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Cost Estimation Proxy Models for Economic Evaluations in Petroleum Projects: A Case Study from the Onshore Gas Field in the Southern Coastal Tanzania Basin

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ABSTRACT

Petroleum economic evaluation involves estimating revenues from forecasted production profiles and field costs including capital expenditures (CAPEX), drilling expenses (DRILLEX), and operating expenses (OPEX). The existing cost-estimating tool requires several inputs making it time-intensive and difficult to use with few data during the early stages of projects. Majority of the previously developed time-saving cost estimations proxy models rely on unrealistic assumptions that include uniform operational costs for different fields with a different number of wells, casings, and drilled depths. This work focused at developing proxy models that consider the variability of the development costs with different parameters. The developed models benefited from a three-step approach for CAPEX, DRILLEX, and OPEX estimations based on datasets from three wells from a gas field in southern coastal Tanzania. Firstly, cost sensitivity analysis was performed using QUE$TOR v15.1.0.18, a cost estimating commercial software to determine the most influential field parameters of the field costs. Secondly, the field cost models were generated based on historical cost data from the gas field using multivariable regression analysis with the help of Statistical Package for the Social Sciences software (SPSS) v22.0. Lastly, errors analysis was done for checking the predictive reliability of the models. Based on the analysis, the CAPEX and OPEX were found to be strongly linearly dependent on the size of processing facilities, number of producing wells in the gas field and production capacity, respectively. On the other hand, a nonlinearity relation was revealed on of the DRILLEX which was strongly dependent on drilled well depth and number of installed well casing. Results show that the developed models are useful and their reliability becomes robust when more data is used. A stochastic modeling approach was further recommended for the models to incorporate uncertainties associated with the parameters used to quantify the cost estimates.

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INTRODUCTION

The oil and gas industry remains the most highly capital-intensive and risky industry in the global. The investment in petroleum is diverse and complex in nature; its profit margins are associated with the high costs of developing new reserves and with many uncertainties (Mian, 2011). Therefore, thorough economic evaluations of any capital investment are necessary for exploration and production companies before committing resources. The economic evaluation of oil and gas projects is complex and several economic indicators including Net Present Value (NPV), Internal Rate of Return (IRR), and Profitability Index (PI) are employed in decision-making processes. The evaluation involves performing various field development scenarios using different models; the model that meets the economic constraints is adopted and implemented (Seong *et al*., 1995; Rowan, 1982). Development of projected cash flows used in such economic models includes three main sub-stages: forecasting field production, generating accurate oil/gas price predictions, and estimation of field cost figures including Capital Expenditures (CAPEX), Drilling Expenditures (DRILLEX), and Operating Expenditures (OPEX). In practice, engineers rely on the use of commercial software for estimating the field costs using value chain elements. However, the method is challenging because its use requires significant input data that is hardly available at the early stages of the projects. In addition, for operating fields, if project design conditions are changed, it takes considerable time and effort to complete the updates thus becoming difficult to optimize the field in real -time. This may lead to delayed decisions. For instance, it would take approximately 8.3-12.5% of the drilling time for onshore fields to run 25 realizations for DRILLEX estimations. The highlighted cost parameters are key to successful investment decisions in any petroleum project but their estimations are quite challenging particularly due to the complexity of the existing approach used and data scarcity at the beginning of the project. As part of efforts to find a simplified approach, this work focuses on the development of proxy models to be used in the estimation of field costs for petroleum projects based on datasets from a gas field within the coastal Tanzania basin (Figure 1).

Review on proxy models

The use of proxy models allows a simplified and time-saving cost estimation process for petroleum projects. The process eliminates repetitive live runs of cost estimation models in updating the project costs due to variations in input parameters (Diana, 2020). In addition, with advancements in technology, cost proxy models can further be used in real-time monitoring of field operating costs by incorporating the models into an automation program that is integrated with data acquisition sensors in the field. Generally, the in early phases of the project, the proxy models serve as the primary tool for cost estimation and are usually used as an estimation validation tool and sometimes for benchmarking purposes in the later phases. The literature presents several studies conducted to generate a parametric estimation of field costs based on historical data that should pass through a normalization process before fitting a model. Some of the studies (Nunes, 2017; Kuznetzov, 2011; Karlik, 1991) used standard regression analysis of cost data to generate equations that fit the normalized historical data to allow predictive estimations of capital costs. By using the same approach, Accioly (2016) generated proxy equations for estimating drilling costs of onshore wells while Diana (2020, 2019) developed proxy models for capital, drilling, and operating costs for offshore oil field development. Several studies (Diana, 2020; Silva, 2018; Nunes, 2017; Kuznetzov, 2011) have provided the cost proxy models based on equations that capture the first-order effect of the field design features under the study of project cost figures. However, one should be mindful that the generation of these proxy models involved a set of simplifications. For instance, Diana (2020) and Stanko (2020) assumed all wells drilled in a specific period had the same costs per well; their model estimation approach neglected the variability of the well's costs with depth and number of casing (N_c) strings. On the other hand, Nunes (2017) and Silva (2018) proxy equations are only suitable for numerical optimization schemes or analysis of uncertainty where the input is varied several times in an iterative process. The current work presents a method of developing proxy models for the estimation of the costs for petroleum projects based on actual data retrieved from three wells (Figure 1) penetrating different reservoir zones/intervals of an onshore gas field located in the southern coastal Tanzania basin.

