Tlou Energy Limited (ASX: TOU, AIM: TLOU, BSE: TLOU)

Gas-to-power project advances on recent capital raisings

Overview

Three raisings totalling ~$8.0m have moved Tlou closer to executing the first phase of its Lesedi gas-to-power project. Assuming additional funding in H1 2023 we expect power sales to commence next year at 2 MW, expanding to 10 MW and then to the 25 MW facility limit. We have reviewed the project's economics in detail and await confirmation of well performance outcomes from the next drilling phase. Our valuation has decreased to $0.14/sh (prev. $0.25) due to increased share dilution reflecting the price of recent and expected future raisings, combined with more conservative well deliverability assumptions following review of coal qualities and well geometry. We estimate upside to $0.20 on further project derisking.

Key points

Investment thesis: gas and power in energy short southern Africa. Tlou provides exposure to 41 bcf of 2P reserves (427 bcf 3P) and 214 bcf of 2C contingent resources at its Lesedi and Mamba coal bed methane projects in central Botswana, with a further 8 tcf of prospective resources. The 2P+2C resources can supply >100 MW of generation for 20 years, reducing Botswana's imports (240 MW in 2020), with 3P+2C sufficient for full replacement. Tlou's proposed hybrid gas and solar PV project should provide energy supply security at reduced carbon emissions.

Lesedi power project: Tlou has an initial five-year 10 MW power purchase agreement (PPA) with the Botswana Power Corporation to be supplied from Lesedi CBM. Construction of a 100 km 66 kV transmission line with 25 MW capacity has commenced, with completion expected by late-2023. Power generation will ramp up as gas engines are progressively added, with each 1 MW engine requiring ~200 kscfd (~71 TJ/yr) of gas and delivering revenue of >$1m/yr. Expansion to 25 MW transmission capacity should deliver revenue of >$30m/yr with expected PPA price escalation.

Recent funding: TOU raised $8m in Q4 2022, of which $7.5m was provided by investor Dr Ian Campbell, who now owns 25.79% following ratification by shareholders in January. The funds are proposed for drilling of gas production wells and construction of Lesedi power project infrastructure. We estimate a total project cost of ~$US14m for 2 MW supply and a further $US20-25m to expand to 10 MW.

Project economics: Key uncertainties remaining are Estimated Ultimate Recovery (EUR), peak gas flow rate and drilling costs per well. Each of these impacts on capital efficiency, which is critical to commercial success. The next phase of drilling aims to materially increase the effectiveness of new laterals by eliminating the water pooling inhibiting gas flow in existing wells.

Next steps/price catalysts: Conclusion of project finance arrangements (1H 2023) to fund substations, gas engines and additional wells for 2 MW supply, demonstration of increased CBM well flowrates (2023), hydrogen prototype trials (2023), first power sales (2024), solar PV concept development (2024).

Risks: (1) Remaining project funding for 2 MW power delivery, (2) demonstration of CBM well performance, (3) hydrogen prototype performance and project economics.

SHARE PRICE PERFORMANCE

Closing price as of 19th Jan 2023

CAPITALIZATION	
Last price	$0.035
52-week range	$0.023-0.048
Capitalization	$26m
Cash: 31st Dec	~$13.9m
Debt: 31st Dec*	$7.2m
EV	$19m
Shares	830.9m
Options/rights	12.7m
Conv Notes	115.8m
Balance date	June
'* convertible notes	

RESERVES AND PRODUCTION	
1P	0.3 bcf
2P	41 bcf
3P	427 bcf
2C/3C	214/3043 bcf
2U	8596 bcf
FY22a	0 bcf
FY23e	0 bcf
SHAREHOLDERS (%)	
Board/mgt	6.81
IC Australia	25.79
Other	67.40
LEADERSHIP	
Chair	Martin McIver
MD/CEO	Tony Gilby
FD/CFO	Colm Cloonan
ED	Gabaake Gabaake
NED	Hugh Swire

Disclosure: This is a commissioned research report and K1 Capital will receive a fee for preparing this report.

