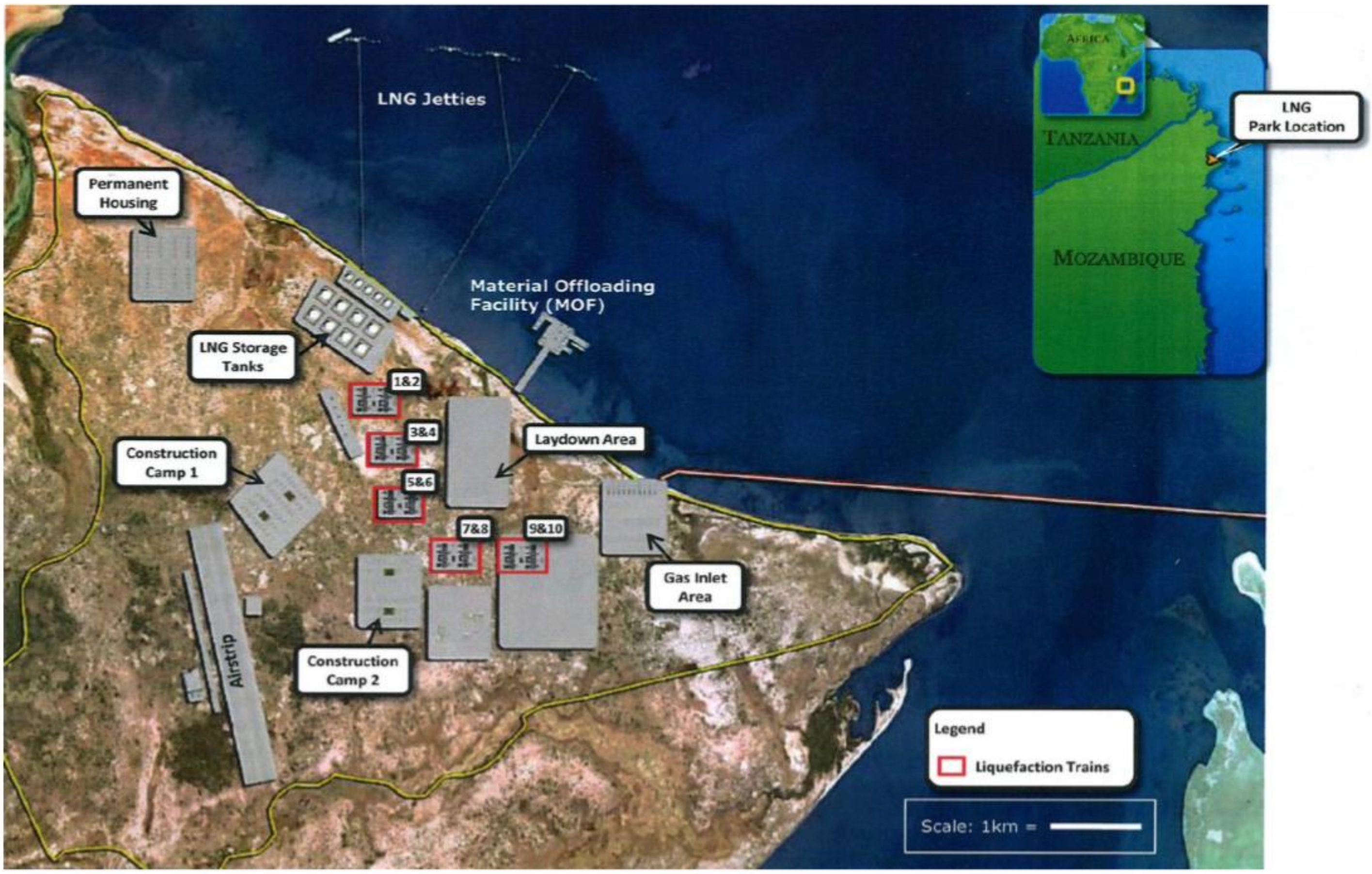

Economic analysis of Mozambique's LNG projects

AKap Energy

April 2019

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Contents

Executive summary

Around 10 years after the first major gas discoveries, Mozambique should see two mega LNG projects sanctioned this year, with an investment of almost four times the country's GDP. There is huge value creation potential for the people of Mozambique and a good return for the project participants, if the Government can ensure a sound economic environment to operate in. Over the life of projects, there is the potential for around US$100bn in cash flow to the Mozambique people, which would clearly be transformational for Mozambique, with current GDP <$15bn and GDP per capita of <$500. For example, LNG catapulted Qatar to having a leading global GDP per capita. For Mozambique, accessing these future cashflows is reliant on the success of the project financing discussions currently taking place.

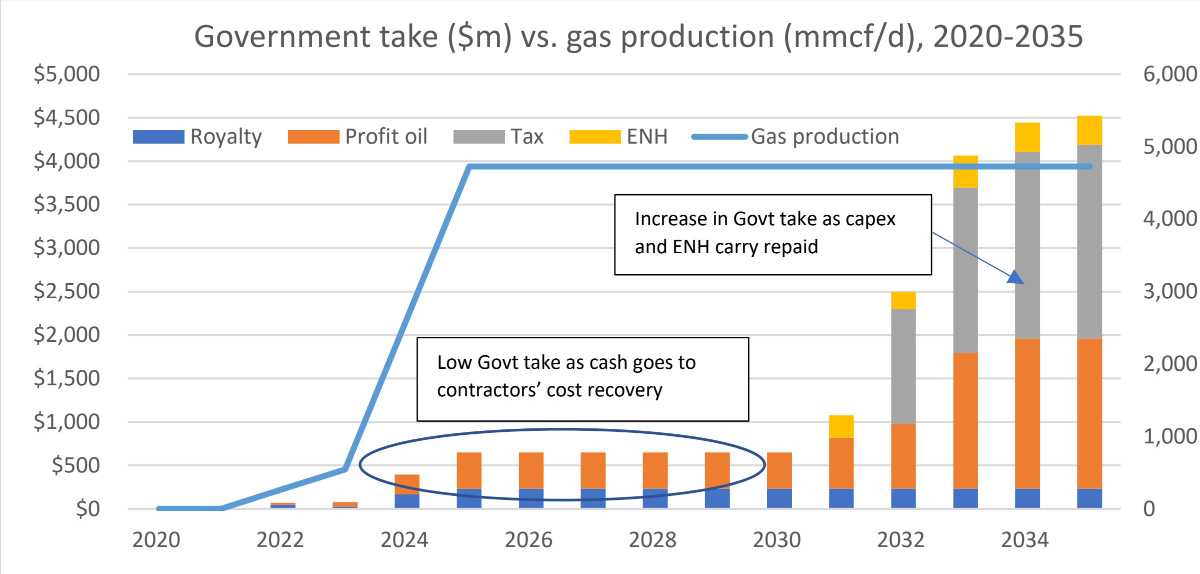
The initial three developments in Mozambique will develop ~40tcf (7bnboe) of reserves and see production reach 5bcf/d (~800kboe/d equivalent) or >30mtpa of LNG (close to 10% of the current global market or 6x the LNG production out of Angola). We estimate that $10bn has already been spent on exploration, appraisal and pre-FID work on the blocks. The total development capex is >$50bn and ~2/3 of this is likely to be project financed. Assuming an LNG price of $7.5/mcf, the yearly revenues from the projects will be $12bn by 2025 (close to Mozambique's current GDP) or >$300bn over the life of the project. There is the potential to triple production over time from the existing discovered resource.

We see most of the milestones achieved to allow the two projects to proceed, such as project design and securing LNG offtake. However, there is a crucial element that still needs to be completed, which is the financing of the projects. There are two key financing challenges: the ability of the partners to raise project financing debt and secondly the funding of state oil company ENH's obligations (both debt and equity).

It is not helpful that the Government is in a default situation, when companies are trying to raise ~$30bn in project financing. The partners are likely to see a higher cost of project financing debt facilities as a result (sovereign credit ratings give information about the country's and its companies' ability to repay their debts). If we assume a 1% higher borrowing cost for the project financing, it reduces the life of field revenues to the Government by $2bn. The impact is more significant on the Government in the early years as it further pushes back when the Government can access the revenues. So, for the country and the economy to benefit, a stable economic climate is needed.

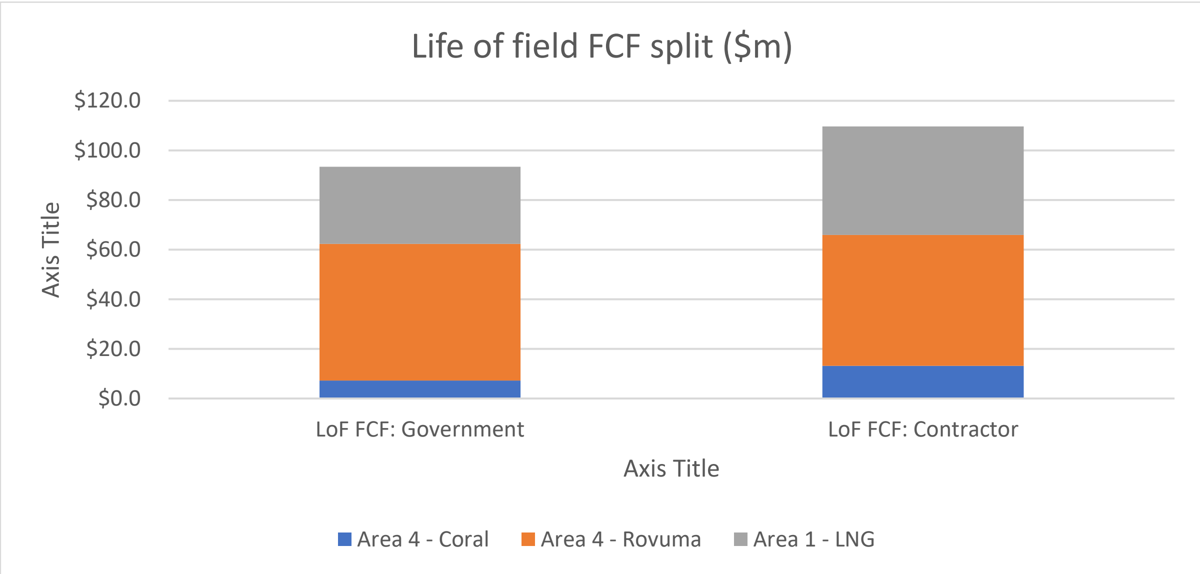
ENH's total required investment into the projects is around 50% of Mozambique's GDP. ENH may also have a further funding requirement for other blocks and developing domestic gas. It is important for the Government to have a clean financial bill of health, as it will need to rely on the debt market over the next decade to support itself, ahead of the future cash windfall in the 2030s. For example, the Government needs to provide a sovereign guarantee for the project financing of Area 1 by ENH. ENH is currently looking to refinance around $2bn of its exposure.

The gas finds are therefore potentially game-changing for Mozambique, if the political and economic environment is in place, to allow the developments to move forward. Although there will be an economic benefit through the construction phase, significant Government/ENH revenues will only be seen in the 2030s. ENH won't see any revenue until 2030 as its share of cash flow will go towards repaying its carried exploration spend to date (~$1.25bn on our estimates), as well as the development capex, which is carried by the partners. This could have implications on how Mozambique finances its domestic infrastructure projects and therefore there may well be a greater need for support from the IMF and access to international capital markets in the near term.



Source: AKap Energy estimates

Between 2022-2030 the projects combined will generate around $70bn in total pre-tax operating cashflow but <$5bn of this will go to the Government as most of the funds will go to repaying the capex and compensating the equity holders. In the 2030s, Government take increases to >$4bn per annum.



Source: AKap Energy estimates

Despite the huge numbers involved in terms of reserves, production and revenue the returns on the projects aren't spectacular. Based on the initial developments, in aggregate we see an NPV10 valuation for the equity holders of $7bn without any leverage – factoring in leverage there would be a $10bn NPV10. The project level IRR is 11% and the equity IRR is 15%. Area 1 has better economics than Area 4 on a point forward basis.

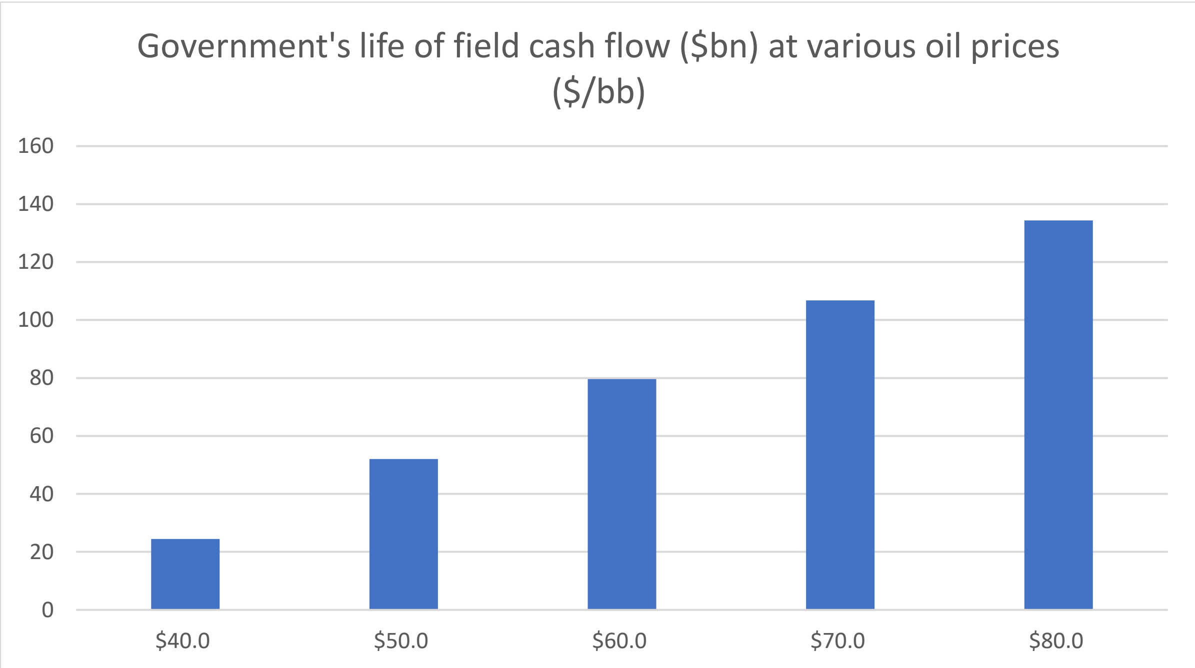
To put the valuation in context, Exxon's purchase of a stake from Eni implies a gross value of $25bn in total for Area 1 and 4. Therefore, the companies are either betting on higher LNG prices or factoring the value from further developments (potential to get to 100mpta). On our estimates if a further 2 trains were sanctioned on Area 1, with economies of scale cost savings factored in, the NPV would be $4bn to the equity holders of Area 1 and $5.5bn to the Mozambique Government.