Study area: location, geology, and petroleum system

The studied gas field is within the Ruvuma Basin of the southern coastal Tanzania basin. The datasets used are based on wells P, Q and R whose locations are shown by the green dots (Figure 1). Projection of this map is based on WGS 1984 UTM 37S. Development of the area has been mostly influenced by extensional tectonics and strike slip faulting (Thompson *et al*., 2019; Nicholas *et al*., 2007; Kapilima, 2003; Kent *et al*. 1971). Tectonically, basin development began during the Permo-Triassic following an extensional tectonic regime that initiated fragmentation of the Gondwana landmasses (Thompson *et al*., 2019). During this time period, the coastal Tanzania basin documented continental sedimentation that caused deposition of the Karoo organic-rich sediments (Magohe, 2019; Seward, 1922,) believed to have generated significant hydrocarbons along the coast (Mvile *et al*., 2021). The Permo-Triassic tectonic regime was followed by the Jurassic-Cretaceous extensional tectonics that culminated at the complete separation of Madagascar from East Africa (Thompson et al., 2019; Nicholas *et al*., 2007). This time period also recorded at least two transgressive-regressive cycles and episodic gravity flows that supplied sediments to the deeper basinal areas (Mvile *et al*. 2021). One of the regressive events was associated with widespread erosion of previously deposited sediments. This erosional event is reflected by the Albian unconformity (Figure 2; Mvile *et al*., 2021). The Miocene extensional tectonics and post Miocene extensional tectonics and strike slip faulting (Nicholas et al., 2007; Kent *et al*., 1971) followed old structural grains and formed several offshore depocenters. The strike slip faulting is believed to have created several structural traps. These structural traps contain significant gas accumulations in the offshore Tanzania basin (Sansom, 2018).

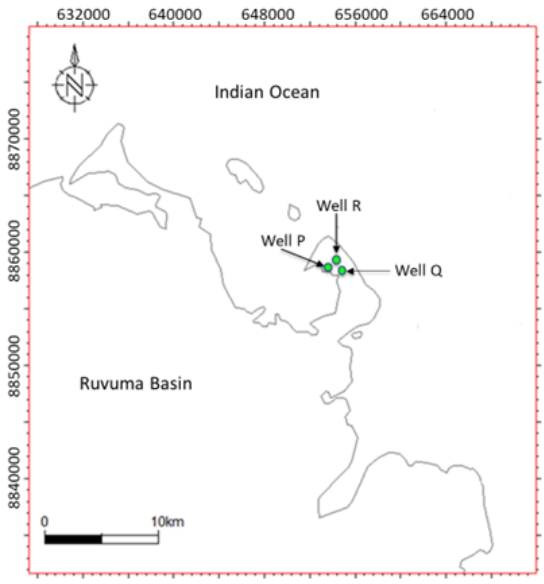

Figure 1: Location map of the study area.