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1. Financial summary

	Units	FY21a	FY22e	FY23e	FY24e	FY25e	FY26e
CPI, forex & prices							
US inflation rate	% pa	2.20	2.20	2.20	2.20	2.20	2.20
Australian inflation rate	% pa	2.50	2.50	2.50	2.50	2.50	2.50
Inflation Factor - US : Dec-20	-	1.005	1.028	1.050	1.073	1.097	1.121
$US/$A forex (base)	$US/$A	0.75	0.73	0.70	0.70	0.70	0.70
Brent	$US/bbl	54	92	98	88	81	79
Nat Gas (Henry Hub)	$US/mmBtu	2.8	4.6	5.7	4.8	4.5	4.6
Nat Gas (Sth Africa) - wholesa	$US/mmBtu	7.1	9.3	9.8	9.3	9.0	9.0
Received prices							
Oil	$US/bbl	-	-	-	-	-	-
Condensate	$US/bbl	-	-	-	-	-	-
Gas	$US/mmBtu	-	-	-	-	-	-
LPG	$US/bbl	-	-	-	-	-	-
LNG	$US/t	-	-	-	-	-	-
Electricity	$US/MWh	-	-	-	-	113.2	116.2
CO2e	$US/t	-	-	-	-	-	-
Total	$US/boe	**-**	**-**	**-**	**-**	**84.9**	**87.1**
Net production by project							
Lesedi: 2->10 MW	mmboe	-	-	-	0.00	0.04	0.03
Lesedi: 10->20 MW	mmboe	-	-	-	-	-	0.01
-	mmboe	-	-	-	-	-	-
Power to Orapa (90 MW)	mmboe	-	-	-	-	-	-
Remaining 2P* (50 MW)	mmboe	-	-	-	-	-	-
Delta 3P vs 2P (220 MW)	mmboe	-	-	-	-	-	-
-	mmboe	-	-	-	-	-	-
-	mmboe	-	-	-	-	-	-
-	mmboe	-	-	-	-	-	-
-	mmboe	-	-	-	-	-	-
Total	mmboe	**-**	**-**	**-**	**0.00**	**0.04**	**0.04**
Net production by product							
Oil	mmbbl	-	-	-	-	-	-
Condensate	mmbbl	-	-	-	-	-	-
Gas	PJ	-	-	-	-	-	-
LPG	mmbbl	-	-	-	-	-	-
LNG	Mt	-	-	-	-	-	-
Electricity	TWh	-	-	-	-	0.03	0.03
CO2e	Mt	-	-	-	-	-	-
Total	mmboe	**-**	**-**	**-**	**-**	**0.04**	**0.04**
Total production	kboed	**0.00**	**0.00**	**0.00**	**0.00**	**0.11**	**0.11**
Production growth	%		-	-	-	-	-
Revenue							
Oil	M$A	-	-	-	-	-	-
Condensate	M$A	-	-	-	-	-	-
Gas	M$A	-	-	-	-	-	-
LPG	M$A	-	-	-	-	-	-
LNG	M$A	-	-	-	-	-	-
Electricity	M$A	-	-	-	0	5	5
CO2e	M$A	-	-	-	-	-	-
Total modelled	M$A	**-**	**-**	**-**	**0**	**5**	**5**
Total reported	M$A	-	-	-	-	-	-
Revenue growth	%		-	-	-	-	2.6
Operational metrics							
Revenue	$A/boe	-	-	-	-	111.7	111.5
Production & transport costs	$A/boe	-	-	-	-	-33.2	-25.0
Royalties & prod purchases	$A/boe	-	-	-	-	-14.1	-14.5
Admin	$A/boe	-	-	-	-	-57.3	-57.5
EBITDA margin	$A/boe	-	-	-	-	7.2	14.5
D&A	$A/boe	-	-	-	-	-232.4	-18.1
Tax and financing	$A/boe	-	-	-	-	290.6	-19.9
Normalized NPAT	$A/boe	-	-	-	-	65.4	-23.5
Resource/production	years	-	-	-	-	22.8	22.3
Product mix	% liquids	-	-	-	-	-	-
Change vs. prior report							
USD/AUD (average)	$US/$A	-	-	-	-	-	-
Brent USD	$US/bbl	-	-	-	-	-	-
Brent AUD	$A/bbl	-	-	-	-	-	-
Production	mmboe	-	-	-	-	-	-
Revenue	$m	-	-	-	-	-	-
Cash opex (-ve = inc.)	$m	-	-	-	-	-	-
EBITDA	$m	-	-	-	-	-	-
Normalized NPAT	$m	-	-	-	-	-	-
Cash (YE)	$m	-	-	-	-	-	-
Debt (YE, +ve = inc.)	$m	-	-	-	-	-	-
Capex (+ve = inc.)	$m	-	-	-	-	-	-