The equity holder's valuation is very sensitive to LNG prices and the discount rate. For example, a move in the oil price to $55/bbl from $65/bbl will result in the NPV10 valuation of the equity holders' stakes falling by almost 50%.

Project level IRR at different oil prices and % of Brent for LNG price

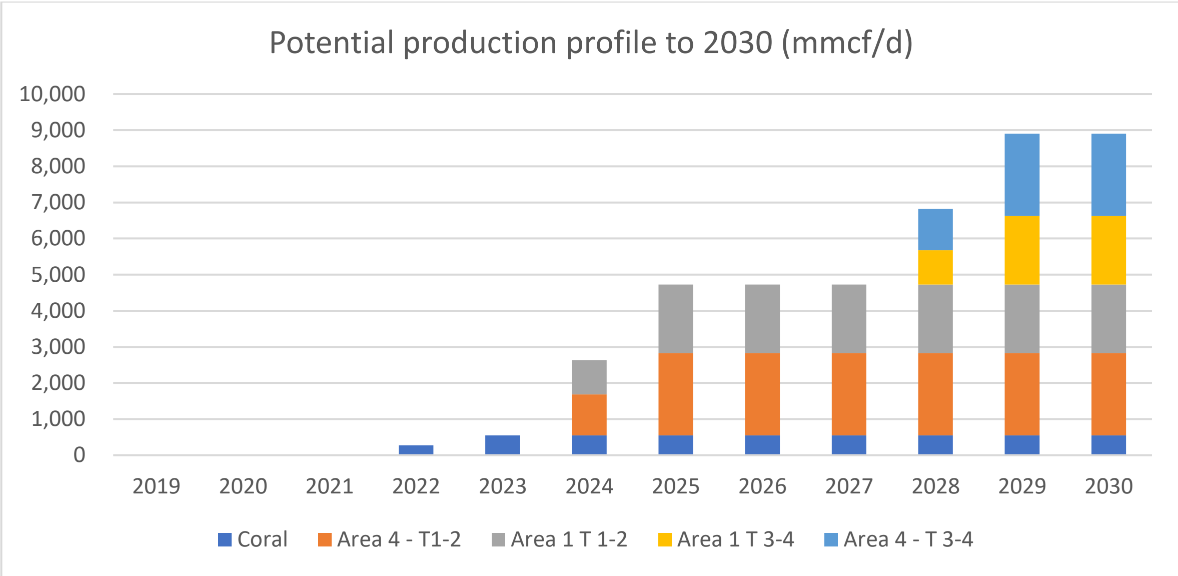
		Oil price ($/bbl)				
		$45.0	**$55.0**	**$65.0**	**$75.0**	**$85.0**
Slope (% of Brent)	**9.0%**	5%	6%	8%	9%	10%
	10.0%	6%	7%	9%	10%	12%
	11.0%	6%	8%	10%	11%	13%
	12.0%	7%	9%	11%	12%	14%
	13.0%	8%	10%	12%	13%	15%
	14.0%	9%	11%	12%	14%	16%

Source: AKap Energy estimates



Source: AKap Energy estimates

Production outlook

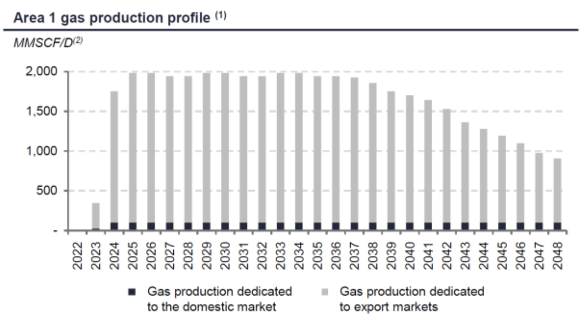


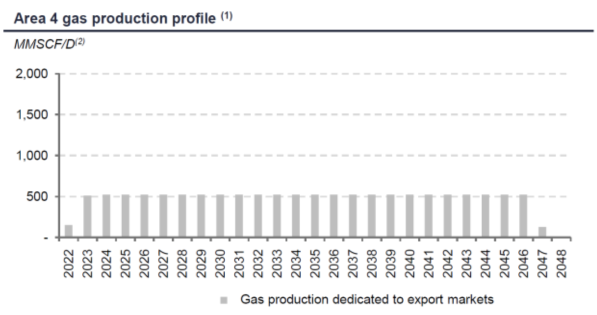
Source: AKap Energy estimates

We see Mozambique as having the potential to reach ~9bcf/d of production (or 60mtpa of LNG) by the late 2020s. Currently, the Coral FLNG project has been sanctioned and will come on line in 2022 and we expect the Area 1 and Area 4 onshore projects to be sanctioned later this year. Further expansions aren't likely to be sanctioned until around 2023 in our view but there is the potential for Mozambique to become one of the world's largest suppliers, eventually reaching 100mtpa from the existing resource base.

We include the Government's latest published projections for production below. The key different is that the Area 4 onshore production is not included in the Government forecasts from 2024. We also include speculative production from 2028 onwards.

Republic of Mozambique projections for gas production, June 2018





Source: Government of Mozambique; (1) Production profile only presents gas production, excluding condensate production

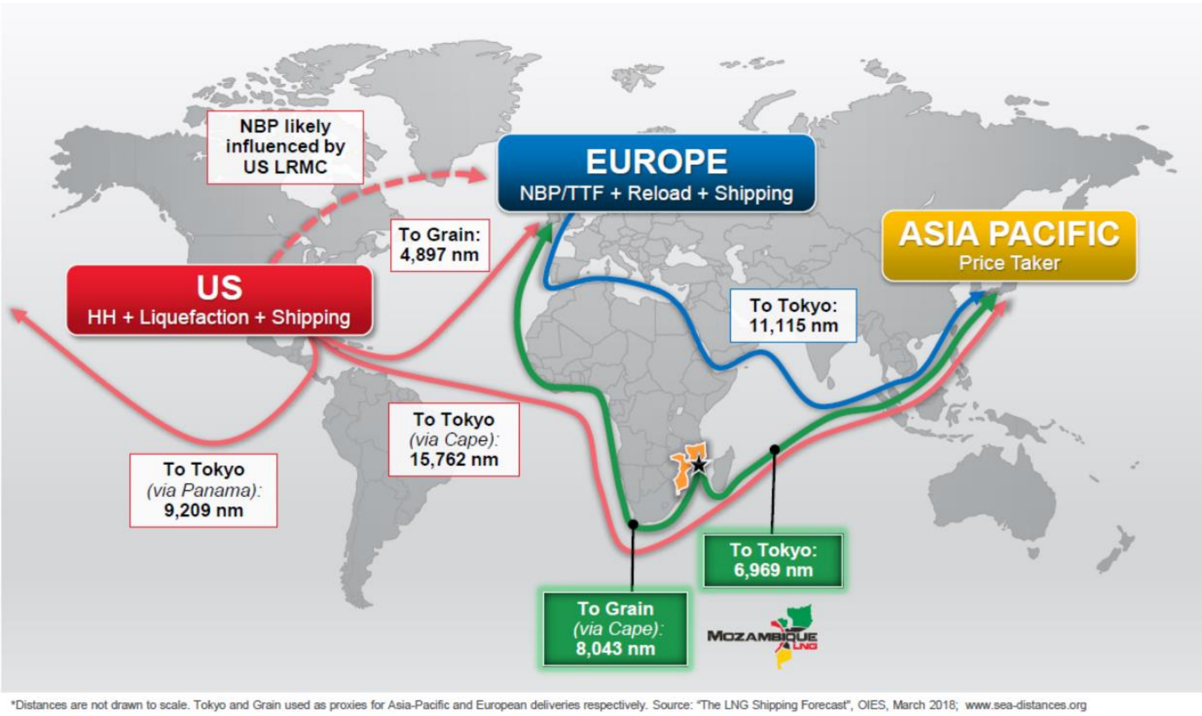
Why LNG in Mozambique

Strengths and positives

Large resource: A huge amount of gas means that there is no concern about having enough reserves. There is more value/upside from running the facilities for longer and there is the longer-term value of developing the remaining gas, whilst benefitting from economies of scale and existing infrastructure.

Prolific production: The well performance has been shown to be strong, with the potential to produce at 100-200mmcf/d, which is positive as it reduces the number of wells required and the associated development cost.

Location: The favourable central geographic location means the country is well positioned to meet the needs of customers in the Atlantic and Asia-Pacific markets. India is a key potential market as one-way voyage times to Northern India are just 7 days.



Source: Mozambique LNG

Favourable fiscal terms: The fiscal terms are attractive for the contractors with the key features being a low royalty, high cost recovery, a high contractor profit share and accelerated depreciation.

Past spending: The ~$10bn that has been sunk in the past is cost recoverable and allowable for depreciation, which improves the point forward economics.

Financing: Coral achieving $5.7bn of project financing shows that there is confidence in the project and bodes well for the project financing for the future expansions. However the current Government debt default raises some concern for the current project financings planned.

Strategic assets: The entry of Exxon, CNPC of China and the Indian IOCs shows the strategic value to these companies.

Weaknesses

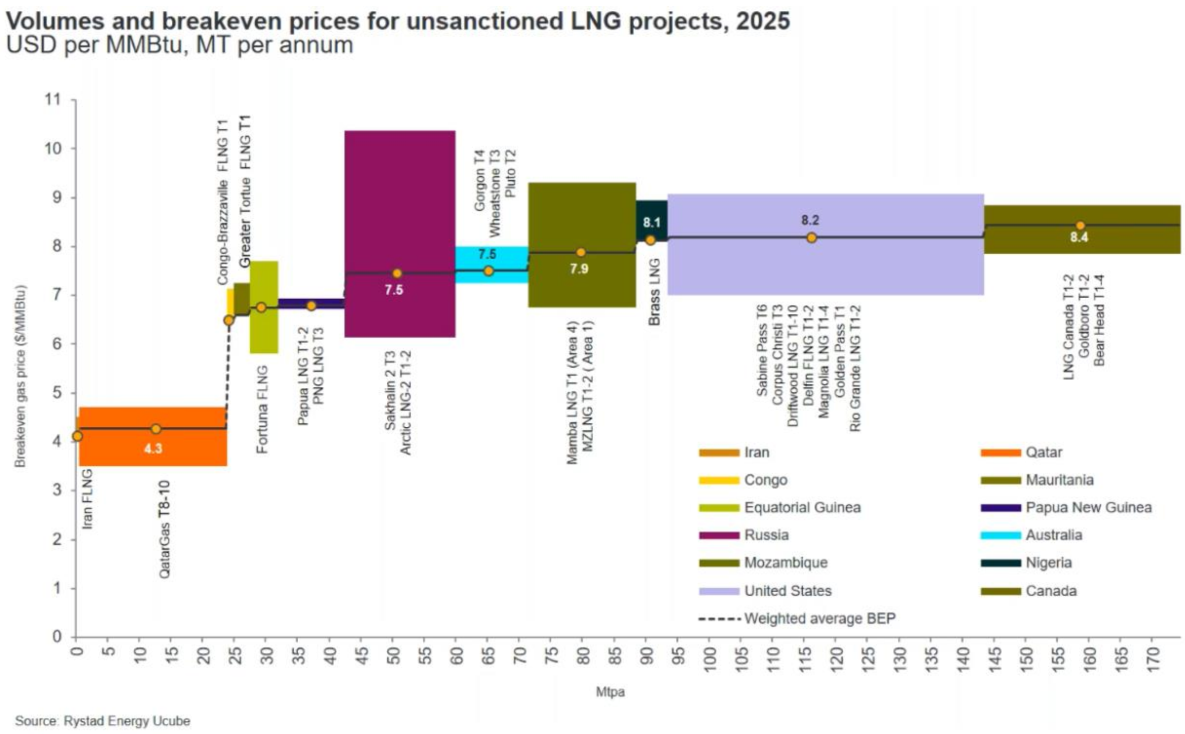
Greenfield project – The fact that the projects are greenfield means that the cost is higher as there is no existing infrastructure in place and the risk level is also higher. Much of the labour will have to be brought in from abroad.

Geo-political risk – There is the perception of weak governance and a difficult business climate (135th out of 190 countries in the *2019 Doing Business* ranking). Elections scheduled for October 2019 may test the country's political stability. The credit rating of Mozambique is currently in 'default' due to lack of completion of restructuring with bondholders, which adds to the financing risk for the projects.

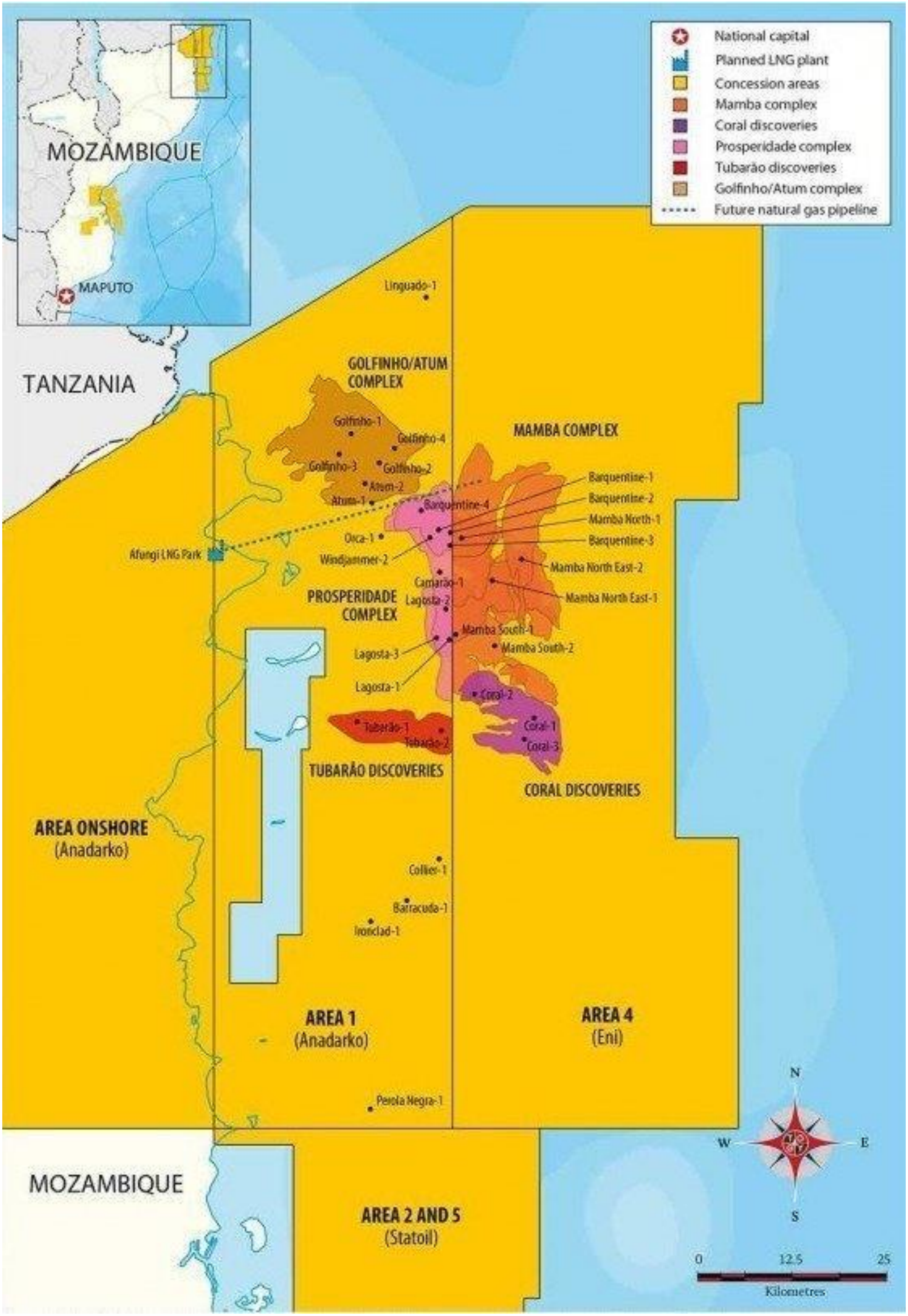
No liquids – The Mozambique gas is "dry" with little in the way of associated liquid hydrocarbons. Although this reduces the upfront capex and processing cost, the value of the liquids is normally much higher than the LNG and hence improves the economics.

