scenario.

onsite natural gas consumption and further reduces the system expenditure by 0.2 BEUR from the operational cost. Despite the operations being with a 4-hour resolution, H_2 appears useful as an energy storage to buffer OWP variation. In the 2055-60 period, one gas turbine returns to use. One reason that could be more extensive OWP fluctuations in that period need extra capacity to handle the change, as indicated by the increase of H_2 electrolyser and fuel cell. Besides, as the platform operation comes to an end, installing new OffWT becomes less economically attractive than gas turbines.

Both the repurposing scenarios present their value in stretching the profitability of offshore O&G platform assets in quantity as well as time. While the expenditure increases significantly in asset investment, revenue growth outperforms that, raising a net revenue of 7.4 and 9.2 BEUR to the system in *RepurpBlueH2* and *RepurpGreens*, respectively. In *RepurpBlueH2*, CCS gets installed from the beginning to provide a carbon injection service and decarbonising platform operation. In contrast, SMR takes over the heat supply responsibility from the replaced gas turbines by OffWT, which also supplies electricity for CCS. Because the SMR process generates heat, there are fewer electric boilers for heat supply. During the post-decommissioning period, CCS continues to offer a carbon injection service as long as the reservoir allows. In *RepurpGreens*, the system maximises the installation and production of utility OWP and export. Note that green H_2 generation presents no advantage under the break-even price.

Reservoir recovery remains the dominant expenditure of the electrification scenarios *ElectrifyPFS* and *ElectrifyOffWT*, whereas in the repurposing scenarios *RepurpGreens* and *RepurpBlueH2*, investment becomes equally significant. This suggests 1) the importance of involving reservoir recovery in the transition planning model for the offshore O&G sector, and 2) profit increase being one driving motivation for repurposing the platform.

IV. CONCLUSION

This study presents a multi-year investment planning model for low-carbon energy transitions of offshore O&G platforms. The proof-of-concept model allows investments in platform asset repurposing in addition to normal capacity expansion and decommissioning decisions, captures platform-level techno-economic operational details, and represents continuous expenditure on reservoir recovery.

We apply the model to a synthetic North Sea O&G platform to analyse low-carbon transition strategies which encompass platform electrification and repurposing and account for the influence of crude oil, natural gas, electricity, carbon emission and H_2 onshore market prices. Low-carbon technologies for the transition include SMR harnessing field-produced gas, CCS utilising the O&G field reservoir, PFS via offshore power cables, OWP enabled by OffWT, H_2 conversion and storage by utilising H_2 electrolyser, fuel cell and storage tank, with offshore-specific multipliers applied to the investment and fixed operational costs. Modelled results illustrate the techno-economic benefits and challenges of the low-carbon transition to the offshore O&G platform. The studied case demonstrates the capability of the developed model in assessing low-carbon offshore O&G transitions, highlighting long-term opportunities at an individual platform level.

Due to the research scope, a few limitations remain to be addressed in future research. The demonstrative case study focuses on a single platform, omitting the diversity of the offshore O&G installation and the interaction between multiple platforms. Future studies in this direction would need the model to capture transmission flow physics of diverse energy vectors such as electricity and H_2. On formulating investment decisions, the model omits the economic discounting effect, which can make a difference to the system decisions for long-term planning, and thus needs to be considered in cases targeting the real world. Although the asset decommissioning and repurposing are introduced in the model, their influence on the platform reservoir recovery lacks explicit representation in the demonstrative case. Besides, a more systematic and finer temporal structure, e.g. an optimally selected representative period in hourly resolution, could improve operational details of targeted technologies. This could benefit the analysis on e.g. OWP [36], H_2 being an energy storage, and operating reserves.

Addressing the mentioned aspects would require modelling formulations with advanced computational efficiency to navigate the complexity of the enhanced MILP transition problem with operational details, e.g. [37]. Furthermore, as the transitioning offshore O&G systems are of multi-energy-vector by nature, representationally efficient formulations (e.g. [38]) would play a pivotal role in preserving model tractability.

