Kinetiko Energy Limited (ASX: KKO)

Near term gas from South African CBM

Overview

Kinetiko Energy is a gas and coal bed methane (CBM) exploration company seeking to supply South Africa's significant unmet energy demand. The company has a 49% interest in 5 permits covering ~4,600 km², with 2.4 tcf of net 2C contingent resources. Kinetiko will commence selling gas in early 2021 by restarting existing wells, followed by a 3rd party-funded 20-well pilot program, delivering production of ~1-2 TJ/d by year end. Successful demonstration should lead to a 300 well project commencing in late 2022, delivering production of ~12 TJ/d, with later expansion to 100+ TJ/d. We value Kinetiko at $0.39/sh, with upside to $0.88/sh on project derisking.

Key points

Investment case: large gas resource onshore South Africa: Kinetiko offers exposure to multi-tcf CBM and conventional gas resources in energy short South Africa. Potential markets include CNG, diesel replacement, gas-fired power generation and feedstock for South Africa's gas-to-liquids industry. Low drilling costs (~$US0.35m/well) and high gas prices (~$US7/MMBtu) provide attractive economics, with an estimated IRR after tax of over 30%.

Value proposition: Kinetiko has a 49% interest in 4.9 tcf of 2C net resources across five largely contiguous permits. We estimate development of 20% of that amount (~1 tcf gross) would supply 120+ TJ/d and deliver free cash flow of $60+m/yr over a 15-year plateau period. Kinetiko is trading at a discount to ASX-listed CBM peers, indicating potential rerating as risks decline.

Good location in energy short market: Kinetiko's permits are located close to South Africa's industrial and population centres (Johannesburg, Durban). Rising regional energy demand, constrained coal fired power generation and declining gas pipeline imports offer scope for new gas markets.

Demonstrated gas flow to surface: Previous pilot wells have delivered gas flows of up to 350 kscfd and evidence of recharge during shut-in periods. Demonstration of sustained production from both sandstones and coals and repeatability over the project area is required to confirm project economics.

Funded pilot program imminent: Kinetiko expects to start a 20-well pilot program early next year, with the $15-20m project funded by a major South African institution. The project has approval for initial gas sales of 500 MMscf/y (1.3 MMscfd), with offtake arrangements currently be negotiated.

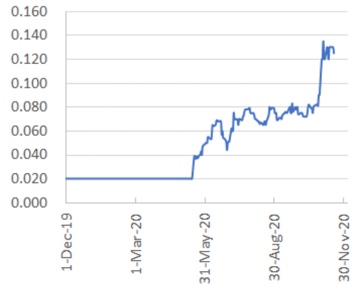
Multi-permit optionality: Kinetiko's operatorship of its five permits and high equity interest provides options for staged farm-down to fund future development and monetize its resource base in advance of gas sales.

Price catalysts: Commencement of multi-well pilot; resource upgrades and maiden reserves; confirmation of well performance parameters; gas sales agreements; further exploration outcomes, expanded project FID.

Risks: Project schedule delays; resource consistency; community support; ongoing funding; immature domgas industry and independent power sectors; gas pricing; competition from recent large offshore gas discoveries.

Next steps: Commence 20-well pilot program (early 2021); apply for gas production right ER56 (early 2021), update reserves (2H-2021); progress gas commercialization (2021); take FID on larger development (2022).

SHARE PRICE PERFORMANCE



Closing price as of 18th Nov 2020

CAPITALIZATION	
Last price	$0.13
52-week range	$0.02-0.14
Capitalization	$70.7m
Cash: 30th Sep	$0.5m
Debt: 30th Sep	nil
EV	$70.2m
Shares	543.7m
Options/rights	51.1m
Conv Notes	-
Balance date	June
RESERVES AND PRODUCTION	
1P (30 Sep 20)	- MMboe
2P “	- MMboe
3P “	- MMboe
2C “	400 MMboe
2U “	74 MMboe
FY20a	- MMboe
FY21e	- MMboe
SHAREHOLDERS (%)	
Board/mgt	35.8
Substantial	17.2
Other	53.0
LEADERSHIP	
Chairman	Adam Sierakowski
MD/CEO	Johan Visage
NED	Donald Searle
NED	Geoffrey Michael

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

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Disclosure:

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1. Financial statements

	Units	FY20a	FY21e	FY22e	FY23e	FY24e
CPI, forex & prices						
US inflation rate	% pa	2.20	2.20	2.20	2.20	2.20
Australian inflation ra	% pa	2.50	2.50	2.50	2.50	2.50
Inflation Factor - US	-	0.984	1.005	1.028	1.050	1.073
$US/$A forex (base)	$US/$A	0.67	0.70	0.70	0.70	0.70
Brent	$US/bbl	51	45	51	55	56
Nat Gas (Henry Hub)	$US/mmBtu	2.1	2.6	2.9	2.8	2.9
Nat Gas (Sth Africa)	$US/mmBtu	6.9	6.6	7.0	7.3	7.5
Received prices						
Oil	$US/bbl	-	-	-	-	-
Condensate	$US/bbl	-	-	-	-	-
Gas	$US/mmBtu	-	4.4	7.0	7.5	7.5
LPG	$US/bbl	-	-	-	-	-
LNG	$US/t	-	-	-	-	-
Electricity	$US/MWh	-	-	-	-	-
CO2e	$US/t	-	-	-	-	-
Total	$US/boe	**-**	**-**	**36.2**	**39.6**	**42.4**
Net production by project						
Amersfoort - 2021 Pi	mmboe	0.00	0.00	0.02	0.02	0.02
Amersfoort - Stage 2	mmboe	-	-	-	0.02	0.11
Amersfoort - Stage 3	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
-	mmboe	-	-	-	-	-
Total	mmboe	**0.00**	**0.00**	**0.02**	**0.05**	**0.14**
Net production by product						
Oil	mmbbl	-	-	-	-	-
Condensate	mmbbl	-	-	-	-	-
Gas	PJ	-	0.01	0.11	0.28	0.84
LPG	mmbbl	-	-	-	-	-
LNG	Mt	-	-	-	-	-
Electricity	TWh	-	-	-	-	-
CO2e	Mt	-	-	-	-	-
Total	mmboe	**-**	**-**	**0.02**	**0.05**	**0.14**
Total production	kboed	**0.00**	**0.00**	**0.05**	**0.14**	**0.38**
Production growth	%		0.0	0.0	150.0	179.2
Revenue						
Oil	M$A	-	-	-	-	-
Condensate	M$A	-	-	-	-	-
Gas	M$A	0	0	1	3	8
LPG	M$A	-	-	-	-	-
LNG	M$A	-	-	-	-	-
Electricity	M$A	-	-	-	-	-
CO2e	M$A	-	-	-	-	-
Total modelled	M$A	**0**	**0**	**1**	**3**	**8**
Total reported	M$A	-	-	-	-	-
Revenue growth	%		0.0	0.0	0.0	0.0
Operational metrics						
Revenue	$A/boe	-	-	48.7	53.3	56.6
Production & transpo	$A/boe	-	-	-12.1	-12.1	-12.0
Royalties & prod purc	$A/boe	-	-	-2.5	-2.7	-2.8
Admin	$A/boe	-	-	-48.7	-19.6	-7.0
EBITDA margin	$A/boe	-	-	-14.7	19.0	34.8
D&A	$A/boe	-	-	42.1	-6.8	-3.9
Tax and financing	$A/boe	-	-	-5.0	-12.2	-12.4
Normalized NPAT	$A/boe	-	-	22.4	-0.1	18.5
Resource/production	years	-	-	48.7	19.0	6.7
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	FY20a	FY21e	FY22e	FY23e	FY24e
P&L	M$A					
Sales revenue		-	0	1	3	9
Other revenue		0	-	-	-	-
Production costs		-	-0	-0	-1	-2
Royalties & prod purchases		-	-0	-0	-0	-0
Admin		-1	-1	-1	-1	-1
Other		-0	-	-	-	-
EBITDA		**-1**	**-1**	**-0**	**1**	**5**
Deprec & Amort		-0	1	1	-0	-1
EBIT		**-1**	**0**	**1**	**1**	**5**
Net Interest Expense		-0	-0	0	-0	-1
EBT		**-1**	**0**	**1**	**0**	**4**
Tax expense		-	-0	-0	-0	-1
Minorities / prefered dividend		-0	-	-	-	-
Normalized NPAT		**-1**	**0**	**0**	**-0**	**3**
Abnormals		-0	0	-	-	-
Reported NPAT		**-1**	**1**	**0**	**-0**	**3**
Effective tax rat	%	*0.0*	*22.3*	*29.3*	*103.2*	*30.6*
Cash flow	M$A					
EBITDA		-1	-1	-0	1	5
Change in work cap		-	-	-	-	-
Deferred tax		-	-	-	-	-
Other operating items (tax, e		-1	0	0	-0	-0
Operating cash flow		**-2**	**-1**	**-0**	**1**	**5**
PPE capex		-	-	-	-	-
Exploration capex		-	-	-	-	-
Development capex		-	-0	-0	-8	-8
Other investing items		-0	1	-	-	-
Investing cash flow		**-0**	**1**	**-0**	**-8**	**-8**
Inc/(Dec) in Equity		3	6	7	-	-
Inc/(Dec) in Borrowings		-	-	-	-	-
Dividends paid		-	-	-	-	-
Other financing items		0	0	-0	-	-
Financing Cash Flow		**3**	**6**	**7**	**-**	**-**
Net Inc/(Dec) in Cash		**1**	**6**	**6**	**-7**	**-3**
Free cash flow		**-2**	**-0**	**-0**	**-7**	**-3**
Balance sheet	M$A					
Cash & cash equivalents		1	7	14	7	4
Other current assets (DTA)		0	7	7	9	10
PPE, Exp & Dev		7	7	9	17	25
Intangible assets		-	-	-	-	-
Other non-current assets		**-**	**-**	**-**	**-**	**-**
Total Assets		8	22	29	33	40
Short term debt		-	-	-	-	-
Other current liabilities (DTL)		1	1	1	1	1
Long term debt		-	-	-	-	-
Other non-current liabilitie		**-**	**4**	**5**	**9**	**12**
Total Liabilities		1	5	5	9	13
Minorities		-	-	-	-	-
Total shareholders equity (		**7**	**17**	**24**	**24**	**27**
Total Funds Employed		7	17	24	24	27
Net debt		-1	-7	-14	-7	-4
Business metrics						
EBITDA margin	%	-	-905.6	-30.2	35.5	61.4
EBIT margin	%	-	419.7	56.3	22.8	54.5
Normalized NPA	%	-	288.3	46.0	-0.2	32.7
Revenue growt	%	-	-	900.0	180.0	203.6
EBITDA growth	%	-	0.1	-66.6	-429.2	424.8
EBIT growth	%	-	-146.3	34.2	13.2	626.9
Normalized RO/	%	-13.3	1.3	1.6	-0.0	7.0
Normalized ROI	%	-14.4	1.7	1.9	-0.0	10.4
Fully diluted shares (million)		543	1,062	1,062	1,062	1,062
Wtd diluted shares (million)		389	932	1,062	1,062	1,062
Leverage						
Net Debt / Book	%	-15	-44	-58	-30	-16
Net Debt / (ND+	%	-18	-79	-138	-43	-19
Net Debt / Total	%	-14	-34	-47	-22	-11
EBIT Interest cc	x	-150.9	8.6	-	1.4	7.3
Debt / Free Cas	x	-	-	-	-	-
Valuation metrics						
Norm. EPS	c/sh	-0.3	0.0	0.0	-0.0	0.3
EPS growth	%		-111	40	-101	-52,319
PER	x	-48.2	420.3	299.8	#######	49.7
Op Cash flow	c/sh	-0.4	-0.1	-0.0	0.1	0.5
Price/Op Cash	x	-29.8	-136.3	-983.2	143.8	27.8
EV/EBITDA	x	-				

Source: company data and K1 Capital forecasts

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

2. Valuation

2.1 Methodology and assumptions

We have valued Kinetiko using discounted cash flow analysis for the Amersfoort Gas Project and enterprise value to resource multiples for undeveloped resources and exploration prospects. Our resource multiples are based on analogous projects cross-checked with market or transaction metrics which are price adjusted for the value differences between oil and gas. We apply risk factors to account for technical and commercial maturity. Our investment model incorporates probability distributions for key variables, including reserves and resources, commodity prices and exploration success, and uses Monte-Carlo simulation to quantify the range of share price outcomes.

Table 1 Key valuation assumptions

Assumption	Comment
WACC	10% nominal, plus South Africa country risk premium of 1.2% (c.f. Australia 0.0%). [1]
Commodity prices	$US52/bbl Brent (Dec 2020 real dollars) [2]; $US7.00/MMBtu South African gas prices. Sth Africa CPI 3.9%pa (2021), 5.1% (2022-25). [3]
Forex	0.70 $US/$A long term
Fiscal terms	Royalties: 0.5-5.0% on gross sales per Mineral and Petroleum Resources Royalties Act (royalty rate = min(0.5%+EBIT/gross sales*12.5,5%); i.e. 5% if net margin>36% [4] Income tax: 28% (petroleum sector). Immediate deduction of 200% of exploration capex and 150% of development capex allowed. [5] [6] Carbon price: not included
Amersfoort Stage 1 pilot	20-well pilot program, commences early 2021, gas sales from early 2022 ▪ Capex funded by Sth African institution for assumed 50% interest in pilot (KKO 25%) ▪ EUR 0.30 bcf/well on 60-acre spacing. ~100 kscf/d/well peak rate. ▪ $US400k/well drilling + completion/tie-in, ~$10m compression/CNG (3rd party) ▪ $US1.7k/well/mth cash opex, $US0.50/GJ gas processing, $US0.10/bbl water ▪ $US7.00/MMBtu (real 2020) field gate gas price. ▪ Sales via third-party CNG infrastructure. ▪ 500 MMscf/yr (1.4 mmscfd) production right for first two years
Amersfoort Stage 2 development	300-well larger-scale development, FID end 2022. (KKO 49%) ▪ ~90 bcf (~2% of the existing 4862 bcf of gross 2C) ▪ Plateau production of ~12 TJ/sd (~4.3 PJ/yr) for 15 years; field life of ~40 years. ▪ $US350k/well drilling + completion/tie-in ▪ Sales gas for on-site/local power gen. ▪ Produced water treated for agricultural use (nil revenue assumed).
Amersfoort Stage 3 development	3000+-well large-scale development, FID end 2025. ▪ ~900 bcf (~20% of the existing 4,862 bcf of gross 2C) ▪ Plateau production of ~120 TJ/sd (~44 PJ/yr) for 15 years; field life of ~40+ years. ▪ Sales gas for large scale power gen ▪ KKO 49% funded by equity/debt. Potential to fund via partial sell-down prior to FID.
Undeveloped contingent and prospective resources	Resource multiple valuation. Unrisked resource value based on Amersfoort DCF model, discounted for time to development. Undeveloped 2C (80% conversion to 2P/sales) and Prospective 2U (80% conversion), both commercialized from 2030.
Other	Potential for helium recovery. No valued assigned at this time.