Security risk: The security risk is high both in terms of the potential for terrorist attacks onshore and the piracy that affects the offshore in East Africa.

Cost competitiveness – Based on the project costs and returns, we don't think these projects would be in the top quartile, especially on a risk adjusted basis. The chart below shows the Mozambique projects around mid-ranking globally. N

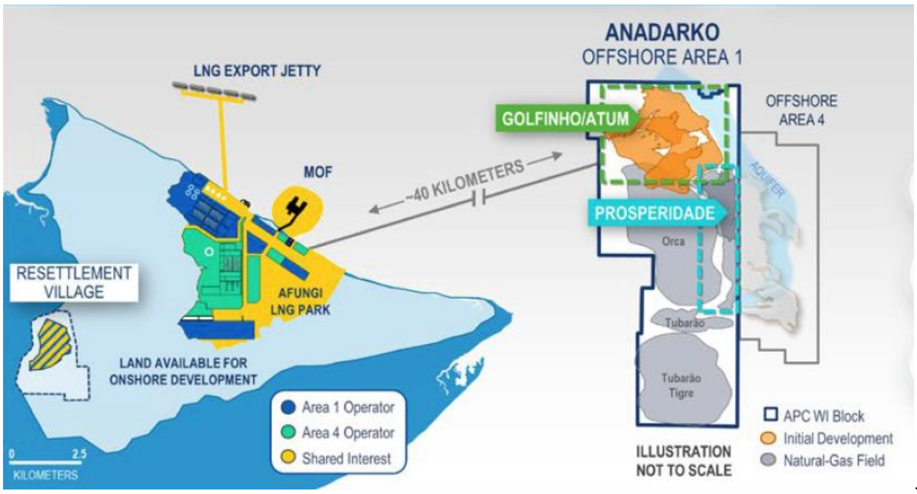


Mozambique Area 1 and Area 4 concession map



Source: Anadarko

Area 1: Mozambique LNG (Golfinho/Atum)



Source: Anadarko

Location: 40 kilometres offshore and in water depths of approximately 1,600 metres.

Partners and stakes: Anadarko 26.5% and operator, Mitsui 20%, PTT 8.5%, ONGC Videsh 16%, Bharat Petroleum 10%, Oil India 4% and ENH 15%.

Scope: 12.88mpta from two LNG trains, each with capacity of 6.44mpta, which is an increase of 1.44mtpa per train over the original plan. The scope also includes two LNG storage tanks, each with capacity of 180,000cm, condensate storage, multi-berth marine jetty and associated utilities and infrastructure.

Future potential: There is significant future expansion of up to 50mpta from Offshore Area 1.

Reserves: 75tcf recoverable; 17tcf will be produced from T1-2. According to Oil India there are certified 2P reserves of 31.9tcf in Golfinho-Atum and Prosperidade.

Wells: An initial 20 wells are planned.

Production rate per well: Each flow test successfully flowed at facility-constrained rates of 90-100mmcf/d, which supports well designs of 100-200mmcf/d. Gas will be piped directly to shore. The gathering system will be capable of handling 2bcf/d of natural gas

Total cost and financing: $20bn or $1,550/t. Cost of the LNG trains is $7.7bn or $600/t. There is a project financing objective of up to 2/3 of the cost – the process was launched in December 2018. Anadarko has reportedly secured interest for $12bn from ECAs and is looking for $14-15bn of project financing in total.

Payback: At $60/bbl Brent Anadarko expects payback in 3.5 years. However, this doesn't take into account the historic spend to date.

Initial exploration contract: December 2007; **First discovery:** February 2010 marked the first deepwater discovery offshore Mozambique at the Windjammer prospect.

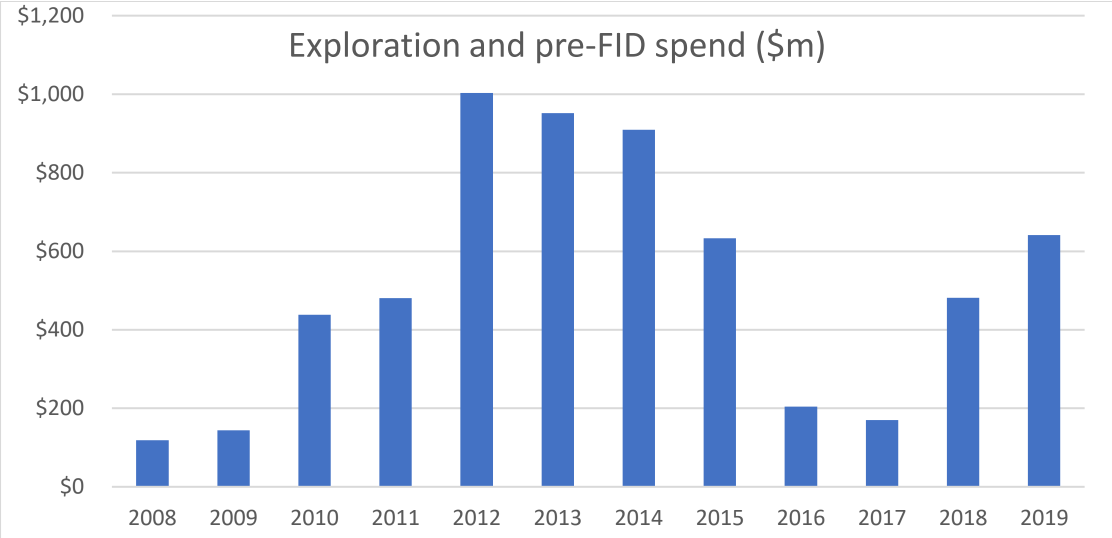
FEED awarded: December 2012; **FID:** Planned for H1'19

Start-up: 2024: First cargoes approximately 5 years post-sanction. Interesting to note that back in 2011 Anadarko was expecting first LNG in 2018!

Contractors: CB&I, Chiyoda and Saipem (CCS JV). The E&C contract value is estimated at $8bn.

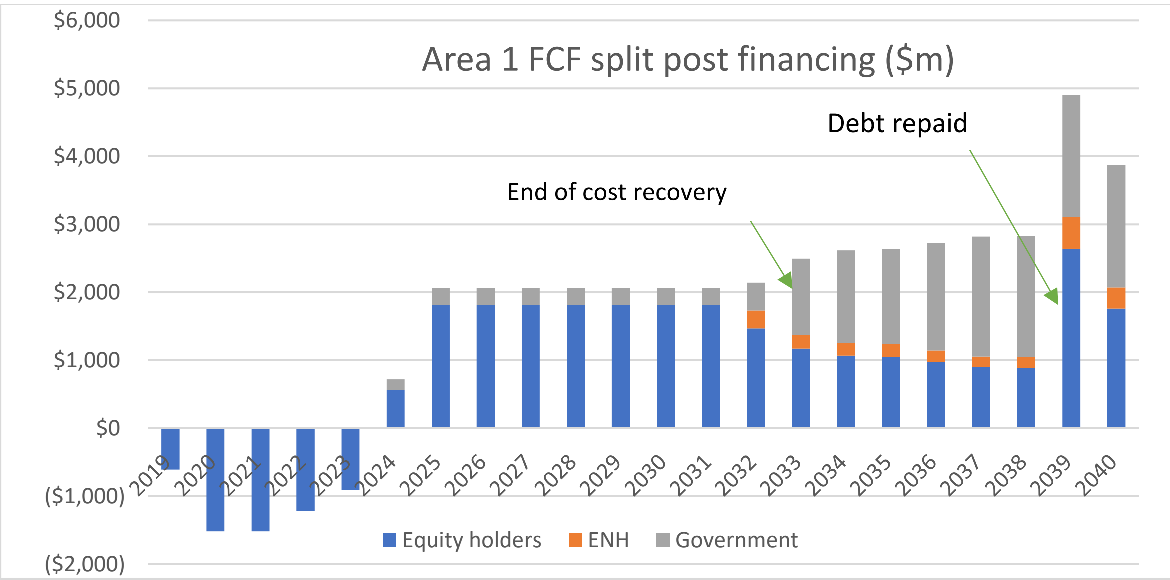
LNG contracts: The project aimed to secure 9 to 11 MTPA of long-term SPAs and so far, has executed >9.5mtpa. The off takers are: EDF (1.2mtpa for 15 years); CNOOC (1.5mtpa for 13 years); Centrica/Tokyo Gas (2.6mtpa for ~20 years); Shell (2mpta for 13 years); Bharat Petroleum (1mpta for 15 years); Pertamina (1mpta for 20 years); Tohoku Electric Power Company (0.28mpta for 15 years). Anadarko said that the majority is oil-based pricing with some European gas price related.

Domestic obligation: Offshore Area 1 will provide initial volumes of approximately 50mmcf/d per train (100mmcf/d in total) for domestic use. The gas will be provided at pricing that is "fair to all parties and supports local natural gas development", and the concessionaires are prepared to sell up to 300mmcf/d of additional volumes into the domestic market in future years as projects are matured and commercial terms agreed. However it is unclear whether there is any obligation surrounding this.



Source: Mitsui, Anadarko, AKap Energy estimates

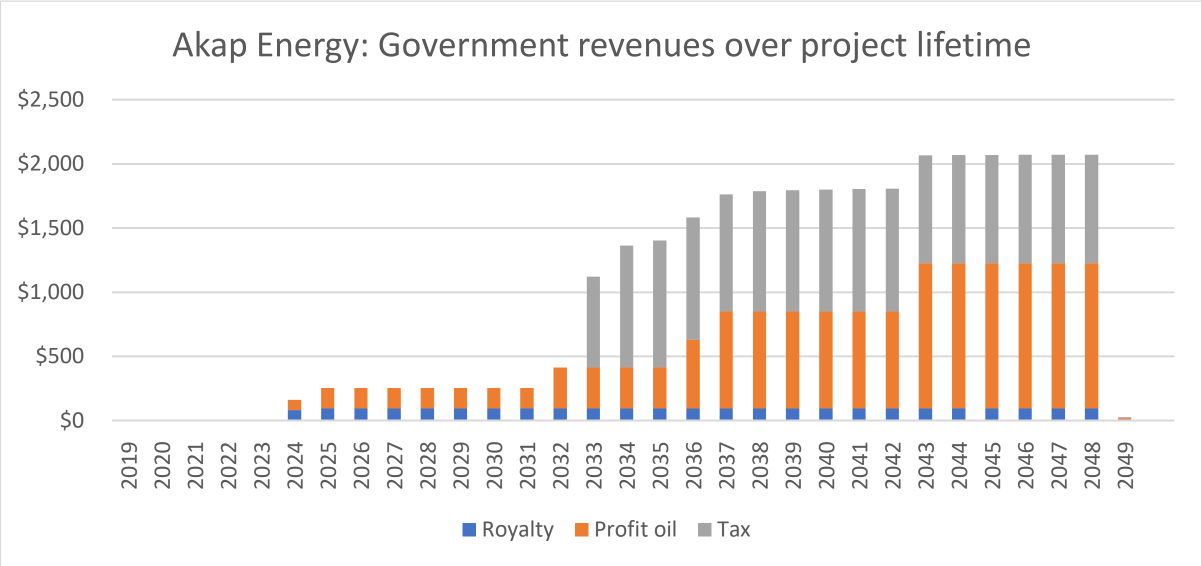
Capex invested: We estimate that around $5bn has been spent on exploration and appraisal of the block. Anadarko expects to invest approximately $200m in the Mozambique LNG project in 2019 on pre-FID activities implying around $600mm gross.