	Units	FY21a	FY22e	FY23e	FY24e	FY25e	FY26e
P&L	M$A						
Sales revenue		-	-	-	0	5	5
Other revenue		0	-	-	-	-	-
Production costs		-	-	-	-1	-1	-1
Royalties & prod purchases		-	-	-	-0	-1	-1
Admin		-2	-2	-2	-2	-3	-3
Other		0	-0	-	-	-	-
EBITDA		**-1**	**-2**	**-2**	**-3**	**0**	**1**
Deprec & Amort		-1	-1	-	-0	-10	-1
EBIT		**-2**	**-4**	**-2**	**-3**	**-10**	**-0**
Net Interest Expense		0	-0	-3	-4	-5	-2
EBT		**-2**	**-4**	**-6**	**-6**	**-15**	**-2**
Tax expense		-	-	2	2	18	1
Minorities / prefered dividends		-	-	-	-	-	-
Normalized NPAT		**-2**	**-4**	**-4**	**-5**	**3**	**-1**
Abnormals		-	-0	-	-	118	-
Reported NPAT		**-2**	**-4**	**-4**	**-5**	**121**	**-1**
Effective tax rate	%	*0.0*	*0.0*	*30.0*	*29.3*	*119.5*	*41.4*
Cash flow	M$A						
EBITDA		-1	-2	-2	-3	0	1
Change in work cap		-	-	-	-	-	-
Deferred tax		-	-	-	-	-	-
Other operating items (tax, etc)		0	0	-3	-3	-13	-4
Operating cash flow		**-1**	**-2**	**-6**	**-6**	**-13**	**-3**
PPE capex		-0	-0	-9	-8	-8	-9
Exploration capex		-1	-2	-	-	-	-
Development capex		-	-1	-	-6	-10	-18
Other investing items		-	-	-	-	191	-
Investing cash flow		**-1**	**-3**	**-9**	**-14**	**173**	**-27**
Inc/(Dec) in Equity		7	-	16	14	-	-
Inc/(Dec) in Borrowings		-	7	-	2	14	-7
Dividends paid		-	-	-	-	-	-
Other financing items		0	-0	-0	0	-	-
Financing Cash Flow		**7**	**7**	**16**	**16**	**14**	**-7**
Net Inc/(Dec) in Cash		**5**	**2**	**0**	**-4**	**175**	**-37**
Free cash flow		**-2**	**-5**	**-15**	**-20**	**160**	**-31**
Balance sheet	M$A						
Cash & cash equivalents		6	8	8	4	179	142
Other current assets (DTA)		0	1	20	22	1	1
PPE, Exp & Dev		50	51	61	76	62	91
Intangible assets		-	-	-	-	-	-
Other non-current assets		**1**	**1**	**1**	**1**	**1**	**1**
Total Assets		57	60	90	103	243	235
Short term debt		-	-	-	3	7	7
Other current liabilities (DTL)		0	2	2	2	4	2
Long term debt		-	7	10	8	19	13
Other non-current liabilities		**0**	**0**	**9**	**10**	**12**	**15**
Total Liabilities		1	9	20	24	42	36
Minorities		-	-	-	-	-	-
Total shareholders equity (exc mi		**56**	**51**	**69**	**79**	**200**	**199**
Total Funds Employed		56	51	69	79	200	199
Net debt		-6	-1	1	7	-153	-122
Business metrics							
EBITDA margin	%	-	-	-	-	6.4	13.0
EBIT margin	%	-	-	-	-	-	-
Normalized NPAT r	%	-	-	-	-	58.6	-
Revenue growth	%	-	-	-	-	-	2.0
EBITDA growth	%	-	-	-	-	-	-
EBIT growth	%	-	-	-	-	-	-
Normalized ROA	%	-3.6	-7.0	-4.5	-4.4	1.2	-0.4
Normalized ROE	%	-3.6	-8.2	-5.8	-5.8	1.4	-0.5
Fully diluted shares (million)		600	1,533	1,535	1,535	1,535	1,535
Wtd diluted shares (million)		372	833	1,535	1,535	1,535	1,535
Leverage							
Net Debt / Book Ec	%	-11	-1	2	9	-77	-62
Net Debt / (ND+Bo	%	-13	-1	2	8	-326	-160
Net Debt / Total As	%	-11	-1	2	7	-63	-52
EBIT Interest cover	x	-	-16.9	-0.7	-0.8	-2.1	-0.1
Debt / Free Cash Fl	x	-	-1.4	-0.6	-0.6	0.2	-0.6
Valuation metrics							
Norm. EPS	c/sh	-0.6	-0.5	-0.3	-0.3	0.2	-0.1
EPS growth	%		-10	-47	14	-163	-137
PER	x	-6.3	-7.0	-13.4	-11.7	18.7	-51.0
Op Cash flow	c/sh	-0.4	-0.3	-0.4	-0.4	-0.8	-0.2
Price/Op Cash	x	-9.1	-12.4	-9.4	-8.6	-4.3	-15.6
EV/EBITDA	x	-					

Source: company data and K1 Capital forecasts

$A currency unless otherwise noted. Nominal $ basis. Year ending June.

2. Valuation

We have valued Tlou using discounted cash flow analysis for the Lesedi gas and power projects backed by reserves and 2C contingent resources and applied enterprise value to resource multiples for 3C resources and exploration prospects. Our resource multiples are based on analogous projects cross-checked with market metrics. We apply risk factors to account for technical and commercial maturity. Our valuation cases are summarized below. Our base case currently assumes notional value for the hydrogen project, pending field validation of prototype performance and market offtake.