Source: K1 Capital analysis. See Appendix 10.7 for more detailed description of assumptions

2.2 Valuation summary

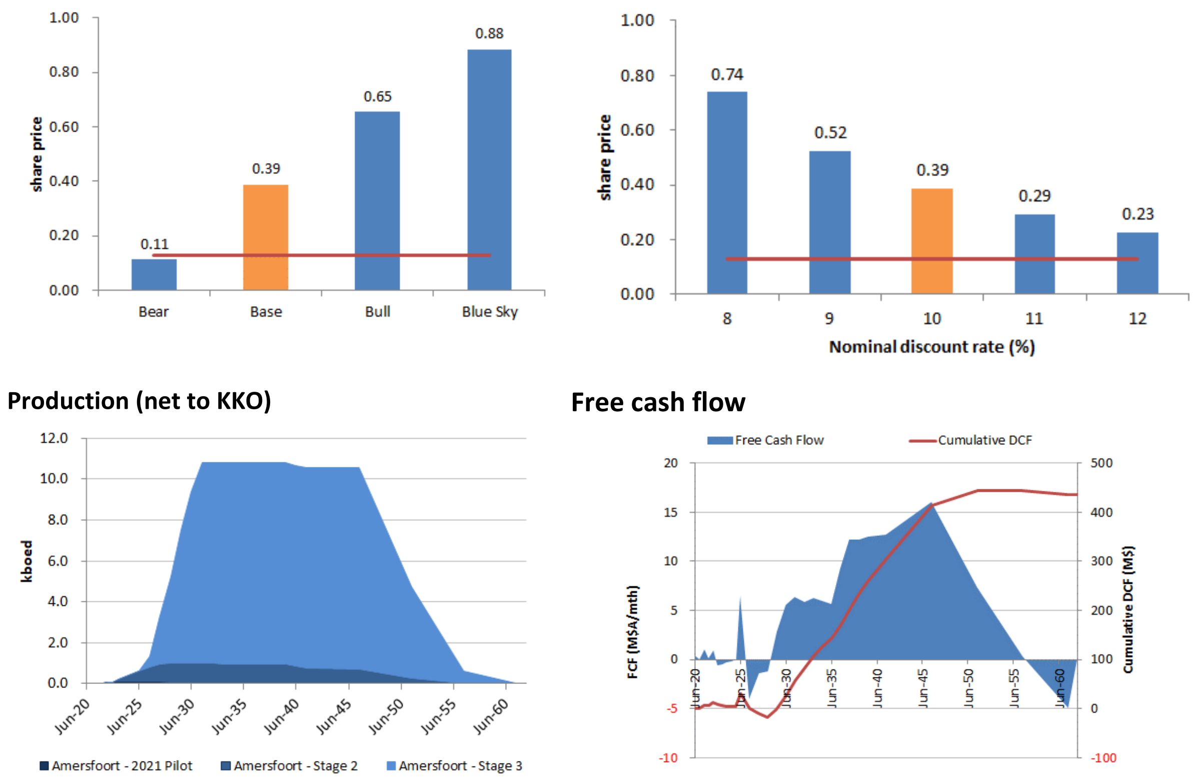
We estimate a base case risked valuation of $0.39/share, assuming just under half the 2C contingent resources are developed, with a range from 0.11 to 0.65 and upside to $0.88/share on full derisking (assuming only 80% of 2C resources convert to reserves in line with Australian industry experience).

Table 2 Valuation cases

Case	Description	$m	$/sh
Base	1 tcf gross staged development of the Amersfoort project, with 20-well pilot commencing early in 2021 (Stage 1) and 300-well development (~12 TJ/d) commencing end 2021 (Stage 2), before expansion to ~120 TJ/d from 2025 (Stage 3). $US7.00/MMBtu gas price. 80/60/40% risk factor for Stage 1/2/3 respectively. Remaining 2C contingent and 2U prospective resources are developed from 2030, risked at 40% and 10%. In effect just under half of the 4.9 tcf of gross 2C resources are developed in total.	**410**	**0.39**
Bear	1 tcf staged development but no value ascribed to remaining 2C and prospective resources. $US6.00/MMBtu gas.	119	0.11
Bull	Base @ $US9.00/MMBtu gas	694	0.65
Blue Sky	2C contingent resources (80% conversion) unrisked @ $US7.00 MMBtu gas. Prospective resources still risked at 10%.	936	0.88
Memo:	Current share price (18th November 2020 closing price)		$0.13

Source: K1 Capital analysis. Assumes fully diluted share count of 1062m shares (c.f. current 543.7m shares). Includes $6m of additional equity in CY21, $6m in CY22 and $40m in CY25 to progress the exploration, appraisal and staged development before operations can be internally funded. CY25 equity requirement can be eliminated with partial sell down prior to full field development.

Figure 1 Case values and base case discount rate sensitivity

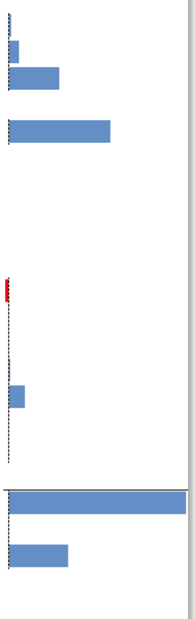


Source: K1 Capital analysis. Maroon line on case values and DCF sensitivity denotes current share price. Valuation is based on the nominal discount rate shown plus country risk premium (1.2%) for each project.

Table 3 Base case valuation summary

NPV @ 10.0% WACC+country factor Valuation as of 31 Dec 2020	Net volume PJe	NPV value $A/GJ	Risk factor %	Risked value M$A	Risked value $A/sh	Unrisked value $A/sh	Project WACC %
Projects (DCF model valuation)	**505.3**			**144**	**0.14**	0.32	
Amersfoort - 2021 Pilot	1.4	3.40	80	4	0.00	0.00	11.2
Amersfoort - Stage 2	45.5	0.81	60	22	0.02	0.03	11.2
Amersfoort - Stage 3	458.3	0.64	40	118	0.11	0.28	11.2
Exploration / Appraisal	**1,923.3**			**237**	**0.22**	0.66	
Undeveloped 2C (80% conversion)	1,538.8	0.36	40	223	0.21	0.53	
Prospective 2U (80% conversion)	384.5	0.36	10	14	0.01	0.13	
ER 320 Prospective 2U	-	-	10	-	-	-	
Other (corporate, cash, debt, etc)				**29**	**0.03**	0.03	
Corporate costs				-9	-0.01	-0.01	
Hedging & Investments				-	-	-	
Franking credits (@ 0 %)				-	-	-	
Cash				1	0.00	0.00	
Additional Equity				37	0.03	0.03	
Debt				-	-	-	
Minorities / Other				-	-	-	Previous
Equity Valuation @ base case	-			**410**	**0.390**	1.00	0.00
Equity Valuation @ spot prices	@ $US44/bbl real Brent & 0.73 f			-	-		0.00
Mkt Cap @ current share price	(and undiluted share count)			**73**	**0.130**		
Total shareholder return (%)					**n/a**		
Number of shares (undiluted)	000,000			563.3	@ valuation date		
Number of shares (diluted)	000,000			1,061.8	for fully funded development		

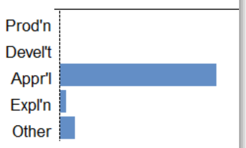
Risked value $A/sh



Oil price and forex sensitivity: $A/sh — Real Brent oil price, $US/bbl

$US/$A forex	20	40	60	80	100	120
fx=1.00	0.013	0.132	0.263	0.398	0.530	0.664
fx=0.90	0.052	0.197	0.341	0.480	0.615	0.754
fx=0.80	0.108	0.258	0.407	0.552	0.700	0.848
fx=0.70	0.149	0.310	0.470	0.625	0.780	0.940
fx=0.60	0.174	0.348	0.521	0.690	0.859	1.032
fx=0.50	0.149	0.345	0.536	0.722	0.912	1.102

Valuation analysis:



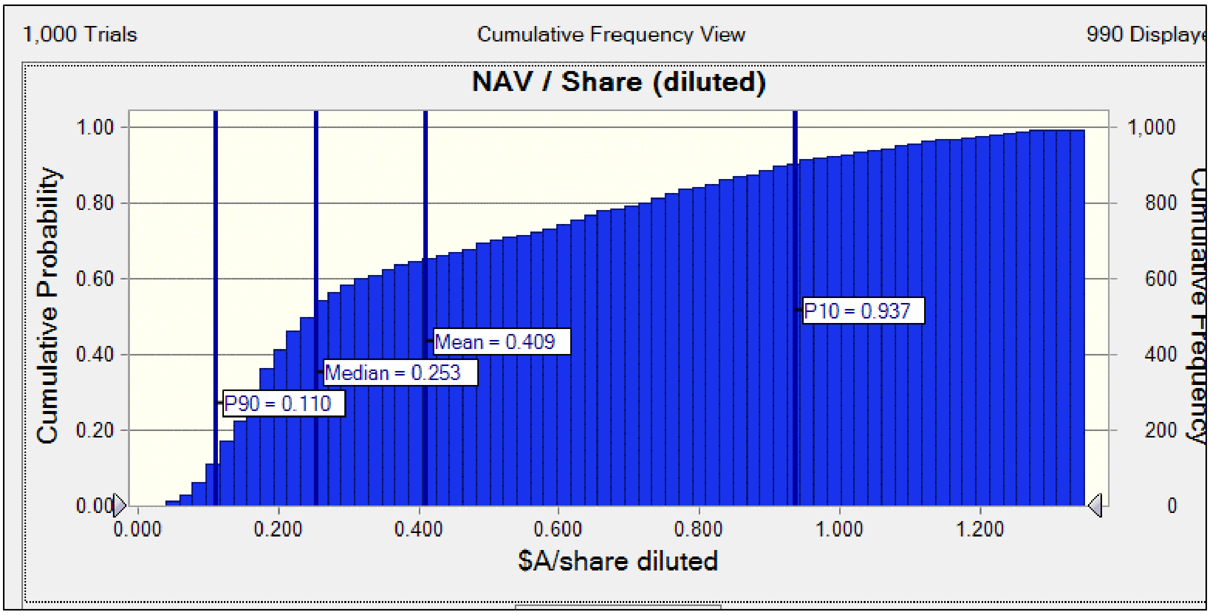
Predicted change in value per $US1/bbl increase in oil price	$A/sh	0.007
Predicted change in value per $US0.01 increase in forex	$A/sh	-0.006

Source: K1 Capital analysis. South African natural gas price is linked to global energy prices (Brent as proxy) via government energy pricing mechanism.

2.3 Sensitivity analysis

Simulation: Our simulation-based DCF model estimates an expected value of $0.41/share, close to our base case valuation of $0.39/share, with lower (P90) and upper (P10) limits of $0.11 and $0.94/share respectively, demonstrating potential upside with development of 2C resources.

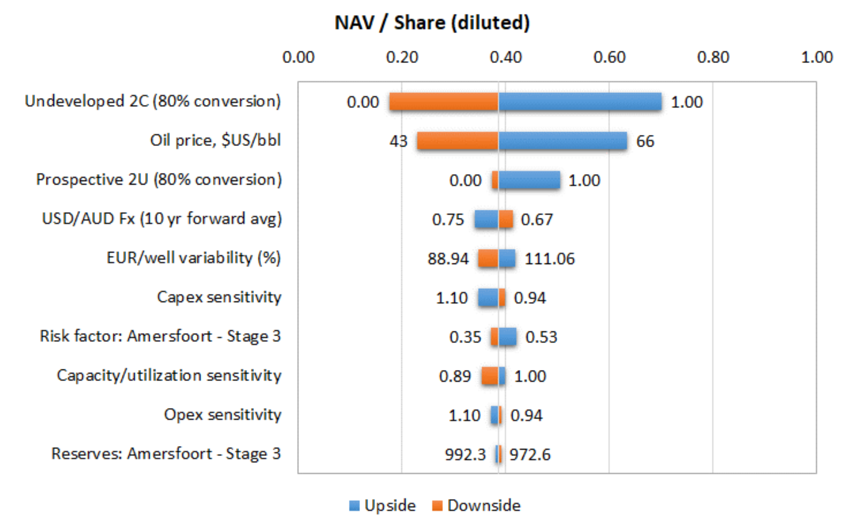
Figure 2 Monte Carlo simulation



Source: K1 Capital analysis. Assumes 80% conversion of 2C contingent resources to 2P/sales.

Tornado Chart: The Tornado Chart shows that the extent of 2C resource development has the largest impact on valuation: if only ~1000 bcf of gross resources are developed (Stage 3) the valuation reduces to $0.18/share; if 80% of the 2C is developed the valuation increases to $0.71/share. The mid-case effectively assumes ~2,200 bcf gross is developed, ~45% of the current independently assessed 2C amount. Oil price has the second largest impact, driving the South African gas price.

Figure 3 Tornado chart



1. Variables are ranked from highest to lowest impact on the valuation and are centred on the base case level.
2. The bars correspond to the low case (red bar) and high case (blue bar) level for each variable.
3. Probabilities are reported as being above a given level: e.g. P90 = 90 % probability of being above that level.
4. The values at the end of each bar are the values of the variable at the low (P90) and high (P10) cases.

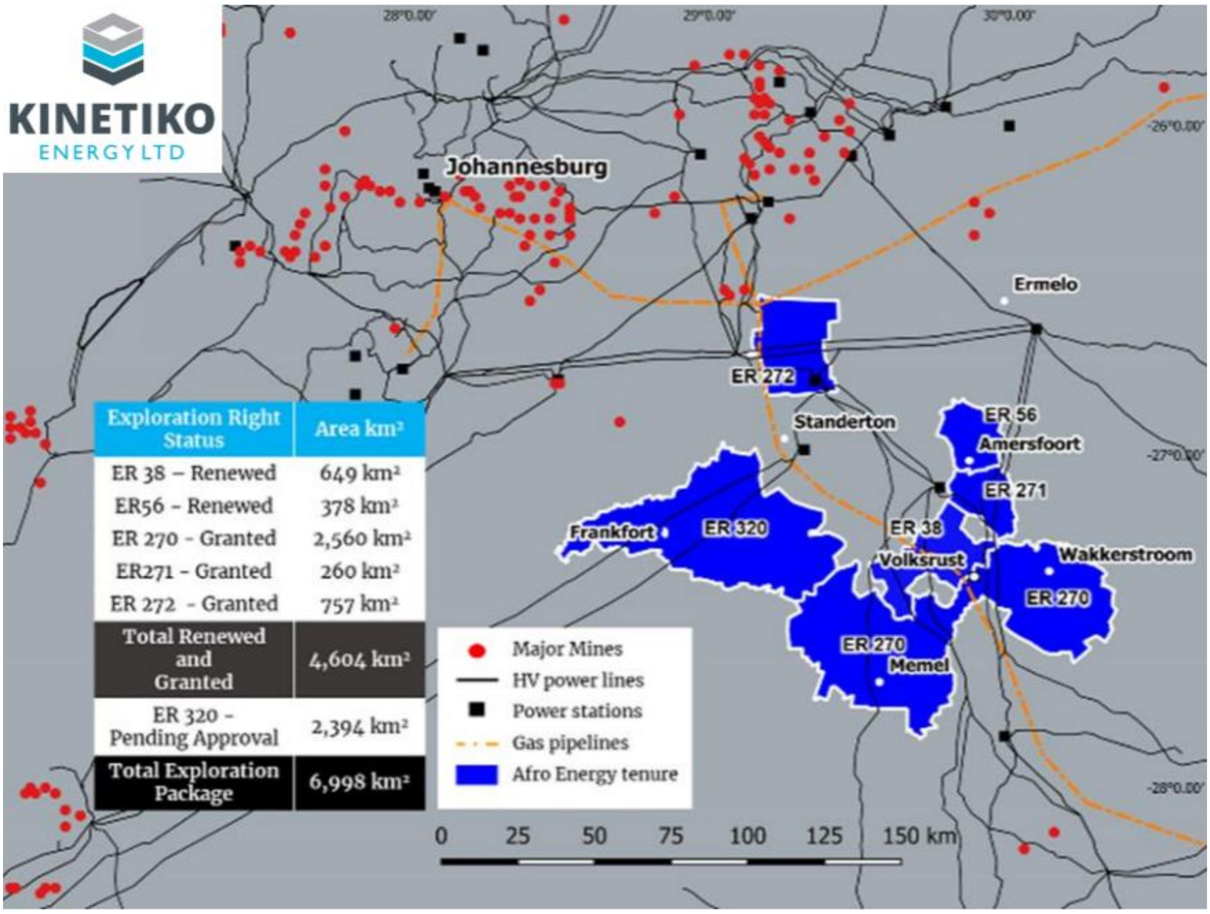
Source: K1 Capital analysis

3. Project overview

3.1 Exploration Right (ER) interests

Kinetiko has a 49% economic interest (and 50% voting interest) in Afro Energy, a joint venture with Black Economic Empowerment (BEE) partner, Badimo Gas. Afro Energy owns five CBM exploration rights in South Africa's Karoo Basin in Mpumalanga province, between Johannesburg and Durban. The area is close to South Africa's existing coal-based energy and power generation infrastructure and major industrial, mining and manufacturing areas, as shown in Figure 4 below.