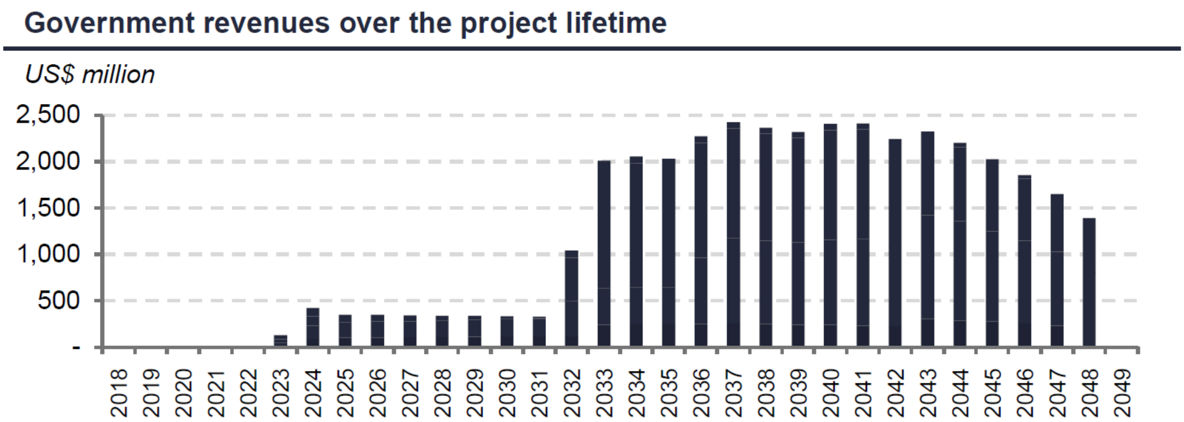
Source: AKap Energy estimates

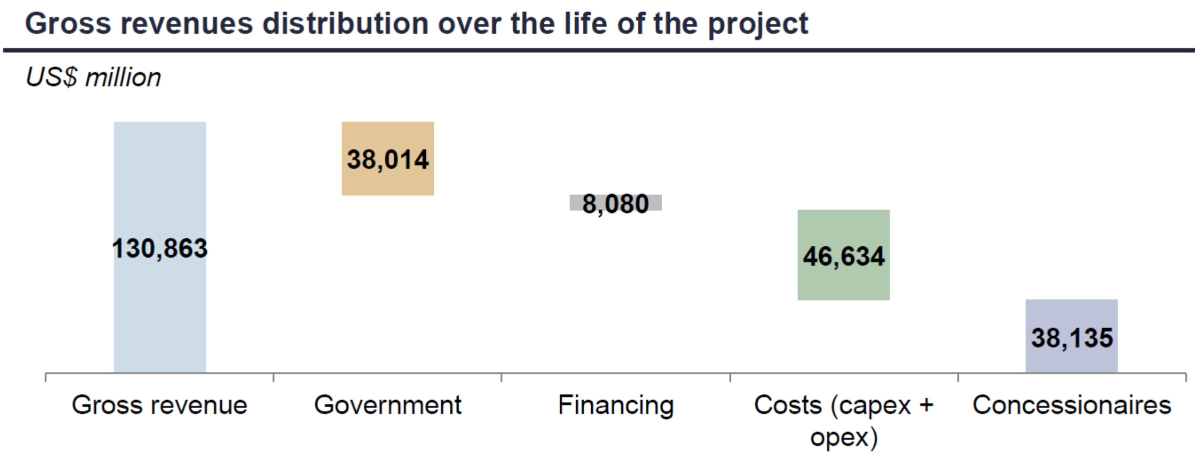
Area 1 government take

Our estimates (top chart) for Government take show a similar profile to the Government's own estimates (middle chart) under its base case scenario.



Source: AKap Energy estimates





Source: Government of Mozambique

Area 4: Rovuma LNG (Mamba straddling within Area 1)

The Mamba complex consists of 8 different pools aged between Paleocene and Oligocene.

Partners and stakes: Eni 25%, ExxonMobil 25%, CNPC 20%, Galp 10%, Kogas 10% and ENH 10%.

Area 4 total resource: 85Tcf of gas in place. Mamba reserves developed: 12Tcf.

LNG capacity: 15.2mpta: two trains of 7.6mtpa. Upstream production rate of 2.4bcf/d. Potential future capacity with further stages of 40mpta.

Exploration contract award: December 2006

First exploration well: Mamba South in September 2011. Further discoveries were made in Mamba North (2011), Mamba Northeast (2012), Coral (2012) and Agulha (2013).

Development plan submission: July 2018

FID: mid-2019

First LNG: 2024

Data acquired: During this period, 15 wells were drilled with a rate of success very close to 100%. Six production tests (DST) were successfully completed and six reservoirs were cored. Seismic acquisition activity continued alongside the exploration drilling with another 2D survey in 2012 (2,184 km) and two more 3D campaigns in 2012 (1,864 sq. km) and 2013-2014 (3,060 sq. km).

Discoveries: 6 discovery areas have been approved by the Government of Mozambique which are: one for Coral reservoir (730 sq. km), 4 covering the Mamba Complex (2,076 sq. km envelope) and one for Agulha (390 sq. km).

Contractors: Tender launched in Q1'19: Bids to build the Mamba trains were submitted by three groups - JGC with Fluor, TechnipFMC working with Samsung Engineering and China Huanqiu Contracting & Engineering and thirdly the CCS group of CB&I, Chiyoda and Saipem. TechnipFMC and VanOord will handle the engineering, procurement, construction and installation of the offshore subsea system for the project.

Scope: 24 subsea wells.

Offtake: Area 4 co-venture participants have secured liquefied natural gas (LNG) offtake commitments from affiliated buyer entities of the partners.

Shared facilities: Some infrastructures and facilities, such as MOF, Jetty, access roads and Afungi LNG Park fence, will be common for the Area 4 and Area 1 developments.

Mamba investment: $27bn according to press reports quoting ENH. We assume $25bn in our analysis.

Area 4: Coral South

The Coral project aims to exploit the hydrocarbon resources discovered in the Coral Eocene 441 reservoir. The FLNG vessel will be about 430m long, 66m wide, and will weigh about 210,000 tons. It has a design life of 25 years.

Capacity: 3.37mpta or 475mmcf/d

Coral reserves: 15.65tcf of gas in place. The production profile has a plateau of over 40 years, and a gas cumulative production of approximately 5tcf in the 25 year production period.

Phases: The project will be developed in two phases through two FLNG units. The first phase of the Coral Development will be focused on the resources located in the southern portion of the Coral reservoir. The 2nd phase if it goes ahead will be sanctioned 2023+.

Capex: $7-8bn (~$2,225/t) of which $4.7bn was project financed (60% project financed). FLNG vessel cost of $1,550/t.

Approval: Plan of development approval issued in Feb 2016 and FID take in June 2017.

Start-up: mid-2022

Upstream facilities: 6 wells and 3 subsea manifolds.

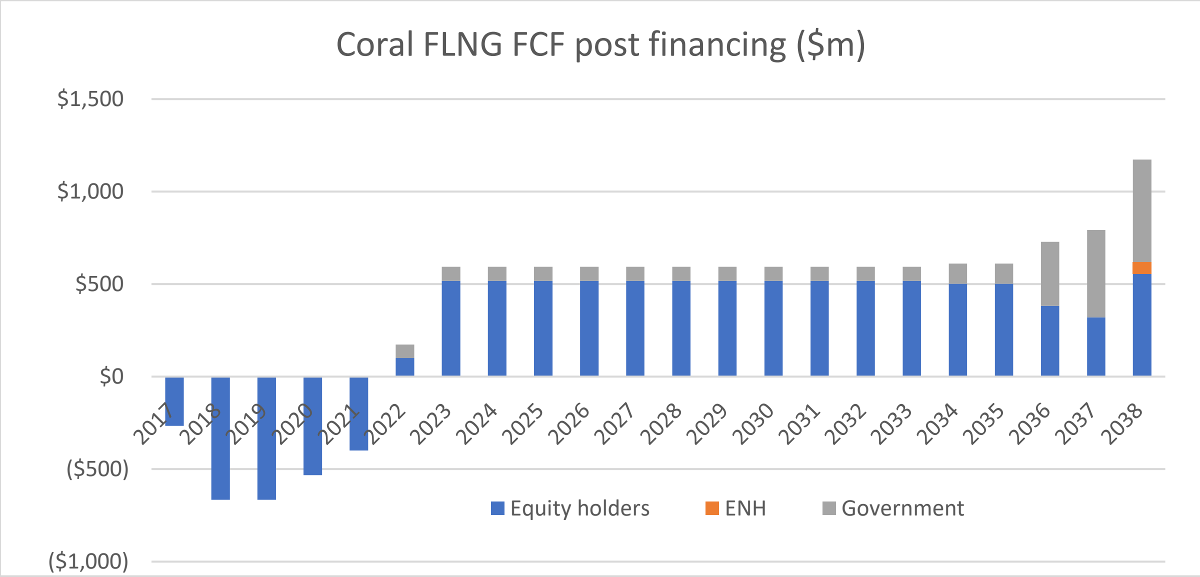
Contractors: Technip, JGC and Samsung for FLNG unit. Engineering Procurement Construction Installation and Commissioning (EPIC) contract value of $5,248m. BHGE won the contract for the subsea trees and manifolds.

LNG contracts: BP will take 100% of output at an estimated 11-11.5% of Brent (i.e. at $60/bbl BP will buy the LNG at $6.6-6.9/mcf at the vessel).

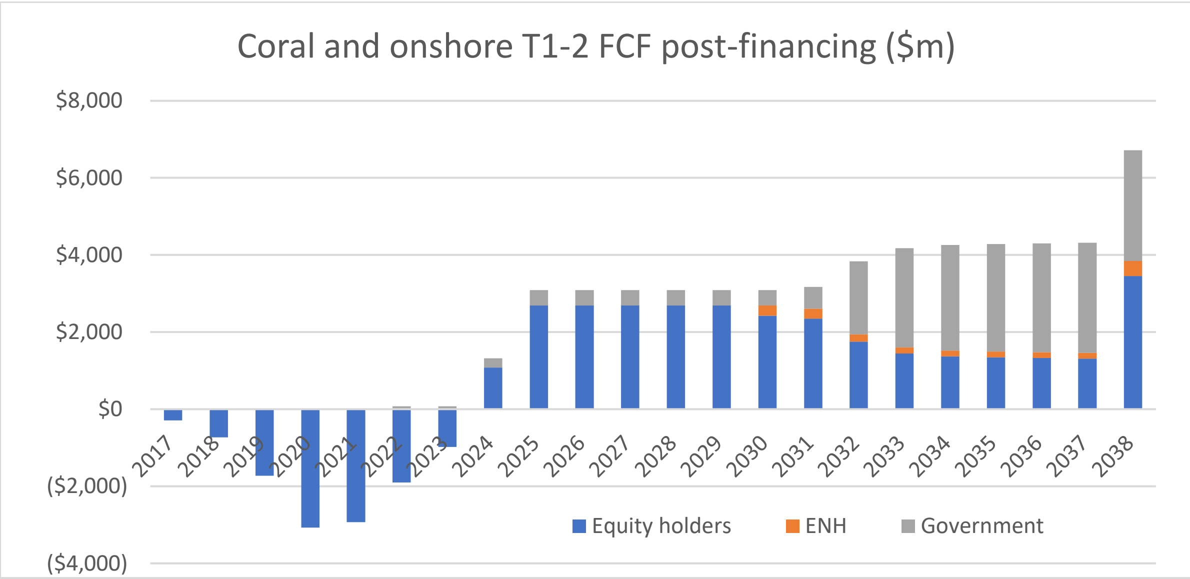
Project finance lenders: 5 Export Credit Agencies and 15 banks were involved in what was Africa's largest-ever project financing and the world's first FLNG project financing. Credit Agricole is financial advisor to Eni for the Area 4 project.

The export credit agencies were Coface (BPI), K Exim, K Sure, Sace and Sinosure. The banks involved were Credit Agricole, HSBC, SMBC, ABN AMRO, BNP Paribas, Korea Development Bank, Millennium BCP, Natixis, Societe Generale, Standard Bank, UBI Banca and UniCredit, Bank of China, China Development Bank and Industrial and Commercial Bank of China (ICBC).

ENH guarantee: The partners will finance ENH's share of capex up to a maximum of $500mm net or $5bn gross.



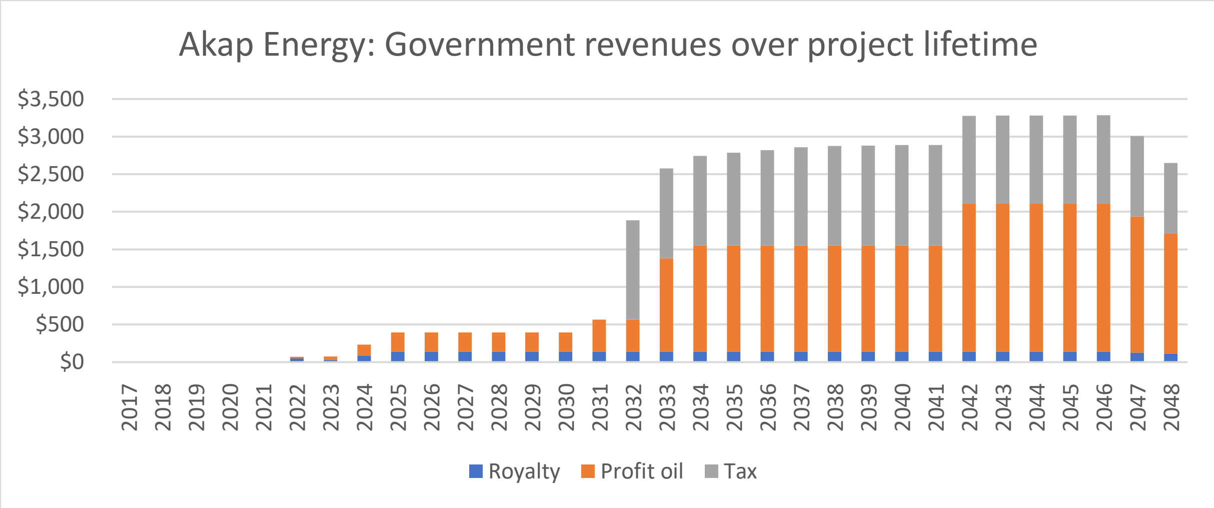
Source: AKap Energy estimates



Source: AKap Energy estimates

Area 4 government take

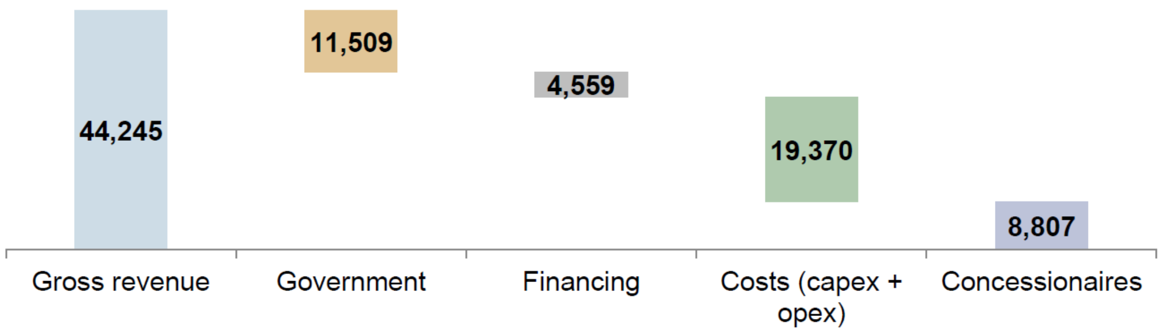
Our estimates for Government take for Area 4 (top chart) is much higher than the Government's own estimates (lower charts) under its base case scenario as the Government doesn't include the onshore Area 4 project which is likely to be sanctioned this year and is a much more material project than the Coral FLNG that it only includes in it estimates.



