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Evaluation of tieback developments for marginal oil fields with timing flexibility ☆

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ABSTRACT

The average size of new oil discoveries on the Norwegian Continental Shelf (NCS) is steadily decreasing. As standalone developments are often not economically viable for marginal fields, tiebacks to existing production facilities are considered in many cases. At the same time, many production facilities in mature production areas have spare capacity due to depleted reservoirs. In this paper we evaluate tieback development concepts for a marginal field having the choice between two hosts with different characteristics. We develop a model that allows to (1) evaluate the tieback development concepts; (2) determine the optimal choice of host facility for the field operator; and (3) optimize the timing of development taking into account oil, gas price and CAPEX uncertainty using a real options approach. In order to be able to reflect how the capacity constraints of a host affects the production potential of the field over time, we incorporate a production optimization model as part of the methodology. We apply the model to a real case on the NCS. We identify characteristics that drive the optimal choice of hosts. Specifically, we show how lifetime extension, reduction of CAPEX and additional spare capacity individually and in combination affect the competitiveness of one host over another therewith, providing valuable insight for tariff negotiations and portfolio planning. Apart from that we find that timing flexibility is of high importance in case of high downside risk. This makes our approach particularly relevant for marginal oil field development which are often characterized by prominent uncertainties.

1. Introduction

The average size of discoveries on the NCS has been steadily decreasing over the last decades. The average size of discovered reserves on the NCS in the '80s was between 80 and 100 million Sm^3 o.e. In contrast, the corresponding figures in the last 20 years have been below 10 million Sm^3 o.e. Norwegian Petroleum Directorate (2020). Since exploration and development of smaller oil fields require expensive technology and advanced engineering solutions to access them Lund (1999), it is usually considered less attractive by E&P companies. The economic value of so-called *marginal oil fields* is small compared to significant discoveries and usually does not warrant standalone production facilities. At the same time, many existing production facilities are approaching the end of their lifetimes as production volumes are declining. At the start of 2021, 22% of the petroleum fields on the NCS had already reached maturity, and several of the largest reservoirs contained less than 10% of their original potential (Norwegian Petroleum Directorate, 2020). Since the production is declining, it enables new petroleum sources to be connected to the existing infrastructure. These existing production facilities with spare capacity are becoming very relevant for tiebacks of small, neighboring discoveries.

The concept of tiebacks offers an important solution to the challenges of small discoveries. At the same time it can help to extend the producing life of existing fields and infrastructure and enhance opportunities for improved recovery and increased value creation from host fields (Norwegian Petroleum Directorate, 2022c). A tieback includes a subsea production system that usually consists of wellheads, manifolds, and other components that are installed on the seabed and connected to an existing production facility or platform with a tieback pipeline (Lin et al., 2013). This existing facility (host) may be processing oil and gas from multiple nearby fields. Tiebacks exploit synergies and avoid building dedicated production facilities for each individual field. See Fig. 1 for an illustration of planned tiebacks to an existing host facility

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Nomenclature

$CAPEX$	Capital expenses
DCF	Discounted cash flows
EUA	European Union allowances
GBM	Geometric Brownian Motion
NCS	Norwegian Continental Shelf
NOD	Norwegian offshore directorate (Prior to 1.1.2024: Norwegian petroleum directorate)
NPV	Net present value
$O\&G$	Oil and gas
$OPEX$	Operational expenses
ROV	Real options analysis

at Utsira Nord at the NCS. For a marginal discovery, the timing of the investment in the tieback solution is critical since the reserves need to be produced before the host is decommissioned (The Norwegian Petroleum Directorate, 2019).

The NOD estimates that less than 50% of the recoverable petroleum on the NCS is extracted and that value creation from further exploration lies between NOK 1200 billion and NOK 1700 billion (Norwegian Petroleum Directorate, 2021). A large proportion of future production is expected to come from smaller fields. Hence, smaller reservoirs may still provide substantial value. For Norway to maintain its role as a stable, long-term and secure oil and gas supplier to Europe, it is crucial to be able to develop small discoveries in an economic viable way that complies with environmental requirements (Norwegian Petroleum Directorate, 2022c). Here new methods for economics analysis are needed that consider the key characteristics of tieback development projects to provide decision support for the different stakeholders involved.

In this paper we study the potential development of a marginal oil field that is located in proximity to two existing production facilities, to which a tieback is technically feasible. We consider this problem from the perspectives of a field operator, a host facility owner, and the Norwegian society. The decision problem for the field operator consists of assessing if any or both of the tiebacks are economically feasible. If more than one tieback development concept is profitable, the decision is to identify the *most* profitable one. Moreover, if there is at least one profitable tieback, the decision problem also includes determining the optimal timing of investment. This is because waiting for favorable market conditions can enhance the project value. This decision problem relates to both the field operator and the Norwegian society as both parties seek to maximize the value of the marginal oil field. However, their objectives may conflict when considering the optimal allocation of a number of potential tieback developments. In reality the regulator has to consider a whole portfolio of undeveloped oil fields in combination with existing host facilities. Providing decision support for a tieback field development and understanding the drivers of optimal host selection is an important step towards the development of larger scale decision support models that allow identification of the optimal allocation for potential tieback developments for a whole area containing a portfolio of undeveloped fields and available host facilities. In this paper we aim to take a first step in the development of economics analysis methods that provide decision support for the development of small fields by tieback solutions.

Inherent in tie-back developments are tariffs, which represent the fees charged by the host for using the host's existing infrastructure to process and transport hydrocarbons from a new development. They are the result of agreements negotiated between the field and host operators and are concerning the NCS subject to guidelines set by the regulator (Forskrift om andres bruk av innretninger, 2005). A tariff can be based on the volume transported and processed, the duration of usage or a combination of factors. The host operator has to consider the trade-off between earning more by charging higher tariffs, while still representing the preferred choice among alternative host facilities for the field operator. Considerable costs are associated with abandoning the host facility. Therefore, additional production due to tiebacks is usually of great value for the host owner.

Our results provide insights that can facilitate and enhance the allocation of tiebacks for marginal oil fields and serve as insight for tariff agreements and host choice. For tieback developments of marginal fields timing is critical due to the capacity constraints of the host and decommissioning plans. Therefore, decision models are needed that account for the possibility to optimize tieback timing. The key contributions of this paper can be summarized as follows: (1) we evaluate tiebacks for marginal oil fields under market uncertainty; (2) we establish an optimization model that maximizes O&G production rates and integrate it with the cash flow model that constitutes the base for the economics analysis, which allows us to account for the impact of a host's capacity constraints on field development timing; (3) we identify the key drivers of optimal host selection and provide insight for tariffs negotiations for both field and host operators as well as the regulator; (4) we provide a methodology that can serve as decision support in terms of optimal field development timing and host choice for marginal fields.

Combining mathematical optimization of field development together with economic valuation based on a real options approach, allows us to study the tie-in selection problem for a marginal discovery with managerial flexibility. The number of existing contributions in both domains is extensive, while the combination of the two methods in our study constitutes a novel contribution to the literature. The only contribution that can be directly compared to this study is the one of Bakker et al. (2021). Bakker et al. (2021), however, study a field's late lifetime decisions, while we evaluate an investment opportunity considering a new discovery. Contributions studying optimal tie-in selection under uncertainty are scarce. By filling this gap, we not only extend the research frontier but also provide valuable insight for decision makers.

The strand of mathematical programming for the purposes of field development pertains to contributions seeking to identify optimal decisions regarding production rates, scheduling the installation of the facilities and well drilling, location of offshore structures, and platform capacities under certain constraints. Recent reviews of this literature include Khor et al. (2017), Mirzaei-Paiaman et al. (2021), and Lei et al. (2021a). Lin et al. (2013) present a methodology that evaluates three kinds of flexibility as a means to mitigate uncertainty in subsea tiebacks: the ability to tie back new fields, the ability to expand the capacity of a central processing facility, and the dynamic allocation of processing capacity. Sales et al. (2021) combine in-place oil volume, well productivity and oil price uncertainties and employ a non-linear numerical optimization to test the "base case" field design and define an optimal one. Lei et al. (2021b) propose a methodology to represent the tieback development of an oil field focusing on the optimal allocation of production rates and installation sequence of subsea facilities. Lei et al. (2021b) analyze two different tieback concepts based on a mixed-integer linear problem. The model enables an evaluation of the two concepts considering different project costs, host capacities, and field production rates. The authors also perform an uncertainty analysis to identify trade-offs between the two tieback scenarios. We extend this approach by accounting for stochastic behavior of oil and gas prices and managerial flexibility in terms of investment timing that can be crucial for the economics of a marginal field.

We therewith, also contribute to the recently growing strand of literature providing economic assessment methods for marginal oil fields. Among earlier contributions in this area are Laine (1997), Lund (2000), Galli et al. (2001) and Armstrong et al. (2004) who show the potential of flexible strategies under technical and market uncertainties and the ability of the real options analysis to identify substantial additional value of marginal oil and gas fields. Recent contributions, developing methods to assess strategies based on managerial flexibility

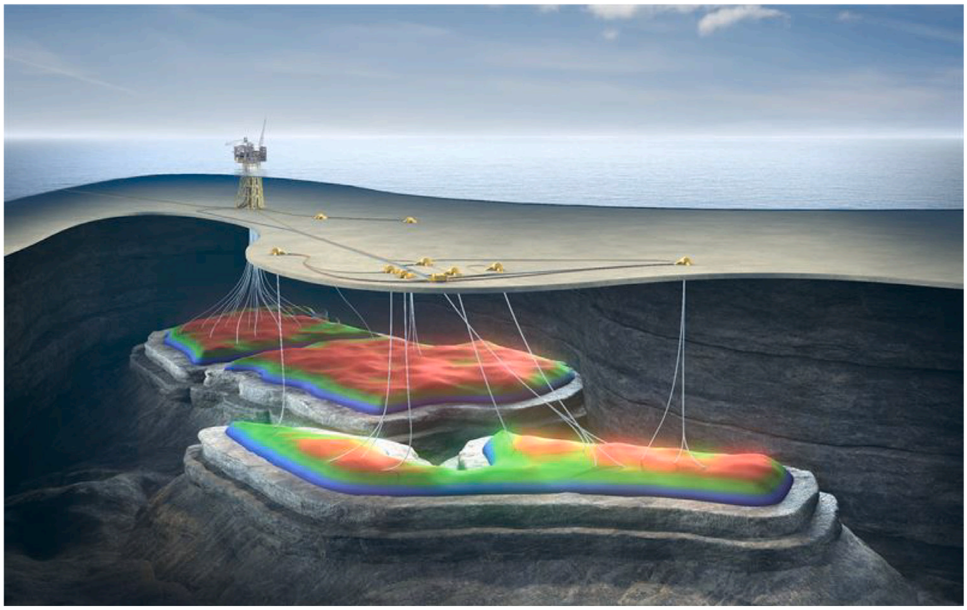


Fig. 1. Planned tieback projects at Utsira Nord on the NCS.
Source: https://akerbp.com/en/borsmelding/three-tie-ins-will-utilise-capacity-in-existing-infrastructure-at-utsira-high-2/.