Figure 4 Kinetiko Energy project location and nearby infrastructure



Source: Kinetiko Energy Limited, "Third 2020 High Resolution Aeromagnetic Survey Commenced", 18th November 2020, p 3

3.2 Geology – gassy coals, sandstones and helium

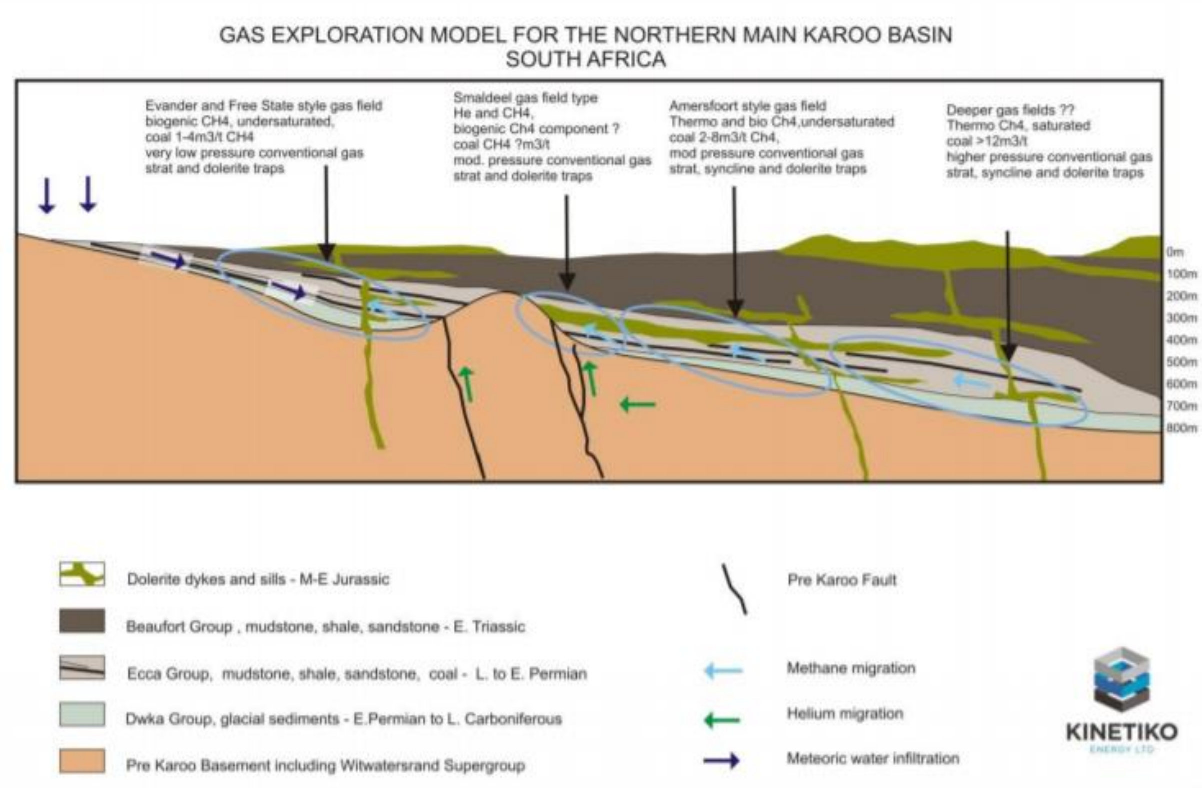
Gas is sourced from sub-bituminous Permian-age (299-251m years ago) coals (from the Vryheid Formation of the Karoo Supergroup), which are similar to the Permian coals of eastern Australia. The coals are located at depths of ~300-500 m, confirmed by ~800 coal exploration holes drilled in the Amersfoort Project area, primarily during the 1980's. Data from these holes indicate gassy coals (2-8 m^3/t) in multiple seams, with cumulative thicknesses of 1 to 16 m.

Some of the methane generated by the coal has migrated into interbedded sandstone reservoirs as well as being present as CBM, similar to the Raton (south Colorado/northern New Mexico), San Juan

(New Mexico/Colorado), Green River (Colorado/Wyoming) and Piceance (Western Colorado) Basins of the USA.

Gas is trapped in compartments bounded by volcanic intrusions (dolerite sills and dykes), inter-bedded low permeability mudstones, conventional closures and stratigraphic[1] or diagenic[2] sediments. Helium is also present in sandstone traps in parts the Karoo Basin, sourced from uranium decay in deeper formations. The presence of helium in Kinetiko's permits has not yet been assessed.

Figure 5 Gas exploration model in project areas



Source: Kinetiko Energy Limited, Amersfoort Project Details, Kinetiko website, accessed 15th October 2020.
https://www.kinetiko.com.au/wp-content/uploads/2014/01/Amersfoort-Project-Details.pdf

3.3 Past CBM exploration

3.3.1 Amersfoort Core Program (2011-2012)

Kinetiko and Badimo commenced a joint venture in 2011 and drilled and logged 21 core holes for gas desorption analysis, with most holes in the 56ER permit. The coal seams contained 2-11 m^3/t of gas. All 21 holes exhibited divergence between the neutron and density measurements of porosity over many tens of metres of sandstone intervals, indicating the presence of gas in the sandstones.

3.3.2 Amersfoort Pilot Program (2013)

Eight single-spot pilot wells were drilled from late 2012 to November 2013 to test the gas flow potential from the coal seams and the adjacent sandstones. The pilot wells were drilled with a modified mineral exploration drilling rig and cost ~$200-240k/well, incorporating low-cost vertical

[1] Stratigraphic: bounded by a depositional limit (i.e. change in rock type)

[2] Diagenic: rocks altered over time, such that porosity is now too low to be reservoir

"barefoot" completions to access both the gassy sandstones and coals. No stimulation (fraccing) was undertaken. Down hole electric submersible pumps were used to dewater the coal seams.

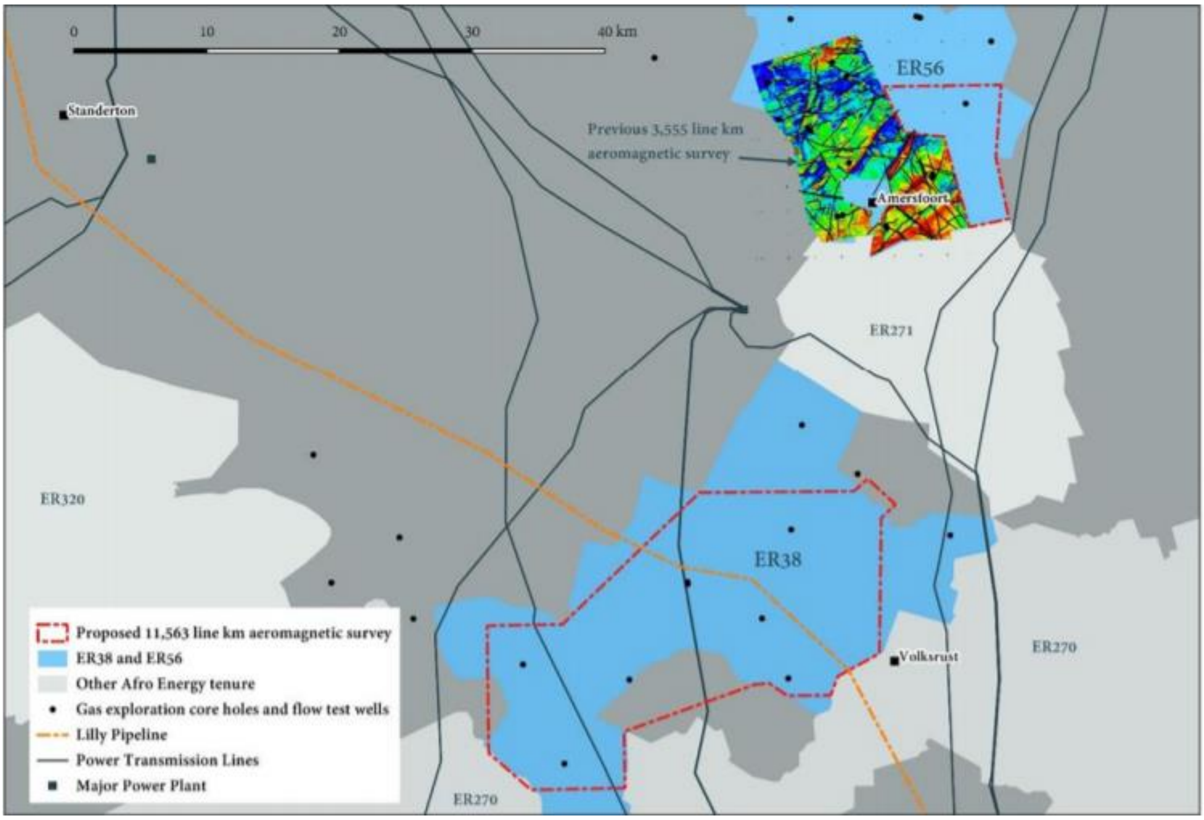
All wells produced gas flows and seven wells produced sustainable gas flares, with one well flowing up to 350 kscfd. Water influx from fractures in the barefoot completion zones limited gas production in several pilot wells. The gas appeared to be sourced predominantly from the sandstones adjacent to the coal seams rather than the coal seams. An initial study conducted by consultants (RISC, September 2012) concluded that shallow conventional gas was expected to contribute 70% of the wells' performance.

Gas content was above 95% methane, with <5% carbon dioxide or nitrogen despite the presence of volcanic intrusions (which can result in high CO_2 levels in some CBM fields). Production performance is not yet well understood and will need to be tested in future multi-well pilots, with further single pilot wells to assess performance other parts of the project area.

3.3.3 High resolution aeromagnetic surveys (2014 and 2020)

Kinetiko conducted aeromagnetic surveys in 2014 and 2020 over parts of its ER56 and ER38 licences to help identify gas compartments created by the dolerite intrusions and faulting. This information will be used to better target ongoing exploration and future resource estimates. Thirty gas compartments have been identified to date.

Figure 6 Location of recent aeromagnetic survey and previous pilot wells



Source: Kinetiko Energy Limited, "Largest Aeromagnetic Survey Undertaken Confirms Significant Increase in Gas Compartments", 14th October 2020, p 2.
Source: Kinetiko Energy Limited, September 2020 Quarterly Activities Report, 27th October 2020.

3.3.4 Gas production approval

Afro Energy received regulatory approval in October 2020 for "bulk gas production and removal" (i.e. production and sales) of up to 500 MMscf per year (1.3 MMscfd) for two years for ER56 and ER38.

Afro may apply for additions or extensions of the approval and intends to apply for a full gas production right following the completion of the next pilot program or earlier if possible.

3.3.5 Forward work program

ER 38 and ER56: The work program includes drilling one zone interval well in early 2021 in each of ER38 and ER56, followed by 14 pilot wells. The well locations will be determined based on the outcome of the recent aeromagnetic survey and the drilling will be funded by a major SA institution. Kinetiko will also workover some of its existing pilot wells to support early gas sales in 2021.

ER 270 – 272: Due to COVID-19 delays the work program will include an aeromagnetic survey in ER 271 commencing in November, followed by drilling and coring between one to four wells in each of the three tenements. The core holes will be followed by pilot test wells at selected positions throughout the tenements.

3.4 Reserves and resources

Contingent and prospective resources were updated by Gustavson Associates in July 2020. Gas-in-place estimates for CBM were based on the geometry and distribution of the coal seams provided by over 800 coal exploration holes and aeromagnetic surveys, together with gas content determined from 21 CBM core holes and 8 production test wells. Conventional gas in sandstone reservoirs was estimated from neutron and density log analysis. Contingent gas resources were based on estimated recovery factors from analogous US projects. The contingencies include: (1) insufficient production data to establish commercial productivity, (2) markets for the gas are not yet firmly established, and (3) no development plan is yet in place.

Table 4 Gross resource statement (n.b. KKO's share is 49% of the gross amount shown)

Item	Units	1C	2C	3C	1U	2U	3U	Comment
Permit area	bcf	4,604	4,604	4,604				
CBM	bcf	4,604	4,604	4,604				assume resource play covers all permits
Sandstone	bcf	4,604	4,604	4,604				"
Gas in place (gross)	bcf	4,204.0	9,306.6	17,465.0	0.0	0.0	0.0	
CBM	bcf	3,114.2	6,883.8	13,097.2				
Sandstone	bcf	1,089.8	2,422.8	4,367.8				
Recoverable (gross)	bcf	2,236.9	4,861.8	9,250.6	361.0	902.5	1,766.7	
CBM	bcf	2,047.1	4,492.0	8,621.2				
Sandstone	bcf	189.8	369.8	629.4	361.0	902.5	1,766.7	
		1C+1U	2C+2U	3C+3U				
Recovery (gross)	bcf	61.8	61.9	63.1				
CBM	bcf	65.7	65.3	65.8				
Sandstone	bcf	50.5	52.5	54.9				
Resource density	bcf/km^2	0.56	1.25	2.39				
CBM	bcf/km^2	0.44	0.98	1.87				
Sandstone	bcf/km^2	0.12	0.28	0.52				
EUR/well	bcf/well	0.14	0.30	0.58				@ 60 acres/well spacing
CBM	bcf/well	0.11	0.24	0.45				
Sandstone	bcf/well	0.03	0.07	0.13				

1. Source: data extracted from Kinetiko Energy Limited, "Significant Gas Resource Increase – Contingent Resources (2C) now 4.9 tcf", 29th July 2020, p 2. Resource assessment per Gustavson Associates LLP, Boulder, Colorado, USA.
2. Resources include exploration rights ER38, ER56, ER270, ER271 & ER272, covering 4,604 kms^2 gross.
3. n.b. Resource Assessment Excludes Exploration Right Application 320, comprising 2,394 km^2 pending approval.

3.5 Well performance assumptions

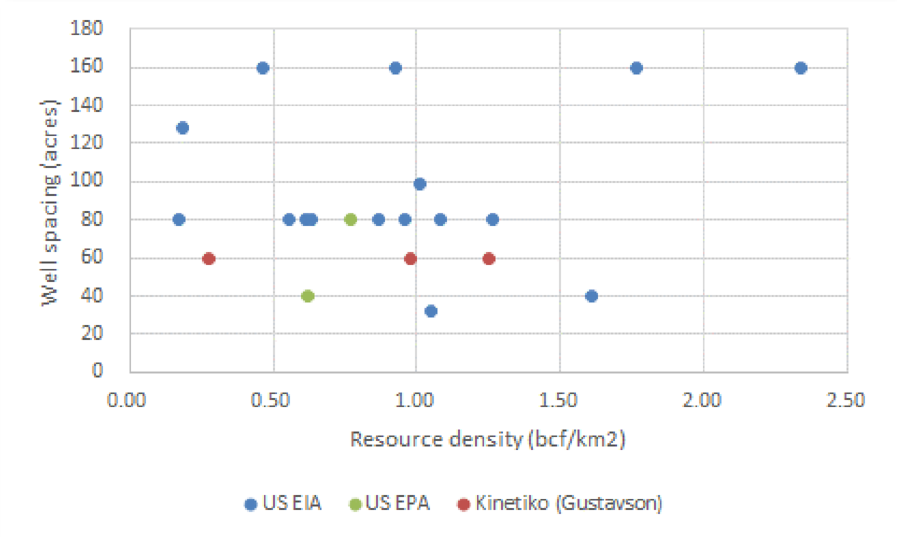
Estimated Ultimate Recovery: There is currently limited data to determine type curves for sandstone and CBM production performance for the Amersfoort area. We have compared the implied resource density and Estimated Ultimate Recovery (EUR) per well derived from the recent Gustavson resource assessment with US Energy Information Administration and US EPA study data for selected US CBM basins in Table 5 and Figure 7 below. The P50 recoverable resource density of 1.25 bcf/km^2 and our assumed well spacing of 60 acres and EUR of 0.3 bcf is within the range of typical US CBM basins.