Source: AKap Energy estimates

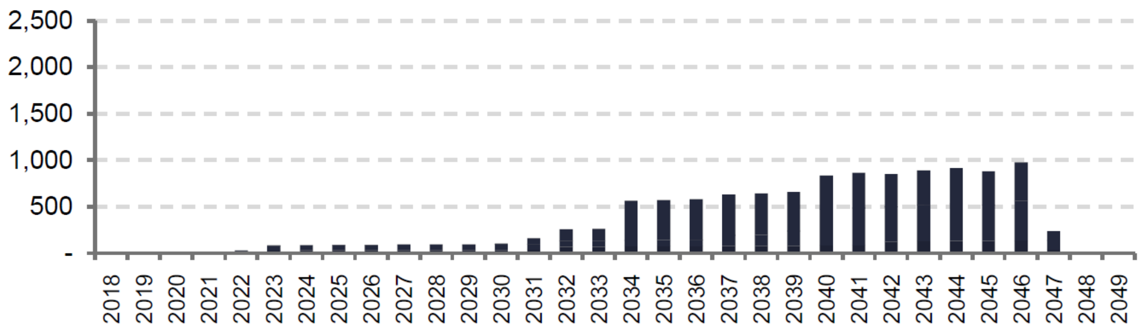
Gross revenues distribution over the life of the project

US$ million



Government revenues over the project lifetime

US$ million



Source: Government of Mozambique

Mozambique project economics

We look at the key operational and financial metrics in the table below which assumes an LNG FOB price of $7.5/mmBtu.

	Units	Area 4 - Coral	Area 4 - Rovuma	Area 4 total	Area 1 - LNG	Area 1 & 4 total
Reserves developed	tcf	5,000	20,000	25,000	17,000	**42,000**
Initial well count		6	24	30	20	**50**
Upstream production rate	mmcf/d	575	2,400	2,975	2,000	**4,975**
LNG production	mtpa	3.4	12.9	16.3	15.2	**31.5**
Pre-FID spend	$bn	$4.0	$0.0	$4.0	$6.0	**$10.0**
Development capex	$bn	$7.4	$25.2	$32.6	$20.1	**$52.7**
Project finance debt	$bn	$4.7	$15.0	$19.7	$14.0	**$33.7**
Project level IRR		9%	10%	10%	11%	**10%**
Project level NPV10	$bn	$2.4	($0.0)	$2.3	$1.6	**$3.9**
Equity holders IRR (ex-ENH)		14%	13%	13%	18%	**15%**
Equity holders NPV10	$bn	$2.1	$3.0	$5.0	$4.6	**$9.6**
LoF revenues	$bn	$33.6	$159.6	$193.2	$114.4	**$307.6**
LoF opex	$bn	$5.8	$26.6	$32.4	$19.5	**$51.9**
LoF royalties	$bn	$0.7	$3.2	$3.9	$2.3	**$6.3**
LoF interest	$bn	$2.9	$7.2	$10.0	$7.3	**$17.3**
LoF tax paid	$bn	$3.0	$20.7	$25.1	$14.3	**$38.0**
LoF Government Profit oil	$bn	$3.6	$31.2	$34.8	$14.4	**$49.1**
LoF Contractors CF	$bn	$20.6	$77.9	$98.4	$63.9	**$162.3**
LoF pre-tax FCF	$bn	$20.5	$107.7	$128.2	$74.8	**$203.0**
LoF FCF: Government	$bn	$7.3	$55.1	$62.4	$31.0	**$93.4**
LoF FCF: Contractor	$bn	$13.2	$52.6	$65.9	$43.8	**$109.6**
Government share		35%	51%	49%	41%	**46%**
Govt NPV10 (ex-ENH)	$bn	$1.3	$8.4	$9.7	$5.3	**$15.1**
ENH NPV10	$bn	$0.0	$0.6	$0.7	$0.5	**$1.2**

Source: AKap Energy estimates

The project level IRR from FID is around 10% for all the projects at $65/bbl or $7.5/MMBtu flat. This implies that the projects will give reasonable but not overly attractive returns. The equity IRR is 15% in aggregate.

The actual life of field free cash flow to the equity holders is >$100bn but on a discounted basis (NPV10) is worth <$10bn.

The Government share of free cash flow is 46% or $93bn and given it doesn't have any capex outflows the NPV10 of its share is $15bn. However, this does mean that the total NPV of the projects to the Government plus equity holders is only ~$25bn relative to the revenues of >$300bn.

Split of the cashflows pre and post 2030

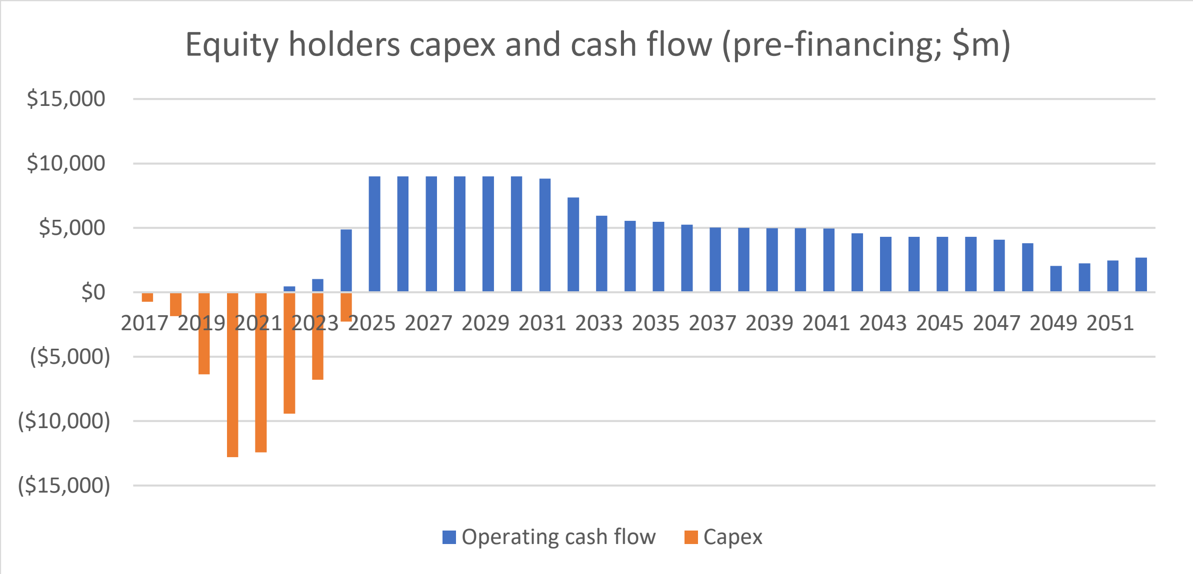
	Units	Area 4 - Coral	Area 4 - Rovuma	Area 1 - LNG	Area 4 total	**Area 1 & 4 total**
Up to 2030:						
Revenues	$bn	$11.4	$47.6	$39.7	$59.0	**$98.6**
Opex	$bn	$2.0	$8.0	$6.8	$9.9	**$16.7**
Royalties	$bn	$0.3	$1.0	$0.8	$1.2	**$2.1**
Interest	$bn	$2.9	$6.6	$6.5	$8.3	**$14.1**
Tax paid	$bn	$0.0	$1.5	$0.0	$0.0	**$0.0**
Government Profit oil	$bn	$0.4	$2.5	$1.5	$2.9	**$4.4**
Contractors CF	$bn	$8.8	$34.7	$30.5	$43.4	**$73.9**
Pre-tax FCF	$bn	$2.1	$14.4	$12.8	$16.5	**$29.3**
FCF: Government	$bn	$0.7	$4.9	$2.3	$5.6	**$8.0**
FCF: Contractor	$bn	$1.4	$9.5	$10.4	$10.8	**$21.3**
Government share		33%	34%	18%	34%	**27%**
After 2030:						
Revenues	$bn	$22.2	$112.0	$74.7	$134.2	**$208.9**
Opex	$bn	$3.8	$18.6	$12.7	$22.5	**$35.2**
Royalties	$bn	$0.4	$2.2	$1.5	$2.7	**$4.2**
Interest	$bn	$0.0	$0.5	$0.8	$1.6	**$3.2**
Tax paid	$bn	$3.0	$19.2	$14.3	$25.1	**$38.0**
Government Profit oil	$bn	$3.2	$28.7	$12.8	$31.9	**$44.7**
Contractors CF	$bn	$11.8	$43.2	$33.3	$55.0	**$88.4**
Pre-tax FCF	$bn	$18.4	$93.3	$62.0	$111.7	**$173.8**
FCF: Government	$bn	$6.6	$50.1	$28.7	$56.7	**$85.4**
FCF: Contractor	$bn	$11.8	$43.2	$33.3	$55.0	**$88.4**
Government share		36%	54%	46%	51%	**49%**

Source: AKap Energy estimates

The table above splits out the main components of the cashflow looking at the period up to 2030 and the period after 2030.

The table shows that the Government gets a small proportion of the revenues in the initial decade (<30%) as the cash flows mainly go to contractors for cost recovery of the capex from the previous years.

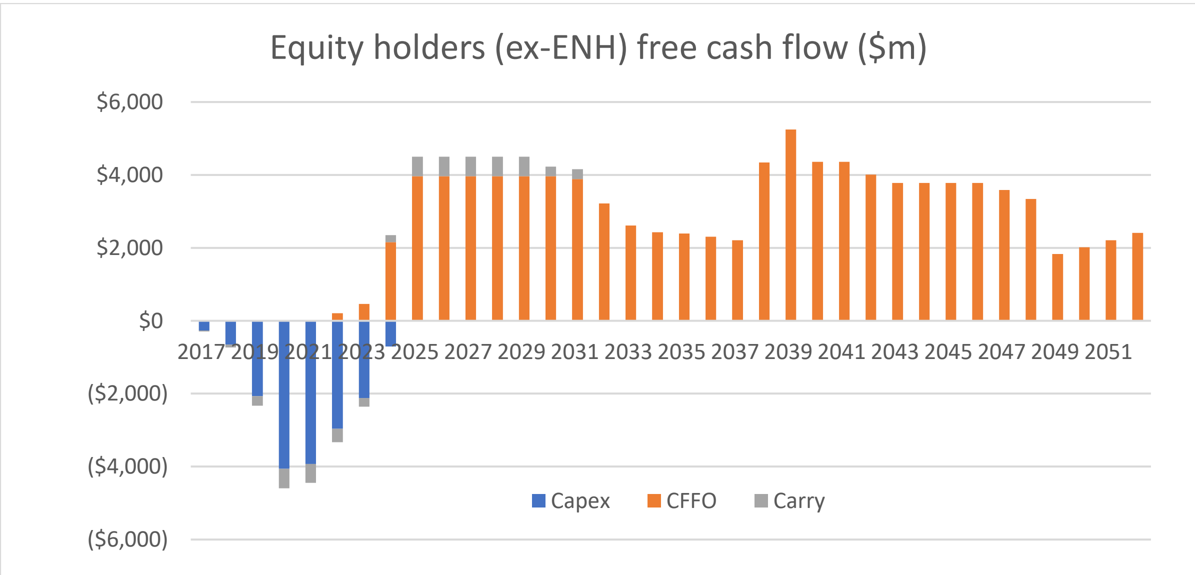
No tax is paid to the Government up to 2030 whereas after 2030 it receives almost $40bn in tax revenue.



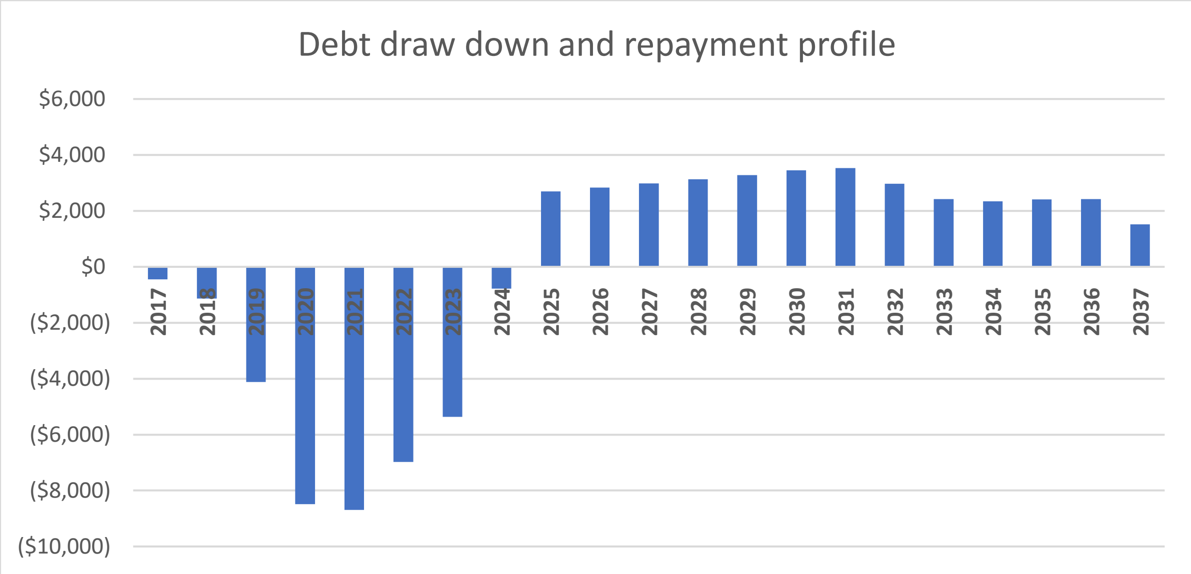
Source: AKap Energy estimates

The top chart shows the capex requirement and cash flow generation that accrues to the equity holders, without considering the project financing impact and ENH carry. From 2025 onwards there is around $9bn in free cash flow for the next 7 years before cost recovery is exhausted and taxes kick in.

The bottom chart shows the free cash flow to the equity holders including the project financing. The capex impact is much lower and we estimate that it takes until the later 2030s to pay off the debt at which point the equity cash flows rebound.