Table 1 Valuation assumptions

Description
Base ($208m, $0.14/sh)
Gas pilot: ▪ Phase 1: Lesedi gas-to-power project constructions starts 2022; 2 MW from 2024, progressively expanding to 10 MW from 2025. Mining lease extended beyond August 2042. 80% risk factor. ▪ $US5.5m transmission line, $US3.5m sub-stations, etc., $US0.5m/MW gas engines (2nd hand) installed. ▪ Phase 2: Expansion of gas-to-power to 20 MW from 2026 to utilize 25 MW grid connection. 70% risk. Phased full field development: ▪ Phase 3: Field development and 90 MW OCGT power generation at Lesedi from 2028 to replace Orapa diesel fired generation[1]. Alternatively, construction of ~150 km gas pipeline to Orapa to convert existing 90 MW diesel power. 50% risk factor. FID Jan 2026 ▪ Phase 4: Development of remaining 2P reserves and 80% of 2C contingent resources expected to convert to 2P, ~50 MW power generation. Assume $US1.3m/MW. FID Jan 2028 ▪ Phase 5: Development of 3P reserves, sufficient for ~220 MW power generation. 20% risk factor. FID Jan 2030 ▪ 70% sell down of Lesedi/Mamba at end FY25 prior to Phase 3 FID to fund full field development, 30% retained interest. Development assumptions: ▪ Average power selling prices $US100/MWh ($US29/MMBtu elec.) in 2021, escalated at Botswana CPI. Gas sales at 75% of diesel import parity price ($US70/bbl Brent long run + $US15/bbl ADO crack + assumed $US5/bbl freight) to provide switching incentive (=> $US14.65/MMBtu ADO, $US11.00/MMBtu gas). ▪ 0.20 bcf estimated ultimate recovery (EUR) per dual lateral well pod, with peak production of ~150-300 kscfd/pod after 2 years. $US0.75m/pod capital cost (drilled, completed, connected). ▪ Risked exploration value for undeveloped 3C and prospective gas resources, incorporating expected time value discount. Green hydrogen/carbon project ▪ Synergen JV. Hydrogen initially used for power generation, carbon pricing to achieve market acceptance. Solar PV project ▪ Progressing 10 MW solar PV, early stage. Notional value assumed at this stage.
Bear ($122m, $0.079/sh)
▪ As for Base, but no value for 3C and prospective resources.
Bull ($316m, $0.20/sh)
▪ As for Base, with Phases 1 to 4 fully derisked. Phase 5 (3P reserves) still at 20% risk factor. ▪ Plasma pyrolysis technology licencing / sales (EV $20m, based on ASX analogues)

Source: K1 Capital analysis. Share prices based on diluted share count of 1,535m shares (current share count = 830.9).

[1] N.b. Orapa 90 MW OCGT diesel/gas power station constructed in 2011. Conversion from diesel to gas may not be warranted by 2028 due to limited remaining service life.

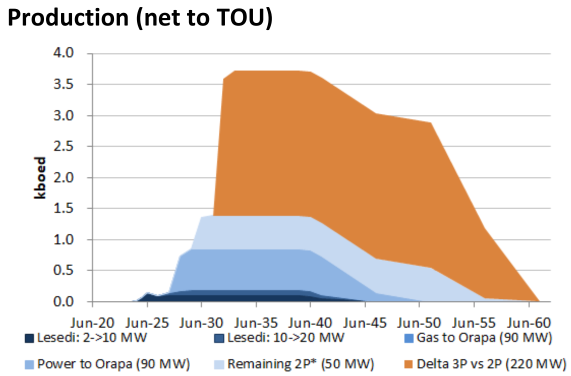
Table 2 Base case valuation summary

NPV @ 10.0% WACC+country factor Valuation as of 31 Dec 2022	Net volume PJe	Resource NPV $A/GJ	Risk factor %	Other value M$A	Risked value M$A	Risked value $A/sh	Unrisked value $A/sh
Projects (DCF model valuation)	**172.6**			**86**	**124**	**0.08**	0.14
Lesedi: 2->10 MW	3.5	0.83	80	5	7	0.00	0.01
Lesedi: 10->20 MW	3.1	0.55	70	-	1	0.00	0.00
-	-	-	-	-	-	-	-
Power to Orapa (90 MW)	21.7	1.55	50	40	57	0.04	0.05
Remaining 2P* (50 MW)	27.0	0.55	40	14	20	0.01	0.02
Delta 3P vs 2P (220 MW)	117.3	0.48	20	27	38	0.03	0.06
Exploration / Appraisal	**3,593.6**				**86**	**0.06**	0.82
Delta 3C resources	899.9	0.49	10		44	0.03	0.29
Karoo prospective resources	2,693.7	0.30	5		41	0.03	0.53
-	-	-	-		-	-	-
Solar PV (10 MW)	-	-	80		1	0.00	0.00
Synergen JV hydrogen/carbon	-	-	20		1	0.00	0.00
Other (corporate, cash, debt, etc)					**-3**	**-0.00**	-0.00
Corporate costs					-21	-0.01	-0.01
Cash					8	0.01	0.01
Additional Equity					21	0.01	0.01
Debt					-10	-0.01	-0.01
Equity Valuation @ base case	-				**208**	**0.140**	0.96
Mkt Cap @ current share price	(and undiluted share count)				**29**	**0.035**	
Number of shares (undiluted)	000,000				830.9	@ valuation date	
Number of shares (diluted)	000,000				1,535.4	fully funded devel't	
"Other value" is consideration for equity selldown or delta to project equity NPV due to product price differences, etc.							