Table 5 CBM recoverable resource density comparison

Data source	Well spacing acres	P90 bcf/km^2	P50 bcf/km^2	P10 bcf/km^2	P90 bcf/well	P50 bcf/well	P10 bcf/well	Comment
Kinetiko (Gustavson)								
CBM+Sandstone	60	0.44	0.98	1.87	0.108	0.237	0.455	
Sandstone	60	0.12	0.28	0.52	0.029	0.067	0.126	
CBM+Sandstone	60	**0.56**	**1.25**	**2.39**	**0.137**	**0.304**	**0.581**	
US EIA								AEO 2020 Oil and Gas Supply Module
Powder River: Big George/Lower FU	40		1.61			0.260		
Powder River: Wasatch	80		0.17			0.056		
Powder River: Wyodak/Upper FU	32		1.05			0.136		
Green River: shallow	80		0.63			0.204		
Piceane: deep	160		0.93			0.600		
Piceane: Divide Creek	80		0.55			0.179		
Piceane: shallow	160		0.46			0.299		
Piceance: White River Dome	80		1.27			0.410		
Raton: Northern	80		1.08			0.350		
Raton: Purgatoire River	80		0.96			0.311		
San Juan: Fairway, New Mexico	160		1.76			1.142		
San Juan: North Basin	160		2.34			1.515		
San Juan: North Basin, Colorado	80		0.86			0.280		
San Juan: South Basin	80		0.61			0.199		
San Juan: South Menefee	128		0.18			0.095		
simple average	99		1.01			0.402		
US EPA								US EPA studies, Mongolia CMM, 2013
Powder River Basin	40		0.62			0.100		
Raton	80	0.22	0.77	1.67	0.070	0.250	0.540	

Source: K1 Capital analysis, derived from US EIA and US EPA [7] [8] [9] [10].
Assumed 60 acre spacing for Amersfoort project. Kinetiko resource density based on 4,604 km^2 granted permit area.

Figure 7 P50 resource density comparison: US CBM basins and South Africa



Source: K1 Capital analysis

Initial production rates: Initial production rates from the pilot wells in the 2013 pilot program varied from 10 to 332 kscfd, as shown in Table 6 below. Gas production was believed to be sourced predominantly from the sandstones adjacent to the coal seams, rather than the coals themselves. As a result the wells did not require extended dewatering periods typical of CBM wells during which production builds towards a peak. We have assumed an initial production rate of 100 kscfd/well, approximately equal to the average of the reported pilot wells, which was influenced by the strong response from a single well (KA-03PT2). We expect the rates from future production wells to be higher than the rates from the initial pilot wells given improvements in well design and drilling practices.

Table 6 Amersfoort 2013 pilot well initial production rates (kscfd)

Pilot well	IP kscfd	TD m
KA-03PT	24	370
KA-03PT2	332	458
KA-05PT		344
KA-06PT	10	
KA-07PT		440
KA-10PTR	45	440
KA-11PT		392
Average	**103**	**407**

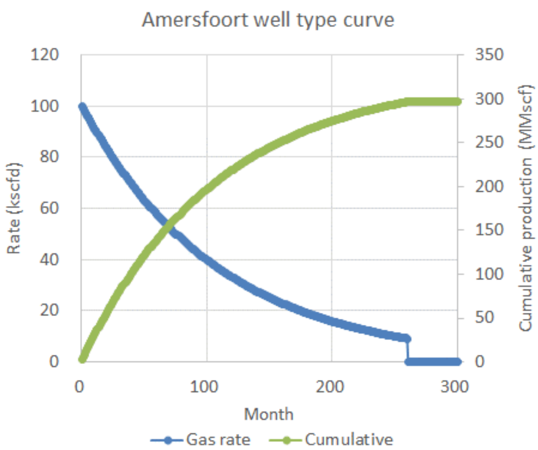
Source: K1 Capital analysis of company announcements

We have assumed an exponential decline profile with a decline rate of ~11% per year, which gives an economic life of ~22 years and EUR of ~300 MMscf, equal to the ~300 MMscf estimated available from a 60 acre spacing based on the resource density in the independent resource report.

This is a first approximation and is subject to significant uncertainty. The well spacing and performance parameters will need to be confirmed through the proposed 20-well pilot program starting in 2021.

Figure 8 Amersfoort well type curve assumptions

Parameter	Units	Value	
Gas higher heating value	MMBtu/kscf	1.013	
IP	kscfd	100	
Decline rate	%/mth	0.92	
Decline rate	%/year	10.5	
EUR	MMscf	297	
Water/gas ratio	bbl/kscf	2.2	
Economic cut-off rate	kscfd	9	
Well life	months	260	21.7 years
Payback	months	25	2.1 years
Discount payback	months	28	2.3 years
NPV/well	k$US	495	
Revenue	$US/MMBtu	7.00	
Royalties	$US/MMBtu	0.35	
Cash opex	$US/MMBtu	2.24	
Net cash margin	$US/MMBtu	4.41	
Discounted net cash margin	$US/MMBtu	1.65	



Source: K1 Capital analysis.

1. Gas composition 97.0% methane, 3 % carbon dioxide/nitrogen.
2. Capex of $US350k/well for drilling/completion/gas gathering (pilot wells are expected to cost more).
3. Opex of $US1750/mth well, $US0.50/GJ gas and $US0.10/bbl water.
4. Revenue $US7.00/MMBtu field gate gas price. 5% government royalty.
5. Economic cut off rate based on cash operating costs, excluding abandonment.
6. Discount net cash margin at 10% real, pre-tax basis for illustration only. Per well basis, excludes G&A.

4. Market analysis

4.1 South African energy sector

South Africa is a significant coal consumer and exporter but produces little conventional oil or gas. The country has a highly developed synthetic fuels industry and the third-largest oil refinery system in Africa (545 kbd, behind Algeria 650 kbd and Egypt 800 kbd) [5].

4.1.1 Natural gas

Natural gas makes up ~3% of the total primary energy mix and this is expected to increase to ~10% over the next decade, still well below OECD economies such as Europe (24%) and the US (28%). The industry is at early stage of development with limited internal competition. Barriers to entry include a lack of infrastructure, high capital costs, community concerns regarding hydraulic stimulation and the lack of an industry development program. Shale gas exploration was halted in 2011 by government moratorium. A 2013 PwC report commissioned by Kinetiko concluded that the discovery of significant new indigenous reserves would have a disruptive effect and create opportunities for new entrants.

The bulk of South Africa's gas requirements are imported by Sasol via pipeline from Mozambique. The ~200 PJ/yr ROMPCO pipeline[3] mainly supplies Sasol's Secunda and Sasolburg petrochemical plants.

Renergen (ASX: RLT) estimates a shortfall of gas of 220 TJ/d (80 PJ/yr) in Johannesburg and stated that the Industrial Gas Users Association of South Africa predicts an imminent supply "crunch", due to depletion of Mozambique's field. Renergen estimates LPG demand of ~60 TJ/d (22 PJ/yr) and plans to commence production of 50 tpd LNG in 2021, sufficient for 400 trucks, rising to 300 tpd (5,000 trucks). We estimate this will require production of ~3 MMscfd, rising to 18 MMscfd from Renergen's Virginia biogenic gas project.

4.1.2 Electricity

South Africa has a large power industry, accounting for more than 80% of the electricity generated and consumed in southern Africa (via the Southern African Power Pool). Demand has effectively outstripped supply since 2007/8 and South Africa has progressively reduced its export generation commitments, exacerbating the shortage in neighbouring countries. Despite a 75% electrification rate nationwide only 55% of the rural population has access to electricity (c.f. 88% in urban areas). According to 2009 IEA data, ~12.5 million people had no access to electricity.

Approximately 90% of South Africa's electricity is generated in coal-fired power stations, with ~5% via nuclear and 5% by hydroelectric and pumped storage schemes. There are few, if any, new economic hydro sites that could be developed to deliver significant amounts of power.

Generation is dominated by Eskom, the state-owned utility, which also owns and operates the national electricity grid. Eskom supplies about 95% of South Africa's electricity. The government approved private-sector participation in the electricity industry in 2003, with future power generation capacity to be divided between Eskom (70%) and independent power producers (IPPs) (30%).

The country is targeting additions of over ~40,000 MW from 2020 to 2030, primarily from coal. Power prices have risen approximately three-fold over the 10-year period from 2008 to 2017 [11].

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[3] Republic of Mozambique Pipeline Investments Company (Pty) Ltd. 25% South African Government, 25% Mozambican Government, 50% Sasol Limited. 26" diameter (plus looping), ~865 km, Temane to Secunda.

4.2 Local economic outlook

The World Bank expects Sub-Saharan Africa to experience the sharpest contraction in activity on record in 2020 due to COVID-19, due to lower growth in major trading partners and a collapse in commodity prices. Although growth is projected to recover in 2021, the region is vulnerable to a longer lasting downturn given the weakness of its health care systems, constrained fiscal policy options, and risk of debt distress given high levels of debt and higher borrowing costs [6] [12].

4.3 South African natural gas pricing

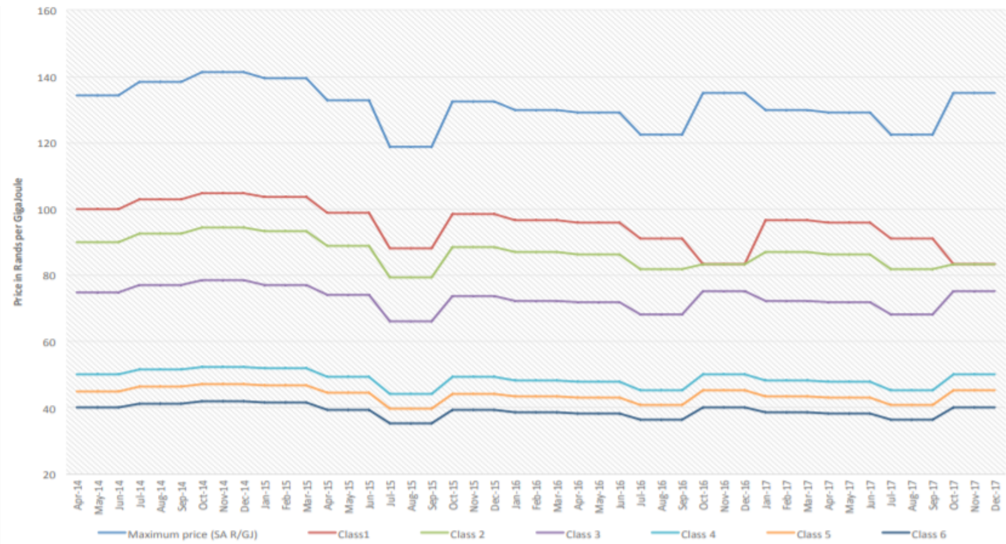
Gas price limits and pipeline tariffs are effectively set by the National Energy Regulator of South Africa (NERSA). NERSA regulations cover natural gas, syn gas, CBM, LNG, CNG and LPG and provide a regulated third-party access / open access regime for pipelines with capped prices. Own-use pipelines are not subject to piped gas regulations, with prices are set by negotiation.

The maximum Gas Energy Prices are determined in accordance with the Methodology to Approve Maximum Prices of Piped-Gas in South Africa promulgated by NERSA in October 2011 [13] [14]. The maximum prices are linked to coal, diesel, electricity and other price indicators, with allowances for trading margins and transmission costs. An alternative cost pass-through method can be used in certain cases, such an LNG imports where the cost of supply exceeds the maximum price. The validity of the methodology has been brought to court by a group of major users [14].

Maximum prices are set for six customer classes, based on size (annual gas consumption) and are adjusted quarterly. Actual prices may be below the maximum levels and are determined through bilateral negotiations. Historical gas prices for each class, prior to the inclusion of trading margins and transmission costs, are shown in Figure 9 below.

Our analysis of the South African wholesale gas price and relationship to Brent crude oil as the global energy price marker is discussed in Section 10.4. We estimate a mid-case wholesale received gas price for producers of $US7.00/MMBtu (@ $US52/bbl real Brent), with a range from $US6.00-9.00/MMBtu.

Figure 9 South African Monthly natural gas prices (2014 to 2017)



Source: "South African Energy Price Statistics – 2018", Republic of South Africa Energy Department, p 50 [11]
Class 1/2/3/4/5/6 max usage: 400; 4,000; 40,000; 400,000; 4,000,000; >4,000,000 GJ/yr

4.4 Gas commercialization options

Kinetiko conducted a preliminary assessment of market size and potential commercialization options during 2013. Consultants engaged by Kinetiko (PwC) estimated potential demand of ~21-37 PJ/yr, from growth in existing markets (2.5 PJ/yr), substitution (1.5 PJ/yr) and new demand (17-33 PJ/yr) from 13 options, including:

- Gas sales into existing coal fired power stations for flame modulation or co-generation,
- Gas supply into the existing gas distribution network (a Transnet pipeline and compressor station are on the southern JV licence area),
- Independent Power Production (IPP) into the grid or direct to a major customer,
- Mini LNG IPP for peak load and distributed demand,
- Feedstock for gas to liquids (GTL), chemicals or LNG, and
- CNG production for manufacturing customers and fleet transport depots.

We expect a staged development, with the initial stage comprising a 20-well pilot to establish well performance parameters and variability across parts of the permit area, probably selling into small-scale third-party CNG facilities. We assume this will be followed by a larger field development at ~10-12 TJ/d for third-party on-site power generation or micro-LNG for diesel fuel replacement before expansion to supply large-scale (~1000 bcf, ~120 TJ/d) gas sales for power generation.

10 TJ/d (3.65 PJ/yr) should support ~45-55 MW gas engine power generation at 40-50% efficiency [15] or ~60 kt/yr (~200 t/sd) LNG[4][5]. 120 TJ/d (43.8 PJ/y) should support ~800 MW[6] of combined cycle power generation at an efficiency of 58% [16], which is ~10% of the 8 GW of new-build gas and diesel fired power generation expected by 2030 [17] p10. Significant existing coal fired generation is expected to retire after 2030, creating additional opportunities for gas demand [17], p52.

Staged development will enable demonstration of gas deliverability and optimization of field operations at relatively low capital cost prior to the large capex and logistical commitment associated with full development. Staged development is supported by interest from existing CNG networks seeking gas for transport and stationary consumers close to the Amersfoort project, with later expanded development accessing the Lilly Pipeline and sites such as the Majuba Power station. We expect Kinetiko will likely partner with a larger organization with the organizational and financial capability to execute the full field development required for these later stages.

[4] Gas engine power generation = 10 TJ/d / (24*3600 s/d) * 40-50% * 10^6 = 46-58 MW.
[5] Micro LNG = 10 TJ/d * 365 day/yr / ~60 PJ/t LNG = = 61 kt/yr = ~167 kt/cd => ~200 kt/sd at 80% utilization
[6] Combined cycle power generation = 120 TJ/d / (24*3600 s/d) * 58% * 10^6 = 806 MW

5. Sector analysis

5.1 Peer comparison

Three ASX-listed companies other than Kinetiko have onshore CBM/unconventional gas interests in southern Africa (Tlou Energy – CBM in Botswana, Strata-X (soon to merge with Real Energy to form Pure Energy) – CBM in Botswana, and Renergen – biogenic gas and helium in South Africa. One unlisted company (Kalahari Energy) is also active. Approximately seven ASX-listed junior to mid-size companies have CBM interests in Australia, with only one, Senex, in production.