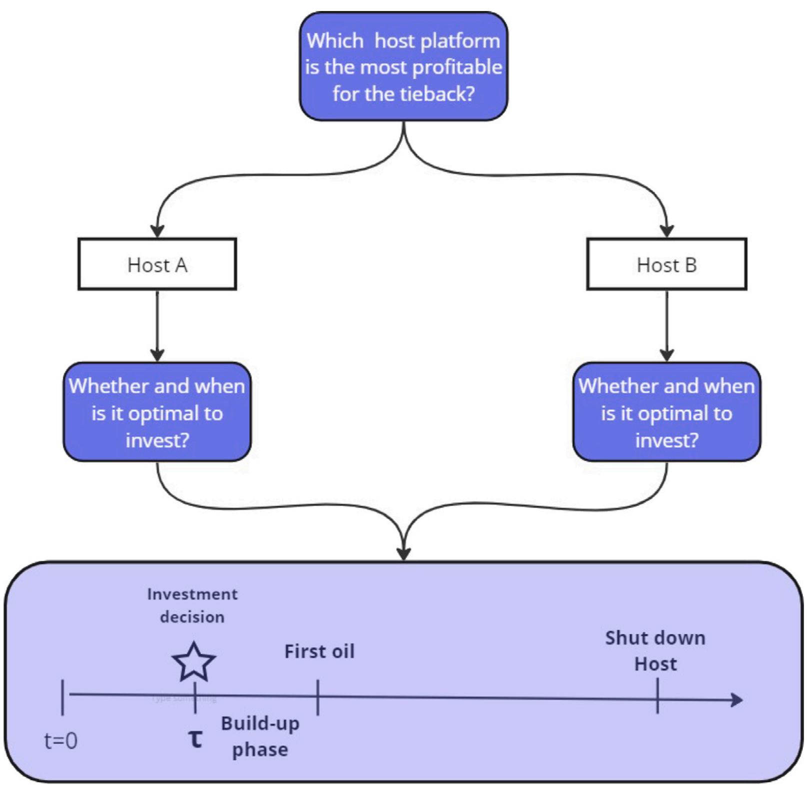


Fig. 2. Decision flowchart from the perspective of a field operator.

include Fleten et al. (2011), who consider expanding an offshore oil field by tying in a satellite field. They find that even if the satellite field is not profitable to develop at current oil prices, the option to tie in such satellites can have a significant value if the oil price increases. Jafarizadeh and Bratvold (2015) highlighted the differences in the economic analysis of small and large discoveries by evaluating a waiting-to-invest option in two hypothetical exploration opportunities (large and small prospects). Fedorov et al. (2020, 2021) develop a methodology to quantify the value provided by a sequential drilling strategy for marginal oil field development in the face of a market and technical uncertainty. The current study contributes to this strand by developing a new methodology of state-of-the-art ROV methods and providing novel insights of how timing flexibility and host constraints affects the economics of tie-in projects. Additionally, we contribute by considering the perspectives of the main stakeholders involved providing insight for tariff negotiations and the regulator.

The remainder of this paper is structured as follows. Section 2 presents the problem description studied and the developed methodology and solution approach. In Section 3, we apply the proposed methodology to a real case provided by NOD. The results including a sensitivity analysis are presented and discussed in Section 4. We conclude in Section 5.

2. Methodology

In this section we introduce the proposed methodology to evaluate the tiebacks for marginal oil fields. In Section 2.1, we describe the decision problem studied and the proposed model setup. The solution approach is presented in Section 2.2. The perspective of the host and social planner are introduce in Section 2.3.

2.1. Problem description and model setup

In this study, we seek to maximize the economic value of a marginal field development project. We consider the problem from the perspectives of the field operator, potential host owner, and the Norwegian society. On the NCS, the NOD has the responsibility to ensure that 'the greatest possible value is achieved from oil and gas activities in Norway for the Norwegian society through efficient and responsible resource management' (Norwegian Petroleum Directorate, 2022a). Therefore, we also refer to the latter as NOD.[1]

Specifically, we consider a field operator with a production license[2] for an undeveloped O&G reservoir. We assume that the initial O&G in place is not big enough to warrant a standalone development. However, we assume there are two existing host facilities nearby, *Host A* and *Host B*, both of which are technically feasible for a tieback. Each tieback is associated with specific capital, operational, and abandonment costs along with a tariff that the field operator would have to pay to the facility owner.

In addition, the host facilities have different spare capacities, which will affect the production rate of the undeveloped reservoir. Finally, the revenue generated by the investment comes from the sale of O&G and is therefore conditioned on their respective market prices, p^{oil} and p^{gas}, and the production volume q^{oil} and q^{gas}. The field operator company must consider all the aspects mentioned above to assess the economic viability of a tieback investment in the presence of considerable market uncertainty.

We first focus on the decision situation of the field operator. The results for the hosts and NOD, respectively, are then calculated taking the optimal decisions of the field operator into account (see Section 2.3).

The field operator wants to evaluate whether a tieback to any of the two hosts is profitable, and if so *which* host is the best choice. In the face of uncertainty, the field operator has an incentive to delay the investment, e.g., to wait for more favorable market conditions. However, waiting to invest comes at a price due to the time value of money. The decision maker has to weigh the cost and potential of waiting against each other to identify the optimal investment timing. The operator has to decide whether and if so when to tieback to which host. The objective of the operator is to maximize the present value of the tieback project. The decision problem of the field operator is illustrated in Fig. 2.

[1] The NOD is a governmental specialist directorate and administrative body established in 1972. It acts as an adviser and reports to the Ministry of Petroleum and Energy (Norwegian Petroleum Directorate, 2022a). NOD holds important data from the NCS, and together with analyses they constitute a crucial factual basis on which O&G activities are founded.

[2] A production license is a concession that grants exclusive rights to conduct exploration drilling and production of oil and gas within a delimited area on the Norwegian Continental Shelf (Norwegian Petroleum Directorate, 2022b).

The present value of the project today given that the operator invests at time τ is given by the expected discounted cash flows of the project,

$$
\begin{aligned}
PV_{t=0,field}(\tau) = \sum_{t=\tau}^{\tau+T} (p_t^{oil} \cdot q_t^{oil} + p_t^{gas} \cdot q_t^{gas} \\
- \mathrm{CAPEX}_t - \mathrm{OPEX}_t \\
- \mathrm{Tariff}_t - \mathrm{ABEX}_t) \cdot e^{-\gamma \cdot t},
\end{aligned} \tag{1}
$$

where t indicates the year, T is the lifetime of the field, $CAPEX_t$ denotes the yearly capital expenditures, $OPEX_t$ is the yearly operational costs of the field, $Tariff_t$ denotes the yearly fees paid to the host owner, $ABEX_t$ is the yearly abandonment costs, and γ is the opportunity cost of capital.

In order to estimate the revenues of the investment, we first construct the production profiles for the tieback developments. We do so by establishing an optimization model that maximizes the yearly production rate of O&G, using estimations of the field's contents, and yearly production. Based on *host spare capacity*,[3] and *field potential* the yearly production rate of the undeveloped field during its whole lifetime is calculated.

The revenues of the field operator are resulting from the product of O&G produced multiplied with their respective uncertain future market prices. In order to predict future *revenues*, we employ a commodity pricing model used to simulate future O&G prices presented in (Section 2.1).

Finally, we estimate the future cash flows of the project by taking into account CAPEX, ABEX, OPEX, tariff, and revenue prediction. This data serves as an input to the objective function of the ROV model which is given by

$$
\begin{aligned}
&ProjectValue_{t=0,field}^{ROV}(p^{oil}, p^{gas}, capex) \\
&= \sup_{\tau} \mathbb{E}\left[\sum_{t=\tau}^{\tau+T} (p_t^{oil} \cdot q_t^{oil} + p_t^{gas} \cdot q_t^{gas} - \mathrm{CAPEX}_t - \mathrm{OPEX}_t - \mathrm{Tariff}_t \right. \\
&\qquad \left. - \mathrm{ABEX}_t) \cdot e^{-\gamma \cdot t} \right],
\end{aligned} \tag{2}
$$

where $\mathbb{E}[.]$ represents the expectation operator $\mathbb{E}\left[.|p_0^{oil} = p^{oil}, p_0^{gas} = p^{gas}, CAPEX_0 = capex\right]$. We then solve the model using a LSM approach described in Section 2.2. Fig. 3 illustrates the main building blocks of the proposed model and describes the information flow between the different building blocks. In order to allow a fair comparison between the results of the ROV versus traditional NPV, we perform a symmetric analysis of the two valuation methods based on equal O&G prices, production assumptions, and discount rate. The traditional NPV approach corresponds to solving the following optimization problem

$$
\begin{aligned}
&ProjectValue_{t=0,field}^{NPV}(p^{oil}, p^{gas}, capex) \\
&= \max\left(0, \mathbb{E}\left[\sum_{t=0}^{T} (p_t^{oil} \cdot q_t^{oil} + p_t^{gas} \cdot q_t^{gas} - \mathrm{CAPEX}_t - \mathrm{OPEX}_t - \mathrm{Tariff}_t \right.\right. \\
&\qquad \left.\left. -\mathrm{ABEX}_t) \cdot e^{-\gamma \cdot t} \right]\right),
\end{aligned} \tag{3}
$$

where the field operator decides whether to invest in the tieback now or never.

In the following we now elaborate on how the production profiles, commodity prices and costs factors are modeled in detail.

Production Profiles

In order to estimate the revenues of the investment, we construct the production profiles for the tieback developments. We do so by establishing an optimization model that maximizes the yearly production rate of

[3] The host capacities will vary over time as hosts enter or continue their decline phase or other tiebacks come on streams.

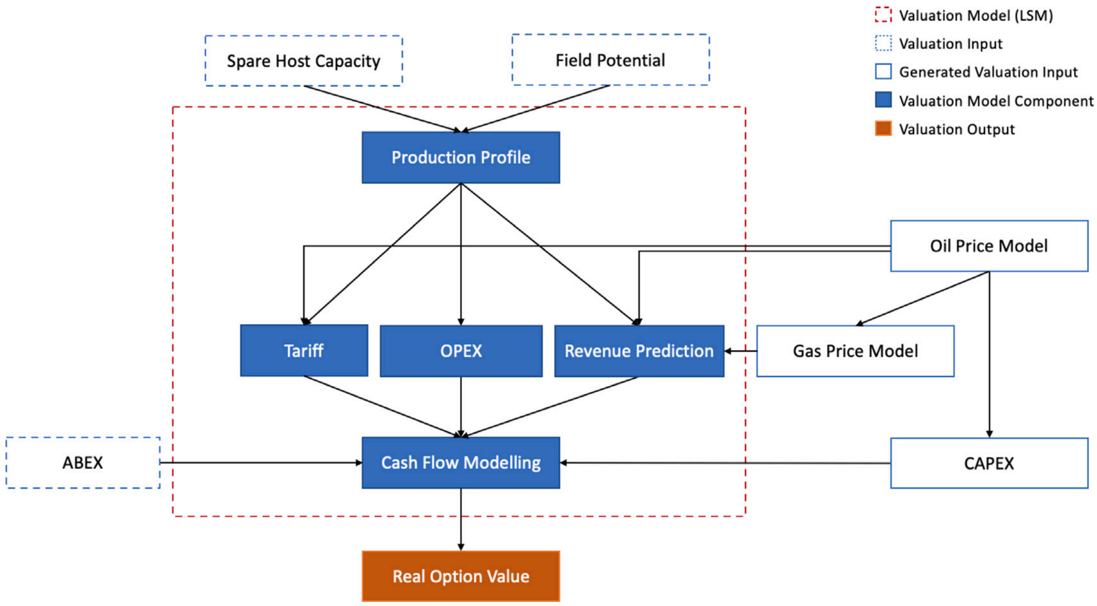


Fig. 3. An overview of the building blocks of the model and the information flow between the different blocks.

O&G, using estimations of the field's contents, and yearly production. Once the investment decision is made, it is economically optimal to produce as much petroleum as possible, as quickly as possible. The main factors limiting production are: (1) initial O&G in place; (2) spare host capacity, and; (3) the field potential. In our case, the hosts are considered to be existing oil production platforms with available spare capacity. The spare capacity may become available either due to the production decline in the field(s) connected to these facilities or due to modifications to the facility. The field production must be adjusted in accordance with the existing host spare capacity, which in some cases means that the field production start must be delayed. In the following we first present the optimization model and thereafter elaborate on the objective function and constraints. The parameters of the established optimization model are summarized in Table 1.

