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How valuable is the option to defer Uganda's crude oil production?

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ABSTRACT

Our study contributes to the limited literature on real options valuation of Africa's oil investments. We establish binomial lattices to assess the value of the option to defer crude oil production in Uganda. We assume that oil prices follow a Geometric Brownian Motion (GBM) stochastic process. In our base case, we find that deferring production by another year adds value of $0.9 billion to the oil project. The value of the option to defer production particularly increases at lower crude oil prices amidst higher crude oil price volatility. When the rate of net convenience yield is high and the oil price is high, the value of the option is lower. At low oil prices, increases in cost inflation result in rejection of the project. We conclude that the Uganda oil project is generally profitable, and that deferring oil production is justified except in the cases where the net convenience yield or cost inflation is high.

Introduction

The upswings in crude oil prices between 2004 and 2013 renewed interests of international oil companies (IOCs) in Africa's vast oil reserves. For instance, between 2011 and 2014, African countries accounted for around 20% of global oil discoveries [22]. In 2006, Uganda joined the list of prospective oil producing countries with 6 billion proven oil reserves in the Albertine Graben of which 1.4 billion barrels are economically viable for extraction [29]. Uganda's peak production is projected to be between 200,000 and 250,000 barrels of oil per day with extraction lasting 25 years (see Appendix B). The cost of extracting oil over this period will amount to approximately $19 billion in capital expenditures and operating expenses. Prior to this production stage, the development of infrastructure, operation facilities and production wells will cost about $12.5 billion.

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In addition to being highly costly, numerous uncertainties, irreversibility and lumpiness of investments in oil projects add to their complexity. Investment towards oil production is a step-wise process, from exploration, appraisal of oil reserves, development of oil fields and support infrastructure, actual production of oil to decommissioning. Investments at each sequential stage of oil project lifecycle are made in lumps and are sunk, for the most part, once expended. More so, each successive stage prior to the production stage typically do not lead to immediate cash flows but open up further investment opportunities. The capital intensity of oil investments makes them irreversible because the oil wells and operation facilities can only be used to produce oil. The complexities of oil projects are further exacerbated by market and technical uncertainties about; oil price volatility, operating expenditures during the long lifetime of the project, economically viable oil reserves, the amount of oil produced from proven reserves, and future world demand for oil [11,14].

The African Union Agenda 2063 advocates for expanded local ownership and increased control of oil and gas reserves[1] [4]. However, like many resource-endowed Sub-Saharan countries, Uganda has limited capacity to solely finance and operate immense complex oil projects [19]. Consequently, in the years 2012 and 2016, the government of Uganda issued oil production licenses to three IOCs under a contractual arrangement in the form of a Production Sharing Agreement (PSA). The issuance of the production licenses set track for investment in the development phase in preparation of oil production. However, slumps in oil prices beginning in 2014 forced IOCs to downsize their prior optimistic investment plans. IOCs significantly trimmed their local workforce and cut their investment budgets by 20 to 30% in response to the erratic downswings of global crude oil prices from USD 95 in mid-2014 to USD 30 in the first quarter of 2016 [28].

On the global front, the recent unprecedented collapse of world oil markets due to the prevalent global Covid-19 pandemic and Russia-Saudi Arabia oil price war in March, 2020, have widely disrupted oil investment activities. The global oil price fell from an average of USD 64 in 2019 to USD 25 in the second quarter of 2020, amidst a record deep in oil demand. Thus, resulting in an estimated drop in 2020 global upstream investment of about one quarter compared with 2019 [23]. New potential oil-producers are likely to be worst hit as they present IOCs with ease of abandoning or downsizing the investments. Although oil prices partially recovered to USD 50 by the close of 2020, the looming ambiguity about the duration of the pandemic has exacerbated the uncertainty of future global oil investments and oil price movements. Another uncertainty facing the oil market is future climate policies, illustrated by the large difference when it comes to global oil demand between the Stated Policy Scenario and the Sustainable Development Scenario in the IEA [24].

These developments in the oil markets have awakened concerns about whether investment in extracting Uganda's oil can deliver sufficient returns to all parties amidst periods of high oil market uncertainty. To address these concerns, this study applies real options methods which recognise the lumpiness, irreversibility, sequentiality [13] of investments in oil projects and the prevailing uncertainty of the economic environment in which those projects are undertaken [15].

Embedded in the specificities of oil contracts, oil investment decisions are treated as real options. As stipulated by the PSA, the government of Uganda retains the ownership rights to the oil resource while the IOCs assume the risks of investing in exploration, development and production. Inherent in their production licenses, the IOCs have the right to exercise different managerial flexibilities in order to strategically capitalize on revenue windfalls arising from periods of high oil prices while mitigating the risks associated with low revenues during times of low oil prices. Among the potential flexibilities, we can identify; i) the option to defer production; ii) the option to expand production to smaller fields; iii) the option to indefinitely abandon production.

How valuable are these flexibilities and how can their value be quantified [35]? Similar studies have applied real options theory to address these research questions (e.g [3,16,17,25,26,34]). Despite the renewed interests of international oil companies (IOCs) in Africa's vast oil reserves in the past two decades, most of these studies are focused on developed reserves in high-income countries. We are aware of only three previous studies on Africa's undeveloped reserves (see [2,18,32]). It is against this premise that this study applies real option methods to value Uganda's undeveloped reserves, while accounting for uncertainty of crude oil price volatility.

