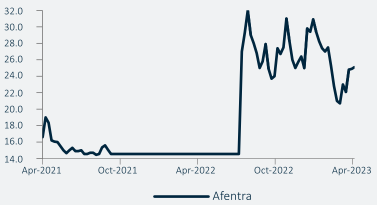
5 May 2023

Buy

Ticker	AET:AIM
Oil & Gas	
Shares in issue (m)	220.1
Next results	FY May
Price	**25.1p**
Target price	37.0p
Upside	47%
Market cap	**£55.2m**
Net debt/(cash)	-£21.6m
Other EV adjustments	£0.0m
Enterprise value	£33.6m

What's changed?	From	To
Adjusted EPS	-	-2.3
Target price	-	37.0

Share price performance



%	1M	3M	12M
Actual	4.1	-14.6	72.5

Company description

E&P company with a 'buy and build' strategy focused on Africa where management has extensive experience

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AFENTRA

Out of Africa

Afentra is on the cusp of completing its first two acquisitions, which will give it an attractive foothold in Angola, a large and mature hydrocarbon province with a highly supportive government that is actively encouraging new foreign investment. These acquisitions will deliver a material non-operated shallow water portfolio containing significant production enhancement, development and exploration opportunities. The producing fields are highly free-cash-generative and will provide a foundation for Afentra's experienced and ambitious management team to construct a significant African-focused independent E&P company, beginning in Angola, that can fill the void left behind by the retreating majors. Completion of the INA portion of the deal (expected) in May 2023, alongside the larger Sonangol stake in the coming months, will provide a launchpad for Afentra's ambitions and its share price. We initiate with a Buy rating and 37p/sh price target.

- **Out of Africa.** Africa is seeing a surge in mature upstream assets being sold by IOCs as they 'core up' portfolios and pursue emissions reduction targets. Afentra is specifically designed to pick up the pieces, with a particular focus on legacy production assets and proven discovered resources with material upside. Led by former Tullow CEO Paul McDade, it is on the cusp of gaining a strong foothold in Angola's IOC/NOC-dominated offshore and a solid platform for its larger African ambitions.
- **Deal completions fast approaching.** Afentra secured its first acquisitions in 2022; two back-to-back deals in Angola with Sonangol and INA for an initial US$102.5m in aggregate. This includes a 24% interest in shallow water producing Block 3/05, up to 5.33% of near-production Block 3/05A and 40% in prospective deepwater exploration Block 23 containing an existing discovery. The INA deal is expected to conclude in early May and, despite delays, completion of the Sonangol deal is now expected by end Q2 2023, contingent upon a licence extension and Ministerial approval of the deal. Recent progress towards the INA completion/licence extension, alongside a mature upstream M&A market and a government keen to attract foreign investment gives us confidence in this timeline.
- **Material producing assets.** The main asset being acquired is a 24% interest in shallow water Block 3/05, containing 8 producing fields and extensive infrastructure. The fields have estimated oil in place of 3.2 Bbbls, of which 43% has been recovered. Recovery rates in this region can exceed 50%, and gross 2P reserves of 115 mmbbl and gross 2C resources of 42 mmbbl have been independently identified, with significant upgrade potential. Gross 2022 production averaged 18.6 kbopd.
- **Strong FCF potential.** The acquisitions are expected to be immediately accretive, have a low oil price break-even and payback in under three years. We estimate a risked NAV for Afentra of 37p/sh at US$70/bbl Brent. Assuming mid-year completion, we forecast 2023 EBITDA of US$21m, rising to US$34m in 2024 and over US$70m in 2025. At our 37p/sh valuation, Afentra would trade on an EV/EBITDA multiple of 2.6x in 2024 and 1.2x in 2025. We estimate FCF of US$23m p.a. over the next five years at US$70/bbl Brent, an average FCF yield of 34% p.a., albeit this is back-end loaded.

Key estimates		**2020A**	**2021A**	**2022E**	**2023E**	**2024E**
Year end:		**Dec**	**Dec**	**Dec**	**Dec**	**Dec**
Revenue	$m	0.0	0.0	0.0	49.0	86.5
Adj EBITDA	$m	-2.0	-4.7	-4.9	20.9	34.4
Adj EBIT	$m	-2.2	-5.0	-5.1	17.1	19.8
Adj PBT	$m	-1.9	-5.0	-5.0	15.2	14.8
Adj EPS	c	-0.9	-2.3	-2.3	5.3	4.0
DPS	c	0.0	0.0	0.0	0.0	0.0
Key valuation metrics						
EV/sales	x	n/m	n/m	n/m	0.9	0.5
EV/EBIT (adj)	x	-19.4	-8.5	-8.3	2.5	2.1
P/E (adj)	x	-36.3	-13.9	-13.7	5.9	7.9
Dividend yield	%	0.0%	0.0%	0.0%	0.0%	0.0%
Free cash yield	%	-3.3%	-6.8%	-6.9%	5.6%	-10.7%

Income statement		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Sales	$m	0.0	0.0	49.0	86.5
Gross profit	$m	0.0	0.0	26.4	39.9
EBITDA (adjusted)	$m	-4.7	-4.9	20.9	34.4
EBIT (adjusted)	**$m**	**-5.0**	**-5.1**	**17.1**	**19.8**
Associates/other	$m	0.0	0.0	0.0	0.0
Net interest	$m	-0.0	0.1	-2.0	-5.0
PBT (adjusted)	**$m**	**-5.0**	**-5.0**	**15.2**	**14.8**
Total adjustments	$m	0.0	0.0	0.0	0.0
PBT (stated)	$m	-5.0	-5.0	15.2	14.8
Tax charge	$m	0.0	0.0	-3.4	-6.0
Minorities/Disc ops	$m	0.0	0.0	0.0	0.0
Reported earnings	$m	-5.0	-5.0	11.8	8.8
Adjusted earnings	**$m**	**-5.0**	**-5.0**	**11.8**	**8.8**
Shares in issue (year end)	m	220.1	220.1	220.1	220.1
EPS (stated)	c	-2.3	-2.3	5.3	4.0
EPS (adjusted, fully diluted)	**c**	**-2.3**	**-2.3**	**5.3**	**4.0**
DPS	**c**	**0.0**	**0.0**	**0.0**	**0.0**

Growth analysis		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Sales growth	%	n/m	n/m	n/m	76.6%
EBITDA growth	%	-139.4%	-2.5%	529.8%	64.6%
EBIT growth	%	-129.2%	-2.3%	436.2%	15.5%
PBT growth	%	-161.9%	-1.1%	400.6%	-2.4%
EPS growth	%	-161.9%	-1.1%	333.2%	-25.3%
DPS growth	%	n/m	n/m	n/m	n/m

Profitability analysis		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Gross margin	%	n/m	n/m	53.9%	46.2%
EBITDA margin	%	n/m	n/m	42.6%	39.7%
EBIT margin	%	n/m	n/m	35.0%	22.9%
PBT margin	%	n/m	n/m	31.0%	17.1%
Net margin	%	n/m	n/m	24.0%	10.2%

Cash flow		**2021A**	**2022E**	**2023E**	**2024E**
Year end:		**Dec**	**Dec**	**Dec**	**Dec**
EBITDA	$m	-4.7	-4.9	20.9	34.4
Net change in working capital	$m	0.2	0.3	-1.1	-2.1
Other operating items	$m				
Cash flow from op. activities	**$m**	**-4.5**	**-4.5**	**16.4**	**26.2**
Cash interest	$m	0.0	-0.1	-2.6	-5.3
Cash tax	$m	0.0	0.0	0.0	0.0
Capex	$m	-0.2	-0.2	-10.0	-28.4
Other items	$m	0.0	0.0	0.0	0.0
Free cash flow	**$m**	**-4.7**	**-4.8**	**3.9**	**-7.4**
Acquisitions / disposals	$m	0.0	0.0	-53.5	-7.0
Dividends	$m	0.0	0.0	0.0	0.0
Shares issued	$m	0.0	0.0	0.0	0.0
Other	$m	-0.3	-8.1	40.4	2.0
Net change in cash flow	**$m**	**-5.0**	**-12.9**	**-9.2**	**-12.4**
Opening net cash (debt)	$m	42.7	37.7	24.9	-24.4
Closing net cash (debt)	**$m**	**37.7**	**24.9**	**-24.4**	**-38.7**

Cash flow analysis		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Cash conv'n (op cash / EBITDA)	%	n/m	n/m	78.6%	76.3%
Cash conv'n (FCF / EBITDA)	%	99.3%	98.8%	18.6%	-21.6%
U/lying FCF (capex = depn)	$m	-4.7			
Cash quality (u/l FCF / adj earn)	%	95.0%			
Investment rate (capex / depn)	x	0.9	0.6	2.7	1.9
Interest cash cover	x	n/a	n/a	6.4	5.0
Dividend cash cover	x	n/a	n/a	n/m	n/a

Working capital analysis		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Net working capital / sales	%	n/m	n/m	-1.1%	-0.6%
Net working capital / sales	days	n/m	n/m	-4	-2
Inventory (days)	days	n/m	n/m	0	0
Receivables (days)	days	n/m	n/m	2	1
Payables (days)	days	n/m	n/m	6	4

Balance sheet		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Tangible fixed assets	$m	0.7	0.6	60.3	81.1
Goodwill & other intangibles	$m	21.3	21.3	21.3	21.3
Other non current assets	$m	0.0	0.0	0.0	0.0
Net working capital	$m	-0.2	-0.5	-0.5	-0.5
Other assets	$m	0.0	8.0	8.0	8.0
Other liabilities	$m	-0.6	-0.4	-0.4	-0.4
Gross cash & cash equivs	$m	37.7	24.9	15.6	3.3
Capital employed	**$m**	**58.9**	**53.8**	**104.3**	**112.7**
Gross debt	$m	0.0	0.0	40.0	42.0
Net pension liability	$m	0.0	0.0	0.0	0.0
Shareholders equity	$m	58.9	53.8	64.3	70.7
Minorities	$m	0.0	0.0	0.0	0.0
Capital employed	**$m**	**58.9**	**53.8**	**104.3**	**112.7**

Leverage analysis		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Net debt / equity	%	no debt	no debt	37.9%	54.7%
Net debt / EBITDA	x	n/a	n/a	1.2	1.1
Liabilities / capital employed	%	0.0%	0.0%	38.3%	37.3%

Capital efficiency & intrinsic value		2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec
Adjusted return on equity	%	-8.5%	-9.4%	18.3%	12.4%
RoCE (EBIT basis, pre-tax)	%	-8.5%	-9.5%	16.4%	17.6%
RoCE (u/lying FCF basis)	%	-8.1%			
NAV per share	c	26.8	24.5	29.2	32.1
NTA per share	c	17.1	14.8	19.5	22.4

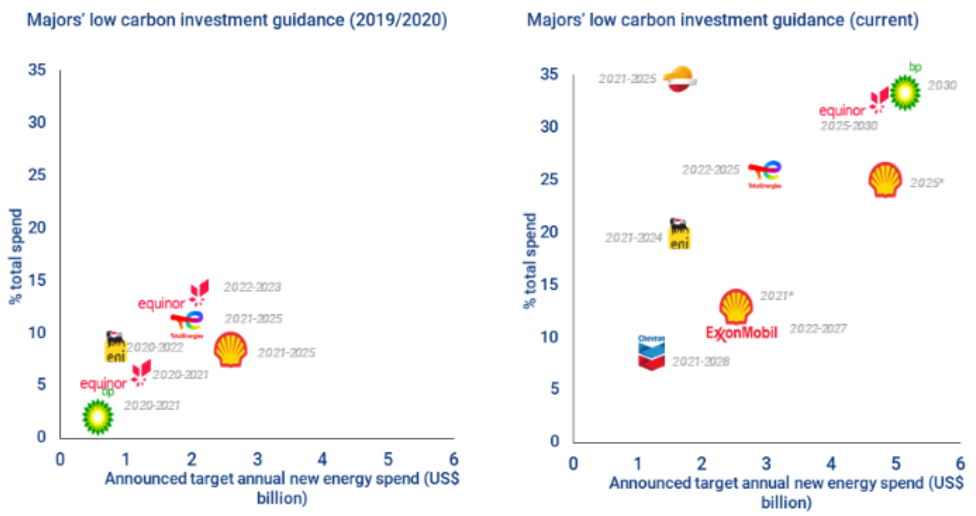
Out of Africa

Afentra is on the cusp of completing its first two acquisitions, which will give it an attractive foothold in Angola, a large and mature hydrocarbon province with a highly supportive government that is actively encouraging new foreign investment. These acquisitions will deliver a material non-operated shallow water portfolio containing significant production enhancement, development and exploration opportunities. The producing fields are highly free cash-generative and will provide a foundation for Afentra's experienced and ambitious management team to construct a significant African-focused independent E&P company, beginning in Angola, that can fill the void being left behind by the retreating majors. Completion of the INA portion of the deal (expected) in May 2023 alongside the larger Sonangol stake in the coming months will provide a launchpad for Afentra's ambitions and its share price. We initiate with a Buy rating and 37p/sh price target.