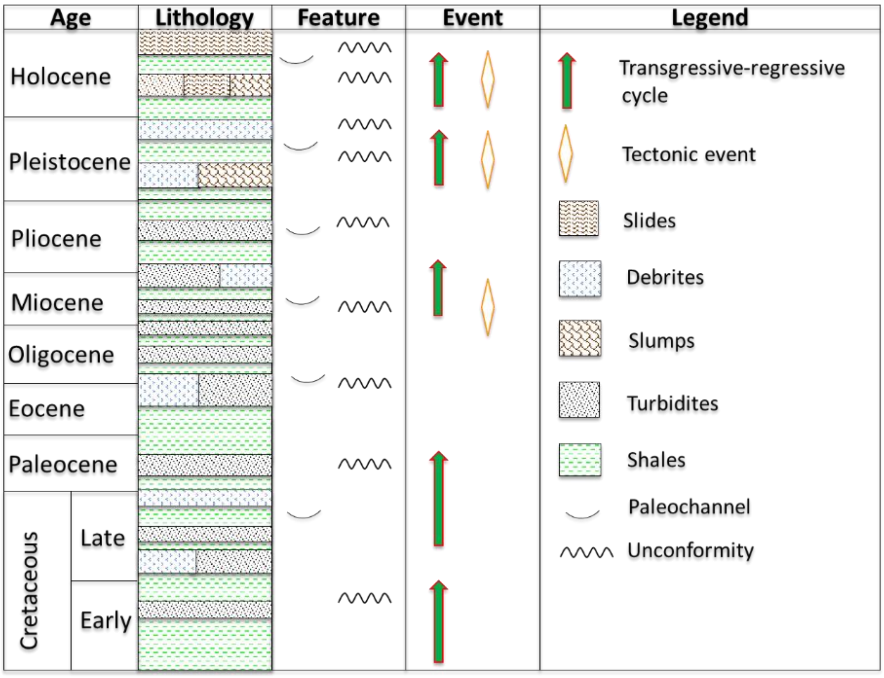

Figure 2: Generic stratigraphic scheme showing distribution of rocks and timing of occurrence of major tectonic events and sea-level cycles that influenced sedimentary development of the study area.

The Miocene and post-Miocene extensional tectonics were also linked to several transgressive-regressive cycles linked to variability in deposits grain-sizes. Periods of active fault movements and rapid sea level fall caused slope failures that triggered downslope movement of the previously deposited sediments to form slides, slumps, debrites, and turbidites units of the coastal Tanzania basin (Figure 3). In some places, these slope failures generated energetic sediment gravity flows that interacted with bottom currents to lay down well-sorted sand bodies with high net-to-gross ratios (Fonnesu *et al*., 2020). These sand bodies occur in the Cretaceous and Paleocene-Miocene intervals (Sansom, 2018) and are forming most of the petroleum reservoirs of the coastal Tanzania basin. Overall, the stratigraphy of the study area is dominated by shaly successions enclosing thin sand bodies with reservoir potential (Figure 2). Occurrence of paleo-channels is shown to be common in the Cretaceous-Holocene stratigraphy. These palaeo-channels may explain presence of several unconformities in the area. In this area, these thin sand bodies are commonly called reservoir zones thus the studied gas field is known to produce from different zones/intervals capped by thick shale layers (Figure 3). Fonnesu *et al*. (2020) and Sansom (2018) interpreted equivalent shale layers to be drift deposits stepping onto the channelized sand bodies forming the reservoir rocks of the offshore southern Tanzania. Occurrence of channelized systems over the whole stratigraphy (Figure 3) may explain turbidites deposition and distribution of unconformities in the area. The Cretaceous-Miocene stratigraphy of the Ruvuma Basin is dissected by several faults (Figure 3). The reservoir intervals (marked by green solid lines) are enclosed by thick shaly/drift deposits (bounded by red dashed lines) which form key seal rocks of the area. This configuration has caused the reservoir intervals of the study area to be subdivided into different zones separated by thick shales. Black solid lines are the faults that dissect the Cretaceous-Miocene strata.

Similar faults have been interpreted to form hydrocarbons migration pathways from deep buried source intervals to shallow seated gas reservoirs of the southern coastal Tanzania basin (Mvile *et al*. 2021).