Source: K1 Capital analysis. Forex = $US0.70/$A.

- Includes additional equity in 2023-2025 (raised at recent price of $0.035/sh) to progress exploration, appraisal and staged development before operations can be internally funded.
- Equity change is the estimated NPV associated with partial sell down from 100% to 30% prior to full field development. Cash received, which will be used to help fund Tlou's equity share of development, will be higher.
- Sell down is assumed to occur at the project's risked NPV, hence the risked value is unchanged by sell down. The unrisked value is reduced due to lower equity interest in future project derisking.
- Production volumes assume the mining licence is extended beyond August 2042. Net volumes assume 30% retained interest across all licences.
- NPV/GJ for exploration/appraisal projects has been adjusted to reflect the expected time to commercialization.

Figure 1 Base case production



Source: K1 Capital analysis. Production assumes mining lease extended beyond Aug 2042.

3. Lesedi gas-to-power project

3.1 Uncertainties

Our key assumptions for the various development phases are described in Table 1 above. Three primary uncertainties remain, to be determined through the pilot phase (production up to 10 MW).

3.1.1 Estimated Ultimate Recovery (EUR) per well

We estimate an Estimated Ultimate Recovery (EUR) of 0.2 bcf/pod (two horizontal laterals intersecting a single vertical well) based on coal parameters and well design. The EUR is set by the amount of coal in communication with the well, the gas content of the coal (m3/t), the gas quality (% methane) and amount recoverable. The amount of coal is set by the ash content, seam thickness, effective lateral length and well spacing. The ash content affects the amount of coal in the seams. This has the widest range of uncertainty of the assumptions at this stage. The well spacing also impacts the amount recoverable, with recovery increasing as well spacing decreases. Decreasing the well spacing will increase the amount recovered but increase the capital cost. Likewise, for a given well capital cost a lower EUR will increase the overall cost of development. Our ash content (42%), gas content (6 m3/t), gas quality (78% methane), seam thickness (6 m), lateral length (750 m) and gas recovery (50%) assumptions are based on Tlou's prospectus, independent reserves assessment and company announcements. We assume an effective lateral length of 600 m (20% discount to the 750 m physical length) and well spacing of 250 m, with the gas recovery assumption at this spacing cross-checked for reasonableness with industry data. This corresponds to a resource density of ~1.2 PJ/km^2, which appears attainable.

3.1.2 Peak production rate per well

The peak production rate per well (and the time it takes to achieve the peak rate) influences project economics by determining the amount of capital that needs to be spent early in the life of the project before the project becomes self-financing. A lower peak rate will require more wells to be drilled to deliver the gas required to meet the power generation requirements. The profile of the current laterals is sub-optimal with water accumulating in the dips in the laterals, inhibiting gas flow to the vertical production wells. Tlou expects peak production rates to improve materially, perhaps by 5-10 times current rates, through improved drilling operations (viz, by drilling "straighter" laterals that slope downwards along the coal seams, assisting water drainage. We assume what we believe is a conservative peak rate of ~150 kscfd, consistent with our EUR estimate and an estimated 15 year well life.

3.1.3 Drilling costs

Current well costs are estimated to be ~$US1.0m per pod. It is normal to expect a reduction in drilling costs will drilling experience: i.e. as more wells are drilled these are usually drilled more quickly and efficiently, leading to lower costs. In addition, we believe there is scope for Tlou to reduce drilling costs further by acquiring its own drilling rig for the production phase, rather than contracting this service. We have assumed drilling costs reduce to 75% of current levels during the development phase, after rig acquisition. We assume a rig purchase cost of $US3m. (On these assumptions the $US3m purchase cost should be recovered after 12 development wells). Looked at another way, the 25% cost reduction should be achievable within 5-6 wells with an improvement rate of 5% per well. This does not appear unreasonable. We estimate production of 10 MW electricity for 20 years will require 99 pods, with production reducing after 20 years due to natural well decline.