Afentra looking to capitalise on the majors' retreat

The energy transition is reshaping the structure of the global oil industry. Large IOCs' environmental credentials are under the investor microscope, which has resulted in companies overhauling strategies to meet the challenges of the energy transition, reducing exposure to oil and gas production while rapidly accelerating investment in clean energy to deliver on their net-zero emissions targets. This saw the majors double their planned low carbon investments over the past two years (Figure 1). While BP has recently moderated the pace of its transition away from oil and gas to clean energy production, and Shell may be considering the same, the trend is inexorable.

Figure 1: Big Oil is rapidly accelerating low carbon investment



Source: Wood Mackenzie

To advance this strategy, IOCs are highgrading their portfolios to focus on the most profitable and significant core oil and gas operations, while paring back in mature/high-cost/high-emission regions. According to Wood Mackenzie, this has involved the majors alone selling over US$30bn of assets since 2018.

This trend has been going on for over 20 years in the North Sea but is still in its infancy in Africa. Nevertheless, activity is accelerating, with more than US$20bn worth of upstream M&A deals announced last year in Africa, 3x the value in 2021 and 4x 2020. Data from Rystad Energy shows that in the first nine months of 2022, 3bn boe of resources were traded in Africa, up 25% on the prior year, with almost two-thirds of this relating to producing assets.

Consolidation among Africa-focused E&P companies in the pursuit of economies of scale and cost synergies has been evident, but there has also been a significant rise in mature asset sales/country exits by IOCs and NOCs.

In Africa, since the start of the pandemic:

- Shell has sold its interest in onshore block OML 42 to Nigerian local company, Neconde Energy;
- Shell, Eni and Total disposed of their interests in OML 17 onshore Nigeria to TNOG Oil & Gas;
- Petronas sold its interest in the Chinguetti offshore oil field in Mauritania to Chinguetti Petroleum;
- Total disposed its onshore producing assets in Gabon to Perenco;
- Shell sold its upstream assets in Egypt to Cairn Energy and Cheiron Petroleum;
- Total sold its Block 14/14k mature producing assets in Angola to Somoil;
- Galp sold its Angolan upstream oil business to Somoil;
- Thai state-owned PTTEP exited Angola, also selling its last asset to Somoil;
- Sonangol is selling its interests in Angola Blocks 18, 27 and 31 to a consortium of Tende Energy (formerly Sirius Petroleum) and Somoil;
- ExxonMobil is selling its Nigerian shallower water business to Seplat;
- ExxonMobil and Petronas announced the sale of their Chad upstream and midstream assets to Savannah Energy, although both deals have subsequently fallen through; and
- Petronas is selling its Southern Sudan upstream business to Savannah Energy.

Afentra believes there is no shortage of compelling acquisition opportunities still to pursue in the more mature markets of West Africa, with limited competition. Financing is available too for credible management teams with a clear plan to add value through asset performance enhancements, notably via the traders and also banks (although a smaller pool than before) and the Nordic bond market depending on deal quantum.

In another sign of the maturing nature of Angola's upstream, BP and Eni combined their Angolan assets into a 50/50 JV last summer, creating Angola's largest independent oil and gas producer, Azule Energy, with ~200 kboepd of production and 2 Bbbls of resources.

This enlarged entity is expected to unlock significant cost savings from more efficient operations while allowing the new company to reinvest within Angola – capital that might well have gone elsewhere under BP/Eni's competitive global capital allocation process. BP adopted a similar strategy in Norway, another mature region, combining its assets with DNO to create AkerBP.

Also noteworthy is the fact that only two of the eight offshore exploration blocks in the Lower Congo and Kwanza Basins offered in the 2022 licensing round attracted any interest from the majors, despite BP, Chevron, Eni, ExxonMobil and Total still having a significant production presence in the country, although mainly in the larger scale deepwater – leaving a void in the still material shallow water and onshore marginal fields.

Instead, the majors are focusing more on frontier exploration in emerging areas such as offshore Namibia, where TOTAL's Venus and Shell's Graff, La Rona and Jonker discoveries have driven considerable excitement. Such successes help to generate interest and demonstrate the potential that remains in Sub-Saharan Africa. However, it further draws the majors' attention and limited investment dollars away from their more mature regions in Africa towards frontier basins, as they look to repeat ExxonMobil's prolific success offshore Guyana.

As more deals emerge and this transition of ownership unfolds, it creates an opportunity for a new breed of independent oil companies to fill the void left behind. As has been witnessed in the North Sea since the 1990s, independent E&Ps are stepping in and acquiring producing asset packages at attractive prices. Typically, the assets are mature and in decline and have been starved of capital. Key to the long-term success of these transactions will be management's ability to inject fresh capital to reinvigorate assets that are typically much larger in scale when compared to the North Sea, for instance, and have near-term, low capex redevelopment potential.

Afentra is not the only company pursuing this strategy, but the trend is still in its early stages in Africa, so should have plenty of running room. Moreover, unlike the North Sea and US Gulf of Mexico, there are a limited number of companies competing for assets, with a notable absence of PE-backed players.

Afentra can thrive in this environment

This was the rationale behind the genesis of Afentra, established in May 2021 through a management and shareholder restructuring of Sterling Energy, an AIM-listed cash shell. The reverse was spearheaded by former senior Tullow Oil executives Paul McDade (ex-CEO/COO) and Ian Cloke (ex-EVP), who alongside Anastasia Deulina (former Head of Strategy, Planning and M&A) were seeking capital to launch the Afentra strategy.

This high-quality management team is a welcome addition to the AIM market as Afentra's CEO, COO and CFO, respectively. They have an extensive rolodex, strong operating experience and are highly respected in West Africa from their Tullow days – ideal credentials for the changing of the guard taking place in a maturing African oil and gas landscape.

Afentra's strategy is to pursue scale through implementation of a buy and build model, positioning itself as a trusted partner of divesting IOCs and host governments to construct a portfolio of assets that can deliver strong growth and deliver value for all stakeholders.

Afentra targets producing assets and discovered resources (with near-term development opportunity) in Africa where management has extensive knowledge, experience and networks. The investment criteria for these target naturally favour West African upstream markets: value accretive, proven reserves with overlooked potential and a robust cash flow profile. Afentra intends to leverage its deep operational experience to enhance production, reduce operating costs and improve environmental performance.

In today's climate-focused environment, companies filling the void need to demonstrate not only appropriate operating capability, but also a commitment to strong environmental stewardship. In such times of intense scrutiny, a social licence to operate is a key requirement for transaction counterparties, host governments and investors alike, and a high priority for Afentra.

First acquisitions secured

Around a year after it was formed, Afentra announced its first acquisitions with two back-to-back Angolan deals in 2022 with Sonangol and INA for an aggregate initial consideration of US$102.5m, which rises to US$163.5m if all contingent payments are included.

The transactions include a 24% non-operated interest in shallow water producing Block 3/05, up to 5.33% of the surrounding development Block 3/05A and 40% in prospective deepwater exploration Block 23, which includes an existing pre-salt oil discovery and has no capital commitments.

The Sonangol transaction is subject to outstanding conditions precedent (CP) including Ministerial approval and extension of the licence. The current Block 3/05 licence expires in 2025 and the JV partners are close to finalising negotiations to extend the PSA until the end of 2040, while it is anticipated that the newly negotiated fiscal terms will be improved. The INA transaction on the other hand did not include the Block 3/05 licence extension as a CP – instead Afentra will pay a contingent payment of US$10m upon granting of the licence extension.

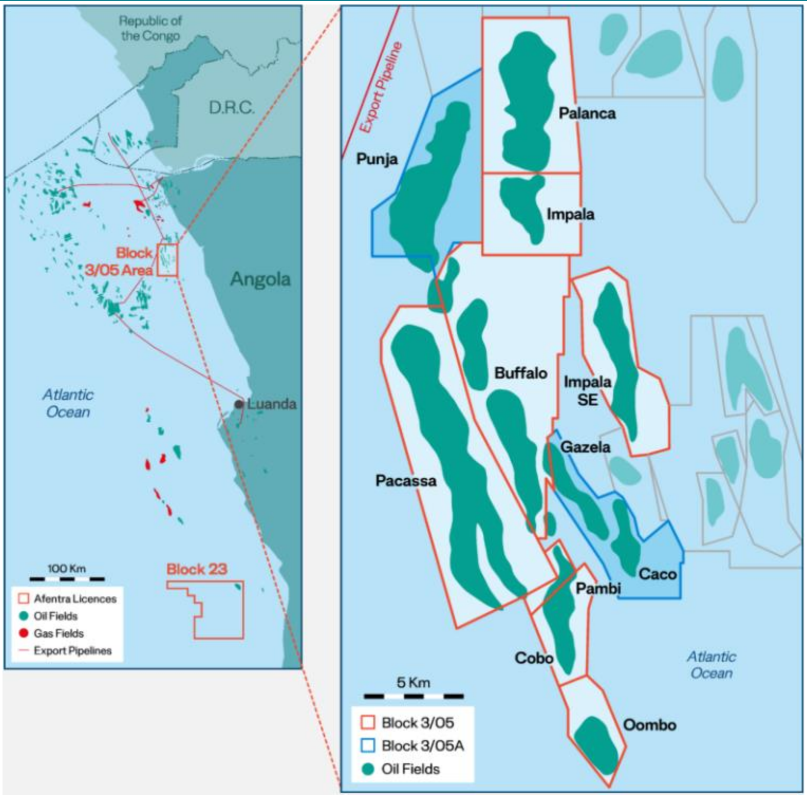
Deals approaching completion

The INA acquisition received Ministerial approval in January, and Afentra is now working with INA to finalise the formal completion, expected in early May 2023. This is encouraging for the Sonangol transaction where, despite delays, completion of the Sonangol deal is now expected by 30 June 2023, contingent upon a licence extension and Ministerial approval of the transaction.

For the licence extension, it is highly encouraging that after an extended period of negotiation between the licence partners and the regulator, ANPG, an acceptable set of enhanced fiscal terms are now on the table for the partners to accept (our modelling is based on the old terms), which would then prompt ANPG to obtain ministerial approval for the extension.

These recent updates combined with the encouraging Angolan market backdrop (an active upstream M&A market with a government keen to accelerate reform in the local oil and gas sector) gives us confidence these deal timelines can be achieved and that Angola can be an attractive jurisdiction for Afentra to establish its business.

Figure 2: Afentra licence acquisitions



Source: Afentra

Extensive asset with significant upside potential

Net 2P + 2C resources of 38 mmbbls and production of ~4,500 bopd

Block 3/05 achieved first oil in 1985 and contains eight producing fields with extensive infrastructure, which helps to provide Afentra with a “portfolio effect”. The fields held estimated oil initially in place (OIIP) of ~3.2 Bbbls with 1.3 Bbbls recovered to the end of March 2022. Production in 2022 averaged 18.6 kbopd, down from a peak of ~200 kbpd in the late nineties. Gross remaining 2P reserves are estimated at 115 mmbbl (net 27.7 mmbbl) plus gross 2C contingent resources of 42 mmbbl (net 10 mmbbl) have been identified with significant potential for future upgrades.

Herein lies the opportunity for Afentra and the key rationale for the acquisition. This is a material shallow water, long life, low decline asset with extensive infrastructure covering eight producing fields. There are multiple low-cost opportunities to increase future production. Well reactivation and the resumption of infill drilling and water injection programmes offers the potential to reinvigorate these mature fields, taking advantage of the extensive but significantly underutilised infrastructure already in place across Block 3/05.

Financing in place

The acquisitions will be financed through cash on the balance sheet and agreed RBL and revolving working capital facilities with Trafigura:

- A 5-year RBL facility of up to US$110m with US$75m available to finance the Sonangol and INA transactions. Incurs interest of 8% over 3-month SOFR (currently 4.87%).
- A 5-yr revolving working capital facility of up to US$30m for financing between crude offtakes, repayable with the proceeds from each lifting. Incurs interest of 4.75% over 1-month SOFR.

In addition to financing, Trafigura will also market Afentra's crude oil entitlement from these acquisitions under an offtake agreement. Hedging of a portion of future production is expected to manage the price risk on crude liftings.

Delay to close has no financial impact

As with most production deals, the transactions include a mechanism to adjust for cash flow generation between the effective dates (Sonangol: 20 April 2022, INA: 30 September 2021) and completion. So, despite an initial aggregate cash acquisition price of US$102.5m before future contingent payments, we estimate the effective date adjustment mechanism will reduce Afentra's net cash outlay to ~US$50m, assuming completion at the end of June. This will reduce the amount of RBL drawdown and cash resources required for the transactions, preserving Afentra's financial resources for future growth investments.