We specifically quantify the value of deferring production and how this value changes at different levels of crude oil price volatility. Our base case results suggest that deferring production by another year adds value of $0.9 billion to Uganda's oil project. The value of the option to delay production particularly increases at lower crude oil prices amidst higher crude oil price volatility. The value of the option to defer production reduces as the net convenience yield rises and reaches zero at a critical price of $65 per barrel of crude oil. At low oil prices, increases in cost inflation result in negative values of both static Net Present Value (NPV) and expanded NPV. We conclude that the Uganda oil project is generally profitable, while deferring oil production is justified except in scenarios where the net convenience yield or cost inflation is high.

In section two, a literature review of the application of real options to the analysis of oil investments and the contribution of our paper are presented. The third section describes Uganda's oil extraction project. The fourth section describes the data and discusses the binomial lattice model, as applied to the project. The fifth section presents the analysis and results of the option value of deferring production. The last section draws some conclusions.

[1] The African Union (AU) Agenda 2063 is a plan for Africa's structural transformation and was agreed upon by the Heads of AU member states in May 2013. The AU envisages 'Transformed Economies and Jobs' as its Goal 5. To achieve goal 5, one of the priority areas is 'Expanded ownership, control and value addition (local content) in extractive industries' (see African Union Commission, 2014).

Literature review

Real options theory was invented in 1977 in response to the various limitations of the traditional discounted cash flow (DCF) theory [27] and first applied to the valuation of oil and gas production projects by Brennan and Schwartz [8]. Since then, there has been growing applications of real options valuation techniques to analyse managerial flexibility in oil exploration and production investments. The literature reviewed presents diverse techniques to real option valuation and the modelling of the stochastic process of crude oil prices. For instance, Lund [26] applied a binomial option pricing model and Geometric Brownian Motion (GBM) as the stochastic process of the oil price to measure the value of initiation, termination and capacity flexibility in Norway, finding that the role of flexibility adds significant value to the oil projects. Fleten et al. [17] applied the Least Squares Monte Carlo (LSMC) method to value expansion of an offshore oil field by tying in a satellite field, and the option of early shut down in Norway, modelling the oil price as a GBM. Their study found that the tie in option has significant value if the oil price increases, while early shutdown has insignificant value.

Aleksandrov and Espinoza [3], estimated a multiple real option optimization problem for Brazil and United Arab Emirates by employing the Least squares Monte Carlo method, assuming that the oil price follows a mean-reverting stochastic process. Their results showed that the net present value of both countries' oil reserves increases significantly when production decisions are made conditional on oil prices. A related study by Elmerskog [16] applied the binomial option pricing model with a GBM price model and the Least Squares Monte Carlo method to estimate the value of co-producing adjacent oil fields in Norway. The study found that including the option of timing production adds significant value while early shut down adds meagre value, in line with Fleten et al. [17].

Kobari et al. [25] estimates the value of an oil sand plant in Canada, while accounting for oil price uncertainty by employing a trinomial tree technique under the assumption of a mean reverting stochastic process for oil prices. The study also found the critical spot oil price should be significantly low for the plant to shut down. Also Abadie and Chamorro [1] applied Monte Carlo simulations to estimate managerial flexibilities in production from oil wells in Canada, drawing on an Integrated Geometric Brownian Motion (IGBM). The authors showed that the value of deferring production was significant while the abandonment option was less valuable.

For the specific regional case of Africa; Abid and Kaffel [2] present a methodology to evaluate an option to defer an oilfield development and apply it to a Tunisian oil project. After identifying the appropriate stochastic processes for three risk factors (crude oil price, convenience yield and risk-free interest rate), they applied LSMC to estimate the value of the option to defer by means of one-factor, two-factor and three-factor pricing models. Their results showed that the value of the option to defer reduced with the number of stochastic risk factors included in the model. Qui et al. [32] also developed a multi-factor real options model and applied it to an offshore oil project located in West Africa. Similar to Abid and Kaffel [2], their results under a multi-factor real options model were more conservative than those given by the single-factor model. These deductions by Qui et al. [32] and Abid and Kaffel [2] are based on a theoretical comparison of single-factor and multi-factor real options models. Our study deviates from their approach by making a base case analysis with oil price as our only stochastic variable followed by sensitivity analyses to estimate how the option to delay production changes with variations in cost inflation, net convenience yield and volatility.

Fonseca et al. [18] applied a binomial tree model to value the option to delay development of an oil field in Africa[2], under the assumption that crude oil prices follow a GBM stochastic process. They also assume that the expiration time for the option is five years. Their results showed that the value of the option to delay development increased with volatility. They also show that the trigger price reduces as the volatility increases and as they near the expiration of the option. Contrary to Fonseca et al. [18], the real options considered in our framework is the possibility to defer production of the first barrel of oil. This is based on the premise that the option to defer production is the most relevant for analysis of undeveloped reserves [15].

Our study establishes binomial lattices to quantify the real options values. A binomial lattice model is considered to be the most suited technique to numerical approaches, as they offer simplicity and intuition [5,7,33]. Binomial lattices method is also proposed because it allows modelling of sequentiality in projects that require irreversible investments [21].

Description of Uganda's oil project

Oil discoveries in the Albertine Graben

After a century of on-and-off oil exploration due to political instability, insecurity, oil price volatility, social concerns, contractual and regulatory disputes, a series of oil discoveries emerged as successful in 2006. The first commercial discovery was made by Hardman Resources on its Mputa-1 well, followed by Heritage Oil with its Kingfisher discovery and other multiple drilling successes in the Albertine Graben thereafter. In the same year, Tullow Oil Uganda acquired the assets of both Harman Resources and Heritage Oil. From 2006 to mid-2014, overall, there was substantial exploration success of 88%, with 102 out of 116 wells yielding proven hydrocarbons. The estimated resources have increased from 300 million barrels in 2006 to 2 billion in 2010 and 3.5 billion barrels two years later. As of 2018, official reports indicated that there are 6.5 billion

[2] The authors did not specify the African country or region.

proven oil resources in the Albertine Graben of which 1.4 billion barrels are recoverable reserves [29]. The Albertine Graben is approximately 500 km long, averaging 45 km in width and measures about 23,000 square kilometres in Western Uganda (see map in Appendix D). The discoveries in these areas are reported to be the largest onshore oil discoveries in Sub-Saharan Africa in over 20 years [28] and place Uganda as the eighth country with the highest proven oil reserves in Africa. Only 40% of the total prospective area in the Albertine Graben has been explored, which indicates potential for additional oil resources upon further exploration.