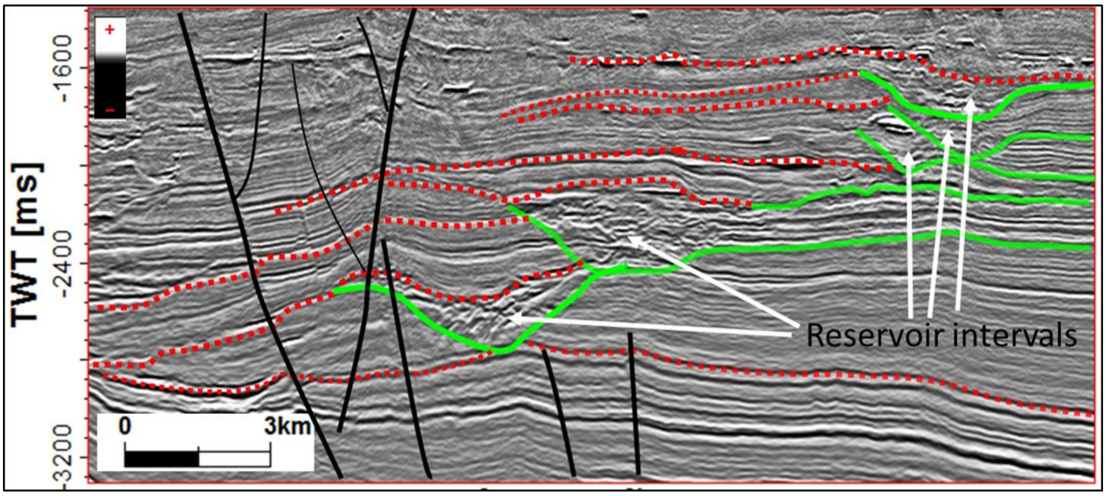

Figure 3: A seismic section showing the depositional configuration of the Cretaceous and Paleocene-Miocene reservoir intervals of the study area.

METHODS AND MATERIALS

Data collection

The field architecture and cots data used in this study were collected from a gas field in the southern coastal Tanzania basin (Figure 1). Data collection process was done in two phases. The first phase involved the collection of QUE$TOR software input data (Table 1) for sensitivity analysis while the second phase involved the collection of data from field reports for model generation (see Table 2, Table 3 &

Table **4**). The second phase was done after identifying different parameters affecting CAPEX, OPEX, and DRILLEX

Table 1: Collected Data inputs and Information

Parameter	Value/ Description	Unit
Onshore wells	3 wells	-
Main product	Gas	-
Condensate – gas ratio	1	bbl/MMscf
Reservoir pressure	2900	Psia
Recoverable reserves	220	Bscf
Gas molecular weight	16.10	g/mol
Carbondioxide	0	Mole%
Hydrogen suliphide content	0	Mole%
Gas production capacity	93	MMscf/d
Capacity of the processing facilities	10	MMscf/d
Capacity of the gathering system	155	MMscf/d

Table 2: Collected DRILLEX data (RPS Energy Canada Ltd., 2019)

Well Name	DRILLEX [Million$]	Depth [m]	Number of casing strings
P	26.350	2012	4
Q	28.157	2749	4
R	28.256	2788	5

Table 3: Collected OPEX data (RPS Energy Canada Ltd., 2019)

Year	OPEX [Million$]	Annual gas production (Bscf)	Onshore producin g wells
2009	5.86	0.34	1
2010	1.98	0.43	1
2011	3.97	0.69	2
2012	4.14	0.69	2
2013	5.78	0.69	2
2014	7.07	0.78	2
2015	6.98	5.78	2
2016	10.34	15.78	3

2017	11.47	17.16	3
2018	12.93	31.72	3

Table 4: Collected CAPEX data (RPS Energy Canada Ltd., 2019)

Year	CAPEX [Million$]
2005	33
2006	81
2015	30

Methods

The methods and steps that were used to accomplish this work involved cost sensitivity analysis, the development of cost proxy models using multivariable regression analysis, and model testing. Figures 4 and 5 summarize key steps that were involved in the successful development of the proxy models reported in this work.

Costs Sensitivity Analysis

This step involved examining variations of CAPEX, OPEX, and DRILLEX following the changes in gas production capacity (G_p), the number of wells (N_w), the capacity of the processing facilities (Q_{pc}), and the capacity of the gathering system. A total of nine (9) different cases were generated by using QUE$TOR software. The first case (base case/scenario) was generated based on the collected field information from three onshore wells (see Figure 1 for their location). This information includes a gas production capacity of 93 MMscf/d and the processing facility capacity and gathering system (manifold capacity) of 10 MMscf/d and 155 MMscf/d, respectively. The other eight cases were generated by varying one of the four parameters from the base case one at a time under the variation factor of $\pm$40%. The factor was derived from the estimated level that can be attained by using the QUE$TOR program which typically ranges between $\pm$25% to $\pm$40% (IHS 2016). A summary of the eight cases is shown in Table 5.

Table 5: Sensitivity analysis Table

Cases	Production capacity	Number of wells	Processing facilities	Gathering system
	[MMscf/d]	[-]	[MMscf/d]	[MMscf/d]
1	+40%	Base value	Base value	Base value
2	-40%	Base value	Base value	Base value
3	Base value	+40%	Base value	Base value
4	Base value	-40%	Base value	Base value
5	Base value	Base value	+40%	Base value
6	Base value	Base value	-40%	Base value
7	Base value	Base value	Base value	+40%
8	Base value	Base value	Base value	-40%

The QUE$TOR software was used to estimate the cost figures for each case, in which the location of each case was assigned to be an onshore project with gas being the main product. An in-built procurement strategy and oilfield units of measure were used. Field characteristics were fed as shown in Table 1. The effect of the gathering system on CAPEX, OPEX and DRILLEX was evaluated by using the value of the maximum amount of gas (in MMscf/d) that can be accommodated from the wellhead to the processing facility through the manifold facility. The percentage changes in CAPEX, OPEX, and DRILLEX from the base case were calculated and presented on Tornado graphs.