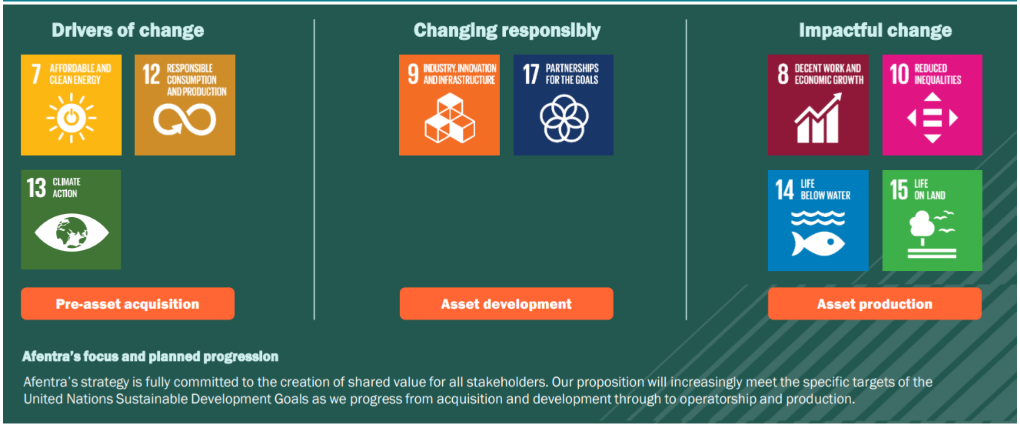
Attractive entry price and deal economics

These deals provide an attractive low-cost entry point for Afentra into a material hydrocarbon province. The initial acquisition cost for the combined 24% interest in Block 3/05 is just US$3.6/2P bbl – Afentra's peers trade at an average of US$5.5/bbl – which rises to a still competitive US$5/bbl if future contingent payments are included.

The acquisitions are expected to be immediately cash flow generative and value accretive post-completion. They have a low break-even oil price (<US$40/bbl), deliver average free cashflow (net to Afentra at the asset level) of ~US$25m p.a. over the next five years at US$70/bbl Brent and payback in less than three years at ~US$75/bbl based on 2P production alone.

The assets also provide scope for positive broad-based ESG impact from emissions reduction (notably via reduced gas flaring, in-line with Angola's Zero Routine Flaring by 2030 initiative), gas utilisation opportunities and positive socio-economic impacts. Afentra intends to work alongside operator Sonangol to support its energy transition strategy, which is closely aligned with Afentra's ESG agenda.

Figure 3: How Afentra's strategy aligns with UN SDGs



Source: Afentra

Valuation and estimates

There is an old adage in the oil industry that 'big fields get bigger'. With an estimated 3.2 bn bbls of oil initially in place on Block 3/05, this asset certainly falls into this category. Cumulative production to date has been over 1.3bn bbls, a recovery factor of 43%. Regionally, recovery rates of over 50% are not uncommon, and with no new drilling on the asset since 2005 and half the well stock inactive, there are plenty of 'low hanging' production-enhancement opportunities to pursue.

We have used the independent CPR on Block 3/05 effective from 1 April 2022 to value the acquired assets. This estimated remaining gross 2P reserves of 115 mmbbl (net 27.7 mmbbl), plus gross 2C contingent resources of 42 mmbbl (net 10 mmbbl) with significant potential for future upgrades. Several projects are planned across the eight fields to both sustain and grow production.

We estimate a risked NAV for Afentra's net 2P reserves and 2C contingent resources of 37p/sh at US$70/bbl Brent, discounted at 10% to 1 January 2023. Block 3/05 makes up the lion's share of this risked NAV, which is comprised of a Core NAV of 24p/sh including the 2P reserves, plus a 13p/sh valuation of the 2C contingent resources.

Figure 4: NAV sensitivity (p/sh)

	Brent oil price (US$/bbl)				
Discount rate	50	60	70	80	90
8%	16.7	31.4	41.5	51.0	60.1
10%	13.6	27.6	37.0	45.6	53.8
12%	11.1	24.4	33.1	41.1	48.5
15%	7.9	20.4	28.4	35.5	42.1

Source: finnCap

Figure 5: Afentra net asset value

Net Asset Valuation	W.I. reserves mmboe	NPV/bbl US$/boe	Unrisked NPV US$m	Unrisked NPV p/sh	Geological CoS	Commercial CoS	Dry hole cost US$m	Risked NPV US$m	Risked NPV p/sh
Net cash / (debt)			28.9	10.5				28.9	10.5
G&A costs (3 years)			-16.5	-6.0				-16.5	-6.0
Options			0.0	0.0				0.0	0.0
Angola acquisitions - initial consideration			-102.5	-37.3				-102.5	-37.3
NPV of contingent payments			-35.7	-13.0				-35.7	-13.0
Acquisitions CF completion adjustment			49.0	17.8				49.0	17.8
Angola Block 3/05 2P reserves	23.0	6.22	143.0	52.0	100%	100%		143.0	52.0
Core asset value:	**23.0**		**66.2**	**24.1**				**66.2**	**24.1**
Contingent resource:									
Angola Block 3/05 Impala South East infill	2.6	6.66	17.3	6.3	75%	100%	0.6	12.4	4.5
Angola Block 3/05 Impala infill	0.7	6.66	4.8	1.7	75%	100%	0.6	3.0	1.1
Angola Block 3/05 Palanca infill	1.1	6.66	7.0	2.6	75%	100%	0.6	4.7	1.7
Angola Block 3/05 Cobo workovers	0.3	6.66	1.8	0.6	75%	100%		1.3	0.5
Angola Block 3/05A 2C contingent resource	1.8	5.00	8.8	3.2	100%	75%		6.6	2.4
Angola Block 3/05 licence extension (2041 to 2045)	5.4	2.50	13.5	4.9	75%	75%		7.6	2.8
	11.8	**4.51**	**53.2**	**19.3**			**1.8**	**35.5**	**12.9**
Prospective resource:									
Angola Block 23 - Azul	12.0	5.00	60.0	21.8	50%	10%	5.0	0.0	0.0
	12.0		**60.0**	**21.8**			**5.0**	**0.0**	**0.0**
Total	**46.8**		**179.3**	**65.2**			**6.8**	**101.7**	**37.0**

Source: finnCap
Discounted to 1 January 2023 at 10%. Assumes long-term Brent oil price of US$70/bbl.

Figure 6, below, summarises our financial forecasts assuming full development of the 2P reserves and 2C contingent resources. This assumes a mid-2023 completion for both transactions.

Figure 6: Afentra estimate summary – 2P reserves+ 2C contingent resources development

FY estimates (to end-December)		2022E	2023E	2024E	2025E	2026E	2027E
Net entitlement production	kbopd	-	1.6	3.1	4.6	4.0	3.0
Brent Oil Price	US$/bbl	100.29	80.00	70.00	70.00	70.00	70.00
Revenue	**US$m**	**-**	**49.0**	**86.5**	**126.2**	**114.8**	**92.3**
Cost of sales	US$m	-	(22.6)	(46.6)	(47.5)	(42.1)	(41.6)
Gross Profit	**US$m**	**-**	**26.4**	**39.9**	**78.7**	**72.7**	**50.6**
Admin expenses	US$m	(5.1)	(5.5)	(5.6)	(5.6)	(5.7)	(5.7)
EBITDA	**US$m**	**(4.9)**	**20.9**	**34.4**	**73.1**	**67.0**	**44.9**
% margin	*%*		*43%*	*40%*	*58%*	*58%*	*49%*
DD&A	US$m	(0.2)	(3.7)	(14.6)	(21.6)	(19.1)	(14.1)
EBIT	**US$m**	**(5.1)**	**17.1**	**19.8**	**51.5**	**48.0**	**30.8**
Net finance expense	US$m	0.1	(2.0)	(5.0)	(4.5)	(2.5)	(0.6)
Profit/(loss) before tax	**US$m**	**(5.0)**	**15.2**	**14.8**	**47.0**	**45.4**	**30.2**
Income tax	US$m	-	(3.4)	(6.0)	(8.8)	(12.5)	(14.4)
Profit/(loss) after tax	**US$m**	**(5.0)**	**11.8**	**8.8**	**38.2**	**32.9**	**15.8**
Net cash flow from operations	**US$m**	**(4.5)**	**16.4**	**26.2**	**61.2**	**51.3**	**27.5**
Capex (incl. E&A)	US$m	(0.2)	(10.0)	(28.4)	(28.0)	-	-
Net acquisitions/contingent payments	US$m	-	(53.5)	(7.0)	(7.0)	(5.0)	(5.0)
Borrowing proceeds	US$m	-	40.0	2.0	(10.0)	(10.0)	(10.0)
Net change in cash	**US$m**	**(12.9)**	**(9.2)**	**(12.4)**	**11.4**	**33.5**	**11.6**
Yr-end cash (excluding restricted)	US$m	24.9	15.6	3.3	14.7	48.2	59.9
Yr-end debt	US$m	-	40.0	42.0	32.0	22.0	12.0
Net (debt)/cash	**US$m**	**(24.9)**	**24.4**	**38.7**	**17.3**	**(26.2)**	**(47.9)**

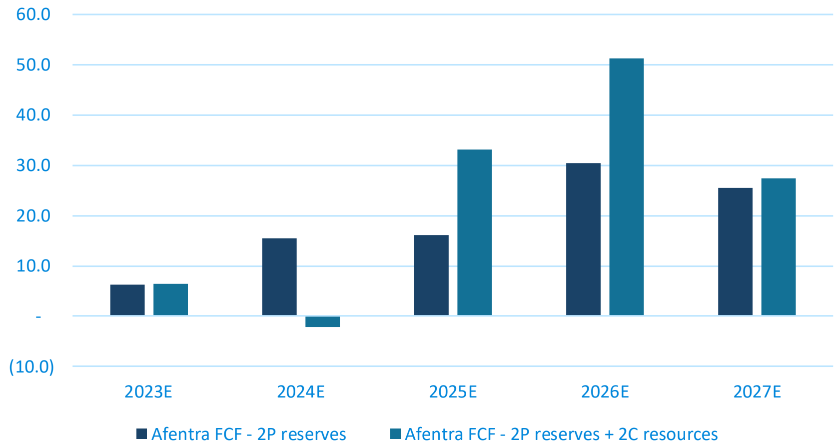
Source: finnCap

- We forecast 2023 revenue of US$49m assuming a mid-year completion and an average Brent oil price of US$80/bbl. In 2024, the first full year including the assets, this jumps to US$86m at US$70/bbl, rising further to US$126m in 2025 as planned investment delivers growth.
- EBITDA rises from US$21m in 2023, to US$34m in 2024, and over US$70m in 2025 at US$70/bbl Brent, representing EBITDA margins of 40-60%. At our 37p/sh target valuation, Afentra would trade on an EV/EBITDA multiple of 2.6x in 2024 and 1.2x in 2025.
- Despite the announced total acquisition price of US$102.5m, we expect Afentra will only pay ~US$50m at a mid-year completion after netting off its cash flow entitlement from the assets since the transaction effective dates.
- Up to 75%, US$40m, of this cost at completion can be funded using the Reserve Base Lending (RBL) debt facility with the remainder paid from existing cash resources.
- We estimate Afentra will need to invest US$66m between 2023 and 2025 to fund its share of the development of the 2P reserves and 2C contingent resources identified in the CPR.
- To fund this capex programme, we estimate Afentra will need to draw a further minimum of US$10m in 2024 from either the existing RBL or working capital facility.

Significant FCF potential

At the corporate level, we estimate the successful recovery of the 2P reserves and 2C resources can deliver Afentra US$23m p.a. of FCF over the next five years at US$70/bbl Brent, an average FCF yield of 34% p.a. However, noteworthy is the fact that this FCF profile is back-end loaded due to the initial capital investment required to develop the contingent resources.

Figure 7: Afentra corporate free cash flow (US$m)



Source: finnCap
FCF = Net CFFO minus capex and E&A spend

With these acquisitions, Afentra will take its first steps, establishing a foothold in Angola with long-life producing assets and material low-risk upside potential from short-cycle development opportunities. This provides a springboard for future growth and consolidation in Angola and across wider Africa. It will build on management's already strong credentials and provide additional credibility and resources for further growth investments.

Afentra is actively screening a pipeline of opportunities consistent with its strategy and aims to continue to build out its producing oil and gas portfolio over the coming months and years through further accretive acquisitions.

Transaction details

Sonangol acquisition a first step

In April 2022, less than 12 months after its launch, Afentra secured its first deal; signing an SPA with Sonangol P&P for non-operated interests in two licences offshore Angola in the Lower Congo Basin:

- 20% of producing Block 3/05 for US$80m plus up to US$50m in contingent payments over 10 years; and
- 40% of deepwater exploration and appraisal Block 23 for US$0.5m.

Angola is a major hydrocarbon province (currently the second largest oil producing country in Africa, marginally behind Nigeria) where the Afentra team have significant experience. It offers an attractive operating environment with stable (and improving) fiscal terms – attracting new investment – and a regulatory environment under a newly independent body, ANPG, assuming a role formerly undertaken by the NOC, Sonangol.

Block 3/05 is a mature, yet significant, mature shallow water producing licence with oil initially in place of 3.2 Bbbls, gross remaining 2P oil reserves of 115 mmbbls and average 2022 gross production of 18,660 bopd. The acquisition has an effective date of 20 April 2022.

INA acquisition extends position

This was quickly followed in July by an SPA with Croatian oil company Industrija Nafte (INA) to acquire of an additional 4% stake in Block 3/05 from, raising Afentra's combined stake to 24%. Afentra will pay an initial consideration of US$9m for the INA stake, plus an additional US$10m upon licence extension and a contingent consideration of up to US$6m over three years, subject to certain oil price hurdles and an annual cap of US$2m.