The objective function is defined by

$$\max \sum_{t=0}^{T} (q_t^{oil} + q_t^{gas}) \cdot e^{-\gamma \cdot t}, \tag{4}$$

where q_t^{oil} and q_t^{gas} are the yearly produced volumes of O&G from the field to a specific host, t is time in years, γ is the discount rate, and T is the lifetime of the project. Once the investment decision is made, the field operator seeks to maximize the project's NPV by producing as much O&G as possible as quickly as possible, given certain constraints. The first constraints

$$q_t^{oil} \le c_t^{oil}, \quad \forall t \in \mathcal{T} \tag{5}$$

and

$$q_t^{gas} \le c_t^{gas}, \quad \forall t \in \mathcal{T} \tag{6}$$

ensure that the yearly production volume of O&G does not exceed the yearly spare host capacity of oil, c_t^{oil}, and gas, c_t^{gas}, as defined in Eqs. (5) and (6), respectively. In addition, the yearly production volume of oil and water cannot exceed the yearly host capacity of liquid, c_t^{liquid}, as defined by

$$q_t^{oil} + q_t^{water} \le c_t^{liquid}. \quad \forall t \in \mathcal{T} \tag{7}$$

Furthermore, the total production volume of oil(gas) cannot exceed the initial oil (gas) in place S^{oil} (S^{gas}) indicated by

$$\sum_{t=0}^{T} q_t^{oil} \le S^{oil}, \quad \forall t \in \mathcal{T} \tag{8}$$

and

$$\sum_{t=0}^{T} q_t^{gas} \le S^{gas}. \quad \forall t \in \mathcal{T} \tag{9}$$

The aforementioned equations handle the first two main factors as indicated in (1) and (2) above and are straightforward to calculate as the yearly spare host capacities and the initial O&G in place are all direct inputs into the model. To calculate the field potential (ref. to point (3) above) is more demanding, because it dependents on various factors. The field potential refers to the yearly maximum volume that is technically possible to extract from the O&G reservoir. In general it is easier to extract petroleum in the first years of production than in the later, due to high pressure. However, as more petroleum is extracted and the pressure decreases, the field potential declines. Thus, it becomes harder to extract the remaining petroleum in the reservoir. Before presenting the field potential constraints, we first describe some of its necessary components. The accumulated produced oil, U_t^{oil}, and gas, U_t^{gas}, are defined by

$$U_t^{oil} = U_{t-1}^{oil} + \frac{1}{2} \cdot \left(q_{t-1}^{oil} + q_t^{oil}\right), \quad \forall t \in \mathcal{T}/0 \tag{10}$$

and

$$U_t^{gas} = U_{t-1}^{gas} + \frac{1}{2} \cdot \left(q_{t-1}^{gas} + q_t^{gas}\right), \quad \forall t \in \mathcal{T}/0 \tag{11}$$

stating that the accumulated O&G for year t equals the accumulated O&G from the previous year and the average of the current and produced oil from the previous year, and set to zero in $t = 0$, i.e.

$$U_0^{oil} = 0, \tag{12}$$

and

$$U_0^{gas} = 0. \tag{13}$$

The recovery factors for oil, r_t^{oil}, and gas, r_t^{gas}, are given by

$$r_t^{oil} = \frac{U_t^{oil}}{S^{oil}}, \quad \forall t \in \mathcal{T} \tag{14}$$

and

$$r_t^{gas} = \frac{U_t^{gas}}{S^{gas}}, \quad \forall t \in \mathcal{T} \tag{15}$$

respectively. They represent the proportion of the current accumulated produced O&G to the initial O&G in place and therefore, indicate how

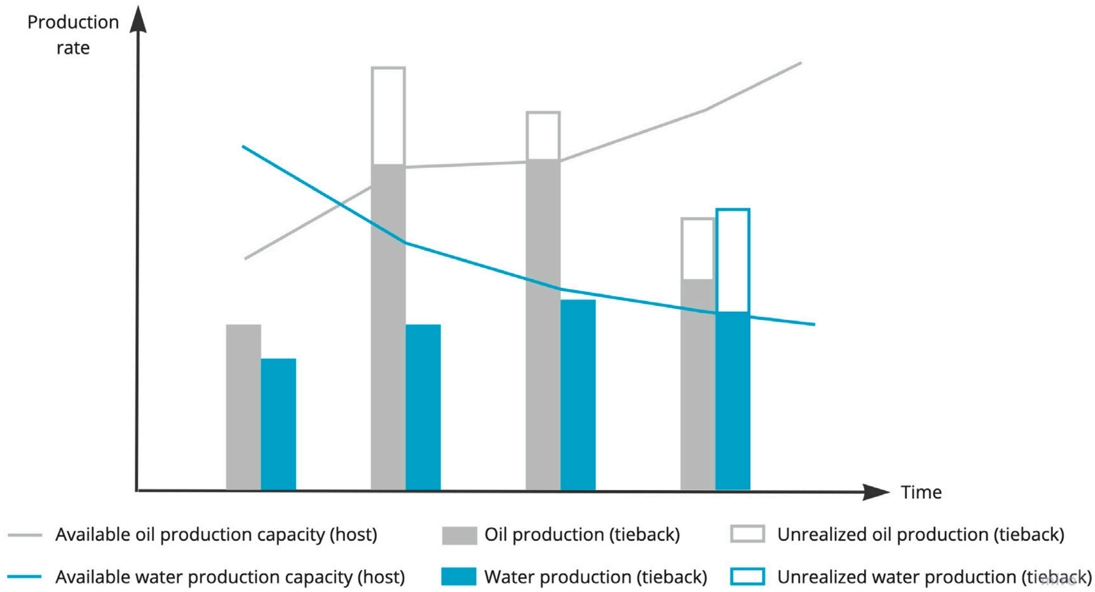


Fig. 4. A given oil production profile with capacity constraints (only for illustration purposes).

much of the initial petroleum has been produced in relative terms. We define the field potential f_t^{oil} and f_t^{gas} by

$$f_t^{oil} = W \cdot \left(1 - \frac{r_t^{oil}}{R}\right), \quad \forall t \in \mathcal{T} \tag{16}$$

and

$$f_t^{gas} = W \cdot \left(1 - \frac{r_t^{gas}}{R}\right), \quad \forall t \in \mathcal{T}. \tag{17}$$

The field potential depends on the maximum well capacity W, which is a product of the maximal extraction rate of the well and the amount of drilled wells in the field. The recovery factor cannot exceed the maximum recovery factor R as it would result in negative field potential values. The component (1-r_t^{oil}/R), reflects the remaining field pressure and will steadily decline as more petroleum is extracted. This means that the field potential will also decline steadily unless W is increased by drilling more wells. Lastly, the ratio of oil production to the field potential for oil cannot exceed the ratio of water to the field potential for water, as defined by

$$\frac{q_t^{oil}}{f_t^{oil}} \leq \frac{q_t^{water}}{f_t^{water}}, \quad \forall t \in \mathcal{T}. \tag{18}$$

This constraint represents a simplified way of modeling the host's water constraint.

Fig. 4 illustrates all the different constraints and their impact on the oil production. This oil production profile is not based on a real case, but highlights the functions of the constraints. Oil can be produced at the field production potential rate up until Year 6. In Year 7, the oil production has to be below the field's production potential due to limited spare capacity at the host. In Year 9, the liquid production (the combined volume of oil and water production) reaches the host's spare liquid capacity, and the oil production has to be reduced and remains below the field's oil production potential. From Year 10 and onward the production follows the field potential constraint.

Revenue structure and product price modeling

The revenues of the field operator are resulting from the product of O&G produced multiplied with their respective uncertain future market prices. In this study, we assume that future O&G prices follow the two-factor stochastic price model proposed by Schwartz and Smith (2000) (following recent contributions like Jafarizadeh and Bratvold (2012), Hahn et al. (2014), Fedorov et al. (2021, 2022a), and Bakker et al. (2021)). The two-factor price process allows to account for mean reversion in short-term prices and uncertainty in the long-term equilibrium level to which prices revert to. The equilibrium prices are modeled as a Brownian motion, reflecting the expectations of the exhaustion of the existing supply, improved exploration and production technology, inflation, and political and regulatory effects. The advantage of this two-factor process is that it is relatively easy to calibrate while it is based on realistic assumptions.[4] Motivated by Villar and Joutz (2006) and Brown and Yucel (2008), who demonstrate that oil and gas prices have been historically related, we assume that the gas price is correlated to the oil price.

We denote P_t as the commodity price at time t, given by

$$\ln(P_t) = \xi_t + \chi_t. \tag{19}$$

Table 1
Parameters of the optimization model.

Parameter	Description
q_t^{oil}	Produced oil
q_t^{gas}	Produced gas
q_t^{water}	Produced water
W	Maximum well capacity
c_t^{oil}	Host spare oil capacity
c_t^{gas}	Host spare gas capacity
c_t^{liquid}	Host spare liquid capacity
f_t^{oil}	Field potential oil
f_t^{gas}	Field potential gas
S^{oil}	Initial oil in place
S^{gas}	Initial gas in place
r_t^{oil}	Oil recovery factor
r_t^{gas}	Gas recovery factor
R	Maximum recovery factor
U_t^{oil}	Accumulated produced oil
U_t^{gas}	Accumulated produced gas

[4] We refer to Al-Harthy (2007), Xu et al. (2012) and Bastian-Pinto et al. (2021) that provide comparisons of different price models in real options applications, including petroleum projects valuation. Fedorov et al. (2021) provide a sensitivity analysis giving insight on the difference of modeling oil prices with simpler one-factor models, specifically a GBM and mean reversion model, compared to the two-factor price model.

The long-term equilibrium price is assumed to follow a Geometric Brownian Motion (GBM) process with drift μ_ξ and volatility σ_ξ, given by

$$d\xi_t = \mu_\xi dt + \sigma_\xi dz_\xi. \tag{20}$$

The short-term deviation is assumed to follow an Ornstein–Uhlenbeck (OU) process that reverts towards zero,[5] given by:

$$d\chi_t = -\kappa\chi_t dt + \sigma_\chi dz_\chi, \tag{21}$$

where κ is the mean-reversion coefficient (it determines the rate at which the short-term deviation reverts towards zero), σ_χ is the short-term volatility, and dz_χ and dz_ξ are the correlated increments of a standard Brownian motion process with $dz_\chi dz_\xi = \rho_{\chi\xi}dt$.

We adopt a risk-neutral pricing approach, which is considered appropriate when the investment opportunity is exposed to various uncertainties (Cox et al., 1985; Smith and Nau, 1995; Smith and McCardle, 1999). This applies in our case as the risk natures of the market and technical uncertainty are different. By taking such an approach, we risk-adjust each uncertainty individually in the model, instead of risk-adjusting the entire cash flow.[6] The two factors can then be described as:

$$d\xi_t = \left(\mu_\xi - \lambda_\xi\right) dt + \sigma_\xi dz_\xi^*, \tag{22}$$

$$d\chi_t = \left(-\kappa\chi_t - \lambda_\chi\right) dt + \sigma_\chi dz_\chi^*, \tag{23}$$

where dz_χ^* and dz_ξ^* are the correlated increments of a standard Brownian motion process with $dz_\chi^* dz_\xi^* = \rho_{\chi\xi}dt$, and λ_χ and λ_ξ represent the risk premiums that constitute constant reductions in the drift rates of the two factors. Hence, the risk-neutral short-term factor reverts towards $-\lambda_\chi/\kappa$, and the risk-neutral long-term factor's drift corresponds to $\mu_\xi^* = \mu_\xi - \lambda_\xi$

Since we generate O&G cash flows by using Monte Carlo simulations, we must discretize the price processes. The discretized version of the long-term component is given by:

$$\xi_t^* = \xi_{t-1}^* + \mu_\xi^* \Delta t + \sigma_\xi \epsilon_\xi \sqrt{\Delta t}, \tag{24}$$

where μ_ξ^* is the drift rate of the Brownian motion, while σ_ξ is the long-term volatility, and ϵ_ξ is the long-term standard normal random variable. The discretized short-term risk-neutral component is given by:

$$\begin{aligned}\chi^*{}_t =& \chi^*{}_{t-1} e^{-k\Delta t} - (1 - e^{-k\Delta t})\frac{\lambda_\chi}{k} \\ &+ \sigma_\chi \epsilon_\chi \sqrt{\frac{1 - e^{-2k\Delta t}}{2k}},\end{aligned} \tag{25}$$

where ϵ_χ and ϵ_ξ are standard normal random variables that are correlated in each time period with correlation $\rho_{\xi\chi}$. As proposed by Wiersema (2008), Cárdenas (2017), and Fedorov et al. (2022b), the correlation coefficient for the two random variables is given by

$$\epsilon_\xi = \rho_{\xi\chi} \cdot \epsilon_\chi + \sqrt{1 - \rho_{\xi\chi}^2} \cdot \epsilon. \tag{26}$$

We employ the commodity price model above for oil and gas, respectively. In order to account for the correlation of gas prices to oil prices, we apply Eq. (26) to their respective short-term random variables, such that

$$\epsilon_{\chi^{gas}} = \rho_{\chi^{gas}\chi^{oil}} \cdot \epsilon_{\chi^{oil}} + \sqrt{1 - \rho_{\chi^{gas}\chi^{oil}}^2} \cdot \epsilon. \tag{27}$$

In order to calibrate the price processes for oil and gas we need to estimate seven parameters (κ, σ_χ, μ_ξ, σ_ξ, $\rho_{\chi\xi}$, λ_χ and λ_ξ) in addition to two initial parameter values χ_0 and ξ_0. Since these parameters are usually not observable in the commodity markets, we estimate them by using the Kalman filter[7] Kálmán (1960). The Kalman filter[8] generates an updated (posterior) prediction of a state vector's mean and covariance at time t, conditional on all information available up to and including time $t-1$ (Goodwin, 2013). If historical oil prices (P_t) are considered as the measurement, then because of Eq. (19), the Kalman filter can produce estimates of ξ_t, which in turn can be used to estimate the parameters in Eq. (20). For a wider coverage of the Kalman filter, we refer the reader to Harvey (1989), Hamilton (1994) and West and Harrison (1996). We implement the Kalman filter in the same manner as Schwartz and Smith (2000), Goodwin (2013), Fedorov et al. (2021) and Fedorov et al. (2022a) in ordThanner to calibrate these parameters, with the results presented in Section 3.3.