Table 7 Peer companies

Company as of 18-Nov-20	Code	Mkt Cap M$A	EV M$A	Description
Kinetiko Energy	KKO	71	70	CBM exploration in South Africa. 49% interest in the Amersfoort Project. Suspended since late 2017, pending resolution of funding issues with JV partner Badimo Gas.
Australian CBM (6)				
Blue Energy	BLU	76	72	Conv. & unconv oil & gas exploration in Qld/NT (Bowen, Surat, Cooper, Maryborough, Wiso, McArthur Basins). ATP 814P CSG block adjacent to Arrow's Moranbah field.
Comet Ridge	COI	49	44	CSG expln/appraisal in the Bowen Basin (Mahalo JV with Santos & APLNG), Galilee Basin (own and JV with Vintage), and Gunnedah Basin (JV with Santos).
Carbon Minerals	CRM	7	4	NSW CSG exploration, Gunnedah Basin JV with Santos
Galilee Energy	GLL	171	152	CSG expln/appraisal in the Galilee Basin (Glenaras lateral pilot, Queensland) and CSG licence application in the Magallanes Basin in Chile. Withdrawing from US onshore.
Real Energy	RLE	8	6	Planned merger with Strata-X 4Q 2020. Qld Cooper Basin Patchawarra basin-centred gas and CBM; permits also prospective for conventional oil
State Gas	GAS	93	80	100% interest in the Reid's Dome Gas Project (PL 231), Rolleston Wests (ATP 2062) central eastern Queensland.
ASX International CBM/helium (5)				
Elixir Energy	EXR	92	89	Nomgon IX CBM PSC, South Gobi Basin, Mongolia
NuEnergy Gas	NGY	18	19	Indonesian CBM; six PSCs in South Sumatra, Central Sumatra and East Kalimantan, including 45% Tanjung Enim PSC and 100% Bontang Bengalon PSC (East Kalimantan)
Renergen	RLT	129	107	Helium and biogenic gas E&P, Freestate, South Africa
Strata-X	SXA	10	9	Planned merger with Real Energy 4Q 2020. Serowie CSG project in Botswana, plus CBM in Queensland.
Tlou Energy	TOU	35	33	CBM exploration in Botswana. 100% interest in the Lesedi and Mamba CBM projects. Low initial gas flowrates; successful tenderer for gas and power supply to government.
ASX oil & gas producers (3)				
Beach Energy	BPT	3,764	3,755	Cooper Basin oil and gas E&P (with Santos, Cooper, Senex, Strike, Icon), Otway exploration, acquired Lattice Energy (Waitsia gas project (WA), BassGas (Tas), Kupe
Cooper Energy	COE	553	649	Cooper oil, Otway (Casino/Henry/Minerva) gas production, onshore Otway expl'n (JVs with Beach, Vintage), offshore Gippsland gas produciton (Sole & Manta gas fields).
Senex Energy	SXY	494	549	Oil & gas exploration and production in the Cooper Basin (JVs with Cooper and Beach) and CSG in the Surat Basin of Queensland (WSGP and Atlas domgas project).

Source: market capitalization per ASX, closing prices 29th October 2020

At least five ASX-listed companies have withdrawn from CBM exploration in Africa the past 10 years, illustrating the challenge involved in exploring, appraising and developing an onshore gas market.

- Origin Energy: 50/50 JV with Sasol in Botswana (KUBU Energy Resources (Pty) Limited). 9 well program commenced 2012. Appears to be no longer active but retains interest in KUBU.
- Molopo Energy: Held the Virginia and Evander permits prior to Renergen. Secured the first onshore gas production right in SA in 2012. Withdrew to focus on North American shale oil.
- Instinct Energy: two exploration licences in Namibia. Appears to have withdrawn after two attempts to IPO in 2010 and 2011.
- Magnum Gas and Power: 8 CBM licences in Botswana, adjacent to Tlou and Kalahari Energy, licences acquired by Strata-X in 2017/18.

- NuEnergy Gas: CBM exploration in Tanzania and Malawi in 2013 before withdrawing to focus on Indonesia.

Table 8 Current CBM company activity in southern Africa

Company	Key points
Renergen (ASX: RLT) (JSE & Alt^X: JEN)	▪ Focus: Helium and natural gas (biogenic methane), Free State, South Africa ▪ Assets: Virginia Gas Project Production Right (first SA onshore production right) and Evander Exploration Rights. ▪ Status: Onshore production right for Virginia (only one in South Africa). 12 wells production ready. Commenced CNG production May 2016, sold to bus fleet. Joint marketing agreement with Total for onshore LNG distribution. ▪ Reserves/resources: • He; gas: 1P/2P/3P: 1.0/3.4/6.7 bcf; 40.8/139.0/284.2 bcf • He; gas: 1C/2C/3C: 7.9/14.4/20.9 bcf; 273.3/435.9/648.5 bcf • He; gas: 1U/2U/3U: 32.5/106.3/344 bcf; 640/1,278/2,069 bcf ▪ Comment: Average He concentration 3.4% (up to 12%). Methane >90%. ▪ Production: CNG production commenced May 2016 to Megabus. Will cease once LNG plant becomes operational. ▪ Near term activity: He Phase 1 = 350 kg/d, Phase 2 = 10,000 kg/d. LNG Phase 1 = 50 tpd (400 trucks), Phase 2 = 300 tpd (5,000 trucks).
Tlou Energy (ASX: TOU)	▪ Focus: CBM in Karoo-Kalahari basin, Botswana ▪ Assets: 100% interest in three CBM project areas: Lesedi, Mamba, Boomslang ▪ Area (gross): ~9,000 km^2 ▪ Status: Mining licence for Lesedi until 2042. Seeking $10m funding for Phase 1 Lesedi development (wells, 2 MW on-site power gen). 100 km 66 kV transmission line to Serowe to be separately funded. $20m for Phase 2 expansion to 10 MW + wells to follow. Awaiting environmental approval for Boomslang exploration. ▪ Reserves/resources: Lesedi: 41 bcf 2P, 252 bcf 3P, ~3 tcf 3C. Mamba: 175 bcf 3P ▪ Near term activity: Phase 1 Lesedi funding. Mamba: core holes, seismic. ▪ Other: Listed 9 Apr-12, raising $10m; led by previous Sunshine Gas management
Pure Energy Corporation (proposed merger of Real Energy and Strata-X)	▪ Focus: CBM in Botswana and Australia and Australian basin-centred gas ▪ Formed by nil premium merger of Strata-X (ASX: SXA) and Real Energy (ASX: RLE) ▪ Assets: Serowe CBM project, Botswana, acquired from Magnum Gas & Power, Windorah basin centred gas, Queensland, Venus CBM Queensland. ▪ Area (gross): 4,784 km^2 CBM (Botswana) ▪ Status: Staged farm-out to BotsGas Pty Ltd announced 5th March 2020 to fund 100% of costs to drill, complete and test up to 19 wells (including 7 appraisal wells and 3 multi-well pilots); $7m earns 49%. First stage is 1 well. Costs capped at $300k/well. ▪ Reserves/resources: Serowe (23 bcf 2C, 2.38 tcf 2U); Windorah (330/770 bcf 2C/3C); Venus (555/694/833 bcf prospective) ▪ Near term activity: ▪ Other: BotsGas planned ASX listing 2021.
Kalihari Energy (unlisted)	▪ Focus: Botswana CBM E&P, Central Kalahari Karoo Basin ▪ Assets: JV with Sekaname, a subsidiary of Kalahari Energy; 3 of 5 permits ▪ Area (gross): 3,912 km (5 permits) ▪ Status: 5-spot pilot July 2010, fracced wells. Seeking to develop 110 MW gas fired power station & 220 kV transmission line to Serule ▪ Reserves/resources: P90/P50/P10 gas-in-place: 5.6, 10.8, 15.1 tcf ▪ Near term activity: studies for on-site power generation ▪ Comment: Active since 2000. JV with Exxaro (Sth Africa mining company) announced March 2009. US Trade and Dev Agency grant received Mar 2020 to support power plant feasibility study.

Source: company announcements

5.2 Comparative valuation

Table 10 below lists current trading metrics for Kinetiko and selected peer companies, together will three mid-cap ASX-listed diversified producers for comparison. K1 Capital analysis of Santos and Origin's CSG to LNG projects indicates that ~80% of 2C resources are converted to 2P over a period of period of 5 years. Hence we use 2P+0.8*2C as the primary CBM comparison metric. Trading metrics for ASX-companies with international CBM operations range from $0.07 to $0.32/GJ 2P+0.8*2C, with an average of $0.13/GJ. Domestic focused companies trade at higher levels, in part due to lower perceived country risk and more mature projects. The only domestic mid-cap producing CBM company, Senex, currently trades at $0.63/GJ 2P+0.8*2C.

Kinetiko trades at a material discount to ASX peers with international operations, probably due to uncertainty regarding future commercialization of Kinetiko's large contingent resource endowment. Successful demonstration of production from the planned 20-well pilot program should see this discount begin to unwind.

Table 9 Reserve & resource spot price equivalence factors

		18-Nov-20	$US/boe	factor	
USD/AUD forex	$US/$A	0.7295	-	-	Reserve Bank of Australia
Brent	$US/bbl	44.34	44.34	1.00	Bloomberg
WTI	$US/bbl	41.53	41.53	0.94	"
Henry Hub	$US/mmBtu	2.72	15.78	0.36	"
EC Australia	$A/GJ	6.00	26.84	0.61	AEMO Wallumbilla firm bench'k 18 Nov
WC Australia	$A/GJ	2.85	12.75	0.29	gasTrading spot price Oct '20
Europe	$US/mmBtu	4.85	28.13	0.63	World Bank, Netherlands TTF, Oct '20
LNG	$US/mmBtu	6.50	37.69	0.85	85% of Brent (14.7% slope)
LNG JPN/KOR spot	$US/mmBtu	6.00	34.80	0.78	Oct 2020 contract price
SAfrica	$US/mmBtu	7.00	43.50	0.98	est. field gate price @ $US52 Brent
LPG	$US/t	435	38.16	0.86	Saudi Contract Price - Nov '20
Helium	$US/kscf	210	1,183	26.67	USGS Mineral Comm Summary 2020

Source: K1 Capital analysis. Helium "boe energy equivalent price" assumes notional 1.03 MMBtu/kscf for comparison

Table 10 Reserve and resource trading metrics

Company	Code	Last Price 18-Nov-20	Total Shares (million)	Mkt Cap M$A	EV M$A	2P PJe'	3P PJe'	2C PJe'	EV/2P $A/GJe	EV/ (2P+0.8*2C) $A/GJe	EV/ (3P+2C) $A/GJe	Gearing D/(D+E) %
Kinetiko Energy	KKO	0.130	543	71	70	-	-	2,463.3	-	0.04	0.03	0
Australian CBM (6)				**404**	**358**	**177.0**	**481.0**	**5,482.4**	**2.02**	**0.08**	**0.06**	**0**
Blue Energy	BLU	0.057	1,327	76	72	71.0	298.0	1,166.0	1.01	0.07	0.05	-
Comet Ridge	COI	0.067	728	49	44	106.0	183.0	286.0	0.42	0.13	0.09	-
Carbon Minerals	CRM	0.390	19	7	4	-	-	183.0	-	0.03	0.02	-
Galilee Energy	GLL	0.630	271	171	152	-	-	3,011.5	-	0.06	0.05	-
State Gas	GAS	0.540	173	93	80	-	-	536.0	-	0.19	0.15	-
Real Energy	RLE	0.023	349	8	6	-	-	299.9	-	0.02	0.02	9
ASX International CBM/helium (5)				**284**	**257**	**542.1**	**1,532.5**	**1,763.8**	**0.47**	**0.13**	**0.08**	**1**
Elixir Energy	EXR	0.130	708	92	89	-	-	-	-	-	-	-
Strata-X	SXA	0.078	127	10	9	-	-	36.0	-	0.32	0.26	-
NuEnergy Gas	NGY	0.012	1,481	18	19	104.8	104.8	51.8	0.18	0.13	0.12	15
Tlou Energy	TOU	0.068	513	35	33	63.8	669.2	335.4	0.52	0.10	0.03	-
Renergen	RLT	1.100	118	129	107	373.5	758.5	1,340.5	0.29	0.07	0.05	-
ASX oil & gas producers (3)				**4,811**	**4,952**	**3,611.7**	**1,514.3**	**1,521.6**	**1.37**	**1.03**	**0.96**	**9**
Beach Energy	BPT	1.652	2,278	3,764	3,755	2,492.7	-	1,205.9	1.51	1.09	1.02	3
Cooper Energy	COE	0.340	1,627	553	649	312.2	416.3	231.6	2.08	1.30	1.00	29
Senex Energy	SXY	0.340	1,453	494	549	806.9	1,098.0	84.1	0.68	0.63	0.46	20

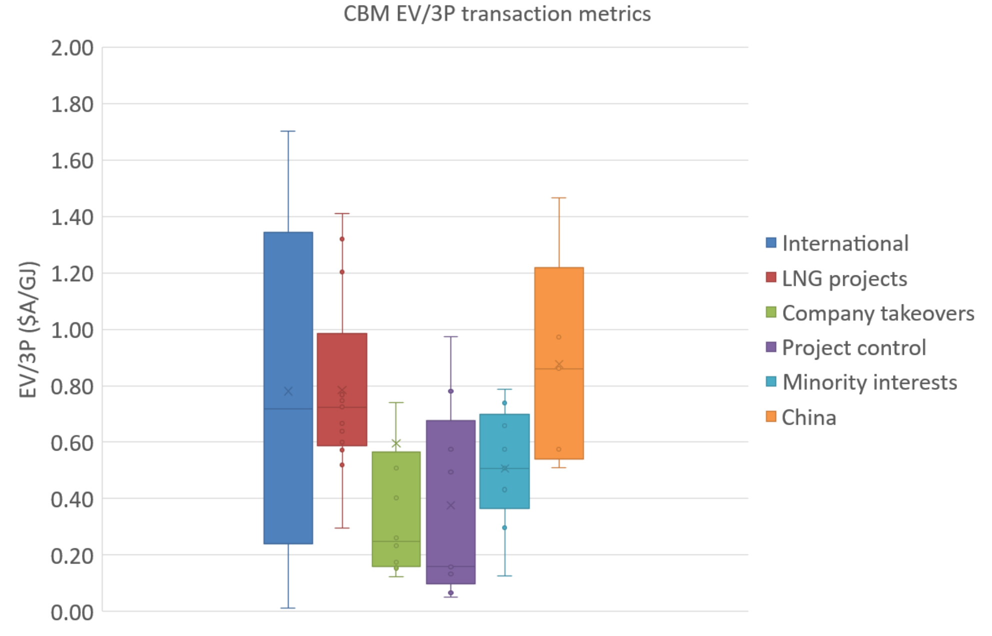
Source: K1 Capital analysis of company data. Expressed relative to the spot east coast Australian gas price of $6.00/GJ.

5.2.1 Transaction metrics

Our database of CBM-related transactions includes ~50 transactions over period from early 2008 to early 2019. We are not aware of recent CBM transactions in southern Africa. Contingent resource data are often not disclosed in transactions, which tend to report 2P and/or 3P reserves. Many of these transactions occurred before the acquired assets had been fully explored, and hence the resource estimates may have understated the amount ultimately recoverable. Hence we have used 3P as our primary transaction metric, rather than 2P, to capture the expected resources acquired.

Our evaluation indicates recent Australian CBM transactions have averaged approximately $0.30/GJ 3P reserves or $1.00/GJ 2P reserves. International transactions have ranged from $0.01/GJ 3P to $US1.70/GJ 3P, depending upon project maturity and premium for control.