Model Generation

The individual well cost was expressed as the function of well depth and number of casing strings to allow the variability in drilling costs per well (Table 2). OPEX data included all costs associated with gas production and the number of onshore producing wells that were on stream in the respective year (Table 3). The assumptions made under CAPEX (see Table **4**) included the following:

1) All capital expenditures incurred in 2006 were due to construction of gas processing facilities (10 MMscf/d capacities) and gathering facilities including pipelines for wells *P* and *Q*.
2) In 2015, capital investment in a vertical separator boosted gas processing capacity by 20%. The CAPEX also included the costs for the gathering pipelines from well *R*.

The collected cost data were normalized to bring every cost to the same basis and unit. An escalation factor was used as the proper index to normalize the cost data. Thereafter, multivariable regression analysis was done using Statistical Package for the Social Sciences (SPSS) software to generate the models for CAPEX, OPEX, and DRILLEX estimations. In establishing the models, a linear relation was first assumed between the variables with a constant term A and unstandardized coefficients B and C (see Table 6 for equations and definition of terms). The regression parameters A, B, and C were initialized and then iteratively evaluated until the error for each parameter in each successive iteration was at most 1.0×10^{-8} (SPSS default value in numerical iterations). The model was accepted upon satisfaction of the following conditions:

i. Values of the regression parameters A, B and C obtained in the final iteration were positive. This was due to the fact that the dependent variables (CAPEX, DRILLEX, and OPEX) are positively correlated to their most influential parameters (independent variables).
ii. The relative error of the estimates from the model to the actual field costs was less than or equal to 5% (calculation of the model correction factor is easier for models whose relative error is less than or equal to 5%).

Failure to meeting the conditions, the multivariable regression models were then analyzed in the order of increasing complexity in derivative evaluations from linear models until the best fit was obtained. That is, in each stage, a nonlinear regression model was developed using the corresponding equation and the values of A, B, and C obtained in linear approximations were then used as initial values in iterative evaluations (Parsimony Principle). However, due to various regression model families used in DRILLEX, OPEX and CAPEX modeling, the model selection procedures were slightly different from one proxy model to another. It should be noted that an additive correction factor of 0.045 million dollars was used to enhance the DRILLEX estimation accuracy and to account for the additional parameters that could have been used in the generation of the model presented by Figure 4.

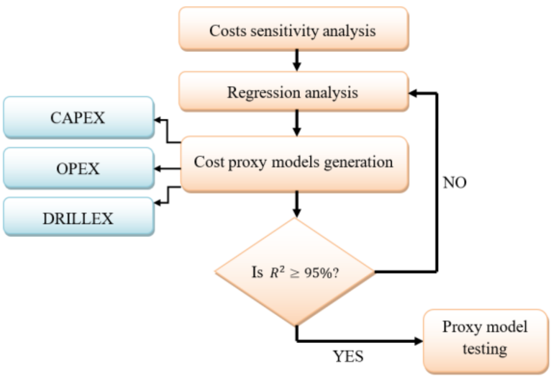

Figure 4: Proxy Model Development Methodology.

Model Testing

Error analysis was performed to check if the developed cost proxy models are valid and reliable. Based on field planned projects for proved and developed cases (RPS 2019), the cost estimates were generated using the models and then compared to the cost estimates generated using a commercial cost model.

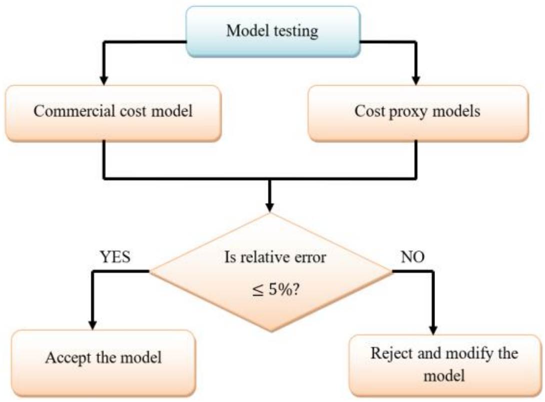

Figure 5: Cost proxy model test workflow.