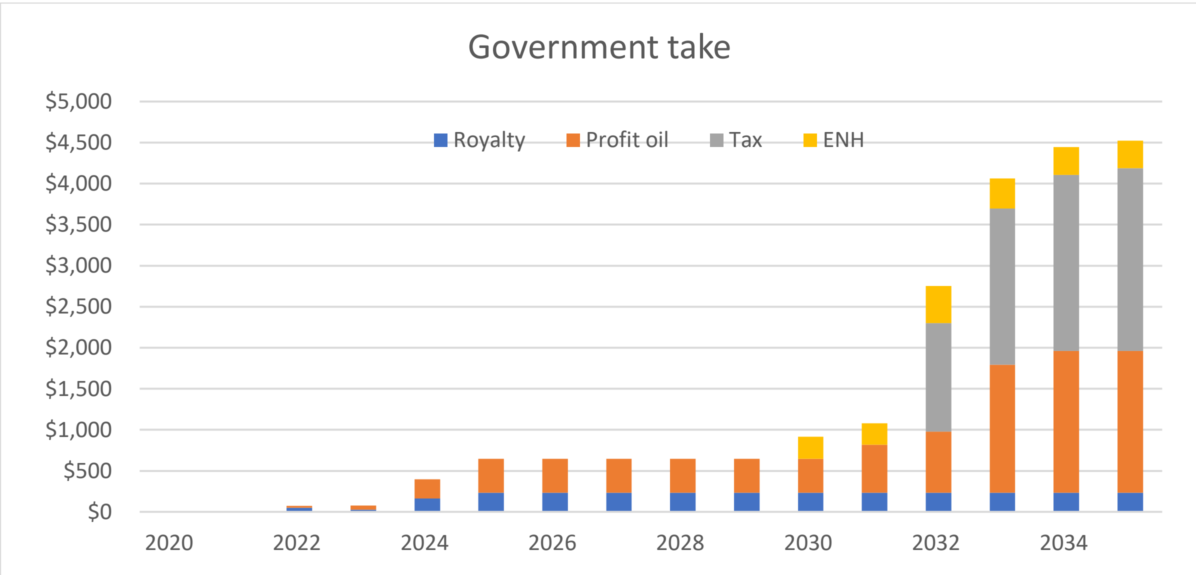
Source: AKap Energy estimates



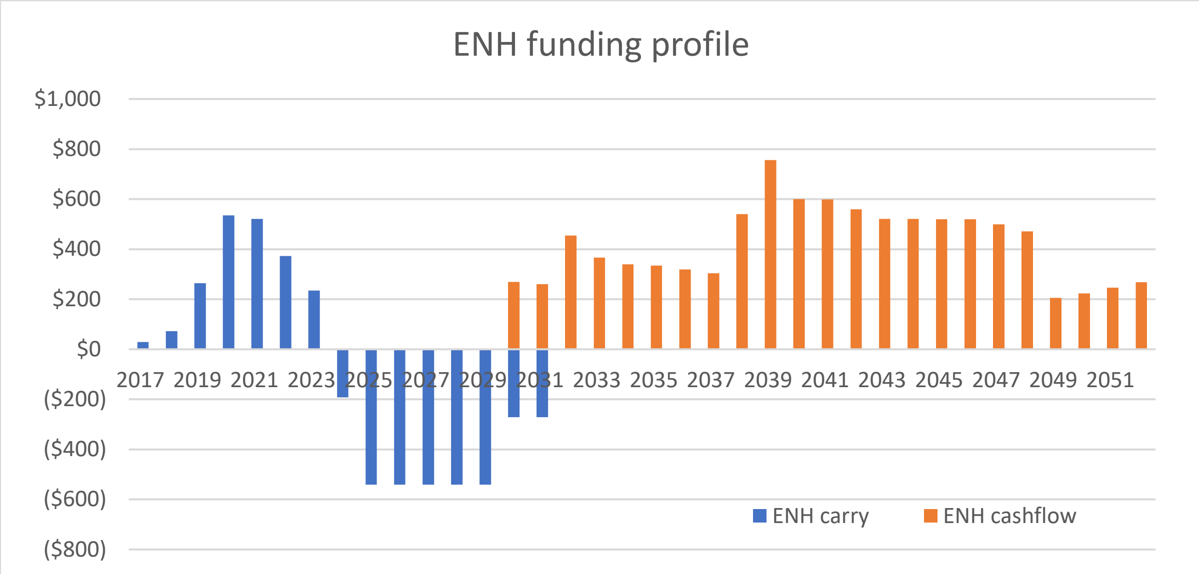
Source: AKap Energy estimates

The chart above shows the debt drawdown and repayment schedule if 50% of free cashflow to the equity holders are used to pay down debt.

The chart below shows that the Government take is minimal until the 2030s. Given the huge capex and accelerated depreciation, tax doesn't become payable until 2032. Also, the profit oil available to the Government is low in the 2020s as the R-factor (measure of cash returns) is still low. However once tax kicks in and the profit oil % increases the Government take increases substantially to ~$4.5bn in the mid-2030s.



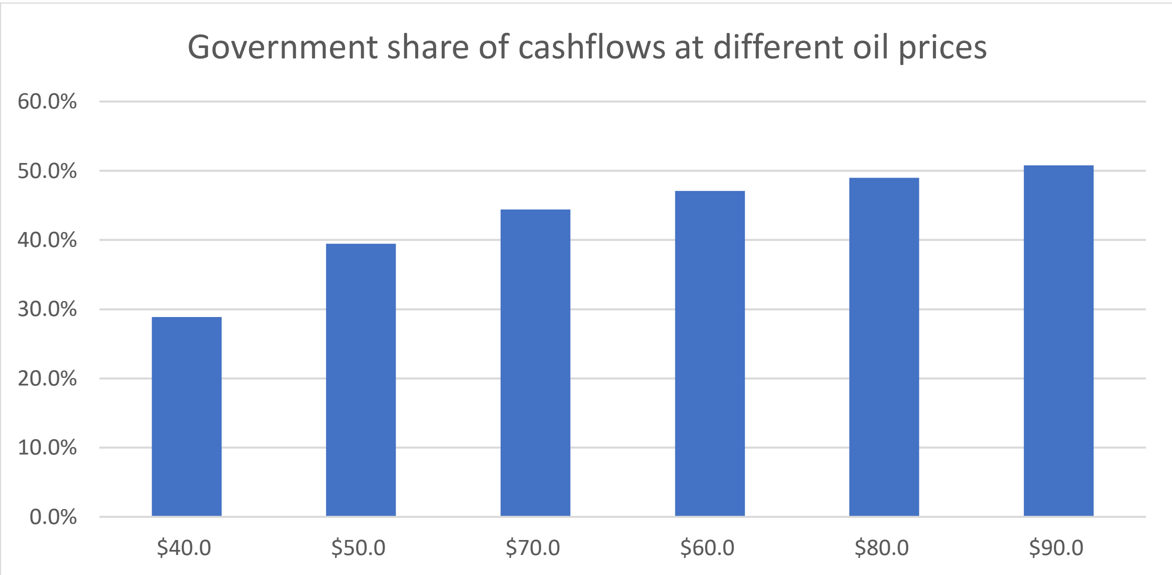
Source: AKap Energy estimates



Source: Akap Energy estimates

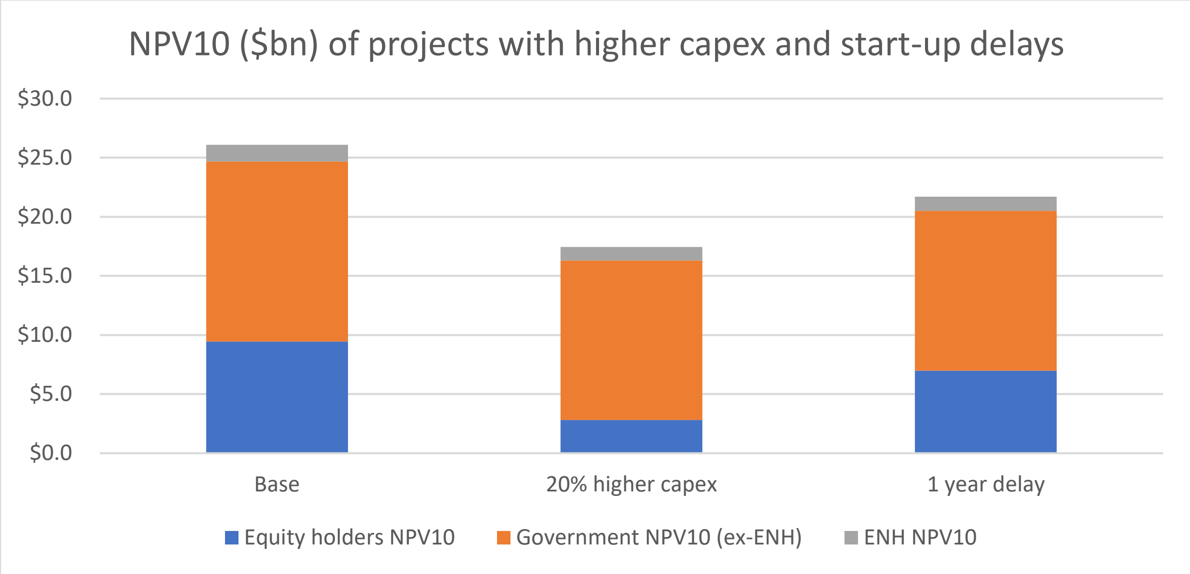
ENH doesn't generate any cashflow until 2030. In the initial years it is being funded by its equity partners – the positive cash flow on the chart above up to 2023 is in essence its share of capex. It then spends the rest of the 2020s repaying the exploration carry (around $1.25bn from pre-2018) as well as the development carry and its share of the project financing.

The Government benefits from a higher share of the cashflows at higher oil prices as the contract is designed to make sure that the contractors are paid back but once they start generating high returns, the Government gets a bigger slice of the pie.



Source: AKap Energy estimates

Impact of delays and cost overruns



Source: AKap Energy estimates

The projects economics are very sensitive to higher capex and delays to the start of production. Assuming 20% higher capex (which isn't an unreasonable outcome based on capex overruns in past LNG projects) cuts the NPV by 33%, however the impact is skewed much more towards the equity holders (-70%) than the Government (-11%) and ENH (-17%), given the bigger upfront cost that the asset owners will have to incur.

A 1-year delay in first production would reduce the value in aggregate by 17% and although the impact again is larger on the equity holders, the magnitude is not as severe. The equity holders' value falls by 26%, the Government by 11% and ENH by 14%.

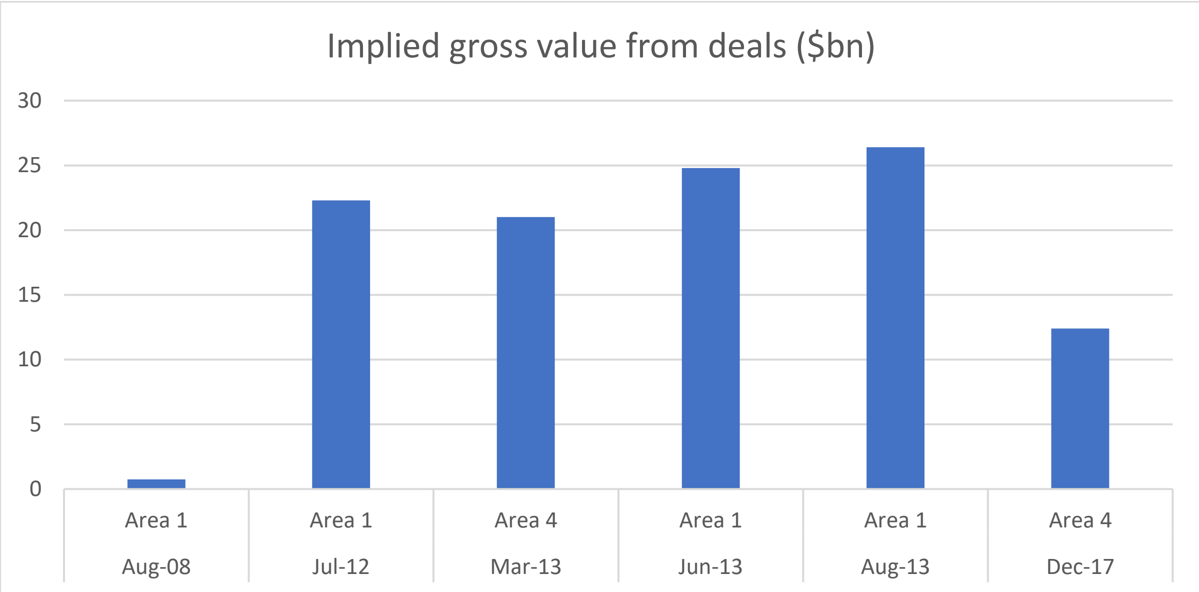
Contingency scenario parameters

	Magnitude	Rationale
Capex cost overruns	+ 20 %	• Cost overruns are common in hydrocarbon (oil and gas) megaprojects • According to Ernst & Young study, 65% of the projects analysed were facing cost overruns with an average escalation of 23% from the approved FID budget
Delays in the start of production	Start of production 1 year later	• Delays are also very common in hydrocarbon megaprojects • According to the Project Management Institute, one in eight major offshore developments with a capital expenditure ranging from US$1 billion and US$3 billion exceeded cost and/or schedule by 40%, or within the first year of operating were producing less than 50% of production capacity

Source: Ernst & Young, Spotlight on oil and gas megaprojects (2014)

Asset sales

There has been a fair amount of M&A activity surrounding the blocks in Mozambique. A lofty valuation was placed on Area 1 shortly after the discoveries were made when PTTEP bought the independent E&P Cove Energy for an implied gross valuation of >$20bn. A year later a similar valuation was achieved by Eni for its stake in Area 4 from the Chinese. A sell down of Area 1 in August 2013 gave an implied value of >$25bn or ~$50bn for the two blocks, which marked the top of the market. The most recent sell down saw the implied value halve to $12.5bn, despite the incremental capex and being post FID on Coral. Based on this valuation, we still think that significant further developments must be factored in to justify the valuation.



Source: AKap Energy estimates

August 2008: BPCL and Videocon take 10% stakes in Area 1 for $75mm each from Anadarko. This was before the first exploration wells had been drilled and gave an implied value of $0.75bn.

July 2012: PTTEP bought Cove Energy's 8.5% stake in Area 1 for $1.9bn after a bidding war with Shell. This gave an implied value of $22.3bn for Area 1. The Government levied a 12.8% tax on the overall transaction value.

March 2013: Eni sold a 20% stake in Area 4 to CNPC for $4.2bn, implying a gross valuation of $21bn. This resulted in a CGT payment of $400m, plus an additional pledge to build a power plant worth $130m.

June 2013: ONGC and Oil India took a combined 10% stake in Area 1 for $2.48bn.

August 2013: ONGC acquired a 10% stake in Area 1 for $2.64bn.

December 2017: Eni sold 25% of Area 4 to Exxon for $2.8bn plus its share of capex in 2016 and 2017 of $0.3bn, a total price of $3.1bn, implying a gross value of $12.4bn for Area 4 at YE'17. Eni reported a €1,985mm book value gain. Capital gain tax revenue ($350m or 2.8% of GDP) accrued from the sale of Coral South to Exxon.

Fiscal terms

Overall the fiscal terms in Mozambique are favourable for the contractors, which is reasonable as these were frontier exploration blocks. Also, given the lower value and longer lead time to develop gas, better fiscal terms are needed to encourage development. The Mozambican parliament passed an LNG Decree Law in December 2014 to establish the necessary legal and regulatory framework for developing the projects. We outline the key terms in the production sharing agreements below.

2% royalty: this is the fee the Government takes as a % of revenue. This is low by global standards.