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APPENDIX

A. Mathematical Formulation

This section briefly defines the employed mathematical formulations. We use the generic entity class provided by `SpineOpt.jl` framework to formulate the proposed energy planning model. For more details on the formulations and functionality implementation of the framework, readers are recommended to look up `SpineOpt.jl` documentation [39].

1) Indices and Sets: In this study, we use the term *vector* to denote a commodity or service such as electricity, heat, H_2, CO_2 emissions, operating reserves, etc.

$n \in \mathcal{N}$	Node: aggregation with storage capability of flows of a single vector.
$u \in \mathcal{U}$	Unit: conversion of flows of one or multiple vectors between nodes, e.g. a gas turbine generator.
$l \in \mathcal{L}$	Connection: transfer of flows of a single vector between two nodes, e.g. a power transmission line.
$t \in \mathcal{T}$	Timeslice for variables and parameters.

Set $\mathcal{T}$ of timeslices is usually divided into two subsets for investment $\mathcal{T}_{inv}$ and operation $\mathcal{T}_{opr}$. Here, we collectively denote unit and connection by *equipment* $e \in \mathcal{E} = \mathcal{U} \cup \mathcal{L}$ that delivers a flow. Nodes having storage form a subset $\mathcal{N}_s$ of all nodes, i.e. $\mathcal{N}_s \subseteq \mathcal{N}$. And we collectively denote node storage, unit, and connection by *asset* $a \in \mathcal{A}$ such that $\mathcal{A} = \mathcal{N}_s \cup \mathcal{E} = \mathcal{N}_s \cup \mathcal{U} \cup \mathcal{L}$.

2) Decision variables:

$v^{flow}_{(e,n)\oplus(n,e),t}$: flow delivered by e to/from node n.
$v^{online}_{u,t}$: online subunits of unit u.
$v^{state}_{n,t}$: storage level of node storage $n \in \mathcal{N}_s$.
$v^{invest}_{a,t}$: invested subunits of asset a.
$v^{mothball}_{a,t}$: mothballed subunits of asset a.
$v^{invest\_avail}_{a,t}$: invested subunits of a that remains available.

Symbol $\oplus$ refers to the exclusive disjunction of two elements represented by the indices. For instance, $v^{flow}_{(e,n)\oplus(n,e),t}$ is equivalent to $v^{flow}_{(e,n),t} \oplus v^{flow}_{(n,e),t}$ and stands for either $v^{flow}_{(e,n),t}$ or $v^{flow}_{(n,e),t}$. An entity pair in a brackets (a,b) specifies a direction from the first entity a to the second entity b. As an example, the variable $v^{flow}_{(u,n),t}$ represents a flow from unit $u \in \mathcal{U} \subseteq \mathcal{E}$ to node n. The value of a variable satisfies $v^{flow}, v^{state} \in \mathbf{R}_{\geq 0}$, and $v^{online}, v^{invest}, v^{mothball}, v^{invest\_avail} \in \mathbf{Z}_{\geq 0}/\mathbf{R}_{\geq 0}$.

3) Parameters:

$C^{vom}_{(e,n)\oplus(n,e),[t]}$: variable O&M cost of delivery of a flow between equipment e and node n.
$C^{fom}_{u,[t]}$: fixed O&M cost of unit u.
$C^{invest}_{a,[t]}$: cost for investing asset a.
$P^{func.}_{e\oplus n,[t]}$: coefficient *func.* defined on e or n.
$P^{func.}_{(e,n)\oplus(n,e),[t]}$: coefficient *func.* defined on e and n.
$P^{func.}_{e,n_1,n_2,[t]}$: coefficient *func.* defined on e, n_1, and n_2.

Here, *func.* is a placeholder for an arbitrary name of the coefficient parameters. Specific coefficient instances will be introduced when they appear in the corresponding formulation. Unlike the variables, timeslice t for a parameter is optional (as indicated by square brackets []), explicit for timeseries values and implicit otherwise.