Cost structure

OPEX and *tariff* represent recurring negative cash flows during the lifetime of the field. OPEX mainly consist of the costs associated with facility maintenance, staffing, fuel, and storage vessel leasing, and will normally increase as the production rate increases. The tariff is an economic compensation paid by the field operator to the host owner, for the use of the host's facilities. Tariff schemes are bilaterally negotiated contracts between the field operator and the host and could be designed in various different ways. We analyze a tariff scheme model that is considered to be close to those frequently used in practice, given by:

$$\text{Tariff}_t = \alpha + \beta_0 q_t^{oil} + \beta_1 p_t^{oil} + \beta_2 q_t^{gas}, \tag{28}$$

where α is a fixed minimum amount and β_0, β_1 and β_2 are the coefficients for the oil volume, oil price, and gas volume, respectively.

CAPEX includes expenditures for host modification, subsea production system, drilling of production wells, SURF (Subsea Umbilicals, Risers, and Flowlines), and project management for all these events. Following Cardenas et al. (2018) and Fedorov et al. (2022a) CAPEX is modeled as a geometric Brownian motion (GBM), equal to

$$d\theta_t = \mu_\theta \theta_t dt + \sigma_\theta \theta_t dz_\theta, \tag{29}$$

where θ_t denotes the CAPEX for year t, μ_θ is the drift rate, σ_θ is the volatility, and dz_θ is the increment of a Brownian motion. We apply the discretized version of the GBM, given by

$$\theta_{t+1} = \theta_t \cdot e^{\left[\left(\mu_\theta - 0.5\sigma_\theta^2\right)\Delta t + \sigma_\theta \epsilon_\theta \sqrt{\Delta t}\right]}. \tag{30}$$

The correlation between CAPEX (θ) and oil prices is modeled by correlating the random variable of the long-term component of the oil price process with the one of the CAPEX process following Fedorov et al. (2022b), such that

$$\epsilon_\theta = \rho_\theta \xi \cdot \epsilon_\xi + \sqrt{1 - \rho_{\theta\xi}{}^2}\,\epsilon. \tag{31}$$

Brandão et al. (2005) and Smith (2005) argue that correlating the cost uncertainty with market uncertainty (i.e. the oil price in our case) allow for a methodological correct approach to treating different types of risks within a single risk-neutral valuation procedure.[9] Evidence

[5] It reverts towards zero because we set the long-term mean (θ) equal to zero in the general definition of an OU-process: $d\chi_t = \kappa\left(\theta - \chi_t\right) dt + \sigma_\chi dz_\chi$.

[6] If a single discount rate is applied for all projects without accounting for specific features of the individual project, it may result in incorrect valuation and poor decision-making (Fedorov et al., 2021).

[7] The Kalman filter has been widely applied in finance to estimate state variables of commodity price models, see e.g., Schwartz (1997), Schwartz and Smith (2000), Manoliu and Tompaidis (2002) and Sørensen (2002), among others.

[8] One drawback of the Kalman filter is the missing-data problem. Since the Kalman filter normally assumes a complete panel data set, which is often not the case in financial markets, it disregards data and causes a loss of information. As a result, other procedures have also been proposed, see e.g., Sørensen (2002), Cortazar and Schwartz (2003), Cortazar et al. (2003), and Jafarizadeh and Bratvold (2012).

[9] Therewith cost uncertainty falls somewhere between the notion of private and market risks. Correlating cost uncertainty with the market parameters allows to avoid bias, as the valuation based on simulation paths with high oil prices and low CAPEX can lead to overestimation of the real option value.

for correlation between CAPEX and oil prices is provided by among others, Willigers et al. (2009).[10]

ABEX are the one-off decommissioning costs for the field operator at the end of the project, including plugging of wells, subsea facility removal, and other costs associated with the disconnection from the host. These costs are assumed to occur the first year after the field's operative period. To the best of our knowledge, there exists no empirical evidence of a correlation between the field operator's ABEX and O&G prices.

2.2. Solution approach

E&P investments with high sunk costs and uncertainty about future revenues have a big potential monetary value in managerial flexibility (Cortazar and Schwartz, 1998; Jafarizadeh and Bratvold, 2009a; Soares and Baltazar, 2010; Fedorov et al., 2021, 2022a). Since the classical DCF approach does not allow to capture the value of such flexibility, we follow a real options approach (ROV) instead. The field operator is assumed to be able to reevaluate the investment decision once a year on the then-current state of the O&G market and the CAPEX. By waiting with investment, the decision-maker potentially loses immediate payoffs, but has the opportunity to receive more information regarding the uncertainties affecting the decision. Upon investment an irreversible investment cost, CAPEX, has to be paid. The investment payoff corresponds to all future discounted cash flows generated by the project. This investment decision can thus be seen as a Bermuda call option.[11]

We apply a least-squares Monte Carlo simulation approach to solve the model. The LSM is considered "a state-of-the-art approximate dynamic programming approach used in financial engineering and real options analysis to value and manage options with early or multiple exercise opportunities" (Nadarajah et al., 2017). This approach is well suited for investment valuation problems in which the investment decision depends on multiple sources of uncertainties and involves multiple decision points. A big advantage of the LSM approach is that it does not suffer from the curse of dimensionality (Longstaff and Schwartz, 2001; Willigers et al., 2009). The fact that is based on a simple least-squares regression makes it computationally efficient, flexible, as well as transparent. Real option valuation methods based on the LSM approach have been compared and verified by Nadarajah et al. (2017) and used in several oil and gas applications (Jafarizadeh et al., 2009; Willigers et al., 2009; Hong et al., 2018; Fedorov et al., 2021).

In our model, we first compute the expected yearly cash flows of the oil field investment by combining simulated production- and cost profiles, as well as O&G prices. Several sets of cash flows are generated forward, where each set corresponds to the simulated cash flows for when the investment decision is made. These cash flows serve as the main input for the LSM algorithm, which compares the estimated value of investing now with the estimated value from continuation at each time step (year). Since the option can be exercised at any time step until maturity, the model is required to work backwards from the last decision point in order to determine the optimal decision. It is, however, not legitimate to use the knowledge of future payoffs on a given simulation path to decide to exercise on a given time step. We resolve this by adopting the technique recommended by Longstaff and Schwartz (2001), who use least-square-regression. The fitted value of this regression is an efficient unbiased estimate of the conditional expectation function and allows accurate estimation of the stopping rule for the option. This technique allows for additional risk factors that affect the expected continuation values (Willigers, 2009), which in our case are oil price, gas price, and CAPEX. Only in-the-money paths are included in the regression as this results in better estimations of the conditional expectation function in the region where exercise is relevant (Longstaff and Schwartz, 2001).

In contrast to American options in the financial markets, where the payoff of the underlying is observable, the immediate investment payoffs of the oil field development are not available. This might lead to suboptimal investment strategies because the regression is biased. This issue is handled by Jafarizadeh and Bratvold (2009b), who extends the original LSM approach by regressing both the continuation values *and* the immediate investment payoffs separately on the oil price from the previous year. This implies that the real option exercise is triggered if the fitted value of the payoff regression is larger than the fitted value of the continuation value regression, given that the fitted payoff is positive.

2.3. Host and regulator perspective

The host owner earns from the tieback by charging tariffs. If the tariffs are priced too high, the host risks being opted out in favor of alternative hosts. Another critical driver for the facility owner is to postpone abandonment. Since abandoning the host facility is costly, any additional production that moves this cost out in time will increase the profitability of the host. We assume that the host charges a tariff that corresponds to all its associated operational costs and a profit margin s (expressed as a percentage).[12] Furthermore, we assume that required host modifications and tieback decommissioning are fully paid by the field operator. Thus, no CAPEX or ABEX are associated with the tieback for the facility owner. In our analysis we are interested in how different host characteristics affect the field operator's choices as well as therewith resulting potential tariffs earned by the host. We calculate the expected present value of tariffs earnings from the perspective of the host resulting from the optimal decisions of the field operator by summing the expected discounted tariffs earned by the host as in

$$ProjectValue^{ROV}_{t=0,host}(p^{oil}, p^{gas}) = \mathbb{E}\left[\sum_{t=\tau}^{\tau+T} \text{Tariff}_t \cdot e^{-\gamma \cdot t}\right] \tag{32}$$

where τ indicates the tieback time chosen by the field operator.

From the societal perspective the regulator seeks to maximize the total value of an area by optimizing for all oil and gas fields as well as hosts. Considering the tieback of one field only, the present value from the societal perspective resulting form the optimal decisions of the field operator is given by

$$\begin{aligned} ProjectValue^{ROV}_{t=0,NOD}(p^{oil}, p^{gas}, capex) = & ProjectValue^{ROV}_{t=0,field} \\ & \times (p^{oil}, p^{gas}, capex) \\ & + ProjectValue^{ROV}_{t=0,host}(p^{oil}, p^{gas}). \end{aligned} \tag{33}$$

3. Case study

We now parameterize the model using data from a real case provided by the NOD. In the following we first present the case (see Section 3.1). Note that sensitive details are left out for confidentiality reasons, including selected values and axes in several figures. We the present the results of the integrated optimization model used to calculate the production profiles in Section 3.2. In Section 3.3, we present the estimated parameter values for the price processes together with simulation results. The cost models used for the case study are introduced in Section 3.4.

[10] Willigers et al. (2009) who provides evidence of a strong correlation between oil prices and oil rig rental rates.

[11] In contrast to a standard American option, Bermuda options are restricted only to allow early exercise at predetermined discrete points in time (in this case once a year).

[12] Instead of including OPEX of the field in Eq. (32), we assume instead that the yearly profit of the host is the product of the tariff and the profit margin.

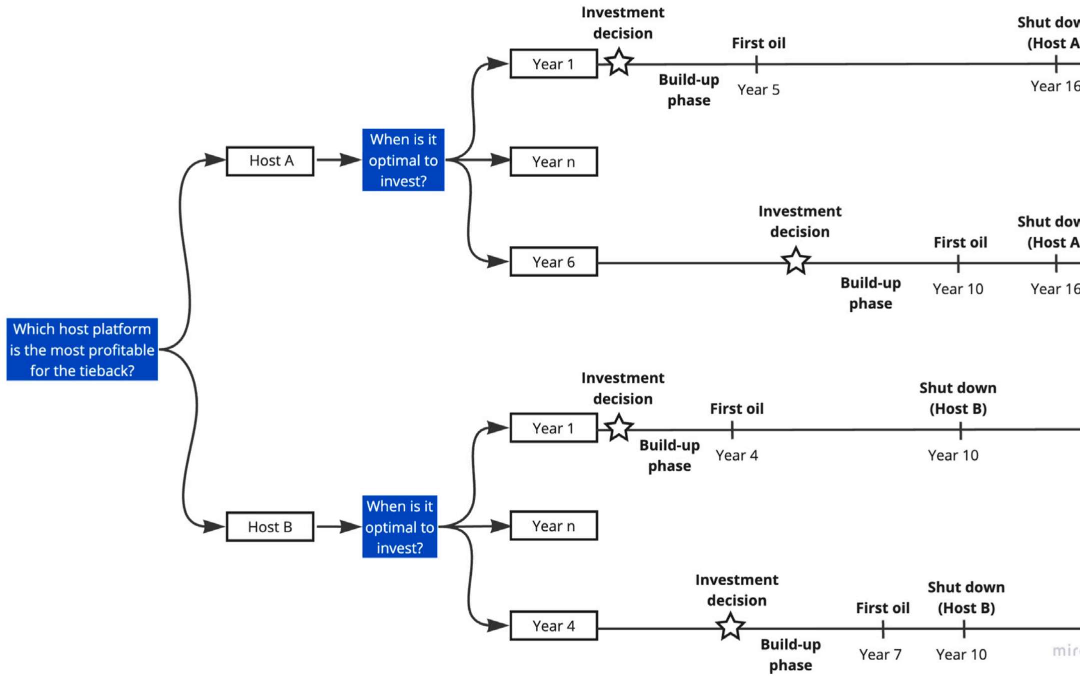


Fig. 5. Illustration of the decision situation, including a timeline.