Figure 10 Box and whisker plot of ASX-listed CBM transaction metrics (by type)



Source: K1 Capital analysis of market transactions from February 2008 to April 2019.
International: acquisition of companies or projects with international CBM operations (8 transactions, includes China)
LNG projects: acquisition of companies or projects related to Queensland CBM to LNG projects (13)
Company takeovers: acquisition of companies not related to LNG projects (10)
Project control: acquisition of a controlling/operating interest in CBM projects (9)
Minority interests: acquisition of minority interest in CBM projects (9)
China: transactions specifically related to CBM assets in China (5 transactions from the International category above)
N.B. the B&W plot shows the minimum, first quartile, median, third quartile and maximum value of each data set

Table 11 CBM trading and transaction valuation metrics summary (EV/3P+2C)

Metric	Low	Mid	High	Comment
Trading metrics				
Aus domestic	0.02	0.15	0.46	COVID-19 / oil price currently impacting sector
Aus domestic'	0.00	0.23	0.60	3Q CY19, pre-COVID-19 / oil price
International projects	0.02	0.04	0.08	Small sample set, illiquid, COVID-19 impact
Transaction metrics				
International assets	0.01	0.74	1.70	3P only (no 2C)
Project control	0.07	0.23	0.57	Excludes non-concluded offers, 3P only (no 2C)
Assumed	**0.05**	**0.15**	**0.35**	Before risking and time value adjustment

Source: K1 Capital analysis. Kinetiko is currently trading at $0.03/GJ EV/(3P+2C)

6. Project funding

6.1 Project funding

We understand funding for the planned 20-well pilot program will be provided by a South African financial institution. However, we estimate Kinetiko will need to raise ~$6m of additional capital over the next year to continue to progress is other exploration and appraisal activities. Our funding requirement estimate is shown below.

Table 12 Kinetiko short to medium term funding estimate

Item	Units	Sep-20 Q4 FY20	Dec-20 Q2 FY21	Mar-21 Q3 FY21	Jun-21 Q4 FY21	Sep-21 Q1 FY22	Dec-21 Q2 FY22	Comment
Opening cash balance	**M$A**	**1.1**	**0.5**	**0.8**	**5.8**	**3.5**	**1.3**	Opening balance 30 Jun 2020
Sales revenue	M$A							expect pilot gas sales from start CY22
Staff costs/administration	M$A	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	FY20 average
Exploration phase 1	M$A	-0.4						aeromag ER 38, 56
Exploration phase 2	M$A		-0.1	-0.5	-2.1	-2.1		aeromag, core holes, etc ER 270, 271, 272
Amersfoort pilot	M$A			0.0				assume externally funded
Options	M$A	0.0	0.6				0.9	51.1m by 31 Dec 2021 @ $0.03
New equity	M$A			6.0				assumed
Capital raising costs	M$A	0.0	0.0	-0.3	0.0	0.0	0.0	assumed 5%
Industry farm-out	M$A							
Closing cash balance	**M$A**	**0.5**	**0.8**	**5.8**	**3.5**	**1.3**	**2.0**	
Estimated dilution								
Shares at start of period	000,000	543.3	543.7	563.7	616.0	616.0	616.0	
Options exercised	000,000	0.4	20.0				31.5	
Share based payments	000,000							
Performance Rights issued	000,000							
Share price before raise	$/sh	0.130	0.130	0.130	0.129	0.129	0.129	
Market capitalization	M$A	70.7	73.3	73.3	79.6	79.6	83.6	
New capital % of prior mkt cap	%	0.0	0.0	8.2	0.0	0.0	0.0	
Cap raising discount to TERP	%	11.0	11.0	11.0	11.0	11.0	11.0	
Cap raising disc. to share price	%	0.0	0.0	11.8	0.0	0.0	0.0	
Assumed raising price	$/sh	0.130	0.130	0.115	0.129	0.129	0.129	
TERP	$/sh	0.130	0.130	0.129	0.129	0.129	0.129	
New shares issued	000,000	0.0	0.0	52.3	0.0	0.0	0.0	
Shares at end of period	000,000	**543.7**	**563.7**	**616.0**	**616.0**	**616.0**	**647.5**	
Market capitalization at EOP	M$A	70.7	73.3	79.6	79.6	79.6	83.6	
Notes:								
1) USD/AUD spot fx	$US/$A	0.729	18-Nov-20					
2) cap raising discount to TERP	%	11.0	per K1 Capital analysis					
3) blue shaded cells denote input data								
4) assumes future capital raisings are linked to the current share price; higher future share prices will lead to less dilution								

Source: K1 Capital analysis. Assumes notional 20m 31-Dec-2021 options are exercised by major shareholders in late 2020 to provide working capital in advance of an equity raising in H1 2021. We estimate further capital will be required in 2022 and 2025 for project development unless funding is achieved via partial sell-down.

7. Investment risks

Kinetiko is an exploration/appraisal company, operating in a country with heightened political and financial risk. Key technical and commercial risks relate to CBM appraisal outcomes and domestic gas market development.

Table 13 Investment risk summary

Risk	Comments
Asset diversification	▪ Multiple permits, but effectively single jurisdiction, single geography/geology, single commodity (gas), which creates a level of concentration risk ▪ Multiple permits provide scope for multiple farm-out / project funding options
Project maturity	▪ Exploration / appraisal stage. Meaningful production / sales some way off. ▪ Gas flowed to surface 2013, reducing resource risk. Progress has been delayed by prior issues with JV partner, now resolved ▪ Presence of thick and extensive coals known from extensive prior coal drilling ▪ Compartmentalization due to dolerite intrusions
Exploration / appraisal outcomes	▪ CBM resource quality and well performance (permeability / flow rates / EUR) ▪ Schedule
Funding	▪ KKO will require continued equity funding for G&A until sufficient revenue from gas sales is achieved ▪ Pilot project funding to be source from South African financial institution reduces equity required for pilot appraisal phase ▪ Potential to partner with infrastructure providers for gas processing / pipeline for larger development(s)
Commercialization options	▪ Limited domestic gas market / pipeline network, but strong regional demand ▪ Negotiation of acceptable gas offtake agreements (volume, duration, pricing to support project funding and FID) yet to be finalized
Competing projects	▪ Two recent multi-tcf discoveries in offshore Block 11B/12B by Total (45%, op), Qatar Petroleum (25%), CNR international (20%), Main Street/Africa Energy (10%). Brulpadda (discovered Feb 2019) 2.8-5.5 tcf GIP, Luiperd (Oct 2020) even larger. These are 70km from a pipeline that connects to the Mossel Bay GTL plant (~300 MMscfd feed, ~35 kbd products). Nearby 740 MW Gourikwa diesel fired power station. Both potentially providing foundation demand.
Access to infrastructure	▪ Lilly gas pipeline (23 PJ/yr, ~60 TJ/d capacity) running through ER38, 270 & 272 ▪ Access to RompCo pipeline (Mozambique to Secunda, South Africa) ▪ Existing CNG and dual fuel (CNG/diesel) market for transport fuel ▪ Emerging LNG market for transport fuel ▪ Ten power stations within 300km (potential for co-firing); high voltage power infrastructure
Community acceptance	▪ Social licence to operate for development and production stages ▪ Local community supportive of exploration stage
Country risk	▪ Limited domestic gas market and early stage petroleum regulatory framework ▪ Moody's country investment risk rating of Ba1 (non-investment grade) ▪ Stern Business School country risk premium of 3.27% (Australia 0.0%) (January 2020, prior to loss of investment grade rating in March 2020). ▪ Coface country risk assessment C, business climate assessment A4 (A1=very low, A4 reasonable, B fairly high, C high, D very high, E extreme). ▪ Analysis indicates political risk is ~1/3rd of CRP derived from sovereign bonds
Legislative changes	▪ Permits are covered by fiscal stability agreements, which prevent changes to existing licence conditions. Newer projects may have different conditions. ▪ Draft legislation announced in Jan 2020 proposes a 20% interest for state-owned partners, carried to the production stage, and a 10% interest for broad-based black economic empowerment (B-BBEE) companies. [18]

Source: K1 Capital analysis

7.1 SWOT analysis

Table 14 SWOT analysis summary

Strengths	Weaknesses
▪ Large contiguous well-located permits ▪ Large contingent and prospective resources ▪ Gassy coals, good permeability (coals and sandstones), low cost drilling, limited water ▪ Operatorship, high equity interest (49%) ▪ Equal voting interest (50%) ▪ Well located with respect to gas demand (power generation, transport, etc.) ▪ Existing infrastructure (gas pipeline crosses permit, etc.) ▪ Limited competing land use (grazing, cropping) ▪ Good topography; relatively low value land (plateau >1,600m above sea level). ▪ Strong in-country relationships, generally supportive local community ▪ Ability to stage onshore development	▪ Subdued investor sentiment towards gas exploration (stronger interest in appraisal/development) ▪ Will require ongoing funding for pilot programs, ongoing exploration and field development ▪ Joint venture partner's funding capability uncertain ▪ Country risk. ▪ Relatively immature petroleum regulatory regime ▪ Relatively immature gas and independent power generation sectors ▪ Large gas resource will require assistance of large, capable partners for full field development (multi-tcf)
Opportunities	**Threats**
▪ Supply direct domgas users, power generation and gas to liquids. ▪ Introduction of strategic partner(s) via farm-down or gas offtake agreement(s) to provide funding and commercial validation	▪ Exploration/appraisal outcomes. ▪ Potential opposition to onshore development by local or special interest groups. ▪ Cost overruns / schedule delays ▪ Delays due to political unrest / changes of government ▪ Delays to pilot programs due to downhole complexity / regulatory processes ▪ Competitive response from existing gas market participants, potential new entrants (e.g. Total)

Source: K1 Capital analysis

8. Board and management

Table 15 Board of Directors and Management

Board
Mr Adam Sierakowski – Non-Executive Chairman Appointed 8th December 2010. ▪ Lawyer and founder of Price Sierakowski and Trident Capital focusing on corporate transactions from private to listed public entities ▪ Extensive experience in capital raising, ASX transactions including developing assets and corporate structures for major companies both in Australia and overseas ▪ Over 20 years of experience as Director of ASX listed companies (Coziron Resources Ltd (ASX: CZR), Dragontail Systems Limited (ASX: DTS), Rision Limited (ASX: RNL), Connected IO Limited (ASX: CIO)).
Mr Donald J Searle – Non-Executive Director Appointed 25th January 2010. B. Sc., PhD, MAusIMM, MAICD, University of WA ▪ Geologist with over 35 years of experience in exploration, project management, project financing and development in both the minerals and energy industries. ▪ Over 20 years in executive and non-executive capacities of ASX listed companies in Australia, Africa and Europe (Titanium Sands Limited (ASX: TSL)).
Mr Agapitos Marcus Geoffrey Michael – Non-Executive Director Appointed 25th January 2020. BA (Uni of WA) ▪ 25 years of experience as a company director and executive and 10 years of experience as a director of Kinetiko. ▪ Experience in managing project teams in investment, project delivery and enterprise development in the resources, energy, engineering, property and technology sectors in Australia, Europe, Asia and Africa.
Senior Management
Johan Visage – In-Country CEO, South Africa Appointed 2015. Oxford College of Petroleum Studies, Henley Management College ▪ Engineer with over 30 years of experience in the oil and gas industry in mid and downstream gas engineering, field development economics and gas sales and purchase agreements ▪ Provides upstream petroleum consulting services in geosciences, operations, petroleum economics, and advisory and management services to South African and international investment banks and petroleum companies ▪ Extensive experience with energy and petroleum regulatory bodies in South Africa, including the Petroleum Agency of South Africa (PASA), the National Energy Regulator of South Africa (NERSA) and Department of Energy.

Source: Kinetiko Energy Limited, website, accessed 29th September 2020 and 2020 Annual Report, pp 2-3

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10. Appendices

10.1 Capital structure

Table 16 Capital structure

Item	# million	$/unit	Capital'n M$	Cash M$	Comment
Equity	594.7	0.119	70.7	1.5	diluted
Shares	543.3	0.130	70.6		at 30th Jun 2020
Shares	0.4	0.130	0.1		issued subsequent to year end
Options (31 Dec 21 @ $0.03)	36.5	0.030		1.1	at 30th Jun 2020
Options (31 Dec 21 @ $0.03)	15.0	0.030		0.4	issued subsequent to year end
Options (31 Dec 21 @ $0.03)	-0.4	0.030		-0.0	exercised subsequent to year end
Debt	0.0	0.000	0.0	0.0	
nil					

Source: Kinetiko Energy Limited, 2020 Annual Report, pp 50-55. Cash amount if all options are exercised.

Figure 11 Top-20 shareholders and substantial shareholders (as of 23rd September 2020)

Name	Number of ordinary shares held	Percentage of capital held
MR BRENDAN DAVID GORE <GORE FAMILY NO 2 A/C>	85,780,455	15.78%
AGEUS PTY LTD <M AND A A/C>	37,046,123	6.82%
TRIDENT CAPITAL PTY LTD	26,293,101	4.84%
EARTHSCIENCES PTY LTD <SEARLE SUPER FUND A/C>	20,233,334	3.72%
IML HOLDINGS PTY LTD	17,790,645	3.27%
AEGEAN CAPITAL PTY LTD <THE SPARTACUS A/C>	17,637,893	3.24%
MR ADAM SIERAKOWSKI	17,555,288	3.23%
MR ROBERT JAMES MACMILLAN	12,350,000	2.27%
HOLDREY PTY LTD <DON MATHIESON FAMILY A/C>	10,821,395	1.99%
PENISH PTY LTD <PETRIDES FAMILY A/C>	10,422,718	1.92%
JGST PTY LTD <JGST FAMILY SETTLEMENT A/C>	10,305,925	1.90%
MFM AUSTRALIA PTY LIMITED MCKELVEY FAMILY NO 2 A/C>	10,018,272	1.84%
AUBURY PTY LTD	10,000,000	1.84%
SHARIC SUPERANNUATION PTY LTD <FARRIS SUPER FUND A/C>	8,483,705	1.56%
BLUE SAINT PTY LTD	7,650,000	1.41%
IML HOLDINGS PTY LTD	7,218,488	1.33%
BOTSKY PTY LTD <N BOTICA NO 3 FAMILY A/C>	7,031,250	1.29%
SDMO AUSTRALIA PTY LTD <THE BOTICA SUPER FUND A/C>	6,000,000	1.10%
GOLDFIRE ENTERPRISES PTY LTD	5,600,209	1.03%
HOLDREY PTY LTD <THE DON MATHIESON FAMILY A/C>	5,568,003	1.02%
TOTAL	333,806,804	61.40%

Shareholder Name		Number of Shares	Percentage	Date of Notice
BRENDAN D GORE & ASSOCIATED ENTITIES		93,372,148	17.17%	04/08/2020
AGEUS PTY LTD	M & A A/C	37,046,123	6.82%	30/04/2020
ADAM SIERAKOWSKI & ASSOCIATED ENTITIES		81,636,129	15.03%	30/04/2020

Source: Kinetiko Energy Limited, 2020 Annual Report, pp 59-60

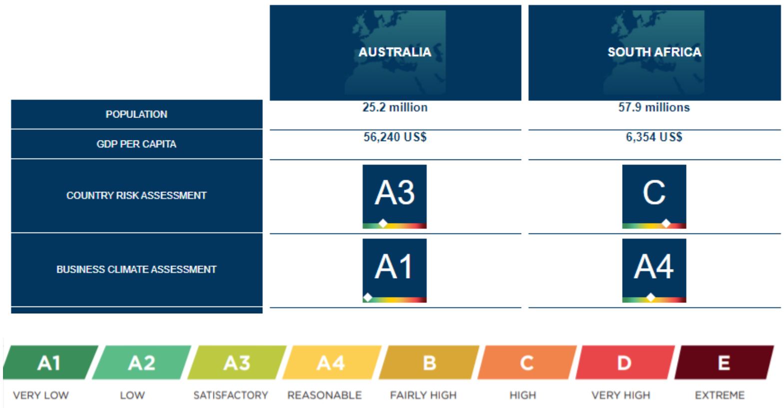
10.2 Exchage rate and country risk

Figure 12 USD: ZAR exchange rate 2011 to 2020

Source: “XE Currency Charts: USD to ZAR”, xe.com, 19th October 2020 [19]

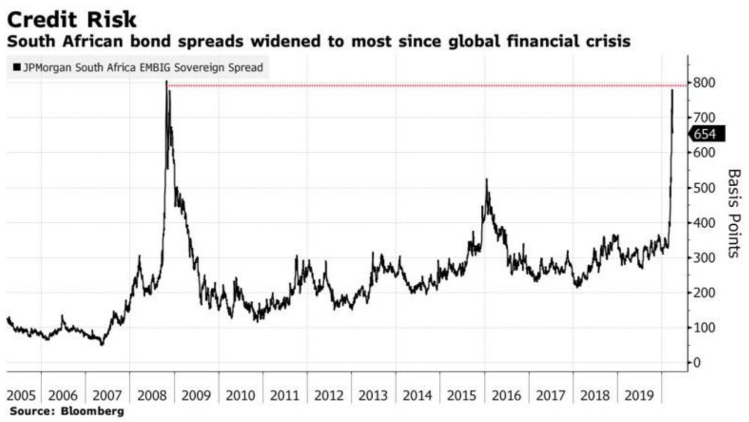
The South African currency has continued to weaken significantly against the US dollar over the past 10 years. Goldman Sachs notes South Africa’s currency has one of the strongest correlations to global risk sentiment and Chinese industrial activity. However, South Africa’s longer-run weak growth and current account dynamics have contributed to a multi-year trend currency weakening, which is expected to continue, to 17.50 by the end of 2021 and 18.00 in 2022 [11].