The INA acquisition also includes an up to 5.33% interest in Block 3/05A, adjacent to Block 3/05, for an initial consideration of US$3m plus an additional US$5m contingent payment upon successful future development of certain discoveries and oil price hurdles. This licence contains existing discovered and flow tested resources, providing tie-back opportunities to the Block 3/05 infrastructure. The INA acquisition has an effective date of 30 September 2021.

In aggregate, the total cost of the two acquisitions if all contingent payments are included is up to US$163.5m, as summarised in Figure 8, below.

Figure 8: Afentra acquisitions structure

Detailed Acquisition Structure		Sonangol Acquisition		INA Acquisition		Aggregate
		Block 3/05	Block 23	Block 3/05	Block 3/05A	-
Working Interest acquired		20%	40%	4%	5.33%[1]	-
Effective date		20-April-2022		30-September-2021		-
Initial Consideration	US$m	80	0.5	9	3	92.5
Licence extension payment	US$m		-	10[2]	-	10
Brent price linked contingent payment	US$m	Up to 50[3]	-	Up to 6[4]	-	Up to 56
Future developments linked contingent payment	US$m	-	-	-	5[5]	Up to 5
Total Consideration	**US$m**	**Up to 130**	**0.5**	**Up to 25**	**Up to 8**	**Up to 163.5**

Source: Afentra
2. Licence extension is a condition precedent to Sonangol deal completion.
3. Payable as US$5m p.a. over 10 years, subject to minimum Brent price of $65/bbl and minimum annual production of 15,000 bopd.
4. Payable as US$2m p.a. over 3 years, paid as a 30% share of revenue upside above a Brent price of $65/bbl.
5. Subject to successful development of existing discoveries and a minimum Brent price of $65/bbl.

The Sonangol transaction is subject to outstanding conditions precedent (CP) including Ministerial approval and extension of the licence. The current Block 3/05 licence expires in 2025 and the JV partners are close to finalising negotiations to extend the PSA until the end of 2040, while it is anticipated that the newly negotiated fiscal terms will be improved. The INA transaction on the other hand did not include the Block 3/05 licence extension as a CP – instead Afentra will pay a contingent payment of US$10m upon granting of the licence extension.

Deals approaching completion

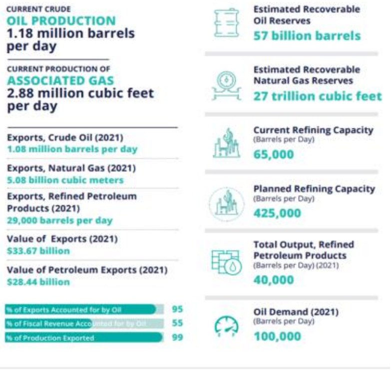
The INA acquisition received Ministerial approval in January, and Afentra is now working with INA to finalise the formal completion of the deal imminently. This is encouraging for the Sonangol transaction, where good progress has also been made.

Completion was initially expected in October 2022, but as we have seen elsewhere, completing upstream acquisitions in Africa can take time. It is not unusual for West African upstream deals to take up to a year or more. The Sonangol deal has the added complication that it also requires a licence extension, but Angola is a mature market that has seen multiple successful upstream transactions in the past couple of years. It also has a government that is keen to attract new foreign companies and investment.

Management now expects the deal to complete ahead of 30 June 2023, around a year after the deal was announced. This is consistent with the timelines for African upstream deal completions seen elsewhere, while imminent completion of the INA deal (anticipated early May) gives us confidence this guidance can be achieved.

A short history of the Angolan oil sector

Figure 9: Angola oil & gas metrics

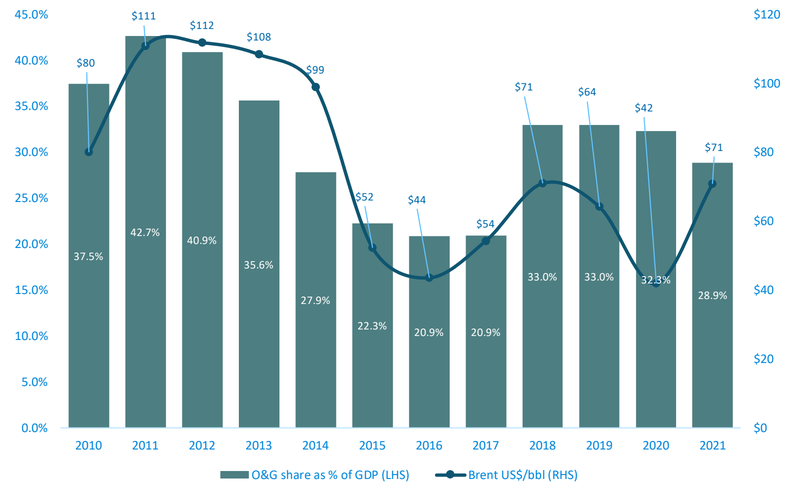


Source: Angola Energy Invest Report 2022

Angola remains one of the largest oil producers in Africa, producing around 1.1 mmbpd in the first two months of the year according to the EIA, which is largely exported to China. Proved reserves at the end of 2021 were 12.2 Bbbls, the third-largest reserve base in Africa behind Libya and Nigeria, and it has been a member of OPEC since 2007.

The oil and gas sector has played a pivotal role for the Angolan economy and still contributes significantly. The industry's contribution to the country's GDP has averaged over 30% in the past 12 years, peaking at close to 43% in 2011 and bringing in valuable foreign currency (US$). In 2021, the industry accounted for 29% of Angola's GDP and, with 95% exported, added over US$31bn to its balance of payments.

Figure 10: Oil & Gas industry share of Angola's Gross Domestic Product; 2010-2021

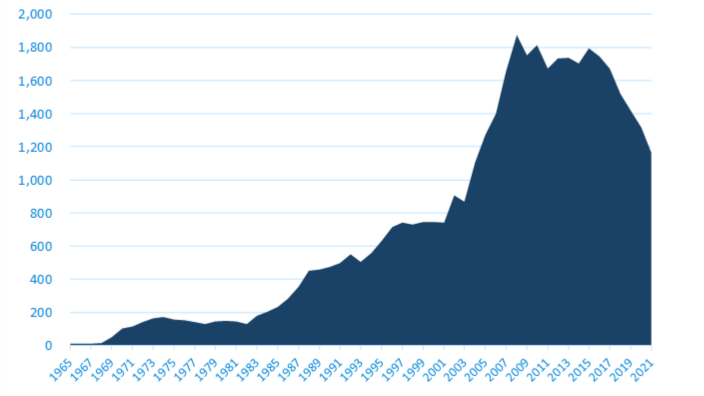


Source: Statista, FactSet

Oil exploration in Angola commenced in 1910 but it was not until 1955 that the country achieved first oil production from the onshore Kwanza basin. The Angolan oil industry has grown significantly since, despite the civil war that raged between 1975-2002, with the offshore focus of activity providing a natural buffer from the conflict.

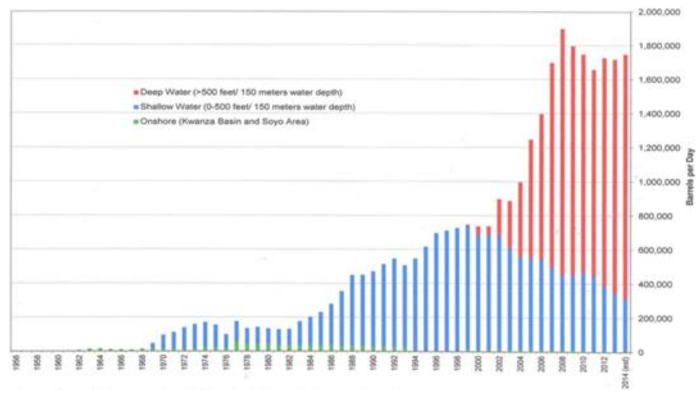
The opening up of Angola's shallow water in the late 1960s drove a significant period of volume growth, with output reaching ~750 kbpd late last century. Shallow water production has been in decline since but the opening up of deep-water exploration in the 1990s created a stampede of IOCs entering the country and has seen over 50 significant discoveries made since. This presaged another period of explosive volume growth that saw Angolan oil production peak at 2.03 mmbpd in 2010.

Figure 11: Angola oil production, 1965 - 2021



Source: BP Statistical Review

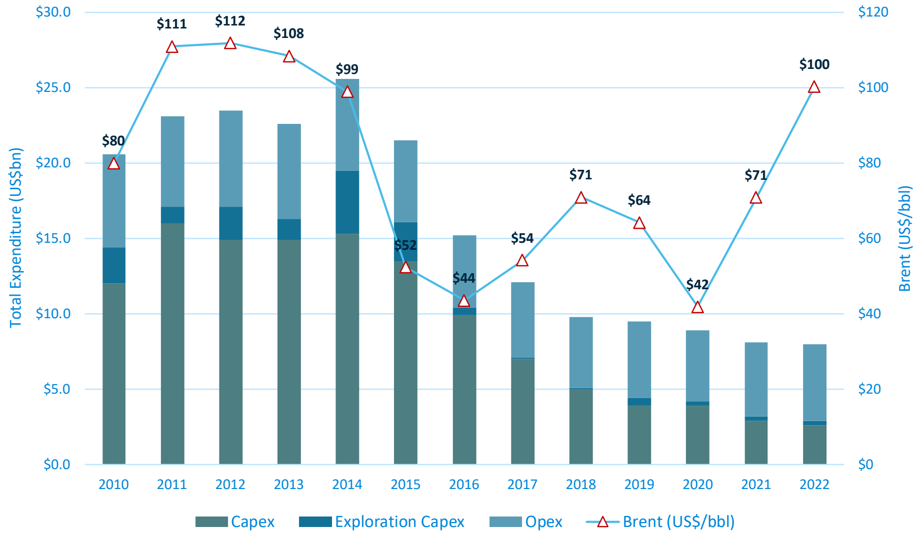
Figure 12: Angola shallow vs deep water oil production to 2014



Source: Sonangol, Angola Finance Ministry

This deep-water investment drive was propelled by the majors: Total, BP, Exxon, Chevron, Eni and Statoil. It saw Angolan upstream capex peak in the early 2010s at ~US$15bn p.a. However, Angola's deepwater province has now also matured and investment levels have dropped sharply, to less than US$3bn in 2022.

Figure 13: Angolan Oil sector investment (US$bn)



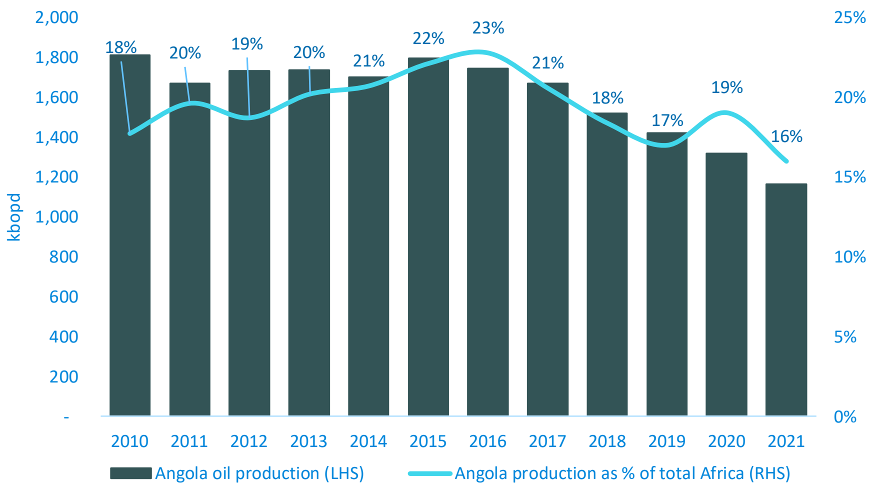
Source: Statista

The decline in investments in the Angolan oil and gas sector coincided with the steep fall in global oil prices caused by the boom in US shale oil production. A maturing deepwater province combined with the slump in oil demand during the COVID pandemic and the energy transition has further impacted the sector, restricting exploration and production activities in the region.

Many of Angola's new field developments were delayed, with only a few coming online, such as the Cuica, Zinia phase 2, and Cabaca Norte projects. Even then, these new projects failed to offset mature field declines. On top of this, IOCs have started to high grade their portfolios to focus on the most profitable and significant core oil and gas operations while paring back in mature/high-cost/high-emission regions, including Angola.

The national hydrocarbon regulator, the National Agency for Petroleum, Gas and Biofuels (ANPG), warned output could plunge to 500,000 bpd in 2028 and almost zero by 2040 without new discoveries being brought into production and much-needed upstream investments.

Figure 14: Angolan oil production trend (bpd)



Source: BP Statistical Review of World Energy

Nevertheless, there are significant remaining developed and discovered resources in Angola. The Oil & Gas Journal puts remaining oil and gas reserves at 7.2 Bbbls and 10.6 tcf, respectively. Naturally, state-owned Sonangol is more bullish, claiming there could be 57 Bbbls of recoverable oil and 27 tcf of natural gas remaining in offshore and onshore areas.

Angola's production to date has been characterised by primary and secondary recovery where most of the oil production rates have plateaued and started to decline. To reverse this trend, enhanced oil recovery (EOR) methods are the best way to boost production from current oilfields rather than frontier exploration, which carries much higher risks and costs, as well as longer timeframes. Using EOR, it is believed Angola can recover more than 50% of the OIIP.