It is however noteworthy that this region has the highest biodiversity in Uganda and is host to 70% of Uganda's protected area encompassing natural forests, national parks, fresh water bodies, game reserves and biosphere reserves (Plumptre et al., 2018). A study by Byakagaba et al. [9] on oil exploration in the Albertine Graben reported noise pollution due to blasting of rocks during exploration, soil erosion due to clearing of vegetation for road construction and wildlife disturbance due to increased human activity in the wildlife reserve as the major environmental impacts. Oil activities in the region thus raise concerns of environmental degradation, particularly their impact on the biodiversity of the natural habitats. Notwithstanding these pertinent issues, environmental concerns are beyond the scope of this study.

Issuance of production licences

By 2016, the Government of Uganda, had granted production licenses to three IOCs; Tullow Oil Uganda, Total E&P Uganda and China National Offshore Oil Corporation (CNOOC) Uganda Limited. The two latter firms acquired a third of Tullow's equity each in a farm-down and formed a joint venture partnership. The production licenses, as part of the comprehensive PSA, are valid for 25 years upon the extraction of the first oil [29]. After the required investments are made and oil is extracted, costs of expenditures on exploration, development and extraction are recovered by the IOCs and the remainder of the rent is shared between the IOCs and the government. The government also receives revenue in form of royalties, bonuses and taxes owed by the IOCs, as per the PSA.

The issuance of these production licenses forms the basis for the Final Investment Decision (FID)[3] in preparation for the development phase, structured under three major oil fields; the Kingfisher, Buliisa and Kaiso-Tonya.

Projects, forecasted production and cost profiles

For purposes of modelling, we present a generic timeline for the overall oil project (see Fig. 1). We consider that development starts from Year -1 to year 0 and thereafter production commences from Year 1 through to Year 25 (see Fig. 1) for Buliisa and Kingfisher oil fields and at a later year for Kaiso-Tonya.

The Buliisa oil fields cover the EA2 North and EA1 blocks, North-East of Lake Albert, with eleven fields under development (see Appendix A). Total is the operator and lead investor, with CNOOC and Tullow as equal partners. The Buliisa fields hold the highest reserves among all three projects, estimated at 819 million barrels of recoverable oil, with its production peak in its fourth year of extraction (see Fig. 2).

The Kingfisher oil field encompasses the EA3A Block, South of Lake Albert (see Appendix A) and is estimated to have 196 million barrels of recoverable oil, with expected peak production in its eighth year of extraction (see Fig. 2). Although CNOOC is the operator and lead investor, equal shares are held by Tullow and Total.

The Kaiso-Tonya fields cover EA2 Block, South East of Lake Albert, with three oil fields (see Appendix A). The oil fields are relatively small, with 39 million barrels of recoverable oil, and would not be economically viable on their own. The fields are thus the least complex and least costly as their production is tied-in to that of the Kingfisher oil field. For instance, Kaiso-Tonya has no central processing facility, as the extracted oil is transported to the facility of Kingfisher. The production from Kaiso-Tonya begins in the ninth year of Kingfisher's production to compensate for the decline in the latter field (see Fig. 2). Tullow is the operator and lead investor in the Kaiso-Tonya fields, with equal stakes held by the two other joint venture partners.

A key precondition for the production stage is the construction of a pipeline that will transport the crude oil for export through Tanzania (see Appendix D for details). Other infrastructural requirements include roads and the Hoima international airport. The initial investment cost at the development stage will amount to $12.5 billion. Appendix B shows the rest of the costs (i.e. the capital expenditures (CAPEX) and operating expenses (OPEX)) expended on the three oil fields. The CAPEX begins two years prior to production and includes all costs on development of oil production plants such as; expenditures on equipment, raw materials (e.g. steel and concrete), prefabrications, construction, engineering designs, project management, insurance and certification. CAPEX will be retrospective costs at the year of production start-up, and hence will be sunk if a decision to delay production is made that year. The OPEX entails the cost of running the oil production plants over their lifetime after construction is completed towards personnel for maintenance and operations, chemicals and fuels, spare parts, well servicing and other expenses to maintain production. Due to the larger number of reservoirs in Buliisa oil fields, contributing to its higher complexity, the absolute CAPEX and OPEX are higher than those of the other two oil fields.

[3] The FID on the oil project has been considerably delayed since 2006 due to tax-related disputes, alterations to contractual terms and political issues. We do not explicitly address the FID delays as they are beyond the scope of our study.