RESULTS AND DISCUSSION

Through cost sensitivity analysis, it has been revealed that the capacity of the processing facilities and the numbers of wells in the studied gas field are the two parameters that strongly affect the CAPEX (Figure 6). This implies that, CAPEX related to onshore gas production projects depends strongly on the weight of processing units and equipment that are installed in the field. Therefore, CAPEX can often be modeled as a strongly dependent variable on the maximum field gas processing capacity $[Q_{pc}]$ and the number of wells in the field $[N_w]$.

On the other hand, OPEX depends strongly on the gas production capacity and the number of producing wells in the field (Figure 5). This suggests modeling of OPEX can be expressed as a function of the gas production capacity (annual gas production) and the number of producing wells in the field. However, to account for the producing wells operating costs, OPEX can be modeled as a strongly dependent variable on the annual gas production $[Q_g]$ and the number of producing wells in the field $[N_w]$ with the correction factor that accounts for the discarded parameters.

Unlike other field costs, DRILLEX is only affected by the number of wells drilled in a specific period. As shown in Figure 7, DRILLEX and the number of wells is positively correlated by approximately a $\pm$ 33% change in DRILLEX per $\pm$ 40% change in number of wells drilled in a specific period. The analysis suggests modeling of DRILLEX as a dependent variable on the number of wells drilled, expressed as wells' unit cost multiplied by the number of wells drilled in a specific period. However, to account for the variability in onshore well costs observed in wells P, Q and R, the authors suggest modeling the DRILLEX not as a function of number of wells but as the function of well depth and number of casing strings.

In DRILLEX modeling, a group of models presented in **Error! Reference source not found.** were obtained. Negative values of C in models 2, 3 and 4 indicate that DRILLEX and number of casings are negatively correlated. Selecting such models would actually imply that a well using many casings costs less which is contrary to practice because a well costs more if the casing numbers increases. Therefore, using the first model selection criterion, models 2, 3 and 4 were rejected because their final iterations resulted into negative values in regression parameter C. Using the second model selection criterion, when compared to the rest, model 7 (equation 1) was found to be the best for DRILLEX estimations since it gives the lowest relative error of 0.16%.

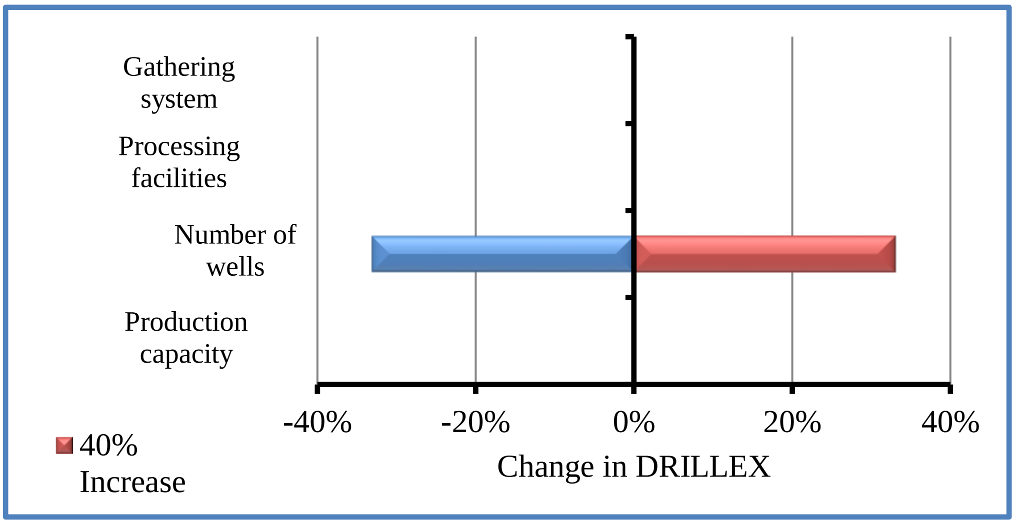

Figure 6: Variation of DRILLEX due to ± 40% change in VCP.