Angola is aiming to stabilise its output at around 1.3 million bpd in the next three years. To facilitate this next phase of Angola's oil industry, the government is actively seeking new investors with the requisite capabilities. In 2019, to help stimulate fresh investment, through ANPG, the government launched a revised Hydrocarbons Exploration Strategy 2020-25 to auction and license 50 new blocks in the Congo, Namibe, Benguela, Etosha, Okavango and Kassange basins. The government also approved new tax incentives and passed the new Private Investment Law 10/21 in April 2021 to provide fiscal incentives to spur investments. Royalties and income tax for marginal discoveries were halved and licences extended.

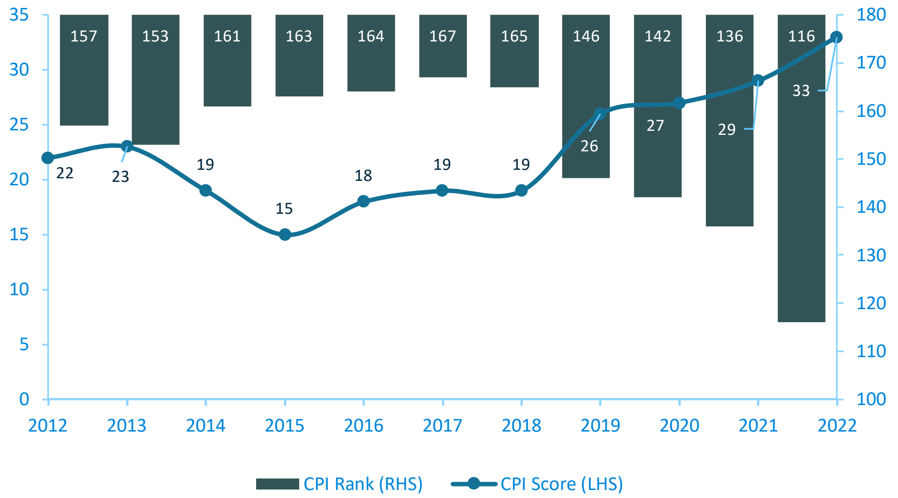
Statista estimates oil and gas investment in Angola is set to increase to US$4bn p.a. between 2023-2030, up from ~US$2.6bn in 2022. However, if Angola really wants to raise activity levels it needs to extend licences and improve fiscal terms to attract fresh entrants and encourage new investment.

Significant improvement in Angola's corruption perception index

Angola has been consistently showcasing improvements in its Corruption Perception Index (CPI) ranking and score since 2018, post the election of former army general João Lourenco, who replaced the incumbent José Eduardo Dos Santos, who had been in power since 1979.

Since his election, Angola has shown the most improvement in CPI ranking amongst the top oil-producing countries of Africa, moving from 165th in 2018 to 116th rank in 2022, as Lourenço propagated his stance to combat corruption.

Figure 15: Angola Corruption Perception Index trend and ranking



Source: Transparency International

Over 3,000 corruption, money laundering and other commercial crime inquiries and cases have been opened since 2017, and more than US$20bn worth of illicit assets seized by authorities in Angola and abroad, according to the government.

Sonangol EP has been subject to corruption allegations for decades, with government officials and high-ranking Sonangol EP employees, including the former CEO, alleged to have benefitted from Sonangol EP's seemingly opaque financial reporting, transactions in which there were suspected conflicts of interest and the alleged direct misappropriation of funds from Sonangol EP.

In a high-profile case, Isabel dos Santos, the former chair of Sonangol and the eldest daughter of former president José Eduardo, was accused of corruption, embezzlement and defrauding the country of billions of dollars, based on an international media investigation called the 2020 Luanda Leaks.

Many of her global assets have since been frozen due to the corruption accusations and in 2021 the US State Department barred her from travelling to the United States, while Interpol issued an arrest warrant for her on receiving the alleged crime files from the Angolan justice system. Her brother José Filomeno Dos Santos was also found guilty of embezzling US$500m from Angola's sovereign fund in the same year. There is also evidence that Sonangol EP is taking steps to develop and enhance an anti-bribery and corruption programme to improve its internal governance and controls.

According to an IMF report on Angola from December 2021, there has been marked improvement in governance since 2018. This has included publishing of audited financial statements by more than 50 state-owned enterprises while laws were brought into line with the best international practices.

On the back of the renewed commitment to transparency and good governance, Angola was accepted as a member of the Extractive Industries Transparency Initiative (EITI) in June 2022, becoming the organisation's 28th member in Africa and 57th in total.

In 2021, Angola received credit rating upgrades from Fitch (CCC to B-) and Moody's (Caa1 to B3), with both credit rating agencies maintaining a stable outlook reflecting the improvements made in the country's fiscal metrics, driven by positive economic growth, sound fiscal management and higher oil prices.

Block 3/05

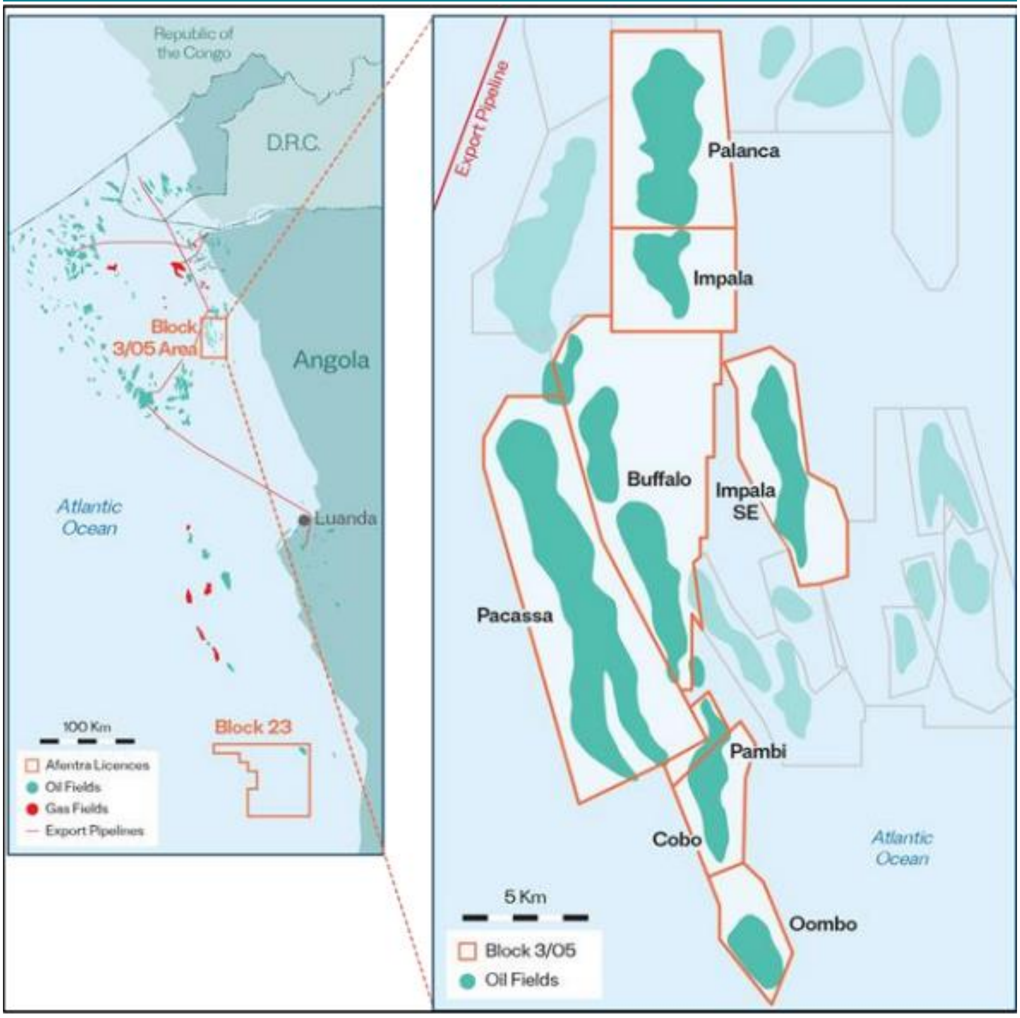
Afentra's main asset is a 24% working interest in shallow water Block 3/05, located 37km offshore Angola in the southern Congo Basin. It is a mature and extensively developed licence with eight producing fields and extensive infrastructure, and has been in production since 1985.

Figure 16: Block 3/05 post deal interests

Company	Interest
Sonangol	30.00%
Afentra	24.00%
M&P	20.00%
Eni	12.00%
Somoil	10.00%
Naftagas	4.00%

Source: finnCap

Figure 17: Block 3/05 map



Source: Afentra, ECRE CPR

Afentra entered into an agreement to acquire a 20% non-operated interest from Angolan state-owned oil and gas company Sonangol P&P in April 2022 for a total consideration of US$130m. This comprises an initial US$80m cash investment plus up to US$50m payable over the next 10 years, contingent on oil prices and minimum annual production.

The remaining 4% stake came via Croatian oil company INA, with Afentra agreeing to acquire its stake in July 2022 (with an effective date of 30 September 2021) for an initial US$9m plus an additional US$10m consideration payable upon the extension of the licence from 2025 to 2040, and a further US$6m payable over 3 years, contingent on oil prices.

The current licence expiry date for Block 3/05 is 30 June 2025. A condition precedent of the transaction with Sonangol is the extension of the licence to the end of 2040 – encouragingly, the JV partners are in final negotiations with ANPG and are anticipating an extension to the PSA with improved fiscal terms. The transaction with INA did not include the licence extension as a condition precedent, which is why it is completing earlier.

The block is operated by Sonangol P&P (30%) alongside five partners: Afentra 24%, Maurel & Prom 20%, ENI 12%, Somoil 10% and NIS-Naftagas 4%.

We would not be surprised to see further consolidation of the licence interests and, assuming a successful conclusion to these transactions, Afentra should be in a strong position to further add to its stake if desired.

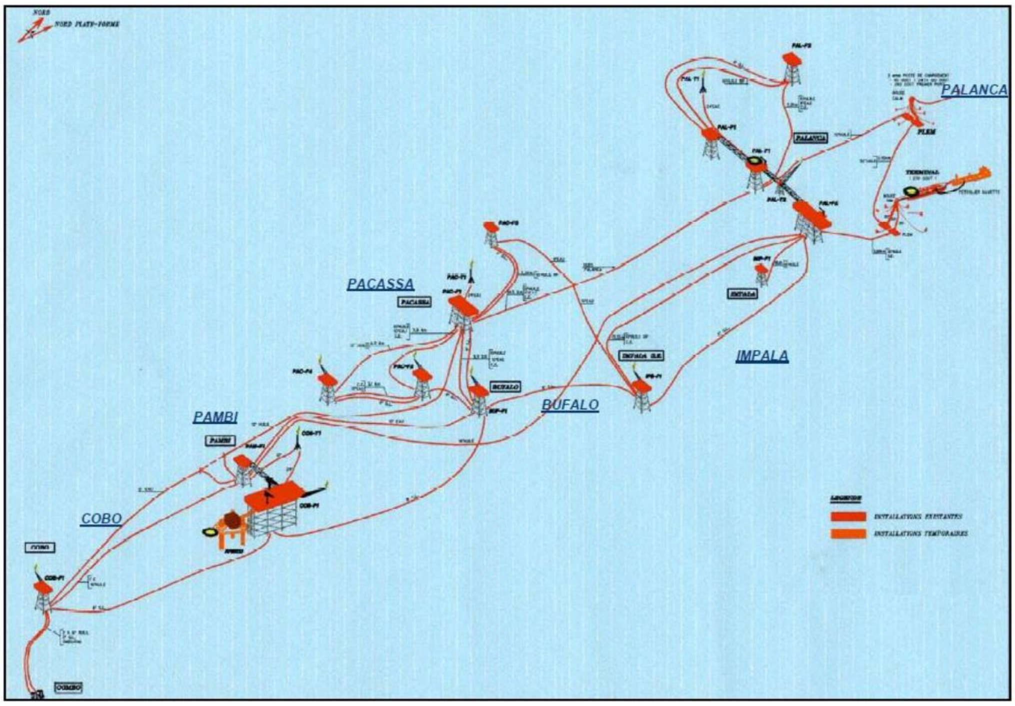
It is worth noting however that Russian majority state-owned Gazprom Neft has a 56% stake in NIS-Naftagas of Serbia and is currently subject to US, EU and UK sanctions, which would take the NIS 4% stake off the table. There would not be a risk that the block itself is sanctioned though.

Also noteworthy is that Somoil, an indigenous Angolan private energy company and 10% partner on Block 3/05, has been a highly active acquirer in Angola, securing positions from Sonangol P&P, PTTEP, Galp and Total since the start of last year; getting closer to this favoured domestic buyer of Angolan upstream assets can be no bad thing for Afentra.

Extensive production infrastructure in place

Block 3/05 contains eight producing fields – Palanca, Pacassa, Bufalo, Impala South-East, Impala, Cobo, Pambi and Oombo. These were discovered between 1981 and 1992 and developed by TotalFinaElf via a network of 4 processing platforms and 17 support structures interlinked by 220 km of submarine pipelines. Oil is exported via the Palanca FPSO Terminal, which has a maximum oil storage capacity of 2 mmbbls.