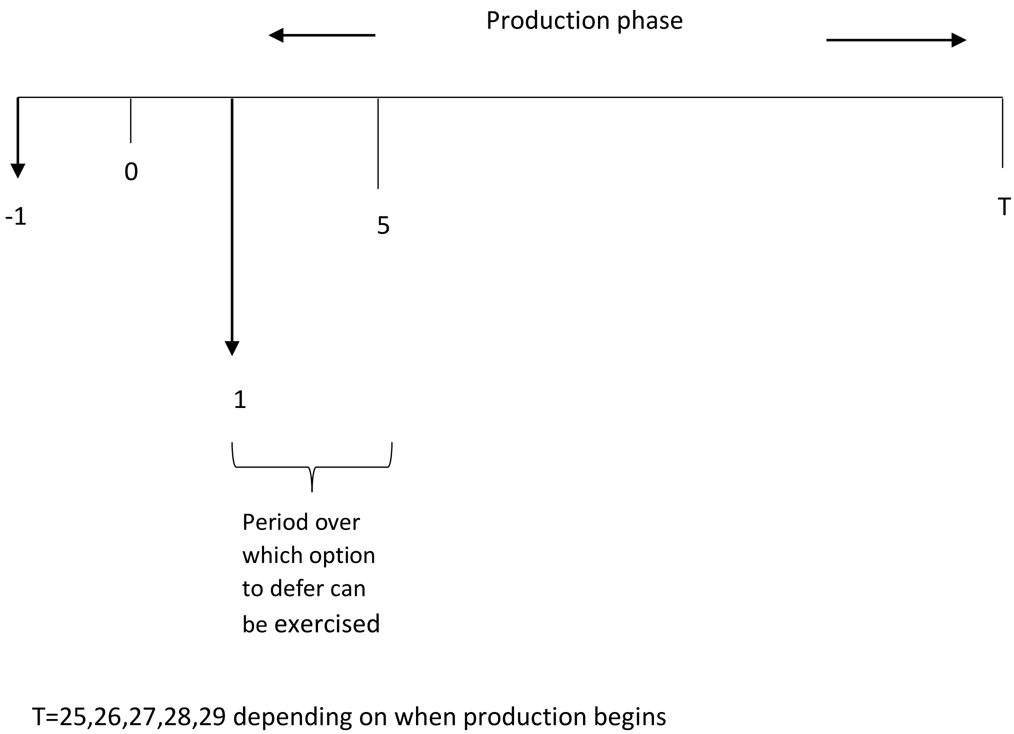

Fig. 1. Generic timeline for the overall oil project showing production phase and when there is an option to defer.

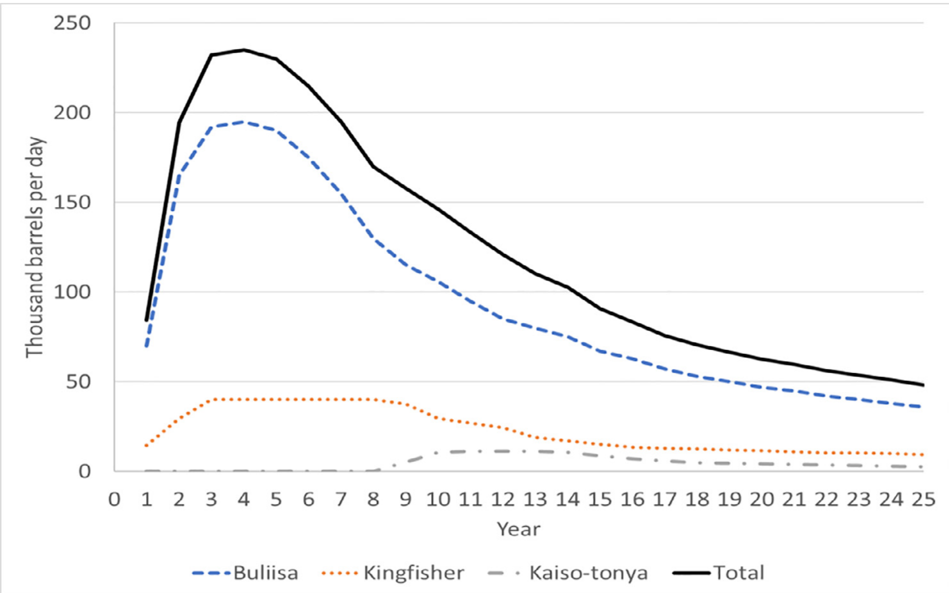

Fig. 2. Production profile for each oil field and in total after start-up of production ('000 Barrels of oil per day)

Valuation framework

The option to defer production and assumptions

Our study focuses on the option to defer production of the Kingfisher and Buliisa oil fields for up to five years (while we do not consider the Kaiso-Tonya fields in our analysis) beyond the planned commencement year 1. We assume that the option to defer is exercisable within the first five years (beyond which it expires) since the IOCs can renew their produc-

Year -1		Year 0		Year 1
				149.94
			118.31	
		93.36		93.36
	73.67		73.67	
58.13		58.13		58.13
	45.87		45.87	
		36.19		36.19
			28.56	
				22.54

Fig. 3. Binomial lattice modelling future oil prices in USD during the first two years of the project.

tion licenses for an additional five years only. A related assumption is that; upon commencement of production, extraction continues without any disruption, since restarting of production would be very costly and thus deemed economically unviable. For every subsequent year, management would save the planned outlays if the conditions are not favourable. Since the option to defer implies sacrificing accruing revenues early, the option is only justifiable if the value of deferring actually exceeds the value of beginning production earlier by a substantial premium [25]. We further assume that the decision to defer production has no impact on the production and costs profiles. For instance, if production is deferred from year 1 to year 2, then all the costs shown in Appendix B, except the two first years before production start-up, are deferred by one year. The valuation framework is finally coded and implemented in Python in order to compute values.

Data and variable description

The data used consists of the oil production profile, cost of development, CAPEX and OPEX of the Kingfisher and Buliisa oil fields, as projected over the period of 25 years (see Figs. 2 and 3). All these cost data were obtained from estimates by Ward and Malov (2016) and through interviews with officials at the Petroleum Authority of Uganda and Ministry of Energy and Mineral Development. The cost estimates exclude sunk costs towards; land acquisition, contingency, Front-End Engineering design (FEED), Environmental and Social Impact Assessment (ESIA), feasibility studies and other studies that are completed before the development phase commences.