3.1. Case study

We now apply the methodology to the following case. A field operator holds a license for an undeveloped O&G reservoir on the NCS. It is not economically viable to develop a standalone facility for the field. However, there are two host facilities located nearby, *Host A* and *Host B*. The field operator wants to evaluate whether a tieback to any of these is profitable, and if so *which* host is the best choice. Furthermore, the field operator wants to assess the optimal investment timing.

The field and each host have a given capacity that limits the production rate. Based on these capacities, production profiles can be calculated for both hosts. We present those in Section 3.2 below. The production rates differ between the two hosts, as they are dependent on the spare capacity at the host facility. In addition, the hosts have different time horizons, as indicated in Fig. 5. The investment decision can be made for the first time in Year 1. Without loss of generality the construction phase is assumed to start the same year as the investment is made. The construction and ramp-up phases take 4 and 5 years for Host A and Host B, respectively, and are assumed to be fixed regardless of the year of investment. The first production starts in the last year of construction, i.e. 3 and 4 years after investment for Host A and Host B, respectively. Host A is planned to be shut down in Year 16, while Host B is planned to shut down in Year 11. In our analyses below, we will investigate scenarios where the lifetime of Host B can be extended.

In order to have a fair comparison between valuation by NPV and ROV, we use the same discount rate for both. In line with Norwegian Petroleum Directorate (2020), we apply a discount rate of 7%.

3.2. Production profiles

As explained in Section 2, the production profiles are chosen to maximize the project's NPV by producing the maximum feasible amount of a field's content of oil and gas. The initial year of the project is Year 0, while investment is possible from Year 1 onwards. The maximum recovery factor R is set to 0.6, which is within a range of expected recovery factors of several fields commissioned recently on the NCS (Seyyedi et al., 2018; Equinor, 2020, 2022).

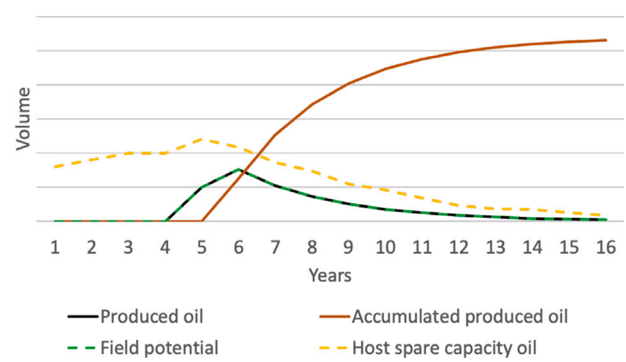


Fig. 6. Oil production for Host A in the base case.

In terms of the presentation of this case study, we intentionally disguise a number of parameter values, including capacities and production, in order to not expose commercially sensitive data. Figs. 6 and 7 illustrate the oil production profiles of tieback to Host A and Host B, respectively, assuming immediate investment. The green dashed and yellow dashed lines represent the field potential and the host spare capacity, respectively. The black line indicates the produced oil, while the brown line represents the accumulated produced oil.

In our case the spare capacity for oil is declining for both hosts due to a gradual shutdown plan. Note that for other cases the spare capacity of a host might increase over time due to the depletion of its original fields. The resulting field potential for both hosts first increases rapidly, before it slowly declines due to a drop in O&G pressure. The fact that the produced oil matches the field potential during the whole lifetime of Host A as shown in Fig. 6, indicates that it is solely the field potential that limits the maximum production of petroleum from the field. For Host B, on the other hand, the spare capacity constrains the production, further decreasing its oil production deficit compared to Host A. In the case of gas production, it is essentially the field potential that restricts the production for both hosts, rather than the spare host capacity. For the sake of space we omit the gas equivalents of Figs. 6 and 7.

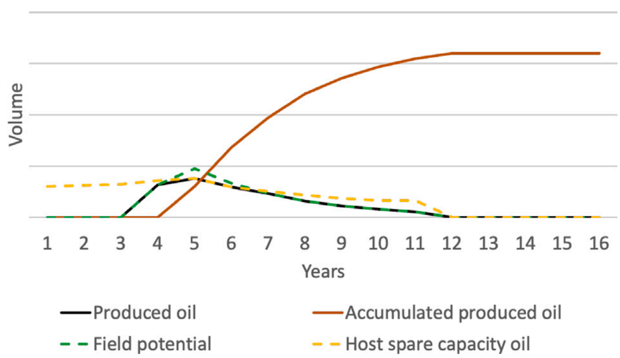


Fig. 7. Oil production for Host B in the base case.

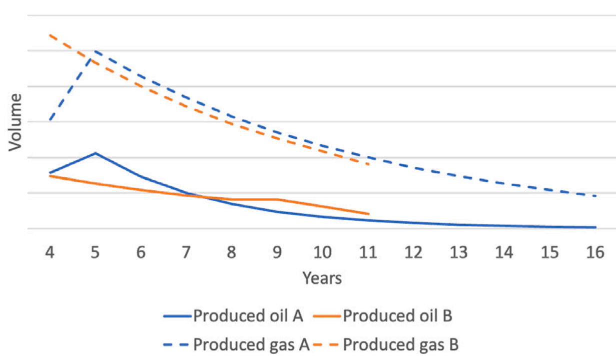


Fig. 8. Field's production profiles for tie-in to Host A and B, respectively.

[Fig. 8](#) presents the field's production profiles of oil (solid lines) and gas (striped lines) with tieback to Host A (blue lines) and Host B (orange lines), respectively.

When comparing the oil production profiles, Host A is able to produce more oil initially, resulting in a quicker decline in production. As mentioned above, the oil production at Host B, is restricted by the spare capacity at the host. Therefore, it will maintain a more stable production over time, resulting in exceeding the yearly oil production at Host A around Year 7. Nevertheless, the oil production profile of Host A is favorable because: (1) more oil is produced initially, which is more valuable due to the time value of money, and; (2) more oil is produced in total because of longer lifetime. The tieback to Host B produces more gas the first year, but slightly less the remaining years of its lifetime. Regardless, Host A is able to produce significantly more gas because it has a longer lifetime. Hence, we can conclude that Host A provides the most attractive production profile for investment in Year 1, mainly because O&G are produced over more years than Host B.

As the hosts' capacity constraints do not limit the oil production sufficiently to affect the production, the conclusion for the base case in terms of choice between hosts is rather obvious. We later perform a sensitivity analysis to gain more insight into the optimal choice of a host from the perspective of a field operator (see Section 4.2). We modify the production constraints such that the production profiles of the two host choices are more similar such that the optimal choice of host is less evident.

3.3. Oil and gas price simulations

The estimated price process parameters for both the O&G price simulations are retrieved from Thomas and Bratvold (2015), where Kalman filter and maximum likelihood estimation were applied for calibration. The parameter values are stated in Table 2.

Table 2
Oil and gas price model parameters (rounded to the nearest second decimal).

Parameter	Oil	Gas
ξ_0	4.26	4.80
χ_0	0.00	0.00
σ_ξ	0.22	0.25
σ_χ	0.47	0.75
λ_χ	−0.08	−0.07
μ_ξ^*	−0.02	−0.05
κ	0.50	0.91
$\rho_{\xi\chi}$	−0.71	−0.63
$\rho_{\chi^{gas}\chi^{oil}}$	0.64	

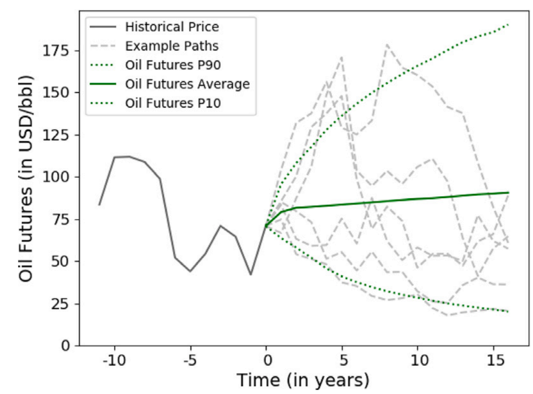


Fig. 9. Historical and estimated brent crude oil prices with confidence bands.

Given the parameter values stated in Table 2, the initial O&G prices are equal to[13]:

$$p_0^{oil} = e^{\xi_0^{oil}+\chi_0^{oil}} = e^{4.26+0.00} = 70.81,$$

and

$$p_0^{gas} = e^{\xi_0^{gas}+\chi_0^{gas}} \cdot 0.13 = e^{4.80+0.00} \cdot 0.13 = 15.80.$$

Figs. 9 and 10 show results from the O&G price simulations. The solid gray lines represent historical O&G prices, while the solid green and blue lines correspond to the expected future O&G prices, respectively. We also indicate the confidence bands corresponding to the 90th and 10th quantile, by green and blue dashed lines, respectively. The dashed gray line represents example price paths chosen from the 15,000 simulated price paths[14] used for the valuation procedure.

3.4. Costs

3.4.1. OPEX and tariff

For OPEX and Tariff, we have developed cost models that resemble the actual data provided by NOD. For confidentiality reasons, the real costs have been modified so that the models do not generate the exact numbers of the real case. The parameters used in the cost models are presented in Table 3. For the base case we assume that the OPEX and tariff parameters are the same for Host A and Host B. Later we relax this assumption in the sensitivity analysis we are conducting. Since OPEX and tariffs depend on the production volume, they are different for the two hosts.

[13] We have converted the gas from p/therm (as received by NOD) to USD/BTU, which gives a factor of approximately 0.13 (see https://ngc.equinor.com/Home/Price).

[14] 15,000 simulations proved to be computationally reasonable and produce a stable result that deviated insignificantly throughout several code-run executions.

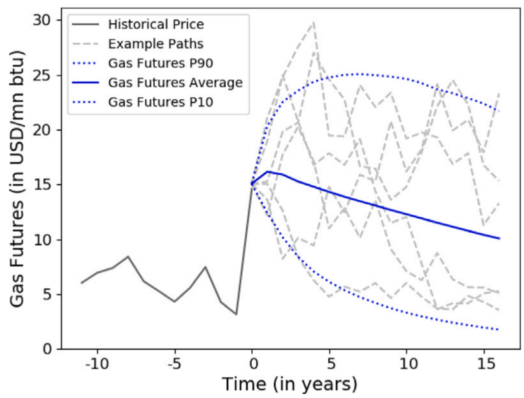


Fig. 10. Historical and estimated natural gas liquids (NGL) prices with confidence bands.

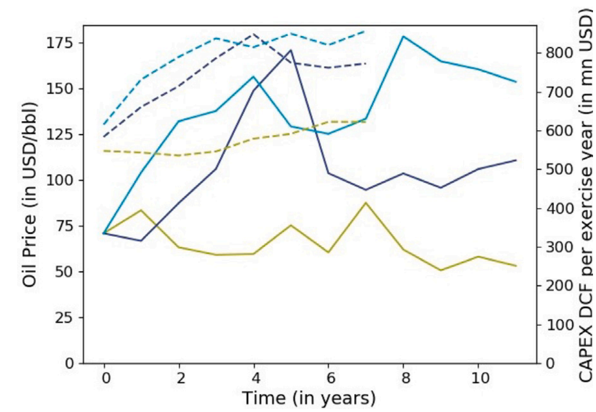


Fig. 12. A selection of paths for future oil prices and CAPEX (dashed) for Host A.