4) Objective Function: The objective function minimises the total system cost comprising the investment, variable O&M, and fixed O&M costs over the corresponding variables subject to the constraints.

$$\min_{v} \sum_{a,t\in\mathcal{T}_{inv}} C^{invest}_{a,[t]} \cdot v^{invest}_{a,t} + \alpha \cdot \Bigg(\sum_{u,t\in\mathcal{T}_{opr}} C^{fom}_{u,[t]} \cdot v^{invest\_avail}_{u,t} + \sum_{(e,n),t\in\mathcal{T}_{opr}} C^{vom}_{(e,n),[t]} \cdot v^{flow}_{(e,n),t} + \sum_{(n,e),t\in\mathcal{T}_{opr}} C^{vom}_{(n,e),[t]} \cdot v^{flow}_{(n,e),t} \Bigg)$$

Here, coefficient α serves as a scaling factor for the operational costs to align with the investment costs with respect to the two temporal structures $\mathcal{T}_{opr}$ and $\mathcal{T}_{inv}$. For example, if an investment spans ten years with one year to represent operational decisions, one should set $\alpha = 10$.

5) Constraints: Constraint (1) formulates the bounds and transitions for investment variables. Here, $P^{candidate}_{a,[t]}$ defines the number of asset a which may be additionally constructed; $P^{lifetime}_{a}$ defines the technical lifetime of asset a; $P^{invest\_avail}_{a_i,[t]}$ and $P^{RHS}_{\Lambda,[t]}$ are customised coefficients for the variable $v^{invest\_avail}_{a_i,t}$ and the right-hand-side, respectively, of constraint (1d).

$$v^{invest\_avail}_{a,t} \leq P^{candidate}_{a,[t]} \tag{1a}$$

$$v^{invest\_avail}_{a,t+1} = v^{invest\_avail}_{a,t} + v^{invest}_{a,t} - v^{mothball}_{a,t} \tag{1b}$$

$$v^{invest\_avail}_{a,t} \{\leq,=,\geq\} \sum_{t_{past}=\max\{0,t-P^{lifetime}_{a}\}}^{t} v^{invest}_{a,t_{past}} \tag{1c}$$

$$\forall a \in \mathcal{A}, t, t_{past} \in \mathcal{T}_{inv}$$

$$\sum_{a_i\in\Lambda\subseteq\mathcal{A}} P^{invest\_avail}_{a_i,[t]} \cdot v^{invest\_avail}_{a_i,t} \{\leq,=,\geq\} P^{RHS}_{\Lambda,[t]} \qquad \forall t \in \mathcal{T}_{inv}, \tag{1d}$$

where Λ denotes an arbitrary set of investable assets.

Constraint (2) formulates the energy balance at a node n and upper bound of node storage $n \in \mathcal{N}_s$. Here, $P^{demand}_{n,[t]}$ defines the demand of a vector at node n, $P^{state\_coeff.}_{n,[t]}$ acts as a coefficient on variable $v^{state}_{n,t}$, and $P^{frac\_state\_loss}_{n,t}$ defines the self-discharge rate per unit of storage state.

$$\begin{aligned} P^{demand}_{n,[t]} &+ \sum_{l\in(n,l)} v^{flow}_{(n,l),t} - \sum_{l\in(l,n)} v^{flow}_{(l,n),t} \\ &+ \sum_{u\in(n,u)} v^{flow}_{(n,u),t} - \sum_{u\in(u,n)} v^{flow}_{(u,n),t} \\ \{\leq,=,\geq\} &\ \frac{P^{state\_coeff.}_{n,[t-1]} \cdot v^{state}_{n,t-1} - P^{state\_coeff.}_{n,[t]} \cdot v^{state}_{n,t}}{\Delta(t,t-1)} \\ &- P^{frac\_state\_loss}_{n,t} \cdot v^{state}_{n,t} \qquad \forall n \in \mathcal{N}, t \in \mathcal{T}_{opr} \end{aligned} \tag{2a}$$

$$v^{state}_{n,t} \leq P^{state\_capacity}_{n,[t]} \cdot v^{invest\_avail}_{n,t} \qquad \forall n \in \mathcal{N}_s, t \in \mathcal{T}_{opr}, \tag{2b}$$

where $\Delta(t,t-1)$ denotes the duration between two consecutive operational timeslices.