The monthly historical spot prices of Nigeria's Bonny Light crude from January 2006 to December 2018 were used to compute the annualised volatility. The spot price of Bonny Light crude is chosen as a proxy for Uganda's crude oil over Brent and WTI crude because of its similar characteristics in terms of API gravity and sulphur content,[4] as well as the geographical location. The price data is obtained from the website of the Central Bank of Nigeria [10].

Geometric Brownian Motion and Risk-neutrality

In this study binomial lattice model based on Cox et al. [12] is established to estimate the value of the project under flexibilities of deferring production. To construct the binomial lattices, we begin by presenting the embedded assumptions and follow by deriving the formulae for the parameters of interest.

We assume that crude oil prices follow a Geometric Brownian Motion (GBM), such that;

$$dP = \mu P dt + \sigma P dW \tag{1}$$

Where $P$is the crude oil spot price at time t, dW is the increment of the Wiener process with $dW = \epsilon * \sqrt{dt}, \varepsilon \sim N(0, 1)$. μ is ε is a normally distributed variable with mean equal to zero and variance equal to 1. the drift rate and σ is volatility rate. μ and σ are taken as constants. In contrast to mean-reverting process, our choice of GBM as the appropriate stochastic process for modelling crude oil price movements is premised on three arguments. First, it is easier to model real options with the underlying assumption of GBM [15,32]. Second, extremely long price series (i.e 100 years and more) are required to correctly confirm that a series is mean reverting (Dixit and [30,31]). Our price series of 13 years is, in this regard, relatively short which limits us from ascertaining whether the series is mean reverting. Third, while empirical studies have shown that oil prices exhibit mean reverting behaviour (see [2,6]), GBM is less likely to result in significant evaluation errors when compared to mean reversion [20,31]. A mean reverting model faces challenges with half-life rates and equilibrium price levels, which when wrongly applied could give evaluation errors [31].

Further, at any time interval $(t,\ t + \Delta t)$ along the lattices, the price may go up by the multiplier u with a probability of q or fall by the multiplier d with a probability of $1 - q$, at the end of the time interval $t + \Delta t$. Following the model by Cox

[4] Bonny Light crude has an API gravity of 32.9°-34.5° and a sulphur content of 0.16%. Uganda's crude has an API gravity of 33° and a sulphur content of 0.16%. WTI's quality is characterised as API gravity of 39.6° and 0.24% sulphur compared to Brent crude with API gravity of 38° and 0.37% sulphur.

et al. [12], the up and down multipliers are computed from the volatility and the time step (Δt) such that;

$$u = \exp(\sigma \Delta t) \tag{2}$$

and

$$d = 1/u \tag{3}$$

Thus, an increase from P_t to $P^+_{t+\Delta t}$ and a decrease from P_t to $P^-_{t+\Delta t}$ are calculated as

$$P^+_{t+\Delta t} = P_t u \tag{4}$$

$$P^-_{t+\Delta t} = P_t d \tag{5}$$

The risk-neutral probability q is calculated as;

$$q = (\exp\left(r_f.\Delta t\right) - d)/(u-d) \tag{6}$$

where r_f is the risk-free rate.

The risk-neutral probabilities q and $1-q$ are constant at all steps of the lattices since we take volatility, σ, to be constant in our model.

The parameters u , d and q are derived such that in case of infinitesimal Δt, the spot price follows a log-normal distribution where its mean and variance are; $E[ln(\frac{\tilde{P}_t}{P_0})] = (r_f - \frac{1}{2}\sigma^2)t$ and $Var[ln((\frac{\tilde{P}_t}{P_0}))] = \sigma^2 t$.

Parameter values

In order to compute the up and down multipliers and the risk-neutral probabilities, we proceed to determine our parameters of interest (i.e volatility, risk-free rate and length of time steps). The historical spot price data of the Bonny light is used to compute the annualised volatility rate and is estimated to be 33.5% per annum (see Appendix E for details on computations). The time step Δt is set to be 0.5 year, and the continuous risk-free rate r_f is 2.39% per year. The risk-free rate corresponds to the US 3-month treasury bill rate (US Department of the Treasury, 2018) since all the project costs and revenues are expressed in US Dollars. Using these parameter values in formula (2), (3) and (6) gives that u = 1.2673, d = 0.7891 and q=0.4662. Thus, $1-q = 0.5338$.

Fig. 3 shows the initial oil price at Year -1 (i.e. two years before first decision at Year 1) and the modelled price outcomes until Year 1 when using half-year size time steps in the binomial lattice. The initial crude oil price used in the binomial lattice is set to $ 58.13 per barrel which corresponds to the average daily oil price in December 2018. For the base case, we apply the December 2018 price but apply varying prices in our sensitivity analysis (see Appendix C). Based on Eqs. (4) and (5), the price goes up by the multiplier u or falls by the multiplier d.

Analysis and results

Present value of starting production at Year 1

At Year 1, the oil prices are observed, and decisions are made to start production or not. For instance, if the oil price at Year 1 is 149.94 and production starts, then future expected revenues in Year 2 will be dependent on the expected oil price in Year 2, and so on for each of the subsequent years. Since an option pricing framework is used, it is the expected oil prices under the risk neutral measure that are of interest. The expected risk-neutral oil price at time m+n, given oil price realization j in Year m i.e. E[$P_{j,m,n,}$], can be determined from the formula $E[P_{j,m,n}] = P_{j,m} \times \exp(r_f * n)$. Where $P_{j,m}$ represents the different prices in the binomial lattice at different start year m, m=[1..5]. This formula is applied to all the remaining years until the 25th year after production starts, i.e. n=[0..24]. Appendix C.1 shows the expected risk neutral prices E[$P_{j,m,n}$] for n=0..4 when m=1, i.e., given $P_{1,1}$ = 149.94, $P_{2,1}$ = 93.36, ..., $P_{5,1}$ = 22.54. That is, given the outcome from the binomial lattice at m=1, the expected risk neutral prices for Year 2-5 are presented. The expected prices for Year 6-25 are omitted from the table for ease of exposition.