Figure 13 Coface country risk ranking: South Africa & Australia



Source: coface.com, accessed 30th October 2020. https://www.coface.com/cofaweb/comparer/686-676

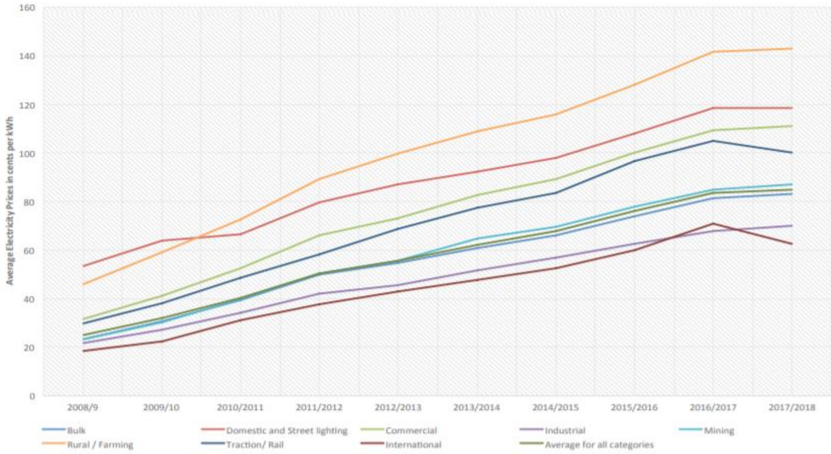
Figure 14 South African credit risk



Source: Bloomberg, “After More Than 25 Years S. Africa Is Now Junk With Moody’s Too”, 28th March 2020 [12]
https://www.bloomberg.com/news/articles/2020-03-27/south-africa-gets-full-house-of-junk-ratings-after-moody-s-cut

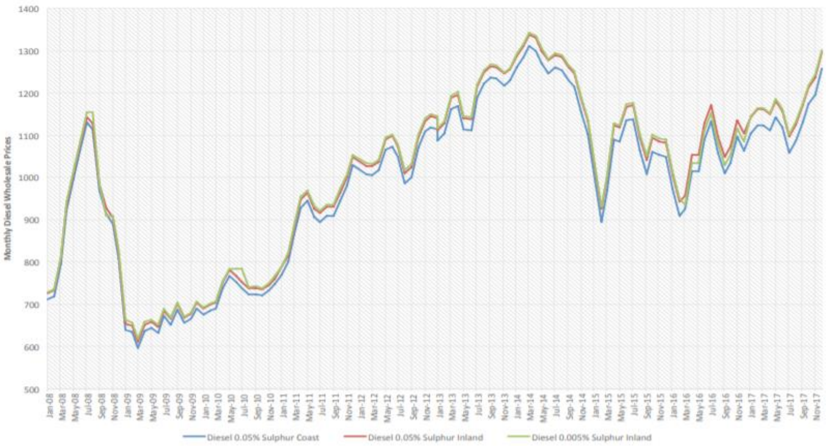
10.3 South African energy sector pricing

Figure 15 South African annual electricity prices



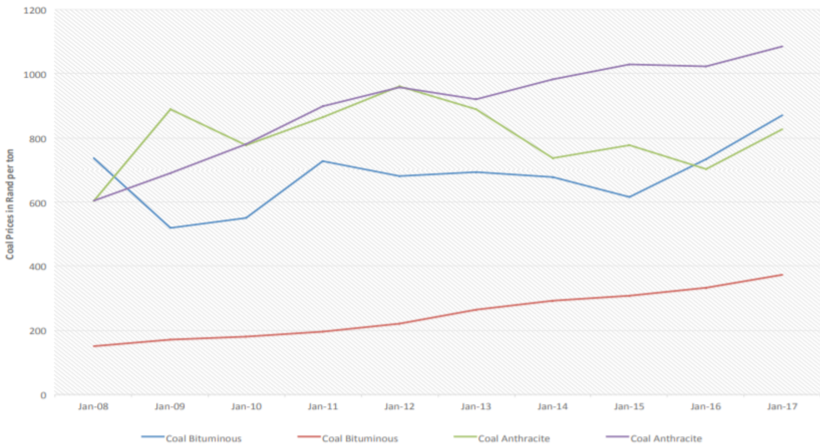
Source: "South African Energy Price Statistics – 2018", Republic of South Africa Energy Department, p 44 [11]

Figure 16 South African monthly diesel prices



Source: "South African Energy Price Statistics – 2018", Republic of South Africa Energy Department, p 27 [11]

Figure 17 South African annual domestic and export coal prices

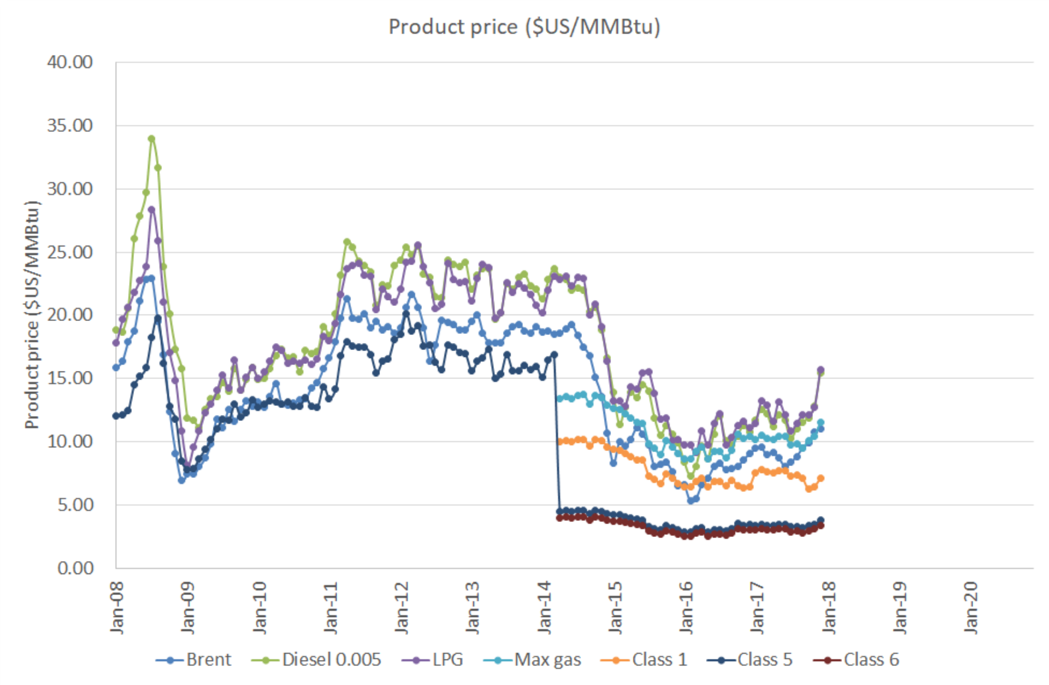


Source: "South African Energy Price Statistics – 2018", Republic of South Africa Energy Department, p 51 [11]

10.4 Natural gas prices

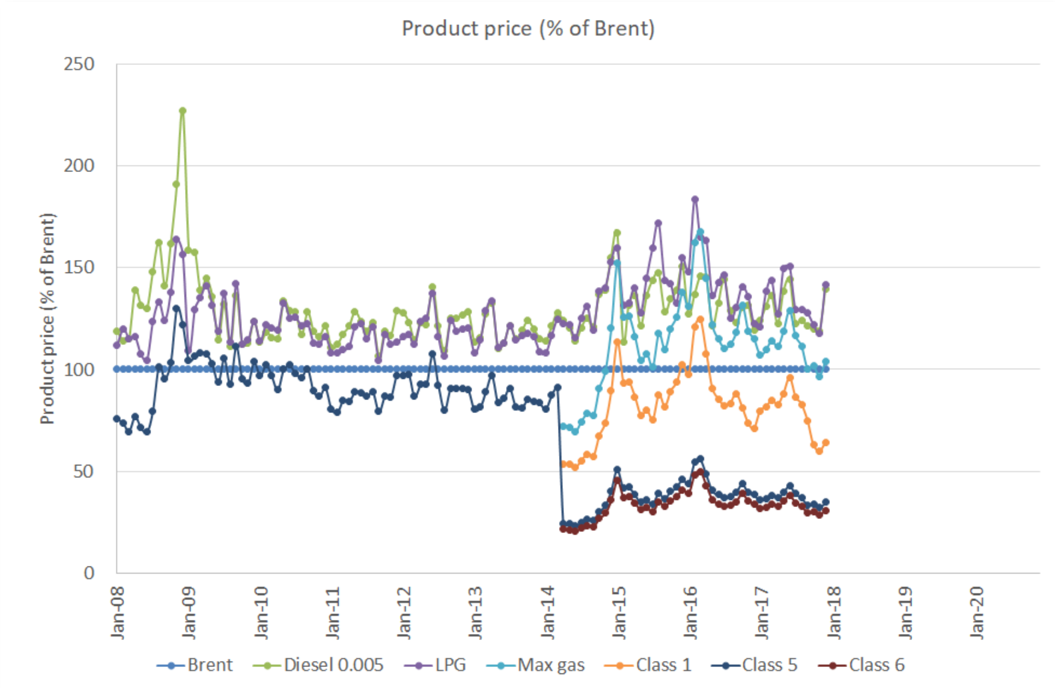
Natural gas prices and selected marker prices (Brent, diesel) are shown in Figure 18 and Figure 19 below, in $US/MMBtu and as a % of the Brent price respectively (with Brent used as a proxy for global energy prices). Prices are based on government data are available from 2008 until December 2017.

Figure 18 Historical South African product prices ($US/MMBtu)



Source: K1 Capital analysis of South African Dept of Energy [9] and NERSA [11] data.

Figure 19 Historical South African product prices (% of Brent)



Source: K1 Capital analysis of South African Dept of Energy [11] and NERSA [20] data

The reporting of South African gas pricing categories changed in April 2014, complicating time series analysis. The price for 0.4+ PJ/yr consumers prior to April 2014 can be roughly linked to the Class 5 (0.4-4 PJ/yr) category from April 2014 onwards. The step change in the Class 5 gas price series in April 2014, shown above, corresponds to the introduction of the NERSA pricing methodology. The difference appears to be related to the exclusion of the gas trading margin and transmission tariffs from the reported gas energy prices, based on our examination of NERSA's assessment for a FY18 CNG pricing determination [20].

Maximum gas prices over the April 2014 to December 2017 period are summarized in Table 17 below.

Table 17 South African energy pricing (April 2014 to December 2017 averages)

Product	$US/MMBtu	% Brent	Comment
Brent	10.20	100	$US60.19/bbl. FOB
Diesel 0.005% Sulphur	13.29	131	$US77.59/bbl. Base fuel price.
Max gas energy price	10.80	113	
Class 1 price	7.85	82	
Class 5 price (0.4-4 PJ/y)	3.61	37	
Class 6 price (>4 PJ/yr)	3.21	33	~30% of Max gas energy price

Source: K1 Capital analysis of Department of Energy data [11]
$US/MMBtu and % Brent values are averaged over 45 monthly periods; the % Brent based on 45 monthly results is not necessarily the same as the % Brent calculated from the 45-month average values.

The Maximum and Class 6 prices reported by the Department of Energy appear to be prior to the inclusion of gas trading margins, transmission tariffs, distribution tariffs (for smaller distribution customers) and storage tariffs. The gas trading margins and transmission tariffs for CNG for FY17 were ~ZAR97/GJ and ~ZAR50/GJ respectively, equivalent to $US7.95/MMBtu and ~$US4.00/MMBtu [20]. It is not clear how much of the gas trading margin is available for gas producers (versus gas marketers).

Assuming the gas price to Brent relationships continue and gas producers achieve half the gas trading margin we estimate the wholesale gas price for producers to average ~$US7.00/MMBtu ($US2.95/MMBtu @ 33% of $US52/bbl real Brent + $US4.00/MMBtu trading margin).

Renergen indicates gas (possibly pipeline gas) is sold at "low pressure" at ZAR 120/GJ (~$US10/GJ) and that LPG is sold at approximately diesel parity [21]. It is not clear if the natural gas price refers to the maximum price. Renergen reports CNG and LNG for diesel replacement are sold at a discount to the SA diesel price to incentivize fuel switching.

10.5 South African petroleum sector

Natural gas is regulated by the Department of Minerals and Energy. The "National Gas Infrastructure Development Plan" provides the framework for the development of gas market infrastructure. Key bodies involved in the natural gas industry and the petroleum permit regime are listed in the tables below.

Table 18 South African petroleum sector bodies

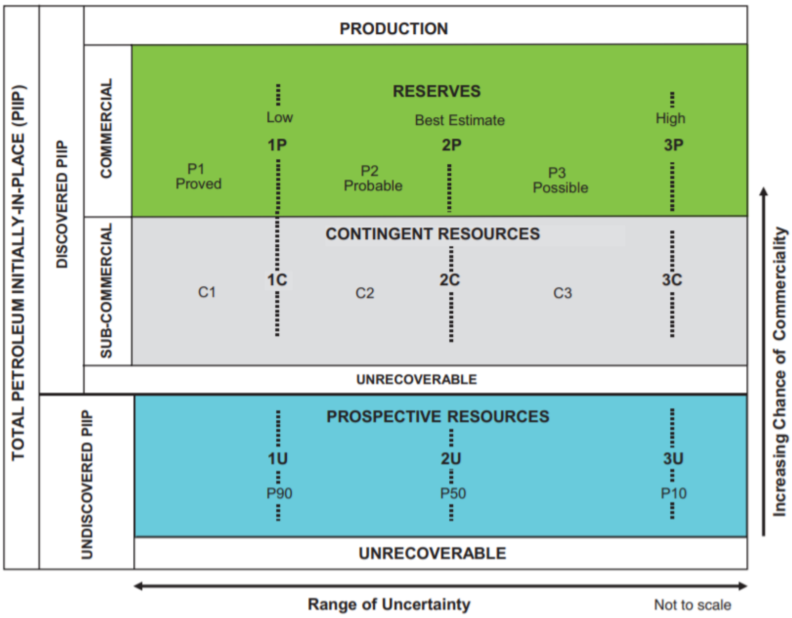
Body	Comment
iGas	Official state agency for the development of the hydrocarbon gas industry
NERSA	National Energy Regulator of South Africa. The primary industry regulator for oil, gas, coal and electricity.
PetroSA	National Petroleum, Gas and Oil Corporation of South Africa South African national oil company. Engaged in domestic and international oil and gas E&P and the production and marketing of synthetic fuels and petrochemicals (Mosel Bay).
PASA	Petroleum Agency of South Africa Promotes and monitors domestic exploration and exploitation (onshore and offshore)
Petronet	Owns, operates, manages and maintains a network of ~3,000 km of high-pressure petroleum and gas pipelines, on behalf of the South African government.
Sasol	Publicly listed integrated oil and gas company with substantial chemical interests. ▪ CTL/GTL: coal to synthetic fuels and chemicals in South Africa (Secunda); natural gas to liquids in Qatar (Doha). ▪ Petrochemicals: manufacturing and marketing in Europe, Asia and the Americas ▪ Oil: exploration, production and refined product marketing in southern Africa. ▪ Natural gas: supplies Mozambique gas to customers and own use in South Africa. ▪ Co-owns and operates the ROMPCO gas pipeline between Mozambique and South Africa.