Figure 18: Block 3/05 facilities layout



Source: Sonangol P&P

Pacassa field

- Discovered in 1982, first oil in 1986 and peak oil production of ~76 kbpd in October 1998.
- Largest field in Block 3/05 with OIIP of 1,103 mmbbls.
- Developed using the Pacassa drilling and production platform PAC-F1 ,which processes oil from the Pacassa and Bufalo fields.
- Water injection peaked at ~130 kbpd in August 2004, which then ceased in December 2016. Water injection was then restored in July 2020 through to January 2022 before being shut-in for field-wide reinstatement works.

Palanca field

- Discovered in 1981, first oil in 1985 and peak oil production of ~53 kbpd in January 1988.
- Second-largest field in Block 3/05 with OIIP of 587 mmbbls.
- Developed using PAL-P1 and PAL-P2 processing platforms, which receive production streams from the PAL-F1 and PAL-F2 wellhead platforms.
- Water injection peaked at ~96 kbpd in September 1991, which then ceased in January 2018, while partial restoration of water injection began in 2022.

Cobo field

- Discovered in 1990, first oil in 1993 and peak oil production of ~47 kbpd in August 1996.
- Third-largest field in Block 3/05 with OIIP of 396 mmbbls.
- Developed via the central COB-F1 drilling platform complex, which also handles production from the Pambi field wellhead platform PAM-F1 and the two Oombo field wells, with final treatment of the oil on PAC-F1 platform on the Pacassa field.
- Water injection peaked at ~80 kbpd in July 2001, which then ceased completely in November 2016.

Bufalo field

- Discovered in 1982, first oil in 1988 and peak oil production of ~24 kbpd in December 1989.
- Fourth-largest field in Block 3/05 with OIIP of 358 mmbbls.
- Developed using the six-slot BUF-F1 production platform, with oil production routed to the PAC-F1 platform on the Pacassa field for treatment.
- Water injection peaked at ~36 kbpd in June 2006, which then ceased in March 2017. Water injection was then restored in July 2020 through to January 2022 before being shut-in for field-wide reinstatement works.

Impala South-East field

- Discovered in 1985, first oil in 1988 and peak oil production of ~29 kbpd in September 1990.
- Fifth-largest field in Block 3/05 with OIIP of 320 mmbbls.
- Developed using via a single wellhead platform IPS-F1 with 14 wellheads. Production is routed to PAL-P2 for processing.
- Water injection peaked at ~37 kbpd in December 1996, which then ceased in June 2019.

Pambi field

- Discovered in 1990, first oil in 1995 and peak oil production of ~29 kbpd in October 1997.
- Sixth-largest field in Block 3/05 with OIIP of 170 mmbbls.
- Developed via a 12-slot wellhead platform, PAM-F1, which gathers the oil and routes it to the COB-P1 platform for processing.
- Water injection peaked at ~40 kbpd in June 1997, which then ceased in December 2016.

Oombo field

- Discovered in 1992, first oil in 1997 and peak oil production of ~22 kbpd in May 2001.
- Seventh-largest field in Block 3/05 with OIIP of 163 mmbbls
- Developed via two subsea wells tied back to the COB-P1 platform.
- Water injection peaked at ~41 kbpd in September 2012, which then ceased in March 2017.

Impala field

- Discovered in 1982, first oil in 1992 and peak oil production of ~4.4 kbpd in January 1999.
- Smallest field in Block 3/05 with OIIP of 60 mmbbls.
- Developed using single production well from the IMP-F1 14 well standalone wellhead platform. Production from IMP-F1 is routed to the PAL-P1 processing platform.
- No water injection has been applied to this field. Impala has been shut-in since March 2018, but the single well is expected to be restarted in 2023.

Figure 19: Block 3/05 field metrics

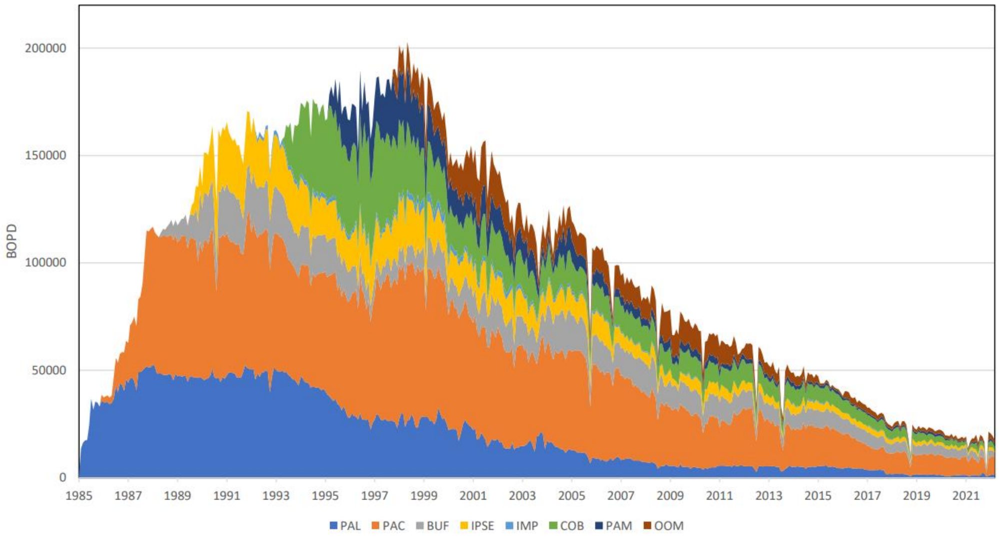
Field	Discovered	First Oil	Peak Oil	Year	STOIIP	Cum. Prod. at End March 2022	Recovery Factor at End March 2022
			Mbbl/d		MMstb	MMstb	
Pacassa	1982	1986	75.9	1998	1103	506	46%
Bufalo	1982	1988	23.8	1989	358	140	39%
Palanca	1981	1985	52.7	1988	587	275	47%
Impala	1982	1992	4.4	1999	60	12	19%
Impala SE	1985	1988	28.9	1990	320	121	38%
Cobo	1990	1993	46.9	1996	396	169	43%
Pambi	1990	1995	28.4	1997	170	52	31%
Oombo	1992	1997	22.3	2001	163	69	42%
Block 3/05					**3157**	**1343**	**43%**

Source: Afentra CPR

Mature, capital-starved fields present reinvigoration opportunity

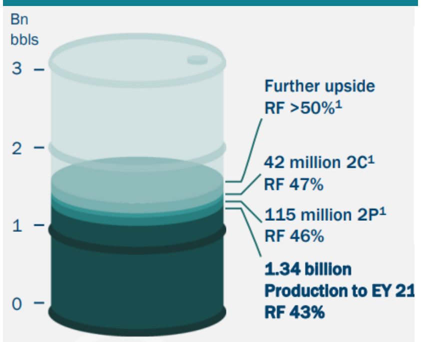
Block 3/05 achieved first oil production in 1985, peaking at ~200 kbpd in 1998 after the development of the eight fields on the licence. Waterfloods were successfully implemented historically on all the fields with a peak water injection rate of ~350 kbpd in 1999.

Figure 20: Block 3/05 historical field production to end-Mach 2022



Source: Afentra CPR

Figure 21: Block 3/05 resources



Source: Afentra

However, between 2005 and 2013 there was a stepwise handover of field operatorships to Sonangol P&P from TotalFinaElf. This is Sonangol P&P's only operated asset, and since the handover there have been no infill drilling campaigns undertaken on the fields. Moreover, water injection reduced sharply from mid-2015 and ceased completely in 2019 as water injection facilities became unavailable due to maintenance issues that were not remediated.

- Around 100 wells have been drilled into the fields, but only 40 are currently actively producing, alongside nine injection wells, delivering output of 19.3 kbpd of light sweet oil in H1 2022.
- The combined oil initially in place (OIIP) for the eight fields is ~3.2 Bbbls and to the end of March 2022 1.3 Bbbls had been produced, representing a recovery factor of 43%.

Decommissioning is often a hidden cost to a mature asset transaction; however, on Block 3/05 these costs have been provisioned for, with over US$0.5bn gross set aside to date. The deal economics are also significantly enhanced by the 24% share of the unrecovered cost pool (US$0.5bn gross) that Afentra inherits as part of the transactions.

The majority of these funds are believed to still sit within Sonangol EP and are yet to be transferred to the new National Concessionaire; Agência Nacional de Petróleo, Gás e Biocombustíveis (ANPG). Afentra has indicated that the timeline for the transfer is unclear.

Herein lies the opportunity for Afentra and the key rationale for the acquisition.

This is a material shallow water, long life, low decline asset with extensive infrastructure covering eight producing fields. There are multiple low-cost opportunities to increase future production. Well reactivation, workovers, and the resumption of infill drilling and water injection programmes offers the potential to reinvigorate these mature fields, taking advantage of the extensive but significantly underutilised infrastructure already in place across Block 3/05.

Figure 22: Block 3/05 oil reserves as of 31 March 2022

Operational Status/ Project	Gross (MMstb)			Afentra Working Interest (MMstb)			Afentra Net Entitlement (MMstb)			Operator
	1P	2P	3P	1P	2P	3P	1P	2P	3P	
Developed Producing										
NFA	33.8	64.4	76.4	8.1	15.5	18.3	6.1	10.5	11.0	Sonangol P&P
Undeveloped										
Water Injection Restoration	36.9	39.4	65.7	8.9	9.5	15.8	6.7	5.1	7.3	Sonangol P&P
Palanca F2 Platform Restart	5.2	7.7	9.6	1.2	1.9	2.3	0.9	1.1	1.2	Sonangol P&P
Well Cobo-001R Workover	1.3	2.9	5.2	0.3	0.7	1.3	0.2	0.4	0.7	Sonangol P&P
Impala IMP-001R Restart	0.4	0.9	1.2	0.1	0.2	0.3	0.1	0.1	0.1	Sonangol P&P
Total Undeveloped	43.8	50.9	81.8	10.5	12.2	19.6	7.9	6.7	9.3	Sonangol P&P
Total All Reserves Classes	**77.6**	**115.2**	**158.2**	**18.6**	**27.7**	**38.0**	**14.1**	**17.2**	**20.2**	Sonangol P&P

Source: Afentra CPR
NFA – No Further Activity

Figure 23: Block 3/05 unrisked oil contingent resources

Oil Contingent Resources by Project and Sub-Class (Unrisked)	Gross (MMstb)			Afentra Working Interest (MMstb)			Operator
	1C	2C	3C	1C	2C	3C	
Development Pending							
Impala South East Infill	6.0	10.8	18.8	1.4	2.6	4.5	Sonangol P&P
Impala Infill	1.0	3.0	4.8	0.2	0.7	1.2	Sonangol P&P
Palanca Infill	1.5	4.4	7.6	0.4	1.1	1.8	Sonangol P&P
Total Development Pending	8.6	18.2	31.2	2.1	4.4	7.5	Sonangol P&P
Development Unclarified							
Cobo Workovers to the Iabe Formation	0.2	1.1	5.8	0.0	0.3	1.4	Sonangol P&P
Development Not Viable							
Licence Extension from 2041 to 2045	12.0	22.6	33.2	2.9	5.4	8.0	Sonangol P&P
Total All Contingent Resource Classes	**20.8**	**41.9**	**70.3**	**5.0**	**10.0**	**16.9**	Sonangol P&P

Source: Afentra CPR

The independent CPR report of Block 3/05 from last March estimates gross 2P reserves of 115 mmbbl (net 27.7 mmbbl), plus gross 2C resources of 42 mmbbl (net 10 mmbbl) with significant potential for future upgrades.

Several projects are planned across the eight fields to both sustain and grow production. This includes workovers on existing wells in the Cobo, Palanca and Impala fields, a new infill drilling campaign and, following successful trials, the re-instatement of water injection for all fields. The latter of these work programmes is the most critical, accounting for 39 mmbbls (78%) of the 51 mmbbls of undeveloped gross 2P reserves identified in the CPR (see Figure 22 above).

Additional Block 3/05 opportunities have also been identified including potential infill drilling into the northern area of the Bufalo field, the potential redevelopment of Oombo, a potential well into the Pacassa SW prospect, and additional volumes in the Iabe formation at Pacassa, Cobo and Oombo. Alternate artificial lift technology applications are also being considered to further enhance production rates from the existing well stock. These opportunities provide potential additions to contingent resources not included in the resource estimates above.

At the end of March 2022, 1.3 Bbbls had been recovered from the fields, representing a recovery factor of 43%, with individual fields ranging from 19-47%. Recovery of the 2P reserves would take the recovery factor to 46%, with development pf the 2C contingent resources increasing this to 47%.

However, it is not uncommon for fields in this region to achieve in excess of a 50% recovery factor using enhanced oil recovery techniques. This creates a significant opportunity for Afentra given every 1% increase in the recovery factor represents an opportunity to add gross reserves of ~30 mmbbls (7.7 mmbbls net) at low cost and risk. Moreover, these reserves can be quickly monetised via the existing infrastructure while helping to reduce unit operating costs.

Block 3/05 valuation

We have modelled the recovery of Block 3/05 2P reserves according to the development details provided in the August 2022 CPR contained within Afentra's Admission Document.