Appendix C.3 shows the net cashflows $C_{j,m,n}$ from the first five years (given that production starts at Year 1), obtained by subtracting the annual CAPEX and OPEX expended on the two oil fields (see Appendix B for CAPEX and OPEX values) from the revenue shown in Appendix C.2.

Appendix C.4 shows the expected present value of the net cash flows ($S_{j,m,n}$) in the case m=1 given as;

$$S_{j,m,n} = C_{j,m,n} + S_{j,m,n+1,}/exp\left(r_f * 2 * \Delta t\right) \tag{7}$$

In general, $S_{j,m,n}$ is computed from the sum of the present value of all future expected cash flows after year m+n and the cash flow generated during year m+n. At Year 1, given m=1 and n=0 in this case, the project may have a total expected present value equal to either 150, 90, 52, 29 or 14 billion US dollar (see Appendix C.4). Which of these five expected values will be realized depends on the realization j of the oil price at Year 1 (see Appendix C.1).

j	Year 1	Year 2	Year 3	Year 4	Year 5
1	150.5	247.8	404.0	655.0	1058.0
2	89.9	150.5	247.8	404.0	655.0
3	52.2	89.9	150.5	247.8	404.0
4	28.7	52.2	89.9	150.5	247.8
5	14.1	28.7	52.2	89.9	150.5
6		14.1	28.7	52.2	89.9
7		4.9	14.1	28.7	52.2
8			4.9	14.1	28.7
9			-0.7	4.9	14.1
10				-0.7	4.9
11				-4.3	-0.7
12					-4.3
13					-6.4

Fig. 4.. Future present value of the project's cashflows if production is started in a given year (Year 1 to Year 5) and a given oil price realization j (in billions of US Dollars).

The present value of starting production at Year 2 to Year 5 and the option to defer

In order to determine the value of the project when there is an option to postpone the production for up to five years, the respective values for starting production at Year 2 to Year 5 must be computed. Then one can analyse if it is the best strategy to start at a given year or defer until the next year and take a new start/defer decision. Since the oil price is modelled as a binomial process, the number of possible price realizations will increase with the number of half-years, i.e. for Year 2 there are seven possible prices, for Year 3 nine prices and so on. In Fig. 4, the present values of the project, for given start years and price realizations, are presented.

In Fig. 5, the present values of the project, when there is an option to defer, are presented. The value of the project, option value to defer included, at each node ($V_{j,m}$) is computed by taking;

$$V_{j,m} = max\left\{S_{j,m,0};\, 0\right\} m = 5 \tag{8}$$

$$V_{j,m} = max\left\{S_{j,m,0};\, \left(q^2.V^{uu}_{j,m+1} + 2q(1-q)V^{ud}_{j+1,m+1,} + (1-q)^2 V^{dd}_{j+2,m+1}\right)/exp\left(r_f * 2\Delta t\right)\right\} m = [1..4]$$

Equations 8 mean that the IOCs are faced with the choices between starting at year m to receive cash flow generated during m and the expected present value of future cash flow, or deferring another year before taking a new decision. If the expected present value of deferring to start the project is higher than starting immediately, beginning production is postponed.

Finally, using backward induction, the expanded NPV at year -1 is computed as;

$$\begin{aligned} &ENPV_{-1} = C_{-1,} + C_0/exp\left(r_f * 2\Delta t\right) \\ &+\left(q^4V_{1,1} + 4 * q^3(1-q)V_{2,1} + 6q^2(1-q)^2V_{3,1} + 4q(1-q)^3V_{4,1} + (1-q)^4V_{5,1}\right)/exp\left(r_f * 4\Delta t\right) \end{aligned} \tag{9}$$

The variables C_{-1} and C_0 typically represent investment outlays that are made during Year -1 and Year 0, e.g., necessary infrastructure and further explorations. The option value to defer at each node is computed by subtracting the NPV with no consideration of options (in Fig. 4) from the expanded NPV (in Fig. 5). In comparison with Year values in Fig. 4, the values in Fig. 5 are slightly higher (151.4; 90.8; 53.1; 29.7 and 15.3 compared to 150.5; 89.9; 52.2; 28.7 and 14.1), which indicates that the value of deferring is slightly higher than starting production immediately. The results also indicate that the relative value of the option to defer is rather small, under the assumptions made in this analysis.

The value of option to defer

The results in the previous sub-section are taken as our base case analysis. From the results of traditional Discounted Cash Flow (DCF) method, the NPV at year -1 is found to be $ 36.5 billion indicating that the oil project is viable. When the option to defer production by another year is considered, the expanded NPV is estimated to be $37.4 billion, thus generating an option value of $0.9 billion. The positive option value emanates from the flexibility to defer expending the remaining OPEX and CAPEX to the subsequent year and management's ability to benefit from random oil price rises while minimising the risks from unfavourable oil price falls. Therefore, production should be postponed. These findings are similar to those of Abadie and Chamorro [1].

j	Year 1	Year 2	Year 3	Year 4	Year 5
1	151.4	248.5	404.5	655.2	1058.0
2	90.8	151.2	248.2	404.2	655.0
3	53.1	90.6	150.9	248.0	404.0
4	29.7	52.9	90.4	150.7	247.8
5	15.3	29.4	52.6	90.1	150.5
6		14.9	29.1	52.4	89.9
7		6.4	14.6	28.9	52.2
8			5.9	14.3	28.7
9			1.7	5.4	14.1
10				1.1	4.9
11				0.0	0.0
12					0.0
13					0.0

Fig. 5. Future present values with when there is an option to defer (in billions of US Dollars).