Constraint (3) formulates the bounds and relationships between flow variables of a connection l. Here, $P^{capacity}_{(l,n),[t]}$ ($P^{capacity}_{(n,l),[t]}$) defines the capacity of a flow from connection l (node n) to node n (connection l) per subunit of connection l, and $P^{ratio}_{l,n_1,n_2,[t]}$ defines a customised ratio between the two flow variables of constraint (3b).

$$\begin{cases} v^{flow}_{(l,n),t} \le P^{capacity}_{(l,n),[t]} \cdot v^{invest\_avail}_{l,t} \\ v^{flow}_{(n,l),t} \le P^{capacity}_{(n,l),[t]} \cdot v^{invest\_avail}_{l,t} \end{cases}$$

$$\forall l \in \mathcal{L}, n \in (l,n) \vee (n,l), t \in \mathcal{T}_{opr} \tag{3a}$$

$$v^{flow}_{(l,n_1)\oplus(n_1,l),t} \{\le,=,\ge\} P^{ratio}_{l,n_1,n_2,[t]} \cdot v^{flow}_{(l,n_2)\oplus(n_2,l),t}$$

$$\forall l \in \mathcal{L}, (n_1,n_2) \in (l,n_1,n_2), t \in \mathcal{T}_{opr}, \tag{3b}$$

where symbol $\vee$ refers to logical inclusive disjunction. Note that connection is a non-committable asset and thus has no commitment variable that formulates online status.

Constraint (4) formulates the bounds and relationships between flow variables of units. Here, $P^{capacity}_{(u,n),[t]}$ ($P^{capacity}_{(n,u),[t]}$) defines the capacity of a flow from unit u (node n) to node n (unit u) per subunit of unit u; $P^{avail\_factor}_{u,[t]}$ defines the capacity availability of unit u; $P^{min\_opr}_{(u,n),[t]}$ ($P^{min\_opr}_{(n,u),[t]}$) defines the minimum operating point of unit u on its flow delivered to (received from) node n. Similar to constraint (3b), $P^{ratio}_{u,n_1,n_2,[t]}$ defines a customised ratio between the two flow variables of constraint (4d) with additional consideration of the online status of unit u; and $P^{online\_coeff.}_{u,n_1,n_2,[t]}$ acts as customised coefficient for the online variable. $P^{flow}_{(u,n_i),[t]}$ ($P^{flow}_{(n_i,u),[t]}$) and $P^{RHS}_{\Phi_u,[t]}$ are customised coefficients for the variable $v^{flow}_{(u,n_i),t}$ ($v^{flow}_{(n_i,u),t}$) and the right-hand-side, respectively, of constraint (4e).

$$v^{online}_{u,t} \le v^{invest\_avail}_{u,t} \qquad \forall u \in \mathcal{U}, t \in \mathcal{T}_{opr} \tag{4a}$$

$$\begin{cases} v^{flow}_{(u,n),t} + v^{flow}_{(u,n_r),t} \le P^{capacity}_{(u,n),[t]} \cdot P^{avail\_factor}_{u,[t]} \cdot v^{online}_{u,t} \\ v^{flow}_{(n,u),t} + v^{flow}_{(n_r,u),t} \le P^{capacity}_{(n,u),[t]} \cdot P^{avail\_factor}_{u,[t]} \cdot v^{online}_{u,t} \end{cases} \tag{4b}$$

$$\begin{cases} v^{flow}_{(u,n),t} \ge P^{capacity}_{(u,n),[t]} \cdot P^{min\_opr}_{(u,n),[t]} \cdot v^{online}_{u,t} \\ v^{flow}_{(n,u),t} \ge P^{capacity}_{(n,u),[t]} \cdot P^{min\_opr}_{(n,u),[t]} \cdot v^{online}_{u,t} \end{cases} \tag{4c}$$

$$\forall u \in \mathcal{U}, n, n_r \in (u,n) \vee (n,u), t \in \mathcal{T}_{opr}$$

$$v^{flow}_{(u,n_1)\oplus(n_1,u),t} \{\le,=,\ge\} P^{ratio}_{u,n_1,n_2,[t]} \cdot v^{flow}_{(u,n_2)\oplus(n_2,u),t} + P^{online\_coeff.}_{u,n_1,n_2,[t]} \cdot v^{online}_{u,t}$$