Table 19 South African petroleum permits

Permit	Comment
Reconnaissance Permit	Allows a company to undertake a reconnaissance survey, e.g. a seismic or geochemistry survey. Valid for 12 months, is not exclusive and is not transferable or renewable.
Technical Cooperation Permit	Allows exclusive desk-top study of an area, utilizing existing data. Valid for 12 months and is not transferable or renewable. Provides exclusive right to apply for an Exploration Right
Exploration Right	Exclusive right to explore for petroleum and produce for testing. The right is transferable and contains a "use it or lose it" clause. The initial period is 3 years followed by three renewal periods of 2 years each (total of 9 years).
Production right	Exclusive right to produce petroleum. The right is transferable and may last for up to 30 years. It can be renewed for a further term.
BEE requirement	Foreign investment within South Africa is affected by South Africa's Broad-Based Black Economic Empowerment Act (2003). BEE is a government program to increase the participation in the economy of historically disadvantaged South Africans. In practice, upstream oil and gas companies generally require participation by a BEE partner with ~26% or more equity in each project.

10.6 Petroleum reserves and resources classification

Figure 20 SPE-PRMS Classification



Reserves are commercially recoverable by the application of "projects" to known accumulations. (Hence discovered, recoverable, commercial and remaining).

Contingent resources are discovered but not commercial (e.g. no market, dependent upon technology, incomplete evaluation, legal title unclear, etc.)

Prospective resources are estimated recoverable amounts from undiscovered accumulations (i.e. exploration)

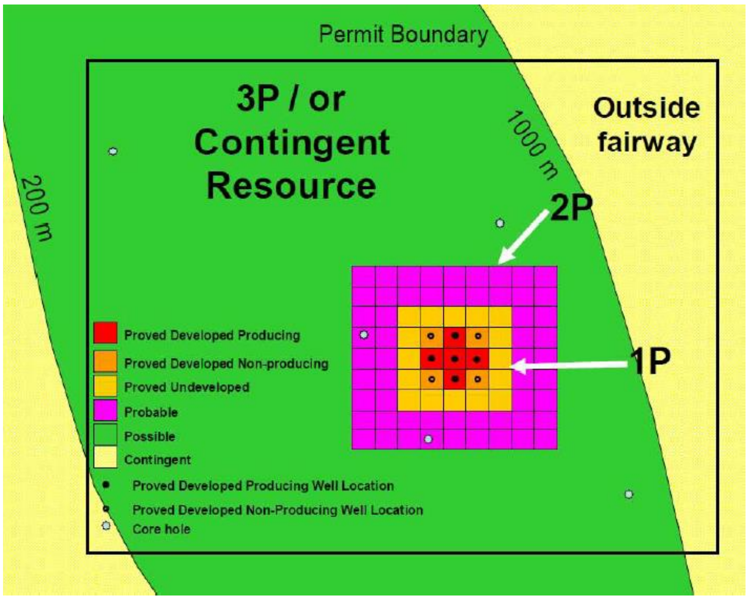
The relative uncertainty is designated by 1P/1C/1U (≥90%), 2P/2C/2C (≥50%) and 3P/3C/3U (≥10%) categories

Source: Guidelines for Application of the Petroleum Resources Management System, June 2018, [22]

CBM resource classification practice

CBM resource classification is commonly based on "well spacing" concepts. This approach assumes uncertainty increases as the distance to well control increases, resulting in a progression from Proved to Probable to Possible categories. Consequently, 1P and 2P reserves grow over time toward a 3P value (which may also increase as Contingent Resources are converted to Reserves). This produces a different maturation profile than for conventional petroleum, where the reserve classification is based on uncertainty and 1P and 3P levels trend towards the 2P value over time.

Figure 21 Reserve classification well spacing relationship



Proved Developed (PD): This applies to the nominal drainage area for producing or non-producing wells that are proven to have commercial quantities of recoverable gas. Well spacing varies depending on the region.

Proved Undeveloped (PUD): Typically one well spacing from PD locations (may be increased to two well spacings if the permeability is high and regional experience justifies good lateral continuity of the coals).

Probable Reserves (P2): Typically two well spacings from Proved locations.

Possible Reserves (P3): Typically two well spacings from Probable locations.

1P = PD+PUD; 2P = 1P + P2; 3P = 2P + P3

Source: Guidelines for Application of the Petroleum Resources Management System, November 2011, pp. 148-150
The 200 m and 1000 m depth contours represent the vertical limits of anticipated commercial production for this example.

10.7 Project assumptions

Table 20 General valuation assumptions

Item	Comment	Ref.
Methodology	Discounted cash flow (DCF) analysis. Monte Carlo simulation to quantify the range of share price outcomes, with probability distributions for key variables (e.g. reserves/resources, commodity prices, capex, opex, forex and exploration outcomes).	
Discount rate	Base discount rate of 10% (nominal basis) plus country risk premium Risk free rate (%) 0.9 US 10-year bond rate, per Bloomberg, 18 Nov 2020 Market risk premium (%) 6-8 Per Brierly & Myers, 5.0% per Duff and Phelps Beta 1.4 Per Duff & Phelps market cap correlation D/(D+E) (%) 20 Estimated oil & gas company long term average Debt premium (basis pts) 550 Per credit spreads, assuming B- rating Size premium (%) - Morningstar correlation => 7.3%	
Country risk	Discount rate premium, per Aswath Damodaran, New York University, based on bond premia and credit default spreads as proxies for country risk, multiplied by a political risk ratio off 33% (derived by K1 Capital from data per Bekaert et al). CRP Australia/South Africa = 0.0/3.7% * 33% = 0.0/1.2%, Jan 2020.	[1] [23]
Project risk factor	We apply a risk factor to each project to reflect our assessment of the technical and commercial maturity of the project: typical factors are 0-20% for exploration prospects, 20-60% for appraisal projects, 40-80% for development projects and 80-100% for production projects. Risk factors are relaxed as milestones are achieved.	
Forex	Spot USD: AUD = 0.71 per RBA. Long run USD: AUD = 0.70. 10-year average forward volatility based on historical analysis (-0.06, +0.09), per K1 Capital.	
Crude oil prices	We model oil prices by defining a base level guided by published forecasts and futures markets, and model uncertainty by applying a probability distribution derived from historical price volatility. We use Brent crude oil as our primary marker. Brent $US/bbl: 2021 ($48), 2022+ ($52), (real Dec-20 dollars, 2% US CPI)	
Gas prices	Sth Africa field gate gas price $US7.00/MMBtu (real $2020) at $US52/bbl real Brent	
Carbon price	Not modelled. $US40/t CO_2e typical.	
Inflation	per PwC Global Economy Watch projections. 2020/2021/2022-26. LT per K1 Capital Australia: 1.1/1.7/2.5/LT2.3%; US: 0.8/2.0/2.3/2.0%; Sth Africa: 2.8/3.6/5.1/4.5%	[3]
G&A expenses	Previous analysis by K1 Capital indicates production levels are a reasonable predictor of administration costs. We assume $2m/yr near term.	
Project delivery	Industry studies note cost and schedule overruns are common. We assume Bear, Base and Bull case overruns of 20%, 0% and 0% respectively.	
Operating performance	S&P assumes base case availability of 90% for refiners and 95% for LNG, with at least 5% reduction for downside cases. McKinsey notes availability of <75% to 97%, with an average of 85%. We assume Bear, Base and Bull case utilizations of 90%, 95% and 100% of design stream day respectively, to reflect planned and unplanned downtime. We assume Bear, Base and Bull case opex overruns of 20%, 0% and 0%.	
Operational incidents	The impact of minor incidents is covered in our operating performance assumptions and discount rate. We assume no major or catastrophic operational incidents.	

Source: K1 Capital analysis of company and public domain information

Table 21 Kinetiko project development assumptions

Item	Comment	Ref.
Project type	Onshore CBM and conventional gas appraisal, South Africa	
Permit / Location	ER38, 56, 270, 271, 272, Karoo Basin, between Johannesburg and Durban	
Lease expiry		
Status	Exploration/appraisal	
History	Kinetiko JV with Badimo Gas 2011, 21 core and pilot wells drilled 2011/2013	
Ownership	49% of Afro Energy (JV with Badimo Gas), operator (n.b. 50% voting interest)	
Partner(s)	51% Badimo Gas (BEE partner)	
Fiscal regime	Corporate income tax 28%, royalties 0.5-5% (deductible for CIT), accelerated depreciation & immediate write-off for exploration (total deduction of 200% of exploration and 150% of post-exploration capex), indefinite carryforward of losses (no ring fencing of fields), R&D incentive, fiscal stabilization contract	[24]
Reserves/Resources (gross)	1C/2C/3C (CBM/Conv): 2.2/4.8/9.3 tcf (gross), July 2020 1U/2U/3U (CBM/conv): 0.4/0.9/1.8 tcf (gross)	
Geology	Sub-bituminous Permian coals at 300-500m, plus adjacent sandstones Project area compartmentalized by dolerite sills and dykes, stratigraphic trapping.	
Drilling	~800 coal core holes (mainly 1980s), 21 CBM core holes 2011/2012, 8 single spot pilots 2012/13. 20-well pilot planned for 2021.	
Well performance	Type curves yet to be determined Conv+CBM: Spacing: 60 acres, EUR/well = 0.3 bcf, IP = 100 kscfd, well life ~21 years.	[8]
Reservoir drive	CBM: gas desorption Conv: gas expansion. Evidence of recharge.	
Development concept	Staged development: - Stage 1: 20-well pilot 2021 ER56; CNG offtake - Stage 2: ~300 well, 90 bcf, 12 TJ/d, 3rd party on-site power generation - Stage 3: ~3000+ well, 900 bcf, ~120 TJ/d, gas sales to power gen (~800 MW)	
Existing Infrastructure	23 PJ/yr (63 TJ/d) 600 km, 16” Lilly gas pipeline (Secunda to Durban) crosses permit. Potential conversion/co-firing of nearby power stations.	[25]
Capex	Stage 1: 20-well pilot: $US400k/well drilling/completion/gas gathering. Wells and $US10m gas processing, compression/CNG etc., funded by 3rd party. Stage 2 & 3: $US350k/well drilling/completion/gas gathering. Third party gas processing/compression.	
Production	20-well pilot: first production early 2021, at ~1.4 TJ/d. 4.8% internal gas use (compression, water pumping, etc.)	
Project life	40+ years	
Quality / Market	Dry gas	
Sales / Revenue	Can sell pilot gas under “sample gas production right” (500 MMscf/yr) for 2 years	
Opex	$US1.75k/mth/well $US0.50/GJ gas processing/compression $US0.10/bbl water	
Next steps	20-well pilot	
Generic risks	Resource quality, commodity prices, gas marketing, approvals process	
Specific risks	Well performance (EUR, IP, decline rate, water production)	

Source: K1 Capital analysis of company and public domain information

10.8 Project economics

Case: Kinetiko Energy Limited (KKO)	Units	Amersfoort - 2021 Pilot	Amersfoort - Stage 2	Amersfoort - Stage 3
nominal dollars unless otherwise noted				
Resource and production assumptions				
Resources (gross, since inception)	mmboe	1.0	15.2	152.8
Resources (gross, remaining)	mmboe	1.0	15.2	152.8
Total production (gross, remaining)	mmboe	1.0	15.2	152.8
Total production (net revenue interest)	mmboe	0.2	7.4	74.9
Net production share	%	24.5	49.0	49.0
% of current resources produced	%	94.0	99.8	100.0
First production	mmm-yy	Dec-21	Jun-23	Jun-26
Peak production	mmm-yy	Jun-23	Jun-28	Jun-31
Production ceases	mmm-yy	Jun-41	Jun-51	Jun-56
Time to peak production (from start-up)	years	1.5	5.0	5.0
Production life remaining	years	19.5	28.0	30.0
Development assumptions				
Number of wells drilled (gross)	-	28	300	3,014
Number of wells successful	-	20	300	3,014
Drilling success rate	%	71	100	100
EUR per successful well	mmboe	0.05	0.05	0.05
EUR per successful well	PJe	0.29	0.31	0.31
Peak rate per successful well	kboed	0.02	0.02	0.02
Peak rate per successful well	TJe/d	0.10	0.10	0.10
Peak production (6 mth avg)	kboed	0.3	2.0	20.1
Peak production (6 mth avg)	TJe/d	1.9	11.9	122.8
Effective decline rate (average)	%/yr	11.7	11.7	11.7
Well life	years	21.5	21.5	21.5
Well capex per successful well	M$A	0.5	0.5	0.5
Total capex (excluding restoration)	M$A	12	174	1,885
Future capex (excluding restoration)	M$A	10	174	1,885
Restoration capex (real $ value)	M$A	2	24	259
PV capex (including restoration)	M$A	10	91	685
NPV				
Discount rate (nominal)	%	11.2	11.2	11.2
Risk factor	%	80	60	40
Unrisked NPV (gross)	M$A	9	75	600
Unrisked NPV (net)	M$A	5	37	294
Risked NPV (net) (reporting currency)	M$A	4	22	118
Risked NPV (net) AUD	**M$A**	**4**	**22**	**118**
Performance measures				
IRR (after tax) gross since inception	%	15.6	36.6	39.2
IRR (after tax) gross incremental	%	36.1	36.6	39.2
IRR (after tax) attributable incremental	%	101.3	36.6	39.2
Profitability Index (=1+NPV/PV capex)	-	1.9	1.8	1.9
DCF payback period (from now)	years	3.5	6.5	9.5
NPV/well (unrisked)	M$A/well	0.43	0.25	0.20
NPV/resource (gross, unrisked)	**$A/boe**	**8.47**	**4.91**	**3.92**
NPV/resource (gross, unrisked)	**$A/GJ**	**1.38**	**0.80**	**0.64**
Cost structure (real Dec-20 $)				
Revenue	$A/GJ	9.41	9.44	9.44
Capex	$A/GJ	1.72	1.87	1.89
Cash opex	$A/GJ	3.01	2.63	2.61
Royalties & sev. taxes	$A/GJ	0.47	0.47	0.47
Income & resource taxes	$A/GJ	1.09	1.32	1.33
Total cost (inc. taxes)	$A/GJ	5.82	5.83	5.83
Net cash (after royalties, before tax)	$A/GJ	5.93	6.33	6.35
NPAT	$A/GJ	3.12	3.14	3.13
Cash margin	$boe	36.3	38.7	38.9
Net cash margin (AR,BT)	% revenue	63.0	67.1	67.3
Net profit margin (AR&T)	% revenue	33.1	33.3	33.2
NPV	% revenue	15.6	8.5	6.8
Royalties	% revenue	5.0	5.0	5.0
Taxes	% EBIT	25.9	29.7	29.8

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K1 Capital disclosures

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