Sensitivity analysis

Behind the figures in the result section there are a number of assumptions that affect the outcomes. In this section we analyse to what extent changes in volatility rates, net convenience yield and cost inflation affect the net present value of the project and the option to defer. In the sensitivity analysis we have also, unless nothing else is stated, applied a binomial tree with 10 timesteps per year, comparted to the two time steps per year illustrated in chapter 4.

Sensitivity to changes in volatility rates

Volatility is a main driver to the option value. In order to illustrate its impact on the net present values for the project, with and without options, we compute the static NPV and option values for different oil price and volatility rates as presented in Appendix C.5. According to our results, notwithstanding the volatity rate, the static NPV is comparably low at lower oil prices and further reductions in the oil price increase the value of the option to defer. This implies that the traditional DCF significantly undervalues the oil project. Our finding is consistent with postulations by Smith [33]; Dixit and Pindyck [15]; and Trigeorgis [35] on justification for real options theory over traditional DCF. Similar to findings by Fleten et al. [17], Abadie and Chamorro [1] and Fonseca et al. [18],[5] our results also show that the option to defer is significant in the case with low oil prices and high volatility rates. This is also an expected outcome since higher volatility increases the possibility for lower oil prices and thus increases the value of having the option to defer the project. Intuitively, when the oil price is low and oil price volatility is high, it is optimal to delay oil production.

Another is that there are equal and approximately equal option values in cases of low volatilities, i.e. 25% and below, and at moderate to high oil prices. The reason is that, in those cases, it is almost certain that the oil price will be at a level where the project is expected to be profitable (when investment decision is made), while the option value comes from the fact that we can push expenses one year ahead. In the base case, it is assumed that there is no cost inflation, thus pushing them forward will increase the NPV. The impact of cost inflation is analysed in Section 5.4.3.

Sensitivity to changes in net convenience yield

In the base case analysis, it is assumed that the net convenience yield is equal to zero during the time horizon. However, since oil is a consumption asset, it is likely that the net convenience yield is different from zero. For instance Qui et al.

[5] Fonseca et al. [18] only analyse the influence of volatility on the option to defer an oil project.

Table 1
Comparing net present values of starting immediately and defer start for different values of oil price, net convenience yield and cost inflation. The optimal decision for each combination is highlighted in grey.

Oil price at Year 1	Net conv. Yield =0% Cost inflation=0%		Net conv. Yield = 0% Cost inflation= 4%		Net conv. Yield=4% Cost inflation = 0%		Net conv. yield =4% Cost inflation =4%	
Action	Start now	Defer	Start now	Defer	Start now	Defer	Start now	Defer
121.10	119 588	120 507	115 333	115 112	84 654	81 178	80 400	76 464
73.82	68 965	69 884	64 711	64 489	47 670	45 644	43 416	40 930
45.00	38 106	39 047	33 852	33 744	25 125	23 983	20 870	19 354
27.43	19 295	20 401	15 040	15 657	11 382	11 122	7 127	7 357
16.72	7 828	9 507	3 573	6 036	3 004	4 272	-	2 125

[32] calculated a value of 1.5% and modelled their net convenience yield as a function of change in oil production, after-tax profit of oil sales and oil value of developed reserves. Abid and Kaffel [2] also showed that the net convenience yield can be negative. For our sensitivity analysis, we assume that net convenience yield varies from -6 to +6%. In Appendix C.6, we therefore present static and expanded NPV for different values of oil price and net convenience yield. Our results show that the NPV, both static and expanded, drops rather significantly as the net convenience yield increases. This is natural since increased net convenience yield reduces the expected oil price increase in the option pricing models and thus will reduce expected future revenues. At an oil price of $65 per barrel and net convenience values of 4-6%, the expanded NPV is almost equal to the static NPV. This implies that the option to defer adds meagre value at high oil prices and high rates of net convenience yield. This is natural, as oil production is almost certain to begin at a high price such that deferring has no value. Our results are similar to those of Abid and Kaffel [2] who found that adding net convenience yield to the real options model reduced the value of the option to defer.

Sensitivity to changes in cost inflation

In the original analysis it is assumed that OPEX and (remaining) CAPEX are not changing if the project is deferred. That is, if a start-up decision is postponed by one year, OPEX and CAPEX are just moved one year ahead in time. So, in case of no inflation and positive discount rate there is an incentive to push OPEX and CAPEX forward in time. In Appendix C.7, the static and expanded NPV are shown for different values of the cost inflation for OPEX and CAPEX. Two different values of the cost inflation, in addition to the base case of no inflation, are incorporated. We assume a cost inflation rate of 2.42% equal to the risk-free rate of return (discrete) and thus identical to the expected price increase of the oil price in the option model. The NPV is, not surprisingly, negatively affected by increasing cost inflation. An oil price of $25 per barrel and an annual cost inflation rate of 4% result in negative NPVs, both static and expanded, and thus rejection of the project (see Appendix C.7). In case of oil prices equal to $45 and $65, the NPVs decline by approximately 10-20% when cost inflation increases from 0% to 4%. In addition, at all oil prices, the value of the option to defer drops with rising cost inflation. In principle, cost inflation rises the oil price required to make the oil project economically viable, and renders the option to defer worthless.