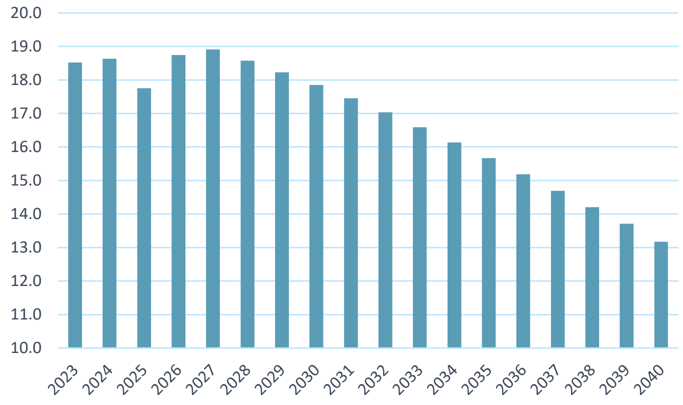
The main fiscal elements of the Block 3/05 Production Sharing Agreement (PSA) include:

- Cost Oil recovery ceiling of 65% of gross revenues.
- 133% uplift for development capital expenditure.
- Development cost amortisation of 25% per annum.
- Profit Oil split 30% to Contractors and 70% to the government.
- Corporate Income Tax of 50%.

The main assumptions we have used in our valuation are as follows:

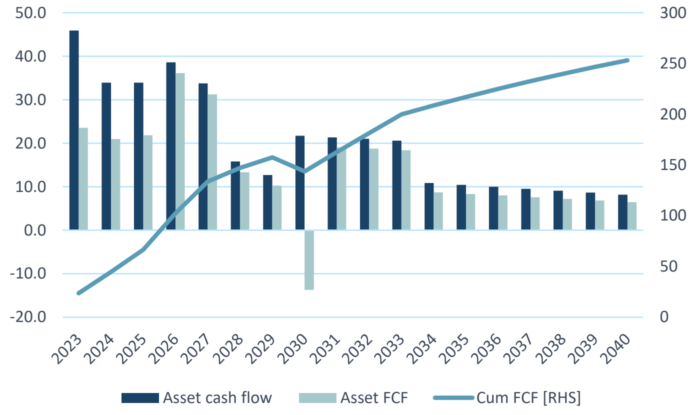
- Gross 2P reserves of 115 mmbbls recovered over the life of the licence to 2040, which includes reserves from water injection restoration, platform restart and other workovers.
- Drilling and facilities capex of US$326m over the life of the licence from the purchase date.
- Average operating costs of US$23/bbl.
- Additional abandonment provisions of US$174m.
- Long-term Brent pricing of US$70/bbl with net cash flows discounted at 10% to 1 January 2023.

Figure 24: Block 3/05 2P reserves production profile (kbopd)



Source: finnCap, Afentra CPR

Figure 25: Afentra asset level 2P cash flow (US$m)

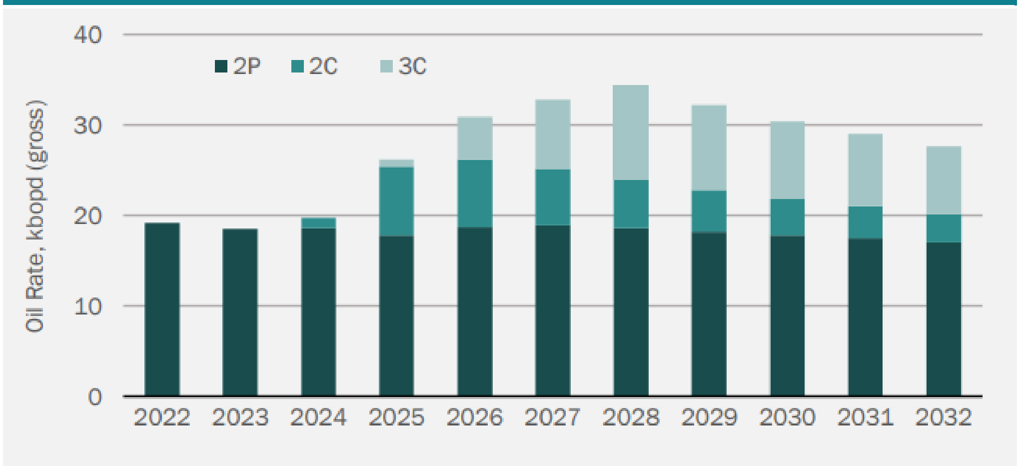


Source: finnCap

Under the CPR development plan for the 2P reserves, we estimate Block 3/05 has an NPV10 of US$143m (52p/sh) net to Afentra at US$70/bbl from the assumed end-June completion date. Over the life of the licence, at US$70/bbl Brent we estimate Block 3/05 can generate US$250m of undiscounted free cash flow net to Afentra, which rises to US$290m at US$80/bbl.

In the next three years, we forecast Block 3/05 can generate average free cash flow net to Afentra from the Block 3/05 2P reserves of US$22m p.a. if the planned work programmes are successful; funds which can be reinvested into the assets in pursuit of the 42 mmbbls of gross 2C contingent resources (3C of 70 mmboe) identified in the CPR.

Figure 26: Block 3/05 2C and 3C contingent resources production forecast

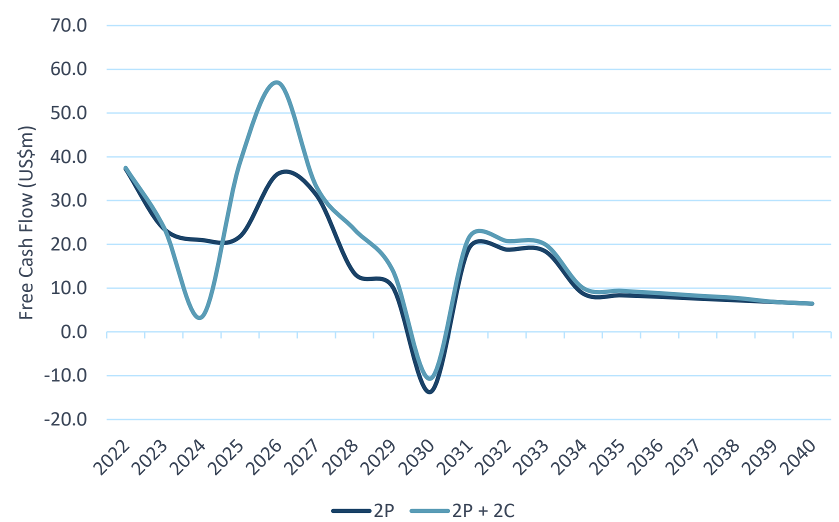


Source: Afentra

Development of the 2P reserves is expected to maintain Block 3/05 output broadly flat for several years before declines set in again. However, management estimates that successful pursuit of the Block 3/05 contingent resources could add a further 10-15,000 bopd (2C-3C) to gross production, driving output to 25-34,000 bopd in the second half of the decade. These barrels would come with relatively low capital costs due to the extensive existing infrastructure on the licence and should help reduce unit operating costs.

We have performed a preliminary valuation of the Block 3/05 2C contingent resources, assuming a slightly later 2025 start-up than in Figure 26. Assuming development costs of US$8/bbl, we estimate an unrisked NPV10 for the 10 mmbbls of net 2C contingent resources of US$44m (16p/sh). If the 2C resources are developed, FCF generation over the life of the assets increases to US$300m.

Figure 27: Block 3/05 development free cash flow



Source: finnCap

Block 3/05A

Figure 28: Block 3/05A post deal interests

Company	Interest
Sonangol	33.33%
M&P	26.67%
Eni	16.00%
Somoil	13.33%
Afentra	5.33%
Naftagas	5.33%

Source: finnCap

In July 2022, Afentra also entered into an agreement to acquire a 5.33% interest in Block 3/05A offshore Angola, adjacent to Block 3/05, of which 4% will come from INA with the remaining 1.33% subject to China Sonangol's exit from the block and the subsequent pro rata allocation of its interest to the remaining partners.

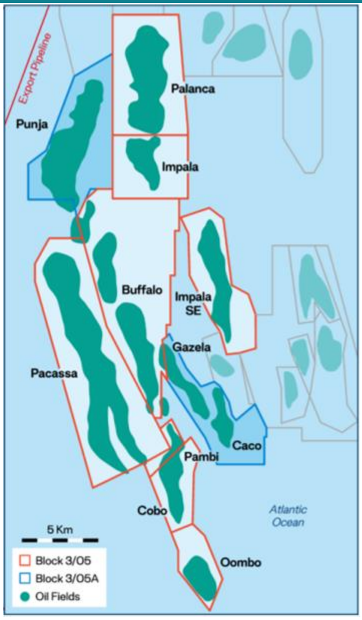
The deal comprises an initial cash consideration of US$3m plus up to US$5m in contingent payments, depending on the future development of existing discoveries. The deal was approved by the Angolan Ministry of Mineral Resources, Oil & Gas in January 2023 and Afentra is working with INA to finalise the acquisition.

Block 3/05A provides Afentra with incremental shallow water development opportunities offshore Angola. The licence is again operated by Sonangol and contains three fully appraised oil discoveries – Punja, Caco and Gazela – discovered between 1982 and 1990. In total, seven wells have been drilled into these fields, encountering light sweet oil and associated gas.

Oil in place resources for these three fields are put at over 300 mmbbls, with gross 2C contingent resources estimated at 33 mmbbls, assuming just an 11% recovery factor, and gross 3C contingent resources 68 mmbbls. Critically, these discoveries have a valid production licence until 2035 and are ideal candidates for subsea tieback to the existing Block 3/05 infrastructure.

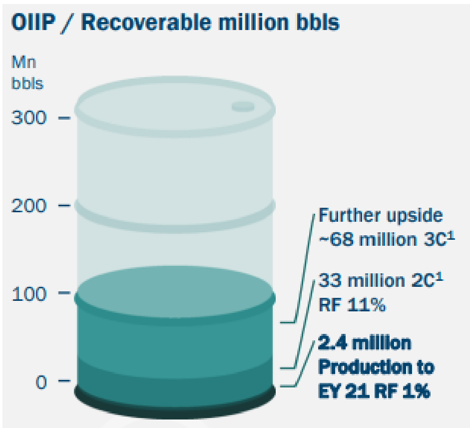
From 2015, approximately 2 mmbbls was produced over two years from a single well in the Gazela field (~2700 bopd), supported by Block 3/05 infrastructure. Assessments to define an optimal development framework for these fields benefitting from use of the nearby Block 3/05 facilities and infrastructure are ongoing. However, initial management estimates suggest this block has production potential of ~10,000 bopd gross and can help reduce unit operating costs and extend the lives of the Block 3/05 assets.

Figure 29: Block 3/05A location map



Source: Afentra

Figure 30: Block 3/05A resources



Source: Afentra

At this early stage of definition, we include just 2.4p/sh for these resources within our risked NAV.

Block 23

Figure 31: Block 23 post deal interests

Company	Interest
Namco, Sequa & Petrolog	40.00%
Afentra	40.00%
Sonangol	20.00%

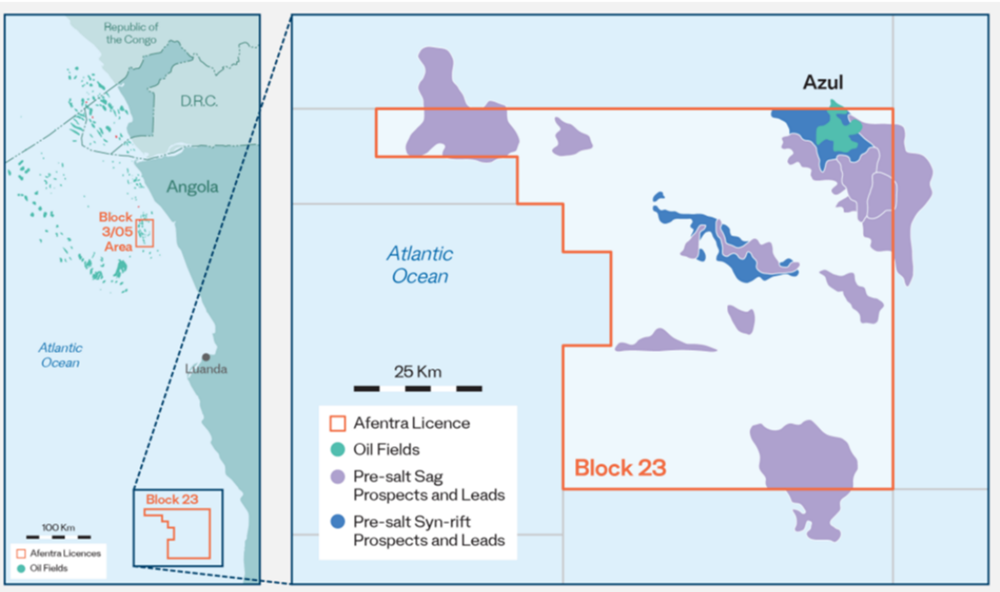
Source: finnCap

Afentra also acquired a 40% working interest in Block 23 as part of the Sonangol transaction for a cash consideration of US$0.5m. This licence expired in December 2022, but has since been extended via Executive Decree through to 2 December 2026, providing time for the new contractor group to discuss and agree a forward work programme. There are no outstanding capital commitments on the licence.