Table 3
OPEX and tariff model parameters.

Parameter	α	β_0	β_1	β_2
OPEX	8.0	–	1.0	0.0
Tariff	35.0	1.0	0.1	0.0

Table 4
Base case results (in mn USD).

	Host A	Host B
NPV	455.6	273.1
ROV	484.5 (+6.3%)	330.5 (+21.0%)

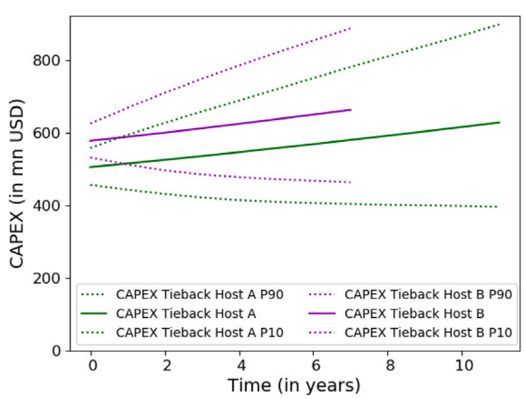


Fig. 11. Future expected CAPEX with confidence bands.

3.4.2. CAPEX and ABEX

The CAPEX for tieback to Host B is on average 20% higher than for Host A, but varies in time as it follows a GBM. We apply the same parameter values as presented in Fedorov et al. (2022b), i.e. the drift rate, μ_θ, is set to 2% and the volatility, σ_θ, to 10%. The results from the simulations of CAPEX are presented in Fig. 11, which shows the expected CAPEX and confidence bands for Host A and Host B during their lifetimes. The CAPEX will generally increase with time due to the positive drift rate.

In terms of correlation of the oil price with CAPEX we follow Fedorov et al. (2022b). Willigers (2009) identified that the rig rental rates in the North Sea correlate with the oil price with a coefficient of 0.87 with a one-year delay. Our CAPEX costs include additional elements with less sensitivity towards the oil price. Hence we use a slightly lower correlation coefficient of 0.7, as proposed by Fedorov et al. (2022b). In order to achieve an actual correlation of 0.7 for the simulated data, we set $\rho_{\theta\xi^{oil}}$ equal to 0.92 in Eq. (31). In order to illustrate the effect of the correlation, we have simulated three different oil price paths (solid lines) and CAPEX paths (striped lines) in Fig. 12. There is a significant relation between the oil price and CAPEX, with one year lag for the latter.

In our case study, the ABEX for Host B is approximately 10% higher than for Host A. The values remain fixed during the whole lifetime of the hosts and almost considered negligible in comparison to other costs due to their initial low values and many years of discounting.

4. Results

We now present and discuss the results of our study. Section 4.1 presents the results of applying our methodology to the base case. Section 4.2 presents sensitivity analyses to better understand the main drivers of the selection of hosts. Finally, we analyze under which conditions timing flexibility with regards to the investment decision in the field is most valuable in Section 4.3.

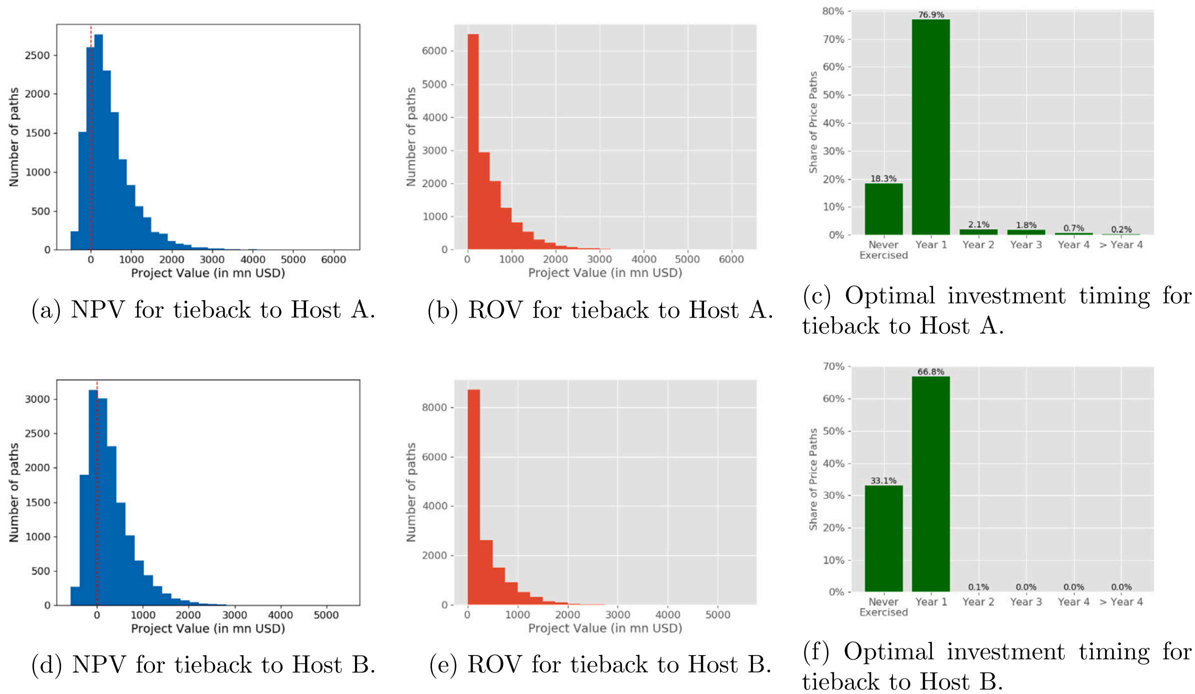
4.1. Base case results

For the main decisions of the field operator, indicated in the decision flowchart of Fig. 2, we conclude the following:

1. Yes, the investment is profitable.
2. Tieback to Host A is the optimal choice.
3. Immediate investment in Year 1 is optimal.

Table 4 states the resulting project values from the perspective of the field operator for tieback developments to Host A and Host B, respectively. The NPV approach values the tieback development to Host A at 455.6 mn USD and Host B at 273.1 mn USD. Taking an ROs approach the value is estimated at 484.5 mn USD for the tieback development to Host A and at 330.5 mn USD for Host B, respectively. These results indicate that tieback to Host A is the preferred choice by a great margin according to both valuation techniques. Lower costs, larger spare capacity, and longer lifetime, are the main reasons why tieback to Host A is significantly more profitable than Host B from the field operator's perspective. The project value for both cases is higher using a technique that allows to quantify timing flexibility, mainly because of two reasons. Firstly and most importantly, substantial losses can be avoided by choosing not to invest if the market conditions are expected to be unfavorable during the project's lifetime. Secondly, the field operator can optimize the timing of investment to exploit upside potential when the project is in-the-money. For the case of Host A, the resulting project value from the ROV is 6.3% higher than using a NPV analysis. For Host B the difference is 21%. We will later explain why the difference is larger for Host B.

Fig. 13 presents different histograms related to the distributions of outcomes from the perspective of the field operator. Figs. 13(a) and 13(d) show the distribution of project values by using the NPV



(a) NPV for tieback to Host A. (b) ROV for tieback to Host A. (c) Optimal investment timing for tieback to Host A.

(d) NPV for tieback to Host B. (e) ROV for tieback to Host B. (f) Optimal investment timing for tieback to Host B.

Fig. 13. Distributions of project values and optimal investment timing for both hosts A and B using an NPV and ROV approach.

approach to valuate tieback to each host, i.e., the number of simulations that resulted in project values within the different intervals. Figs. 13(b) and 13(e) show the corresponding distribution of project values by using the ROV to valuate tieback to each host. Figs. 13(c) and 13(f) show the distribution of the optimal timing of investment to each host according to ROV. As seen in Figs. 13(a) and 13(d), there is a portion of the simulations that result in negative NPVs, showcasing the riskiness of the oil field development we are examining. These results occur due to unfavorable market prices. On the contrary, no project values are negative in Figs. 13(b) and 13(e). Since ROV considers managerial flexibility, the project is only exercised if the market environment indicates that it is profitable. Sometimes, the market conditions never improve sufficiently, so the project is left unexercised, thereby avoiding substantial losses for the field operator.

It is interesting to see that the relative value of flexibility is significantly higher for Host B. This is mainly due to the ability to avoid investments that never become profitable. This is best explained by comparing the results in Figs. 13(c) and 13(f). The majority of the simulations indicate that immediate exercise is most profitable for both tieback alternatives. However, a significant amount of simulations indicate never to invest in the project as it appears unprofitable throughout the whole lifetime. In contrast to tieback to Host A, where 18.3% of the cases are left unexercised, as much as 33.1% are left unexercised for Host B. Since a larger portion of cases would have resulted in negative NPV for tieback to Host B, considering the option to wait with investment and potentially not invest at all adds more value to the project than it does for tieback to Host A. Only 4.8% of the cases for Host A and 0.1% for Host B suggest exercising later than Year 1. This fact implies that the value of waiting with investment for better market conditions is negligible for our base case, in particular for tieback to Host B. Extracting and selling the O&G as quickly as possible is incentified by the time value of money, and the case study's production profiles with declining host spare capacity further demotivate postponement of the investment.

We now perform a sensitivity analysis on the correlation between the oil price and the CAPEX, and how it affects the project value. Fig. 14 shows the NPV (dashed lines) and ROV (solid lines) for tieback to each host, respectively, as a function of the correlation coefficient of oil price

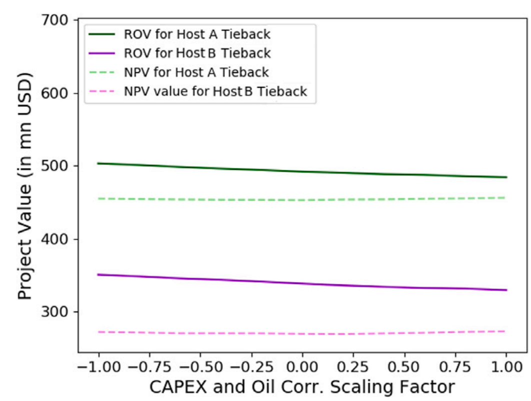


Fig. 14. Field operator's project value as a function of the correlation coefficient between CAPEX and oil price.

and CAPEX. The NPV is more or less independent of the correlation coefficient value, but the ROV tends to decrease as the coefficient increases. The reason is that the oil price and CAPEX contribute in different directions when it comes to the profitability of the project. With a strong positive correlation, the two factors will to a larger extent cancel each other out with respect to the project value. Thus, the project value becomes more stable as it will be less affected by changes in the oil price. However, when there is a strong negative correlation, the oil price and CAPEX will both contribute to the project value in the same direction, leading to either relatively larger profits or losses. This phenomenon resembles the characteristics of the option price when the volatility of the underlying asset increases, which according to option theory adds more value to the project due to managerial flexibility. As a result, larger movements of the project value due to a strong negative correlation will make it more attractive to wait to invest. The value of this flexibility is captured by ROV, which is why the relative difference between the two valuation techniques increases as the correlation coefficient becomes more negative.

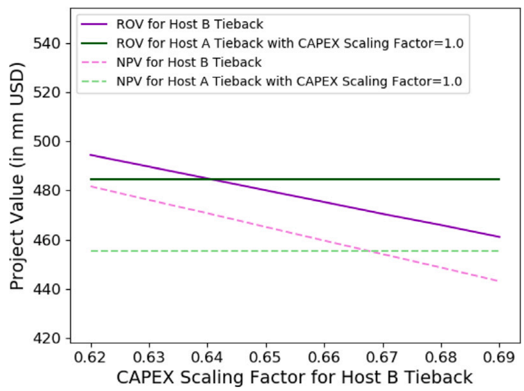


Fig. 15. Field operator's project value as a function of Host B's CAPEX.