Optimal exercise policy

For most cases in the base case analysis the optimal exercise policy is to defer until year 5 (the last opportunity) before exercising the option to start extraction. There are two reasons for that. First, in the original analysis the expected oil price increases more than the increase in cost over time, which has been dealt with in 5.4.3. Second, in case of low initial oil price, starting the project immediately might have a lower NPV than deferring a year and ending up either at a higher NPV or zero NPV in the case of no start-up. The expected NPV from deferring is higher due to limited downside.

It is of interest to see how net convenience yield and cost inflation affect the optimal exercise policy. Table 1 illustrates the optimal exercise policy at year 1, given oil price $45 at year -1 and for different values of the net convenience yield and cost inflation. In this case a binomial tree with two time steps per year is used in order to ease exposition. The table presents the NPV of investing immediately at year 1 and the NPV of deferring for different combinations of oil price realization, net convenience yield and cost inflation.

Each cell in Table 1 presents the NPV of investing immediately (i.e. Start now) to the left of the NPV of deferring. For each combination the highest NPV is marked with a grey shade and it can be seen that there will be different exercise policies. If both net convenience yield and cost inflation are equal to zero, then it will always be optimal to defer, which is what we concluded before in the sensitivity analysis. In case of cost inflation equal to 4% and net convenience yield equal to zero, it will instead be optimal to invest immediately at year 1 if the oil price is 45, 73.82 or 121.10. On the other hand, if a lower price is realized in Year 1, then it is optimal to defer as the best outcome may be to not start the project at all. If the net convenience yield is 4% and cost inflation is equal to zero, then it will be optimal to invest immediately unless the oil price is very low (16.72), in which case it is optimal to defer and consider not extracting at all. There is also a similar pattern for net convenience yield and cost inflation equal to 4%.

As can be seen from Table 1, there will be several factors that will affect whether it is optimal to start or defer production. In the real options literature, see e.g. Dixit and Pindyck [15], it is common to analytically derive a trigger price where it is optimal to invest but these models typically rely on restricting assumptions regarding the project. Our research is based on an existing oil project where it is required to use numerical methods to determine a value and thus no trigger price is determined in an analytical way. The pattern seen in Table 1 is the same as in analytical models, in that when oil prices are higher, this will trigger an investment. The actual trigger price will however be dependent on a combination of oil price, net convenience yield, cost inflation and the characteristics of the project. In the case of existing projects, one has to perform a detailed numerical analysis to find this out. We also conclude that incorporating flexibilities in strategic decision making would give government a higher bargaining power in petroleum licensing, and also ensure high returns from upswings while mitigating losses emanating from downswings in the oil markets.

Conclusion

The upswings in crude oil prices between 2004 and 2013 renewed interests of international oil companies (IOCs) in Africa's vast oil reserves. During this period, Uganda with an estimated 1.4 billion barrels of economically viable reserves, joined the list of prospective oil producers. In 2012 and 2016, the government of Uganda effected its first PSAs with three IOCs. The erratic downswings of crude oil prices between mid-2014 and 2016, however, awakened concerns about whether investment in extracting Uganda's oil can deliver sufficient returns to all parties amidst periods of high crude oil price volatility.

Inherent in the PSA, these IOCs have a number of potential real options. Our study addresses the valuation of the option to defer production, as we consider this most suited as for the analysis of undeveloped reserves. Following Cox et al. [12], we establish binomial lattices to quantify the real options values, and model the stochastic oil price process as GBM. Our study contributes to the scanty literature on real options valuation of Africa's oil projects, as most existing studies are focused on developed reserves in high-income countries.

Our results from the base case analysis show that deferring production by another year adds value of $0.9 billion to the oil project and it is thus optimal for the IOCs to defer production. The positive option value partly emanates from our assumption that management is able to defer expending the remaining OPEX and CAPEX to the subsequent year.

We further analyse the sensitivity of the option value to crude oil price, crude oil price volatility, net convenience yield and cost inflation, and illustrate combinations when it is optimal to start production now or wait, respectively. The value of the option to defer production particularly increases at lower crude oil prices amidst higher crude oil price volatility. In this case, the static NPV is comparably low and further reductions in the oil price may result in a project with negative NPV implying that the value of the project is undervalued by the traditional DCF approach. When the rate of net convenience yield and oil price are high, the value of the option is lower and becomes worthless at a critical price of $65 per barrel of crude oil. At low oil prices, increases in cost inflation result in rejection of the project, as both static and expanded NPV reduce to negatives. When cost inflation is equal to 4% and net convenience yield is equal to zero, the option to defer is worthless at oil prices of $45 and above. We reach the same conclusion when the net convenience yield is 4% and cost inflation is equal to zero.

In this research it is shown using data from an existing oil project case that the option values and optimal exercise policies, i.e. invest or defer, are highly dependent on external factors like oil price, net convenience yield, inflation and volatility. Further numerical analysis can be performed to identify the trigger price for each combination of factors. However, in general, trigger prices will also be affected by project characteristics like investment outlays and oil production profile and thus differ between projects. In case of another project, the analysis must be carried out based on that project's data in order to determine the correct trigger price.

There are some ways in which the research study can be extended. One way to extend the study would be to estimate the value of flexibility under a Production Sharing Agreement (PSA). In our model, the terms of the PSA are excluded and the value of the option to defer does not depict what accrues to the host government and the oil companies, respectively. Also, the study can be extended to analyse how the value of real options depends on the tax policy by examining the implications of the magnitude of taxes on the firm's incentives to invest. Another extension of the study would be to model oil prices as jump diffusion or mean-reverting stochastic processes.

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Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Supplementary materials

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