Production bonus: This is minor in the scheme of things. A one-off $5m is payable at first production and then a further $10m and $20m are payable when production gets to 25kboe/d (150mmcf/d) and 50kboe/d (300mmcf/d) respectively.

Exploration spending: All the pre-FID spending is cost recoverable and available for depreciation purposes.

Cost oil: Between 65-75% of revenues are available for cost recovery. Given the large amount of pre-FID spend and high capex, this means that the contractors can claw back the spending.

Profit oil: The cashflow left over after cost oil is split between the Government and contractors based on the R-factor. The R-factor is defined as cumulative cash inflows divided by the cumulative cash outflows. The profit oil shall be shared between the Government and the Concessionaire according to a scale varying with the value of the R-factor. The scale is generous for the contractors and sees them taking ~80-90% of the profit oil until the early 2030s.

Depreciation: Exploration spend is available to be depreciated from first oil. Capex is amortised on a 25% straight line basis. This allows for accelerated depreciation to push back the point the blocks move into a tax paying position.

Corporate tax: Payable by contractor from profit and cost Oil. The tax rate is 24% for the first 8 years of production and then increases to 32%. A tax law amendment passed by parliament in 2012 came into force on 1 January 2014, imposing a fixed 32% rate on capital gains realised by companies

State Carry – ENH has a 10-15% carried interest to first development plan approval. The carried amounts are recovered (plus interest at LIBOR + 1%) from cost recovery according to both PSCs for Area 1 and Area 4.

The entire PSCs are available to view at: https://repository.openoil.net/wiki/Mozambique

Project financing challenges

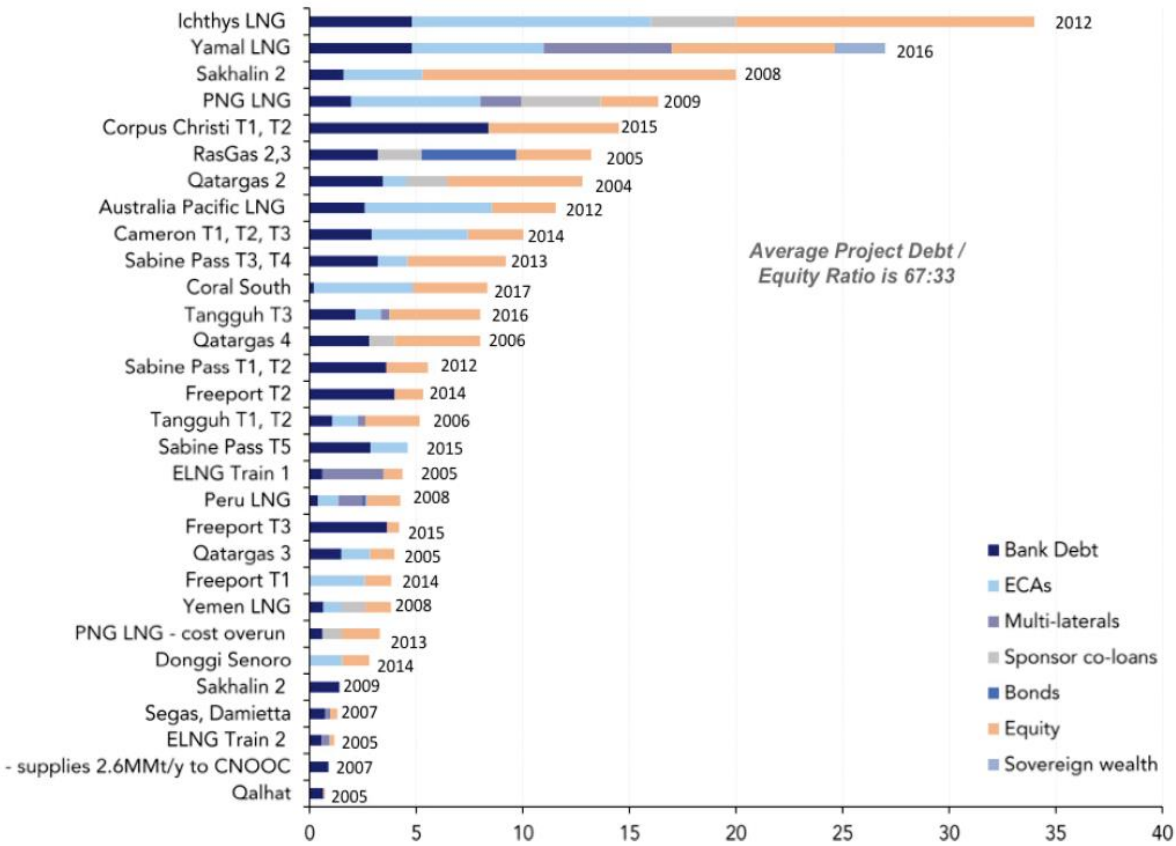
There are two key financing challenges:

1. The ability of the partners to raise project financing debt
2. The funding of state oil company ENH's obligations (both debt and equity).

There is likely to be an increase in the cost of project financing debt facilities as a result of an unfriendly market reputation and/or being in default is significant. This is because sovereign credit ratings are designed to give information to the market about the country's and its companies' ability to repay their debts.

ENH's total required investment into the projects is around 50% of Mozambique's GDP at a time when it has 100% external debt to GDP. ENH may also have a further funding requirement for other blocks and developing domestic gas. For example, the Government needs to provide a sovereign guarantee for the project financing of Area 1 by ENH.

LNG project financing by contributor ($bn)



Source: Poten LNG

So, for the country and the economy to benefit, a stable economic climate is needed. For example, it is not helpful that the Government is in a default situation, when companies are trying to raise ~$30bn in project financing: if we assume a 1% higher borrowing cost for the project financing, it reduces the life of field revenues to the Government by $2bn. The impact is more significant on the Government in the early years as it further pushes back when the Government can access the revenues. It is important for the Government to have a clean financial bill of health, as it will need to rely on the debt market over the next decade to support it, ahead of the future cash windfall in the 2030s.

We include some relevant quotes below from an article from Latham & Watkins[1], which we believe are particularly pertinent to Mozambique:

From an investor's perspective, sovereign credit ratings are important as they give investors an insight into the economic and political risks associated with investing in a particular country. From a country's perspective, particularly developing countries, it is often critical to obtain a good sovereign credit rating in order to attract foreign direct investment and funding in external debt markets.

Sovereign credit ratings convey information to the market about a country's (and companies residing in that country) ability to repay its debt. A downgrade of a country may negatively affect the appetite of these debt providers to lend to a project located in such a country.

Commercial banks typically are willing to take a degree of commercial risk in a project financing but have a more limited appetite for more political or macroeconomic risk. A downgrade of a country in which a project is located likely will negatively impact the willingness of commercial banks to finance that project, particularly if the ratings downgrade is linked to a perceived degree of political instability in that country.

Sovereign credit ratings can affect a country's access to the bond and commercial paper markets as rating levels determine whether some institutional investors are permitted to invest in a particular country's securities. Some investors have mandates that stipulate that they can only own debt with a certain grade, which may narrow the potential pool of investment available to any country or any project located in a country that falls below the required level.

[1]Source: https://www.lexology.com/library/detail.aspx?g=0f5290a4-1757-4473-aafc-7d3011fbba35

ENH

Company overview: Empresa Nacional de Hidrocarbonetos (ENH) is the national oil company of Mozambique and was formed in 1981. When Mozambique declared independence from Portugal in 1975 a planned economy was put in place, with all sectors in the hands of the state. Within this system Mozambique had a Secretariat of Hydrocarbons under the Ministry of Mineral Resources, which was the precursor to ENH, and acted as the commercial venture, the regulator and the policy-maker for oil and gas in the country. As a State-Owned Enterprise, ENH represents the Mozambican state in commercial oil and gas ventures all over the country. ENH became a public enterprise in 1997 and ceased to be the industry regulator in 2004. ENH has the mandate to be totally integrated along the entire oil and gas value chain. It has an existing development with Sasol in the south of the country that has been going for ~15 years. ENH has around 250 employees. It has a 10% stake in Area 4 and a 15% stake in Area 1.

Planned refinancing: ENH appointed Lazard (for Area 4) and Lion's Head Global Partners (Area 1) as advisers to help raise as much as $2bn to refinance its portions of two gas-development projects. ENH received World Bank support to hire the financial advisers as part of the lender's *Mozambique Mining and Gas Technical Assistance Project*.

ENH does not have the liquidity and balance sheet to invest its equity portion into the mega projects and neither does the government. In 2015, when the market was oversupplied and the oil price depressed, there was very little appetite on the part of institutional investors and financial lenders to put money into the upstream development, especially when there was no line of sight for when FID would take place. ENH's backstop option was for its IOC partners to fund its portion of the spending. Now that investor confidence has improved and LNG offtake commitments have been finalised, it sees this as an appropriate time to go back to the market and persuade institutional investors to refinance its portion so it can pay back the IOCs.

We estimate that ENH has been funded to the tune of $1.25bn to date. It has also said that it is attempting to collateralise some of its future revenues and sell forward some of its share of the gas volumes from the projects. ENH's chairman has said that the country's rating agency ranking was not jeopardising the progress of the projects.

ENH's net capex ($m) for three development projects

Project	Pre-FID carry (uninflated)	Debt financed capex	Equity financed capex	Total
Area 1	$900	$2,250	$750	**$3,900**
Coral	$400	$470	$300	**$1,170**
Area 4 T1-2		$1,500	$1,000	**$2,500**
Total	**$1,300**	**$4,220**	**$2,050**	**$7,570**

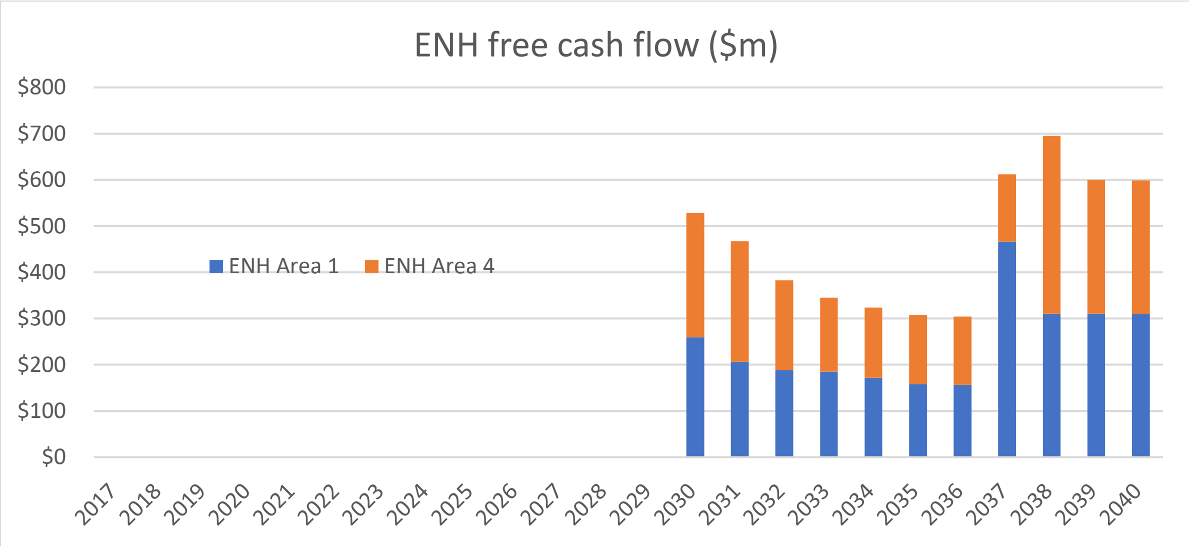
Source: AKap Energy estimates

Area 1: ENH is fully carried through the exploration phase until a plan of development has been approved. However, the carry is repayable through cost oil once production starts and is inflated at rate of LIBOR +1%. In Area 1 ~$6bn has been spent ahead of the plan of development approval. Therefore ~$900mm plus interest needs to be repaid to the consortium just to cover the exploration and appraisal spend on Area 1.

The development will cost ~$20bn gross or $3bn net to ENH of which ~$1bn will be equity financed and $2bn will be debt financed. No guarantee would be needed for ENH's equity share, which will be financed by the other partners in the consortium, with repayments coming out of LNG revenues during the first years of the project's operation. The Government will be required to provide a guarantee for the debt (required by the consortium of export credit agencies and commercial banks). The budget law for 2019 will allow the government to issue loan guarantees for 151bn meticais ($2.5bn).

Area 4 Coral: The other project participants have provided a debt service guarantee for ENH. The Concessionaires have committed to financing the share of capital expenditures to be borne by ENH and to guaranteeing its share of obligations towards the lenders under the debt service undertaking up to a maximum liability of $640m. Therefore, no Government guarantee was required for this project.

Area 4 Rovuma: The development will cost ~$25bn gross or $2.5bn net to ENH of which ~$1bn will be equity financed and $1.5bn will be debt financed. Given the major players involved in Area 4, we expect that a debt service guarantee and capex carry will be provided on this block too.



Source: AKap Energy estimates

Valuation of ENH's stakes

At our base case valuation of $65/bbl ($7.5/MMBtu LNG) for the value of the initial three projects to ENH is $1.4bn (NPV10), of which $0.6bn is from Area 1 and $0.8bn from Area 4. It is a relatively low number as ENH must pay back its exploration carry (>$1.5bn in real terms) and also is being carried on its capex obligations. As a results ENH doesn't have any cash outflows but it doesn't see any cash flow until 2030. The development of another 2 trains at Area 1 would add around $0.9bn of value to ENH. So, there is a lot of option value above the value of the projects that are currently being developed.

ENH NPV10 valuation ($bn) under different scenarios

		LNG price ($/MMBtu)				
		$5.2	**$6.3**	**$7.5**	**$8.6**	**$9.8**
Interest rate on capex	**1.0%**	$0.5	$0.9	$1.4	$2.0	$2.7
	2.0%	$0.4	$0.8	$1.4	$1.9	$2.4
	3.0%	$0.3	$0.7	$1.2	$1.7	$2.3
	4.0%	$0.2	$0.6	$1.0	$1.7	$2.3
	5.0%	$0.1	$0.4	$0.9	$1.5	$2.1
	6.0%	$0.0	$0.3	$0.8	$1.4	$1.9

Source: AKap Energy estimates

The table above shows the sensitivity of the ENH valuation to different LNG prices but also to different assumptions on the cost of funding its share of capex that is being carried by the partners.