Block 23, located in the Kwanza Basin, covers an area of 5,000 km2 with water depths from 600 to 1,600m. The block has a working petroleum system and is currently in exploration phase. Although the block is covered by modern 3D and 2D seismic data sets, around 95% of it is yet to be explored. There are currently no working commitments pending for the block.

The block contains an existing oil discovery from 2012 – Azul – the first deep-water pre-salt discovery made in the Kwanza Basin. The discovery well flow tested at 3-4,000 bopd of light oil and contains estimated oil in place of ~150 mmbbls. Block 23 is still in the exploration phase, and Afentra sees the opportunity to further explore the block by using advanced geophysics and re-processed 3D seismic, further developing its understanding of the Kwanza Basin.

Figure 32: Block 23 location map



Source: Afentra

Currently, we give zero value for Block 23 within our risked NAV.

Odewayne block

Finally, Afentra has a legacy 34% working interest in the large Odewayne block PSA, onshore Somaliland. While this is non-core for Afentra, it offers one of the last opportunities to target an undrilled onshore rift basin in Africa.

Moreover, it represents a free option for now as Afentra is fully carried by Genel Energy for its share of the costs of all exploration activities during the Third and Fourth Periods of the Odewayne Production Sharing Agreement (PSA). The PSA is currently in the Third Period, which has been extended until May 2024.

Figure 33: Odewayne block location map

Source: Afentra

Exploration activity prior to the 2017 regional 2D seismic acquisition programme had been limited to the acquisition of airborne gravity and magnetic data and surface fieldwork studies, with no wells drilled on the Odewayne Block.

In 2021, technical studies were undertaken, focused on determining the presence of a Mesozoic basin in the block and its prospectivity. The current proposed model is of a fold and thrust belt beneath an unconformity and, if correct, would be potentially analogous to petroleum systems in Oman.

In the event of any future discovery, commercialisation will be helped by the fact that the block has access to the Berbera deepwater port less than 100km to the north.

Again, we currently give zero value for the Odewayne block within our risked NAV.

Board of Directors

Paul McDade - Chief Executive Officer

A petroleum engineer with over 35 years in the international oil & gas business has provided Paul with a rich and diverse set of relevant experiences. From his early international involvement in challenging operational, social, security and safety environments, to his 19 years as COO and then CEO of Tullow Oil, he has essential first-hand experience of what is required to build a successful African-focused, responsible oil & gas company. His strong focus on delivering stakeholder value, shared prosperity, environmental performance and strong governance, coupled with his understanding of the role that oil & gas has to play in both the global and African energy transitions, makes him the ideal leader to deliver Afentra's ambitious growth strategy, a company that will have stakeholder objectives and ESG embedded at its core.

Ian Cloke – Chief Operating Officer

A geoscientist with over 25 years of international oil & gas experience and a proven track record of deploying innovative technologies across global upstream projects that positively impact operational, technical and commercial results for the benefit of all stakeholders. As EVP at Tullow Oil, he led multi-cultural and diverse teams focused on safely improving production and operations at pace across Africa and South America, effectively managing risk and social-environmental sensitivities whilst embedding strong financial discipline. He has first-hand experience in several African countries, having discovered and successfully delivered commercial oil and gas in Uganda, Kenya and Guyana amongst others. Having lived and travelled throughout Africa, he has enjoyed the full spectrum of life and business on the continent, making him an ideal founding partner and COO of Afentra.

Anastasia Deulina – Chief Financial Officer

Anastasia's multicultural upbringing and over 20 years of working in the energy sector within global, multinational investment banks, private equity and corporates has given her extensive experience in strategy development, deal origination, structuring and execution, M&A and business transformation. Her primary focus is always on driving sustainable business growth that has a visible positive impact on the bottom line. This, along with her significant prior Board experience (both as NED and committee member), and her strong global business development and financial network means that Anastasia provides expert leadership as Afentra's CFO.

Jeffrey MacDonald – Independent Non-Executive Chairman

Jeffrey MacDonald was a former managing director with private equity firm First Reserve, with responsibility for investment origination, structuring, execution, monitoring and exit strategy, with particular emphasis on the oil & gas sector. Before joining First Reserve, he was a founder and CEO of Caledonia Oil & Gas Ltd., a UK-based exploration and production firm, and a founding member and managing director of Highland Energy Ltd. Most recently, he held the position of Interim CEO and, prior to that, non-executive Director, of Kris Energy.

Gavin Wilson – Independent Non-Executive Director

Gavin Wilson has held the position of Investment Director at Meridian Capital Limited, a Hong Kong-based international investment firm, for over a decade, managing an oil and gas portfolio focused on world-class assets in emerging markets. For over seven years, Gavin founded and managed two successful investment funds – RAB Energy and RAB Octane. Previously, he was Managing Partner of Canaccord Capital London's Oil & Gas division, responsible for Sales and Corporate Broking/Finance.

Income statement		2020A	2021A	2022E	2023E	2024E
Year end:		Dec	Dec	Dec	Dec	Dec
Sales	**$m**	**0.0**	**0.0**	**0.0**	**49.0**	**86.5**
Cost of sales	$m	0.0	0.0	0.0	-22.6	-46.6
Gross profit	**$m**	**0.0**	**0.0**	**0.0**	**26.4**	**39.9**
Operating expenses	$m	-2.0	-4.7	-4.9	-5.5	-5.6
EBITDA (adjusted)	**$m**	**-2.0**	**-4.7**	**-4.9**	**20.9**	**34.4**
Depreciation	$m	-0.2	-0.2	-0.2	-3.7	-14.6
Amortisation	$m	0.0	0.0			
EBIT (adjusted)	**$m**	**-2.2**	**-5.0**	**-5.1**	**17.1**	**19.8**
Associates/other	$m	0.0	0.0	0.0	0.0	0.0
Net interest	$m	0.3	-0.0	0.1	-2.0	-5.0
PBT (adjusted)	**$m**	**-1.9**	**-5.0**	**-5.0**	**15.2**	**14.8**
restructuring costs	*$m*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
share based payments	*$m*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
other adjustments	*$m*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total adjustments	$m	0.0	0.0	0.0	0.0	0.0
PBT (stated)	**$m**	**-1.9**	**-5.0**	**-5.0**	**15.2**	**14.8**
Tax charge	$m	0.0	0.0	0.0	-3.4	-6.0
tax rate	*%*	*n/a*	*n/a*	*n/a*	*22.4*	*40.6*
Minorities	$m	0.0	0.0	0.0	0.0	0.0
Reported earnings	**$m**	**-1.9**	**-5.0**	**-5.0**	**11.8**	**8.8**
Tax effect of adjustments / other	$m					
Adjusted earnings	**$m**	**-1.9**	**-5.0**	**-5.0**	**11.8**	**8.8**
shares in issue (year end)	*m*	*220.1*	*220.1*	*220.1*	*220.1*	*220.1*
shares in issue (weighted average)	*m*	*220.1*	*220.1*	*220.1*	*220.1*	*220.1*
shares in issue (fully diluted)	*m*	*220.1*	*220.1*	*220.1*	*220.1*	*220.1*
EPS (adjusted, fully diluted)	**c**	**-0.9**	**-2.3**	**-2.3**	**5.3**	**4.0**
EPS (stated)	c	-0.9	-2.3	-2.3	5.3	4.0
DPS	**c**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Growth analysis (adjusted basis where applicable)						
Sales growth	%	n/m	n/m	n/m	n/m	76.6%
EBITDA growth	%	n/m	-139.4%	-2.5%	529.8%	64.6%
EBIT growth	%	n/m	-129.2%	-2.3%	436.2%	15.5%
PBT growth	%	n/m	-161.9%	-1.1%	400.6%	-2.4%
EPS growth	%	n/m	-161.9%	-1.1%	333.2%	-25.3%
DPS growth	%	n/m	n/m	n/m	n/m	n/m

Profitability analysis (adjusted basis where applicable)						
Gross margin	%	n/m	n/m	n/m	53.9%	46.2%
EBITDA margin	%	n/m	n/m	n/m	42.6%	39.7%
EBIT margin	%	n/m	n/m	n/m	35.0%	22.9%
PBT margin	%	n/m	n/m	n/m	31.0%	17.1%
Net margin	%	n/m	n/m	n/m	24.0%	10.2%

Cash flow		2020A	2021A	2022E	2023E	2024E
Year end:		**Dec**	**Dec**	**Dec**	**Dec**	**Dec**
EBITDA	$m	-2.0	-4.7	-4.9	20.9	34.4
Net change in working capital	$m	-0.2	0.2	0.3	-1.1	-2.1
Share based payments	$m	0.0	0.0	0.0	0.0	0.0
Profit/(loss) on sale of assets	$m	0.0	0.0			
Net pensions charge	$m					
Change in provision	$m					
Other items	$m	0.0	0.0	0.0	-3.4	-6.0
Cash flow from operating activities	**$m**	**-2.1**	**-4.5**	**-4.5**	**16.4**	**26.2**
Cash interest	$m	0.0	0.0	-0.1	-2.6	-5.3
Tax paid	$m	0.0	0.0	0.0	0.0	0.0
Capex	$m	-0.1	-0.2	-0.2	-10.0	-28.4
Other items	$m	0.0	0.0	0.0	0.0	0.0
Free cash flow	**$m**	**-2.3**	**-4.7**	**-4.8**	**3.9**	**-7.4**
Disposals	$m	0.0	0.0	0.0	0.0	0.0
Acquisitions	$m	0.0	0.0	0.0	-53.5	-7.0
Dividends on ord shares	$m	0.0	0.0	0.0	0.0	0.0
Other cashflow items	$m	0.0	-0.3	-8.1	40.4	2.0
Issue of share capital	$m	0.0	0.0	0.0	0.0	0.0
Net change in cash flow	**$m**	**-2.2**	**-5.0**	**-12.9**	**-9.2**	**-12.4**
Opening net cash (debt)	$m	44.9	42.7	37.7	24.9	-24.4
Closing net cash (debt)	**$m**	**42.7**	**37.7**	**24.9**	**-24.4**	**-38.7**

Cash flow analysis						
Cash conversion (op cash flow / EBITDA)	%	n/m	n/m	n/m	78.6%	76.3%
Cash conversion (free cash flow / EBITDA)	%	113.6%	99.3%	98.8%	18.6%	-21.6%
Underlying free cash flow (capex = depreciation)	$m	-2.3	-4.7			
Cash quality (underlying FCF / adjusted earnings)	%	122.9%	95.0%			
Investment rate (capex / depn)	x	0.5	0.9	0.6	2.7	1.9
Interest cash cover	x	n/a	n/a	n/a	6.4	5.0
Dividend cash cover	x	n/a	n/a	n/a	n/m	n/a

Balance sheet		2020A	2021A	2022E	2023E	2024E
Year end:		**Dec**	**Dec**	**Dec**	**Dec**	**Dec**
Tangible fixed assets	$m	0.8	0.7	0.6	60.3	81.1
Goodwill	$m	0.0	0.0	0.0	0.0	0.0
Other intangibles	$m	21.2	21.3	21.3	21.3	21.3
Other non current assets	$m	0.0	0.0	0.0	0.0	0.0
inventories	*$m*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
trade receivables	*$m*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*
trade payables	*$m*	*-0.2*	*-0.5*	*-0.8*	*-0.8*	*-0.8*
Net working capital	$m	-0.0	-0.2	-0.5	-0.5	-0.5
Other assets	$m	0.0	0.0	8.0	8.0	8.0
Other liabilities	$m	-0.8	-0.6	-0.4	-0.4	-0.4
Gross cash & cash equivalents	$m	42.7	37.7	24.9	15.6	3.3
Capital employed	$m	63.9	58.9	53.8	104.3	112.7
Gross debt	$m	0.0	0.0	0.0	40.0	42.0
Net pension liability	$m	0.0	0.0	0.0	0.0	0.0
Shareholders equity	$m	63.9	58.9	53.8	64.3	70.7
Minorities	$m	0.0	0.0	0.0	0.0	0.0
Capital employed	$m	63.9	58.9	53.8	104.3	112.7

Leverage analysis						
Net debt / equity	%	no debt	no debt	no debt	37.9%	54.7%
Net debt / EBITDA	x	n/a	n/a	n/a	1.2	1.1
Liabilities / capital employed	%	0.0%	0.0%	0.0%	38.3%	37.3%

Working capital analysis						
Net working capital / sales	%	n/m	n/m	n/m	-1.1%	-0.6%
Net working capital / sales	days	n/m	n/m	n/m	-4	-2
Inventory (days)	days	n/m	n/m	n/m	0	0
Receivables (days)	days	n/m	n/m	n/m	2	1
Payables (days)	days	n/m	n/m	n/m	6	4

Capital efficiency & intrinsic value						
Adjusted return on equity	%	-3.0%	-8.5%	-9.4%	18.3%	12.4%
RoCE (EBIT basis, pre-tax)	%	-3.4%	-8.5%	-9.5%	16.4%	17.6%
RoCE (underlying free cash flow basis)	%	-3.7%	-8.1%			
NAV per share	c	29.0	26.8	24.5	29.2	32.1
NTA per share	c	19.4	17.1	14.8	19.5	22.4

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