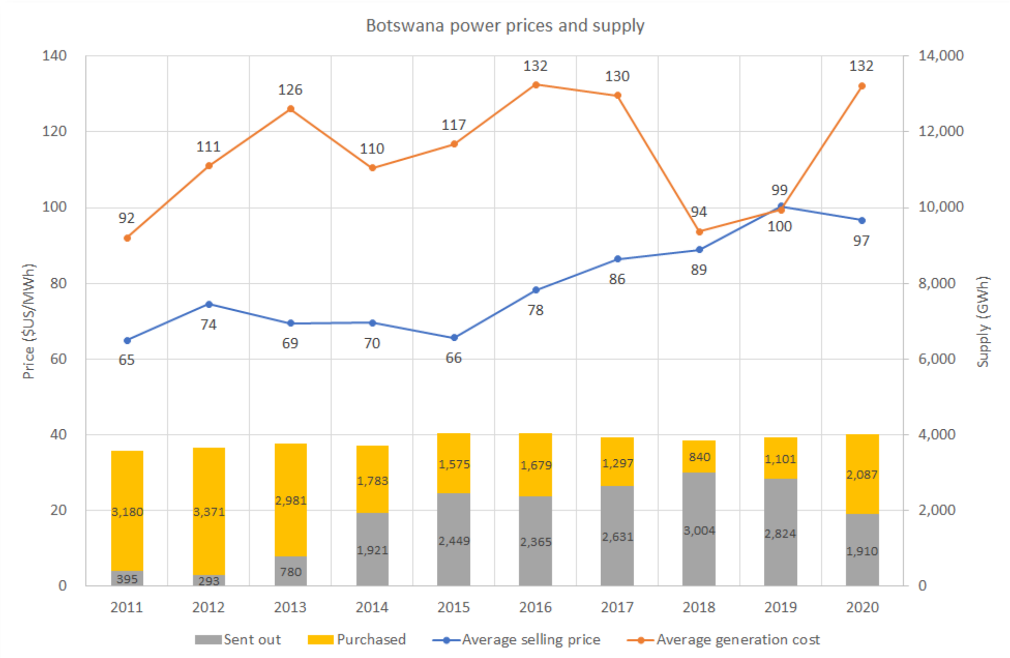
3.2 Power pricing

A key strength of the Lesedi CBM project is the high power prices in Botswana. Analysis of Botswana Power Corporation (BPC) statistics indicates increasing power prices over the past decade and average power prices of ~$US100/MWh in 2019 and 2020, the most recent period for which annual data were available. We expect Tlou's contract with the BPC agreed in late 2021 would reflect similar levels, with price escalation based on domestic CPI likely. Recent CPI has averaged over 10% pa, and CPI has averaged over 6% for the past two decades and ~4% for the 2010 to 2020 period. We assume forward CPI of 5% pa. Our estimate of Lesedi gas-to-power project viability is leveraged to these price assumptions. We estimate escalation of 4% pa will deliver an after tax IRR of ~10%, with escalation of 6% pa delivering an IRR of ~15%.

Figure 2 Botswana CPI 1997-2022

Source: https://tradingeconomics.com/botswana/inflation-cpi

Figure 3 Botswana power prices



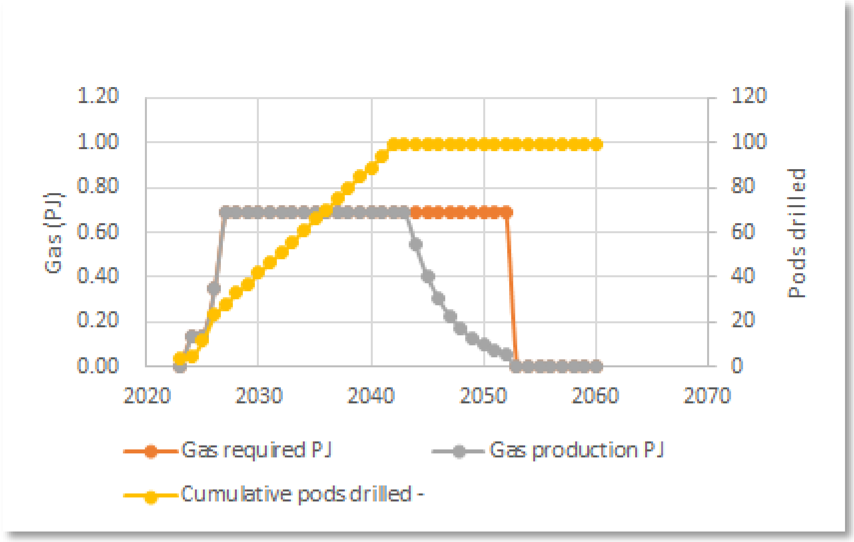
Source: K1 Capital analysis of Botswana Power Corporation data

3.3 Power production

Our model of the Lesedi pilot assumes power production of 2 MW commencing in 2024, with expansion to 5 MW in 2026 and 10 MW from 2027. We assume power production is maintained at 10 MW for a plateau period of 20 years, after which production is allowed to decline in line with natural field decline. A 10-year extension of the current production licence (which would otherwise expire in 2042) is assumed, with power production ceasing in 2052 after a total period of 29 years (26 years at 10 MW).