4.2. The main drivers of host selection

We now aim to identify the main drivers for host selection. Host owners could have several reasons to take measures to become more attractive for tieback. For instance, the decommissioning cost of the production facility is often significant, thus any additional production that can delay this cost is beneficial for the host owner. Furthermore, if the potential of finding undiscovered oil fields near the existing host facility is considered high, it could be important for the host owner to retain production at the facility in order to make some profits (although less than initially), while pending further exploration. To achieve this, the host must be attractive enough for the field operator to be preferred over alternative tieback hosts. At the same time, however, the cost of the measure(s) taken must be lower than the expected payoff from the host owner's perspective. In this section, we will focus on three specific actions the owner of Host B could take to become the optimal choice for tieback: reduce CAPEX, increase spare host capacity and extend its lifetime. For the figures in this section, the solid lines represent the project's ROV as a function of different key factors, while the dashed lines represent the corresponding NPV. Green lines represent Host A tieback and purple lines Host B tieback.

The reduction of CAPEX is the first measure investigated. CAPEX for oil field developments is high and thus constitutes one of the strongest drivers of the project's profitability. If reducing the CAPEX of a tieback is possible, it could very likely change the optimal choice of host. However, it is strongly dependent on each specific case how much CAPEX reduction is required to achieve a different outcome. While the CAPEX for tieback to Host A is kept fixed, we alter the yearly CAPEX for tieback to Host B between 100% to 50% of its initial value. Fig. 15 shows the field operator's project values as functions of the scaling of CAPEX for tieback to Host B. The results suggest that CAPEX for Host B tieback would have to be reduced by 33% and 36% given NPV and ROV, respectively, in order for Host B to present the optimal choice of host. The amount of CAPEX that the host owner is able to reduce is case dependent. A significant part of the field operator's CAPEX is coverage of host facility modifications. In our case study, this is assumed to be the only part of the field operators' CAPEX that the host owner would be able to influence, and amounts to 31.7%. This means that even if all modification costs were covered by Host B, it would not be sufficient to become a more attractive tieback alternative than Host A. Moreover, covering such a large portion of the CAPEX would anyway make the tieback development unprofitable from the perspective of the host owner because the expenses would not be covered by the tariffs. Hence, it will likely not be a preferred strategy for Host B.

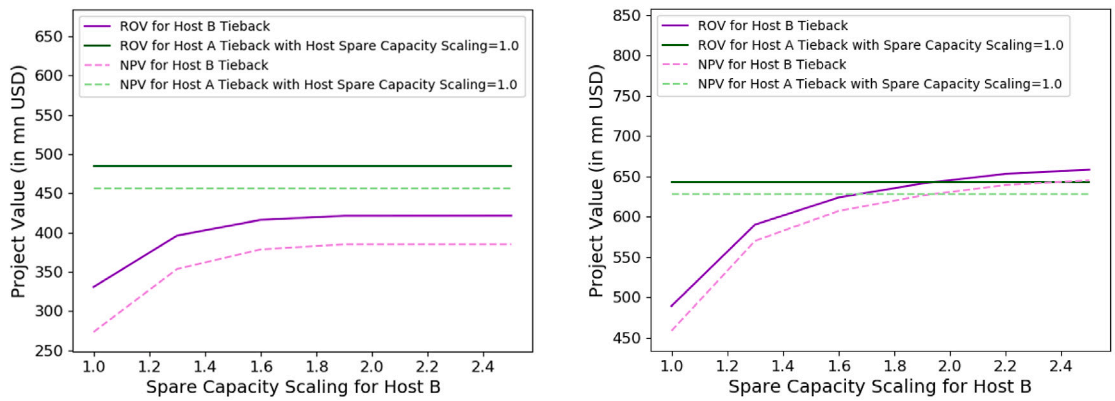
Similar to the outcome of the base case, the project values are higher for ROV than for NPV. By taking into account managerial flexibility, Host A is considered more attractive than Host B for a broader range of CAPEX reduction for Host B's tieback. The required reduction of CAPEX is larger for ROV, because the benefit of lower CAPEX for Host B must outweigh the relatively larger benefits of flexibility identified for Host A in this case. The value of flexibility is represented by the difference between the solid and striped line for each host tieback.

The second measure Host B could take to increase its attractiveness to the field operator is increasing its spare capacity. Specifically, we analyze the effect of altering the spare capacity profile of Host B up to 250% of the initial profile set in the base case, keeping the spare capacity of Host A fixed. As the host owner's profit in the base case amounts to approximately 20 mn USD, it is required that the spare capacity expansion costs less than this in order for this action to be attractive to implement in the perspective of Host B, unless it has other incentives as we have previously explained. Fig. 16(a) shows the field operator's project values as functions of the scaling factor of the spare capacity of Host B. The results show that, in our case study, increasing the spare capacity of Host B alone would never make Host B more attractive for tieback than Host A. The project value for Host B tieback increases significantly when scaling the spare capacity up to 150% of its initial levels, but stagnates when increased above this level. The explanation is that, above this point, the field potential becomes the limiting factor, and any further spare capacity expansion does not impact the field operator's profits. To put this measure of an increase in spare capacity in perspective, we examine how an increase in spare host capacity affects the optimal choice of host if the field potential would be significantly higher than originally expected. This increase can occur, for example, due to higher than expected reservoir performance. We repeat the analysis performed in Fig. 16(a), now doubling the field production potential. Fig. 16(b) shows that, under these conditions, the tieback to host B becomes an optimal choice if the host capacity can be increased by at minimum a factor of 2. This shows that spare capacity, as a measure to increase tieback attractiveness, can be effective for fields with large field potential.

The third and last measure we analyze is an extension of the lifetime of Host B. For this analysis, the host owner is assumed to be able to extend the lifetime of the platform from 11 to 22 years. The yearly spare host capacity is assumed to remain at the same level as for Year 11 during the extended lifetime period. The lifetime of Host A is assumed to remain fixed at 16 years in order to make the results comparable. Fig. 17 shows the project values from the field operator's perspective as functions of the lifetime of Host B. The results suggest that extending the lifetime of Host B alone does not have a sufficient effect to make a tieback to Host B more valuable than to Host A. The ROV project value of Host B tieback increases steadily until Year 16. After this point, further extension of the host's lifetime is not beneficial due to the depletion of the field, that is not able to generate enough revenues to compensate for the tariffs levied by the host.

However, if we look at the same case, but with altered tariff parameters for Host B, a switch in optimal tieback host selection is feasible. Tariffs could be customized in numerous different ways as they are subject to contract negotiations between the field operator and the host owner. These negotiations could be conducted with the objective of making the production facility more attractive for tieback while maintaining profitability for both parts. We change the tariff parameters for Host B by setting the fixed tariff cost to zero, i.e. $\alpha = 0$, and increasing the variable component β_1 from 1.0 mn to 8.0 mn USD/mn bbl produced. Fig. 18 shows the field operator's project values as functions of the lifetime for Host B, with the altered tariff parameters. The tariff parameters and lifetime of Host A are the same as in the base case. With this transition to an exclusively variable tariff scheme, the field operator's preferences change already as Host B's lifetime is increased by two years. Here both valuation methods lead to the same result qualitatively.

Figs. 19 and 20 show the *host owner's* potential project values for a tieback as functions of Host B's lifetime with the original and altered tariff parameters, respectively. The altered tariff schemes will give a total tariff cost roughly equal to the original scheme's total



(a) Field operator's project value as a function of Host B's spare capacity

(b) Field operator's project value as a function of Host B's spare capacity (with doubled field potential).

Fig. 16. Field operator's project value as a function of Host B's spare capacity.

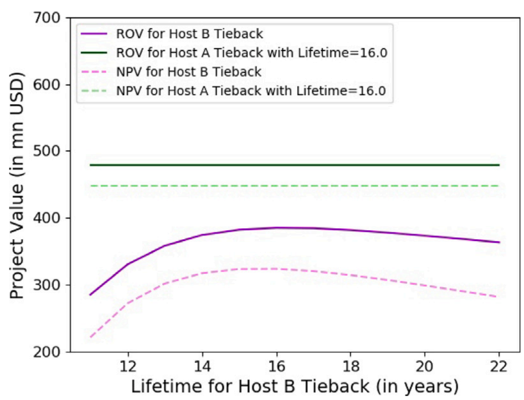


Fig. 17. Field operator's project value as a function of Host B's lifetime (with base case tariff schemes).

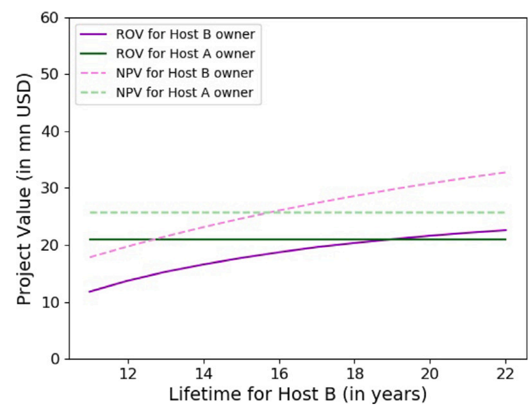


Fig. 19. Host owner's project value as a function of Host B's lifetime (with base case tariff schemes).

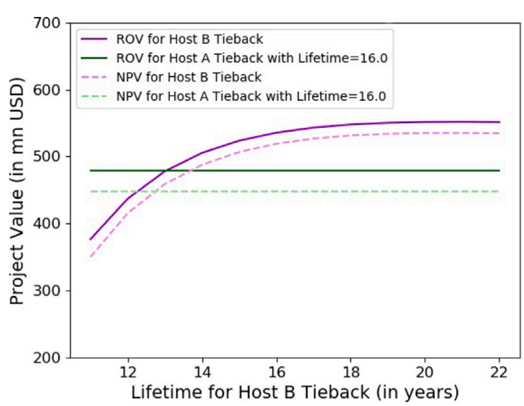


Fig. 18. Field operator's project value as a function of Host B's lifetime (with altered tariff schemes).

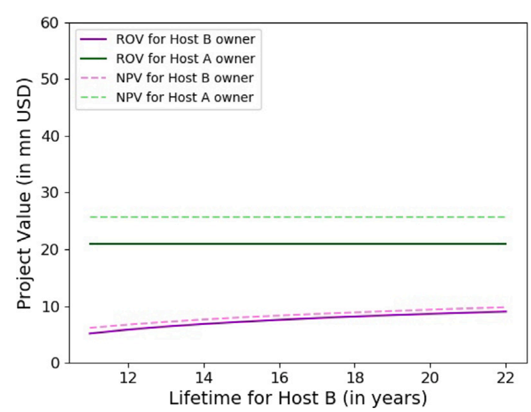


Fig. 20. Host owner's project value as a function of Host B's lifetime (with altered tariff schemes).

cost over a 12-year lifetime, but significantly lower in the later years when production is low due to the lower variable costs. Note that the ROV results in lower profits for the host owner than NPV calculation. Accounting for the field operator's flexibility will actually reduce the revenues for the host owner. The reason for that is that the ROV accounts for the fact that the field owner can adjust its strategy over time according to new information about prices etc. allowing higher revenues and also lower tariff costs.

Comparing the results in Figs. 19 and 20 we see revenues for the host owner are more sensitive to a lifetime increase in case of the original tariff parameter set including fixed yearly costs. Note however, that Host B is never the optimal choice from the field operator's perspective for the case of the original tariff parameter set. Offering the variable tariff agreement would make Host B competitive to Host A conditional on a minimum two year lifetime extension aka at a lower overall project value for Host B. Note that we did not account for potential costs associated to the lifetime extension for Host B. Host B would have to weigh the costs of these measures against the profits gained from hosting the field. Another interesting observation made by comparing Figs. 19 and 20 is that the value of flexibility in the case of Host B tieback is significantly reduced with the altered tariff parameters. Cutting fixed tariff costs make the project less uncertain for the field operator. High fixed tariff components represent a risk in terms of the uncertainty regarding whether the revenue cash flows will be high enough to cover these recurring costs. ROV allows to quantify the value of the managerial flexibility to reflect the response to this risk by timing the investment optimally, or avoiding it if coverage of the tariff does not seem feasible.

In the analysis above we identify the different measures that drive the attractiveness of hosts with different characteristics and discuss their impact on the field operator's strategy. Note that the optimal choice and combination of measures is dependent on the specifics of each case. For our case study Host A is more attractive a priori due to several factors. Neither an increase in spare capacity of Host B nor lifetime extension are sufficient measures to affect optimal host selection on its own. In case of a larger field potential, however, an increase in spare capacity could make Host B a competitive choice to Host A. The same is true for lifetime extension in combination with a tariff agreement with a low fixed tariff share. Offering host lifetime extension in combination with high fixed tariffs at late stages of field lifetime is not appealing from the field operator's perspective due to low production volumes in the later project stages. While CAPEX reduction could in theory serve as measure to make a host more attractive, for our case study, Host A remains the optimal choice even if Host B would offer to cover *all* modification costs.