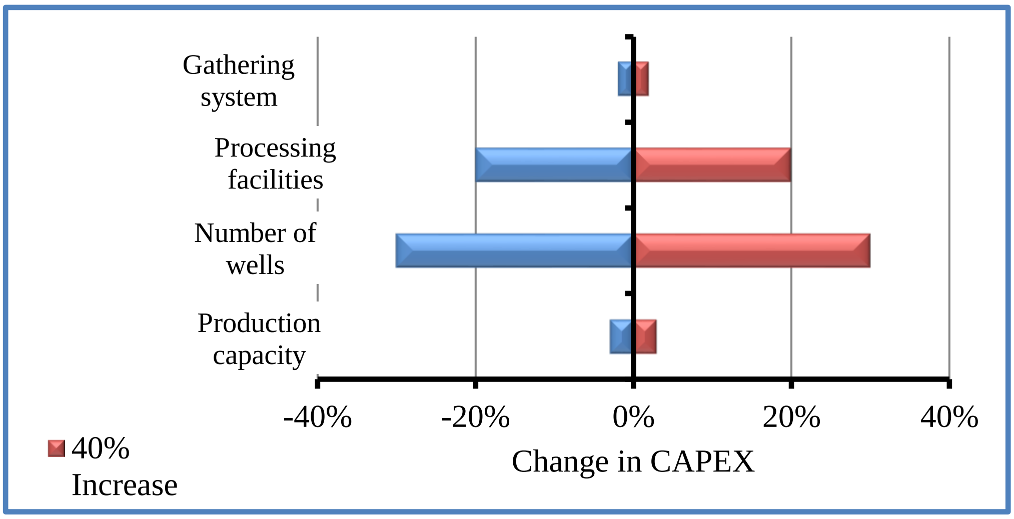

Figure 7: Variation in CAPEX due to ± 40% change in VCP.

Table 6: Summary of the DRILLEX regression results

Model	A	B	C
1. $A + B(\text{Depth}) + C(N_{casing})$	21.403	0.002	0.003
2. $Ae^{(B*\text{Depth}+C*N_{casing})}$	21.986	9×10^{-5}	-4.628×10^{-8}
3. $Ae^{(B*\text{Depth})} + C(N_{casing})$	21.986	9×10^{-5}	-1.306×10^{-6}
4. $A + e^{(B*\text{Depth})} + C(N_{casing})$	23.135	0.001	−0.020
5. $A * (\text{Depth})^B * (N_{casing})^C$	5.216	0.213	0.002
6. $A * (\text{Depth})^B + (N_{casing})^C$	4.691	0.221	0.059
7. $A + (\text{Depth})^B + (N_{casing})^C$	10.005	0.358	0.052

The DRILLEX regression results (Table 6) can be summarized by using seven (7) equations presenting the seven models. Equation (1) presents the selected developed model for estimation of the DRILLEX for onshore vertical wells. Where: DRILLEX is the drilling expenditures in million dollars, D is the measured well depth in meters (m) and N_c represents the number of casings used. DRILLEX for a single onshore vertical well may be presented as a nonlinear function of the well's depth and number of casings shown by equation 1.

$$\text{DRILLEX} = 10.005 + (\text{D})^{0.358} + (N_c)^{0.052} \quad (1)$$

In the OPEX model, the estimation relative error was 0.08% higher than that of the DRILLEX model but less than 5%. Equation 2 represents the generated model for the estimation of the OPEX. Where: OPEX is the onshore field operating expenditures in million dollars, G_p represents the cumulative annual gas production in Bscf and N_w represents the number of onshore producing wells (onshore production well count). OPEX may be presented as linear functions of cumulative gas production and well count as it is shown by equation 2.

$$\text{OPEX} = 3.974 + 0.203G_p + 1.728N_w \quad (2)$$

Lastly, in the CAPEX model the estimation relative error was 4%. However, based on the previous capital costs, the model provides overestimation that averages 3.96 million dollars. Thus, to increase the CAPEX estimation accuracy and to account for the additional parameters that could have been used in its generation, a reductive correction factor of 3.96 million dollars was used to modify the parameters in model. The CAPEX may be presented d as linear function of gas processing capacity and well count as it is shown by equation 3.

$$\text{CAPEX} = 15.507 + 3.639Q_{pc} + 27.713N_w \quad (3)$$

where: CAPEX is the onshore capital expenditures in million dollars, Q_{pc} represents the capacity of the processing facilities in MMscf/d, and N_w represents the number of onshore wells drilled.

Generally, the results from the model testing (**Error! Reference source not found.**) showed that the selected DRILLEX and OPEX proxy models give cost estimates that agree to the estimates generated by the commercial software within an average relative error of approximately 5% as presented in Figures 6 and 7. This implies the accuracy of the developed models and that these models are suitable for the cost estimation purposes for decision in the early phases of the field development. The expectations were different for the CAPEX model as it is shown in Figure 8.