We estimate production over this period will require drilling of 99 pods, with ~15 PJ of gas developed (100% project basis).

Figure 4 Lesedi gas-to-power project gas production (10 MW pilot)



Source: K1 Capital analysis

3.4 Sensitivity analysis

Our economic model of the Lesedi CBM project includes probability distributions for key assumptions, enabling assessment of project outcomes via Monte Carlo simulation and project sensitivity using Tornado analysis. Our Tornado analysis of project IRR, in which each assumption is tested at its upper and lower limits, and simulation, in which the project model is run 1,000 times sampling from each of the assumption distributions are shown below.

Tornado Chart: Lateral spacing has the largest individual impact on project IRR, due to the linkage with gas recovery and EUR and hence on the capital efficiency of the project. CPI has a strong bearing on future power purchase agreement prices.

Monte Carlo Simulation: We estimate the mean NPV (10% nominal after tax) per unit of gas is $US0.46/GJ, equivalent to $A0.65/GJ at 0.70 forex. There is approximately a 70% certainty of exceeding the discount rate, based on current assumptions. As more information on well deliverability is gained from subsequent wells we expect the uncertainty (range of possible outcomes) to reduce.

The following charts are for the 10 MW pilot project only but provide an indicative valuation reference point for full field development of Tlou's 41 bcf of 2P reserves and 214 bcf of 2C contingent resources.

Figure 5 Tornado Chart

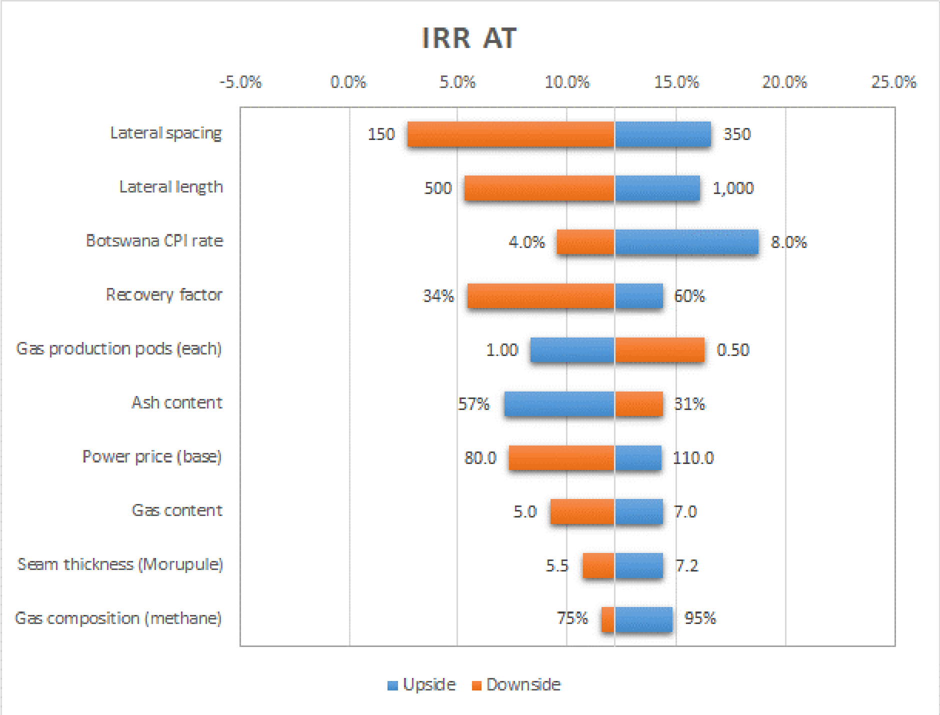
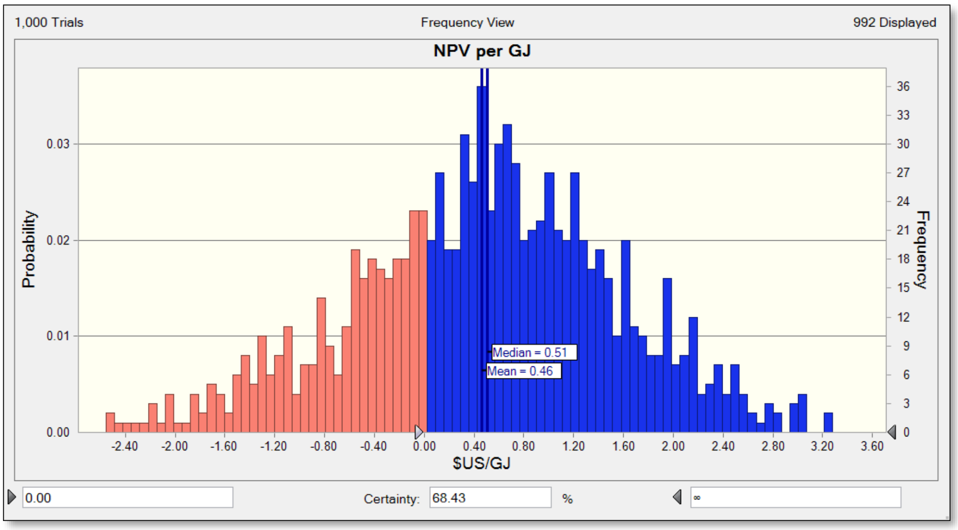