$$\forall u \in \mathcal{U}, n_1, n_2 \in (u,n_1,n_2), t \in \mathcal{T}_{opr} \tag{4d}$$

$$\sum_{n_i \in \Phi_u} P^{flow}_{(u,n_i),[t]} \cdot v^{flow}_{(u,n_i),t} + \sum_{n_i \in \Phi_u} P^{flow}_{(n_i,u),[t]} \cdot v^{flow}_{(n_i,u),t}$$

$$\{\le,=,\ge\} P^{RHS}_{\Phi_u,[t]} \qquad \forall t \in \mathcal{T}_{opr}, \tag{4e}$$

where Φ_u is an arbitrary subset of the nodes linking with the specified unit u. Note that a unit can be committable, of which the operation is allowed to be formulated with the online variable $v^{online}_{u,t}$. In constraint (4b), n_r is the node for reserves associated with a node n for actual demand, i.e. $v^{flow}_{(u,n_r),t}$ is the corresponding reserves for the capacity of unit u that delivers flows $v^{flow}_{(u,n),t}$ to node n.

B. Additional figures

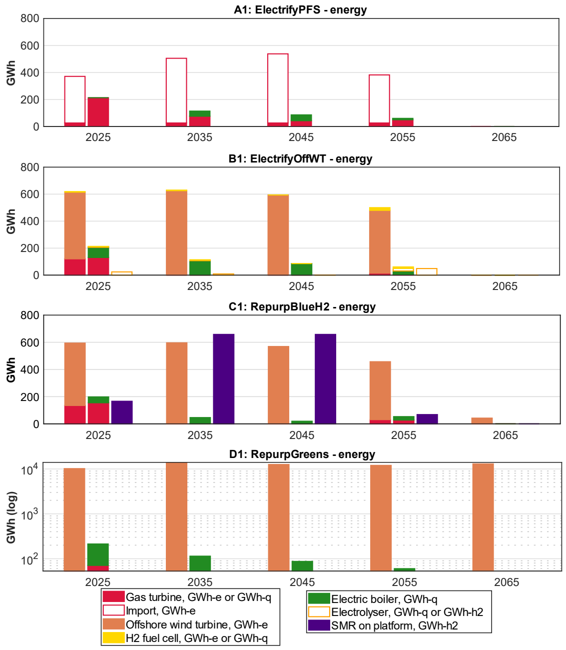

Fig. 4. Results of the modelled platform system: annual production of electricity (GWh-e, the first bar in each year), heat (GWh-q, the second bar in each year) and H_2 (GWh-h, the third bar in each year) per installed technology.

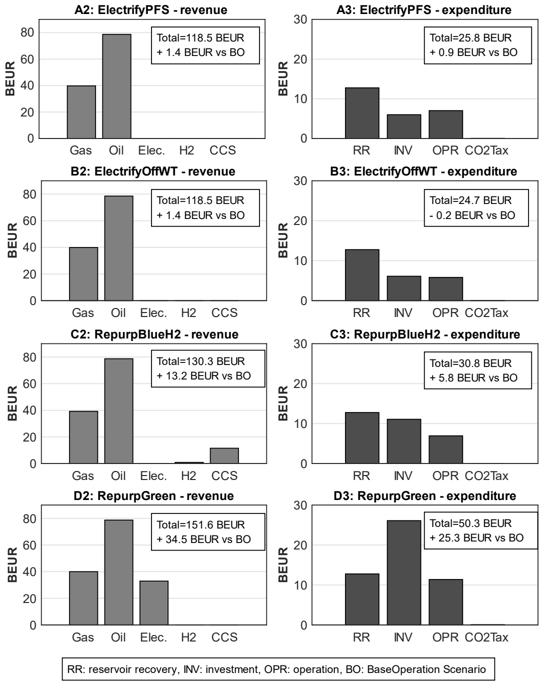

Fig. 5. Results of the modelled platform system: decomposition of the total system cost and comparison with the *BaseOperation* scenario.