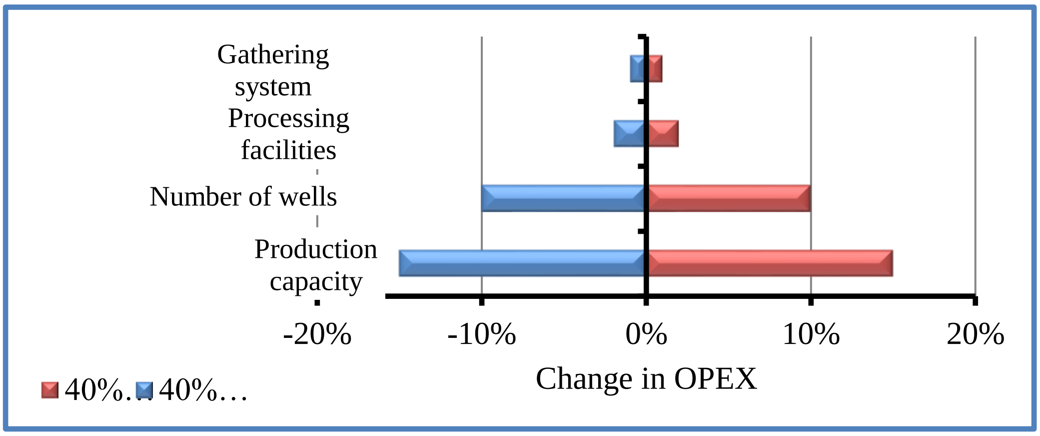

Figure 8: Variation in OPEX due to ±40% change in VCP.

The model gives an average relative error of 36% which is almost 7 times higher than the recommended model selection criterion. This may have been caused by inadequate CAPEX inputs data for the model development. There are no previous projects that were conducted to expand capacity of the gas processing facilities in the field. This this has been one of the challenges encountered during development of the CAPEX proxy model. However, the challenge can be avoided by using stochastic modeling approach (like Monte Carlo simulation or Latin Hypercube). Although the estimation accuracy of the CAPEX model was found to be too high for it to be a reliable, generally the three developed proxy models can still be used with caution.

Table 7: Relative error between commercial software and proxy models cost estimates

Error Analysis										Average
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	%
DRILLEX [Million$]	0.05									5
OPEX [Million$]	0.07	0.10	0.06	0.05	0.05	0.04	0.04	0.03	0.03	5
CAPEX [Million$]	0.36									36

Compared to the current proxy cost models by González, 2020; Stanko, 2020; Kuznetsov *et al*., 2011; and Shereih, 2016; the models developed in this study have considered the variability of DRILLEX with depth and number of the casing. The previous studies made unrealistic simplifications and assumptions whereby uniform costs were assumed for all drilled wells, an assumption that might not be always true. Similarly, recent OPEX model developed by RPS (2019) neglects the significant contribution of the number of on-stream wells. The model considers only the cumulative production. According to RPS (2019), this is an unrealistic as the operating costs normally increase with number of on-stream wells. The models developed in this study include the costs of operating each on-stream well to capture the real cost of operating a particular field for a given production capacity and other parameters such as depth and casing numbers. For example, the wells P [depth = 2012 m and casings = 4] and Q [depth =2788 m and casings = 5] give significant cost differences which when neglected during project evaluation might affect future project decisions. Therefore, this work presents reliable proxy models for the estimation of the costs for petroleum projects when it comes to the onshore gas field. One should be mindful that most of the cost proxy models available so far are for offshore petroleum fields.

CONCLUSION AND RECOMMENDATIONS

Based on the analysis of input data from the three wells of the onshore gas field of the southern coastal Tanzania basin, the following were revealed:

- The developed proxy models may serve as reliable cost-estimating tools because they produce cost estimates that are generally 5% less than commercial cost estimates
- DRILLEX is strongly affected by the number of wells to be drilled in the field
- OPEX is strongly affected by gas production capacity and the number of producing wells in the field
- CAPEX is strongly affected by the capacity of the processing facilities and the number of wells in the field
- CAPEX and OPEX are modeled as linear functions of their affecting parameters while DRILLEX for a single onshore vertical well is modeled as a nonlinear function (power function) of the well depth and number of casings. However, DRILLEX is linearly affected by the number of wells

For the purpose of increasing the accuracy and reliability range of the developed proxy models, the following can be done:

- Proxy models need to be modified as more data becomes available. In this paper, the proxy models were developed using few amounts of data since most of the data were not readily available from the field
- Stochastic methods like Monte Carlo simulation or Latin Hypercube have to be performed so as to be able to incorporate parameters that can quantify the cost estimation uncertainties. This will make the proxy models more reliable

Generally, the proxy models developed in this article should be used with caution and if adequate data will later be available, the same methodology can be used to update the models so as to minimize their estimation error.

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