Figure 6 Monte Carlo simulation



Source: K1 Capital analysis

Disclosure:

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Analyst background: John Young has over 30 years' experience in the petroleum, resources and financial services industries with ExxonMobil, WMC Resources/BHP Billiton, Wilson HTM and Ord Minnett, with qualifications in engineering (BE hons), applied science (MAppSc), operations research (GradDipBusSc), management (GDM) and finance (GradDipAppFin).

4. Appendices

4.1.1 Reserves and resources

Table 3 Tlou Reserves and Contingent Resources

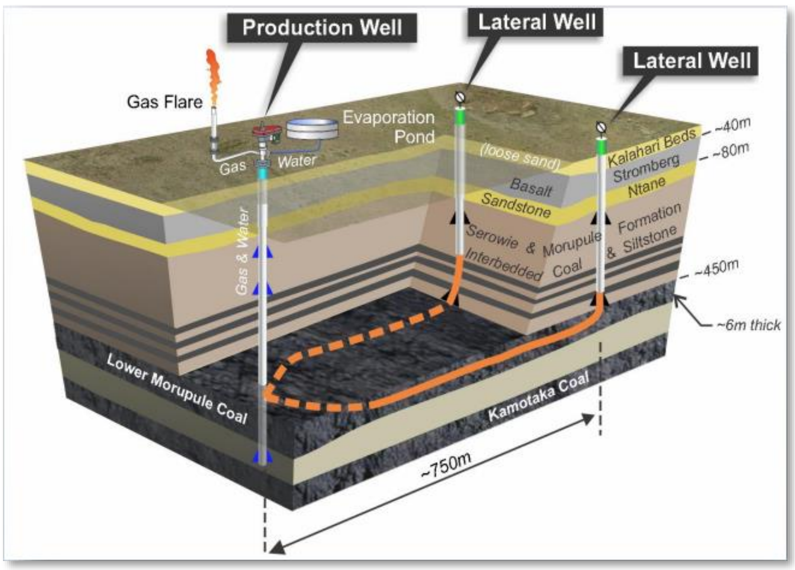
Location	Project	Tlou Interest	Gas Reserves (BCF)					
			30/06/2022	30/06/2021	30/06/2022	30/06/2021	30/06/2022	30/06/2021
			1P*	1P	2P*	2P	3P	3P
Karoo Basin Botswana	Lesedi CBM (all coal seams) PL001/2004, ML 2017/18L	100%	0.34	0.34	25.2	25.2	252	252
Karoo Basin Botswana	Mamba CBM (Lower Morupule coal) PL238/2014 – PL241/2014	100%	0.01	0.01	15.5	15.5	175	175
Karoo Basin Botswana	PL003/2004, PL037/2000	100%	-	-	-	-	-	-
Total			0.35	0.35	40.7	40.7	427	427

Location	Project	Tlou Interest	Gas Contingent Resource (BCF)					
			30/06/2022	30/06/2021	30/06/2022	30/06/2021	30/06/2022	30/06/2021
			1C	1C	2C**	2C**	3C	3C
Karoo Basin Botswana	Lesedi CBM (all coal seams) PL001/2004, ML 2017/18L	100%	4.6	4.6	214	214	3,043	3,043
Karoo Basin Botswana	Mamba CBM (Lower Morupule coal) PL238/2014 – PL241/2014	100%	-	-	-	-	-	-
Karoo Basin Botswana	PL003/2004, PL037/2000	100%	-	-	-	-	-	-
Total			4.6	4.6	214	214	3,043	3,043

Source: Tlou Energy Limited, 2022 Annual Report, 19th September 2022, p 21

4.1.2 Lateral well pods

Figure 7 Production pod schematic



Source: Tlou Energy Limited, 2022 AGM presentation, 18th October 2022, p 10

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