4.3. The value of timing flexibility

We now analyze under which conditions timing flexibility is valuable for marginal oil field development is crucial and whether and how optimal host selection is affected by it. ROV allows to quantify the value of this managerial flexibility, while the NPV approach is likely to underestimate the project value as flexibility cannot be accounted for. In our model setting the value of the timing flexibility can be easily quantified and is equal to the difference of the project values resulting from the ROV versus the NPV valuation.

In the following we investigate under what subsurface and market conditions flexibility is most valuable. Without loss of generality we do so considering tieback to Host A given the case introduced above. Unless otherwise specified, for the following figures the solid lines represent the field operator's project values by ROV for Host A tieback as a function of different key factors, while the dashed lines represent the corresponding for NPV.

Subsurface uncertainty is one of the main concerns for field operators when dealing with oil field development projects. The uncertainty in early field property estimations is even larger for marginal oil fields as less data is usually gathered in these cases. We now analyze how varying the initial oil and gas in place between 50% and 150% of initial estimates affects the result. Fig. 21 shows the resulting project values plotted as functions of the initial oil and gas in place.

As expected the project value increases in the initial oil and gas in place because larger reservoir volumes imply larger revenues and profits. Comparing the values resulting from ROV versus NPV we see that the values converge as the initial oil and gas in place increases. The reason is that flexibility is less important to take into account when the project becomes more profitable and downside risk mitigation becomes less relevant. Equivalently, NPV and ROV diverge as the initial oil and gas in place decreases, hence suggesting a higher value of flexibility for marginal field developments. The reason is that smaller volumes reduce the profitability of the development project such that it might become unprofitable. With the option of waiting-to-invest, the field operator can wait with investment and leave the project eventually unexercised if the future market conditions do not justify investment

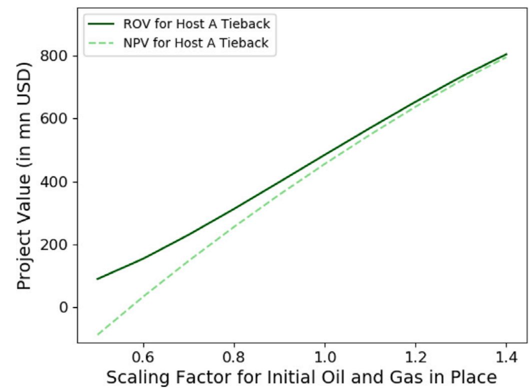


Fig. 21. Field operator's project value as a function of the initial O&G in place in the field.

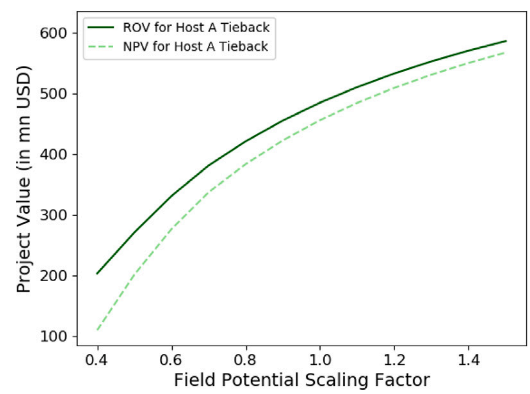


Fig. 22. Field operator's project value as a function of the field potential.

in such a small field. This could be viewed as a partial hedge against the downside risk of the investment. However, we emphasize that a perfect hedge is rarely possible as decisions remain to be driven by future price and production uncertainty (Fedorov et al., 2021). The consequence of making a decision only based on NPV in this case might be that the field operator find the oil field too risky and leave the field undeveloped. However, this could be a wrong conclusion as the oil field could potentially provide substantial value if the flexibility to wait is accounted for. This highlights how ROV could act as a valuable approach to gain insights into marginal oil fields' profitability.

Moreover, we have investigated how the value of flexibility develops if the field operator alters its field potential. We perform this analysis by altering the field potential between 50% and 150% of initial value. Note that we did not account for costs required to increase the field potential (like drilling additional wells etc.). Fig. 22 shows the project values as functions of the field potential. The results suggest that by increasing the field potential, more oil is extracted early, which in general increases the project value due to time value of money. However, the increase decays once the host capacity or the reservoir pressure become limiting factors. Regarding the value of flexibility, we see a similar tendency as in the previous sensitivity analyses: as the project becomes less profitable with lower field potential, there is more difference between the values resulting from the two valuation methods.

Another important concern for the field operator is the market environment. The profitability of E&P investments is highly dependent on O&G prices. O&G are among the most volatile commodities. We conduct a sensitivity analysis on the market uncertainty by altering both the long and short-term volatility parameters between 50% and 200% of the originally calibrated values. Fig. 23 shows the project

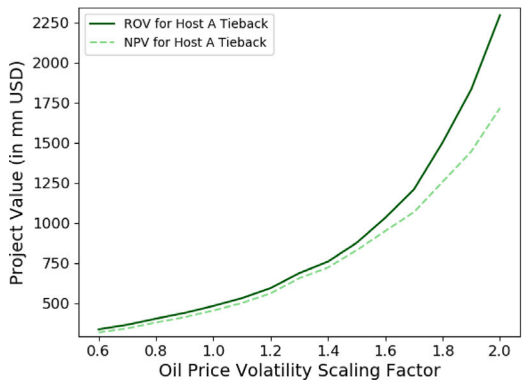


Fig. 23. Field operator's project value as a function of the oil price volatility.

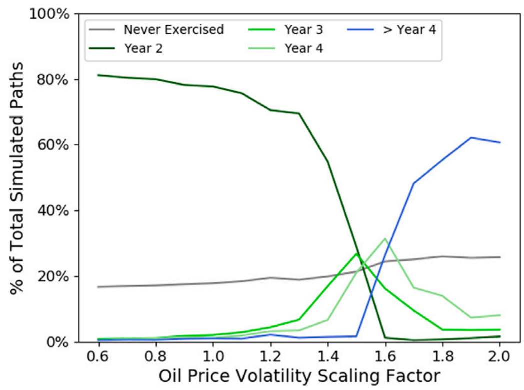


Fig. 24. Optimal exercise timing for Host A with altered oil price volatility.

values as functions of the oil price volatility. The results suggest that the project value increases together with the oil price volatility. The reason is that higher volatility increases the possibility for extreme prices. This leads to higher expected revenues and profits as indicated by both the NPV and ROV results. Additionally, we observe that in line with option theory, increased volatility of the underlying asset results in a greater option value. Higher volatility results in a larger upside potential and therefore, a higher value of waiting (McDonald, 2013). This effect is also reflected in the results of Fig. 24, that shows the distribution of optimal exercise times over all simulated paths. The higher uncertainty the more often investment exercise takes place in later years. For instance, exercising later than Year 4 is optimal for only 5% of the simulation paths for the base case volatility parameters, but it amounts to 60% of the simulations when the volatility is doubled. This highlights the key advantage of ROV that it allows to capture the value of the opportunity to exploit the upside potential of investment decisions. The same results hold in terms of gas price volatility.

We also analyze how capital costs affect the value of flexibility. CAPEX are often largely underestimated in first forecasts and might diverge significantly from the forecasts due to unforeseen additional costs, increasing commodity prices etc. Fig. 25 shows the project values as functions of the initial CAPEX cash flows when varied from 100% to 400% of the initial estimates.

As expected, the project value decreases as CAPEX increase. Moreover, the difference between the resulting value from the two valuation methods increases for higher CAPEX. As previously mentioned, this is a result of the higher downside risks. Managerial flexibility adds value to the field because it can mitigate downside risks by delaying exercise if the conditions are unfavorable, similarly to the analysis of the field potential and initial oil and gas in place. The results illustrated in Fig. 25 show that for a CAPEX higher than double the amount of the

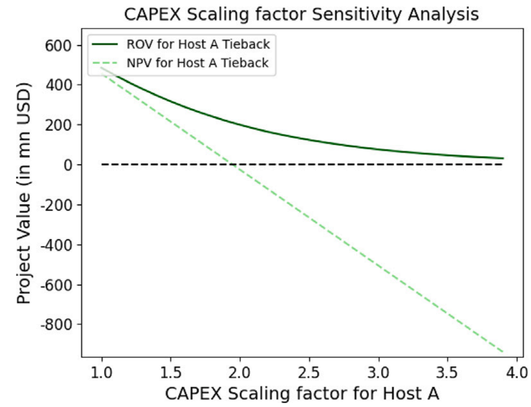


Fig. 25. Field operator's project value as a function of CAPEX.

base case, the NPV for the Host A Tieback is negative. This downside can be avoided accounting for timing flexibility as indicated by solid green line for the ROV which approaches zero from above when CAPEX increase but does not turn negative.

To summarize we find that the value of timing flexibility is most significant under conditions of (1) marginal initial O&G in place; (2) low field potential; (3) high market (O&G) price volatility, and (4) high CAPEX. If one or several of these characteristics hold our results indicate that NPV results can significantly underestimate project value.

5. Conclusion

In this paper we evaluate optimal tieback developments for marginal oil fields with timing flexibility. We develop a model that allows to (1) economically assess the value of a marginal oil field accounting for production optimization based on spare host capacity, initial O&G in place, and the field potential, (2) determine the optimal choice of hosts, and (3) optimize the timing of investment in the field. In order to quantify the value of flexibility we take a ROV and solve the model using a least square Monte Carlo approach. This allows to account for several correlated risk factors. We then apply the methodology to a real case study on the NCS, where a tieback from one marginal oil field to two alternative host platforms was considered.

We perform sensitivity analysis to identify which characteristics drive the optimal choice of hosts therewith, giving insight for tariff negotiations and portfolio planning. Additionally, we analyze under which conditions timing flexibility is (most) valuable. The results suggest for our case no factors alone were able to change the optimal choice of host since Host A was evidently much more attractive. However, altering the parameters of the tariff scheme in combination with extending the lifetime of the host could change the preferences of the field operator. We also identified that the value of timing flexibility increases as the profitability of the project decreases or the uncertainty of the investment increases. As marginal oil field developments often are characterized by relatively low profitability and prominent uncertainties, managerial flexibility is usually of high importance. Hence, ROV proves itself as a better valuation method as it allows us to capture the value of flexibility, while NPV tends to underestimate such investments.

This work is a first step in the direction of optimal field and host allocations for larger portfolios of tieback developments, where aspects as timing of tie-in, lifetime extension of host facilities or potential of new discoveries in proximity to hosts are of importance. According to the regulator in Norway "Exploiting economies of scale through coordinated development across production licences will become increasingly important as the NCS matures. Such area solutions can contribute to lower unit costs and effective exploration, so that as much as possible of the socioeconomically profitable resources can be recovered'' (Norwegian Petroleum Directorate, 2022c). Therefore, the development of economic analysis tools that allow to account for the main characteristics inherent in this decision problems.

An interesting aspect for future research is the consideration of environmental aspects in terms of host selection. Traditionally large volumes of gas were burned to power the energy-consuming oil and gas production on offshore platforms. Electrification of offshore platforms is considered the main way to reduce carbon emissions produces by the Norwegian petroleum industry because power production in Norway is almost entirely based on renewable sources of energy such as wind power or hydropower. A natural extension of the methodology presented in this paper would be to distinguish between hosts with different power solutions and the resulting environmental impact of production in terms of CO2 emissions.

Future work may also incorporate technical uncertainty in the valuation model which is especially prominent for marginal fields.

CRediT authorship contribution statement

Semyon Fedorov: Conceptualization, Investigation, Methodology, Supervision. **Verena Hagspiel:** Conceptualization, Investigation, Supervision, Writing – review & editing. **Richard W.H. Rogstad:** Formal analysis, Software, Writing – original draft, Investigation, Methodology. **Sophie Haseldonckx:** Conceptualization, Data curation, Supervision. **Johannes H. Haugsgjerd:** Formal analysis, Investigation, Methodology, Software, Writing – original draft. **Anders Rønning:** Formal analysis, Investigation, Methodology, Software, Writing – original draft.

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