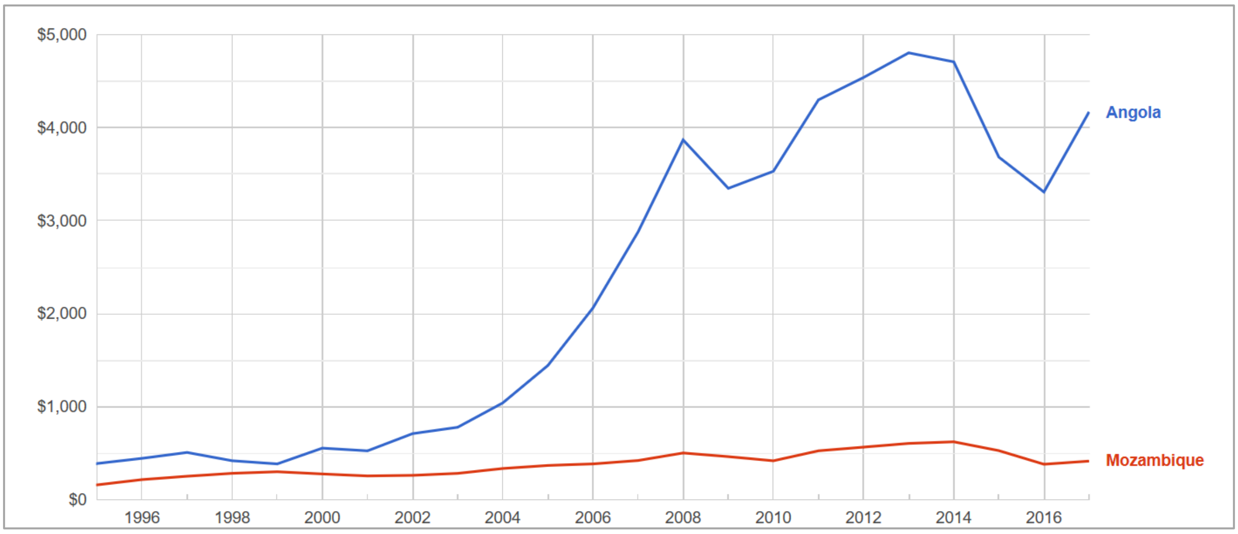
Given the Government debt default (see below), it is also worth seeing the impact of a higher discount rate on the ENH valuation: increasing the discount rate by just 1% reduces the base case valuation by 18%.

Mozambique in the context of Angola

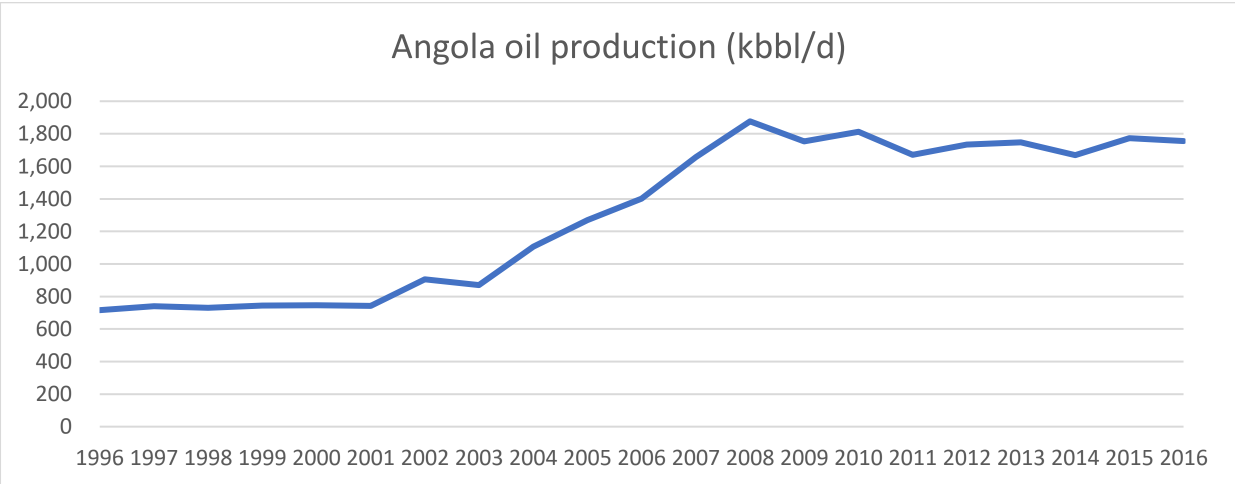
It is interesting to see the impact of deepwater exploration success on Angola and what this could mean for Mozambique. Angola's oil production took off from the early 2000s more than doubling between 2003 and 2008 to >1,800bbl/d. Over this period Angola's GDP per capita quadrupled on the back of the oil boom.

Back in the 1990s, Mozambique was not too far behind Angola in terms of GDP per capita but a huge divide opened up with Angola's surge in production. Both countries have a similar size population. Mozambique should see its production grow by ~800kboe/d by the mid-2020s (a similar amount of absolute growth seen in Angola), which bodes well for solid GDP growth through the 2020s.

Angola and Mozambique GDP per capita 1995-2016 (Current US$)



Source: World Bank

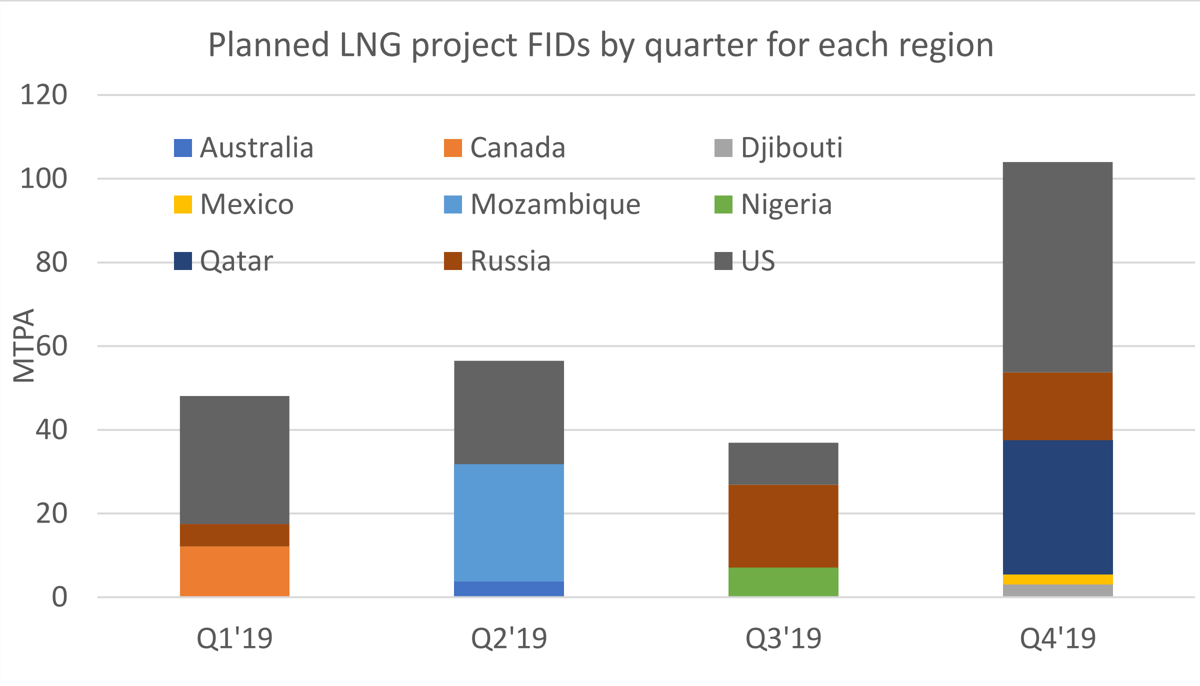


Source: BP Statistical Review of World Energy 2018

LNG project outlook: Mozambique context

Our analysis shows that there are an unbelievable 25+ LNG developers that have stated (within the last year) they will take a final investment decision (FID) on their LNG liquefaction plants in 2019. Unless demand surprises to the upside, the expected LNG supply deficit in the mid-2020s could easily turn into a glut. In total there is almost 250 million tonnes per annum (mtpa) of capacity that plans to take FID this year - the equivalent of 80% of current global supply.

We see this as important to Mozambique, as if it delays sanction of its projects it may miss the boat and there is a risk longer term of lower LNG prices and we have shown earlier the high sensitivity of the valuation to LNG prices.



Source: Akap Energy estimate

Whilst the market appears unconcerned, as the assumption is that very few projects proceed, our bottom up analysis suggests 100-150mtpa will get sanctioned this year (>30% of current supply). There are 13 projects where we see a 75% or higher probability of being sanctioned with a total risked capacity of 110mtpa. In the US alone 115mmpta of capacity is up for FID this year and 100mtpa in Qatar, Russia and Mozambique. Inevitably some of the projects will slip into 2020, however there are a further 15 projects looking to take FID in 2020.

Markets seem to assume that offtake contracts must be in place for projects to proceed, thereby limiting expansion. But, in fact, many projects do appear to have sufficient firm contracts in place (e.g. Mozambique and Calcasieu Pass in the US), some brownfield projects can rely on existing cashflow to fund expansions and many of the supermajor/NOC led projects don't need offtake in place to proceed (e.g. Qatar and Golden Pass). Based on our analysis we have identified ~50mmpta of contracted volumes for the projects, the vast majority of which is associated with the riskier greenfield projects. As well as the typical Asian buyers, European buyers have become more prominent and there are several oil majors that have contracted from independent project developers.

Mozambique economy: key takeaways from IMF report

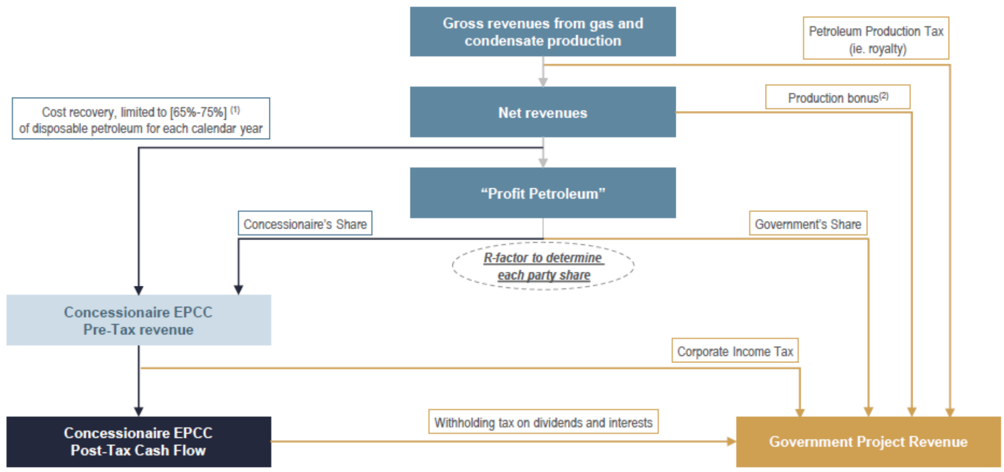
We pull out some of the key issues from the latest detailed IMF report on Mozambique from March 2018.

- Debt remains in distress as the stock of public sector debt-to-GDP reached 128.3% at end-2016, with several debt payments missed, including on the Mozam Eurobond.
- The outlook remains challenging. Absent further policy action, real GDP growth is expected to further decline over time while inflation would remain at current levels. The fiscal deficit would expand, leading to further accumulation of public debt and crowding out of the private sector.
- Banks' rising exposure to the government, combined with high interest rates, create potential macrofinancial vulnerabilities.
- Mozambique's economy is facing difficult challenges. While inflation has declined rapidly, real GDP growth remains weak and macroeconomic imbalances are growing.
- Directors welcomed the approval of a decree establishing a framework for contracting public debt and issuing guarantees.
- Directors called for a renewed effort to strengthen the business climate and governance to boost private investment and job creation to support inclusive growth and further reduce poverty and inequality. They noted that restructuring ailing state-owned enterprises will be key to improving efficiency, and reducing financial losses.
- Risks are broadly balanced, with an upside potential from rising commodity prices, the resolution of the hidden debt issue, and reengaging with donors.
- Downside risks include a deterioration in security conditions; further loosening of expenditures; increased debt service, liabilities from loss making SOEs, unavailability of domestic financing, and delays in megaprojects.
- Mozambique's key challenge is to restore macroeconomic stability, rebuild confidence in the near term, and foster economic recovery over the medium term.

Appendix: LNG fiscal terms

Breakdown of government revenues from the LNG projects

Projects gross revenues water fall is determined in the Concession Agreements:



Government revenues are distributed between 5 "key" elements: (i) royalties (i.e. petroleum production tax), (ii) production bonus, (iii) government's share of profit petroleum, (iv) corporate income tax, and (v) withholding tax on dividends and interests

Note: (1) Ceiling on cost recovery can vary from a Concession Agreement to another
(2) Payments in relation to the production bonus only take place in the first couple of years of production, as this is a one-time payment every time the production capacity reaches and additional tranche of production. The bonus amount is not significant, and this payment is below USD 140 million for both projects between 2022 and 2024

Government revenues are projected to increase gradually during the projects lifetime

The Concession Agreements negotiated between the concessioners and the government allows the concessionaires to recover their investment costs upfront. Hence revenues to the government from the projects are limited during the period of cost recovery

- **Petroleum production tax (ie. royalty)**
  - Royalty rates are fixed at c.2% and c.3% of gross revenues for natural gas and condensate respectively (for production below 500m depth). The rates then increase by 2p.p. every ten years
- **Cost recovery mechanism**
  - The cost recovery mechanism allows the concessionaires to recover 65%-75% of net revenues (gross revenues minus royalties) every year until all past investments have been refunded. Once all capex have been recovered, only the opex and decommissioning capex can be recovered every year, significantly increasing the amount of profit petroleum available to be shared between the government and the concessionaires
- **Government profit petroleum share, based on the R-factor**
  - The R-factor is a cost recovery parameter that determines the distribution of the profit petroleum between the government and the concessionaires. It is calculated as the ratio of the concessionaire's cumulative cash inflows, net of operating costs and tax, to its cumulative capital expenditures
  - According to the agreement reached, the government's share would be between 10% and 15% and will gradually increase to values ranging between 55% and 60% as the R-factor increases

R-factor table

R-factor	Gov. share	Concessionaire share
< 1	[10% - 15%]	[85% - 90%]
< 2	[20% - 25%]	[80% - 75%]
< 3	[30% - 35%]	[70% - 65%]
<4	[45% - 50%]	[55% - 50%]
> 4	[55% - 60%]	[45% - 40%]

- **Corporate income tax**
  - The projects' related financial losses during the first years can be carried forward during 7 years
  - The standard income tax rate stands at 32%. However, an exemption was granted for the first 8 years of production with a rate set at 24%

ENH, as a project concessionaire, is not expected to generate any dividend to the government during the first years of the projects lifetime. Initial ENH revenues from the gas projects would serve primarily to reimburse the company's debt in relation to the equity carry financing during the exploration and construction phase. ENH's ability to generate dividends in the medium term will mostly depend on its ability to refinance its carry

Source: Government of Mozambique

Disclaimer