

Malaysia

ADD

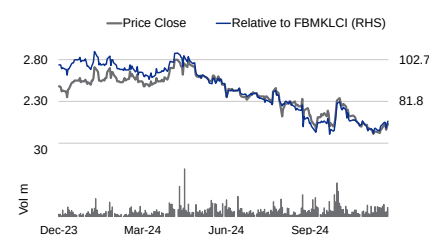
Consensus ratings*: Buy 3 Hold 1 Sell 1

Current price:	RM2.03
Target price:	RM2.81
Previous target:	RM
Up/downside:	38.4%
CGSI/ Consensus:	21.6%
Reuters:	HIBI.KL
Bloomberg:	HIBI MK
Market cap:	US\$350.3m
	RM1,557m
Average daily turnover:	US\$1.61m
	RM6.96m
Current shares o/s:	768.4m
Free float:	75.0%

*Source: Bloomberg

Key changes in this note

► This is an initiation report on Hibiscus.



Source: Bloomberg

Price performance	1M	3M	12M
Absolute (%)	1.0	-7.3	-20.1
Relative (%)	2.3	-3.7	-30.3

Major shareholders	% held
Datuk Michael Tang Vee Mun	12.0
Dr Kenneth Gerard Pereira	10.1

Analyst(s)



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Hibiscus Petroleum Bhd

Multiple projects to drive long-term rerating

- We initiate coverage with an Add and a DCF-based TP of RM2.81 (Ke: 16%) for end-CY25F; the shares have already derated to reflect the macro risks.
- Hibiscus's share price has discounted long-term Brent oil prices of below US\$60/bbl, against the current price of more than US\$70/bbl, in our estimate.
- Potential rerating catalysts include an extension of the PM3 CAA PSC tenure, and ongoing projects to drive production at North Sabah and Teal West.

Driving value through acquisitions and production enhancements

Hibiscus is Malaysia's only listed independent upstream E&P company. Over the past ten years, it has acquired a portfolio of mature producing assets in the UK's Anasuria Cluster; a set of producing assets in Malaysia that include the North Sabah, Kinabalu, and PM3 CAA blocks; with the Brunei Block B MLJ as its latest addition. These acquisitions have driven a step change in its oil and gas production and 2P reserves. We expect production enhancement initiatives on its existing assets to grow its volumes in FY26F. At North Sabah, the water flood project is currently ongoing, as is the upgrade of the gas compressors at Kinabalu, while Hibiscus will drill one well next year at the Teal West field for tie-back to the Anasuria FPSO in the UK. Over three years to 2028F, we expect Hibiscus to kick-off three major projects: 1) development of sizeable gas reserves at the PKNB Cluster offshore Terengganu via tie-back to the existing PM3 CAA production facilities; 2) potential development of several proximate tie-back opportunities to Brunei MLJ; and the 3) development of the Greater Marigold Area Development (GMAD) in the UK North Sea, although this project is lower down the capex priority list.

Near-term challenges and downside risks

Hibiscus's share price has declined almost 30% over the past 6-7 months, reflecting lower oil prices and the weaker US\$ vs. the ringgit. We argue that the correction is largely done, as we do not expect oil prices to weaken significantly from current levels over the next 12 months, while the US\$ has bounced back. Downside risks to our Add call include possible hits to its earnings given that a large deferred tax expense charge in 2QFY25F may be required to reflect the intensified EPL tax regime in the UK and possible exploration capex write-off in 3QFY25F as well as possible unplanned equipment outages given the advanced age of the equipment at Hibiscus's production portfolio.

Potential rerating catalysts include the PM3 CAA PSC extension

On the other hand, Hibiscus has several potential rerating catalysts, with the key one being a likely announcement of the 10- or 20-year extension of PM3 CAA PSC that currently ends on 31 Dec 2027F. An extension, if it happens, may uplift 2P reserves that we expect to result in lower future depreciation and amortisation charges, and give Hibiscus a longer runway to monetise production, including from the proximate PKNB Cluster. We also expect higher production from the North Sabah water flood and Teal West projects to help drive a 41% yoy rise in our FY26F core EPS forecast. We initiate coverage on Hibiscus with an Add rating.

Financial Summary	Jun-23A	Jun-24A	Jun-25F	Jun-26F	Jun-27F
Revenue (RMm)	2,345	2,716	2,440	3,063	2,719
Operating EBITDA (RMm)	1,253	1,273	1,153	1,523	1,273
Net Profit (RMm)	400.5	467.1	240.7	331.5	160.9
Normalised EPS (RM)	0.50	0.58	0.31	0.43	0.21
Normalised EPS Growth	4.4%	16.6%	(47.3%)	41.0%	(51.5%)
FD Normalised P/E (x)	4.08	3.50	6.64	4.71	9.69
DPS (RM)	0.063	0.085	0.080	0.080	0.060
Dividend Yield	3.08%	4.19%	3.94%	3.94%	2.96%
EV/EBITDA (x)	1.22	1.33	2.11	1.28	1.08
P/FCFE (x)	4.01	NA	NA	5.14	3.32
Net Gearing	(3.6%)	2.0%	25.9%	11.4%	(5.0%)
P/BV (x)	0.61	0.53	0.48	0.44	0.43
ROE	16.4%	16.1%	7.6%	9.8%	4.5%
% Change In Normalised EPS Estimates					
Normalised EPS/consensus EPS (x)			0.55	0.81	0.48

SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Multiple projects to drive long-term re-rating

SECTION 1: INVESTMENT CASE

Brief description of Hibiscus ➤

Hibiscus is an independent oil and gas exploration and production (E&P) company listed on Bursa Malaysia. Hibiscus was founded by its managing director, Dr Kenneth Gerard Pereira, together with co-founders Dr Pascal Hos (Country Head, Malaysia and Vietnam), and Ms Joyce Vasudevan (Head, Corporate Finance). All three individuals continue to play active and important roles in the company.

Hibiscus started out as a special purpose acquisition company (SPAC), which was first listed in 2011. It experienced many setbacks in its early years when it focused primarily on oil exploration; this ultimately resulted in the write-off and loss of its investments in the Middle East, Norway and Australia.

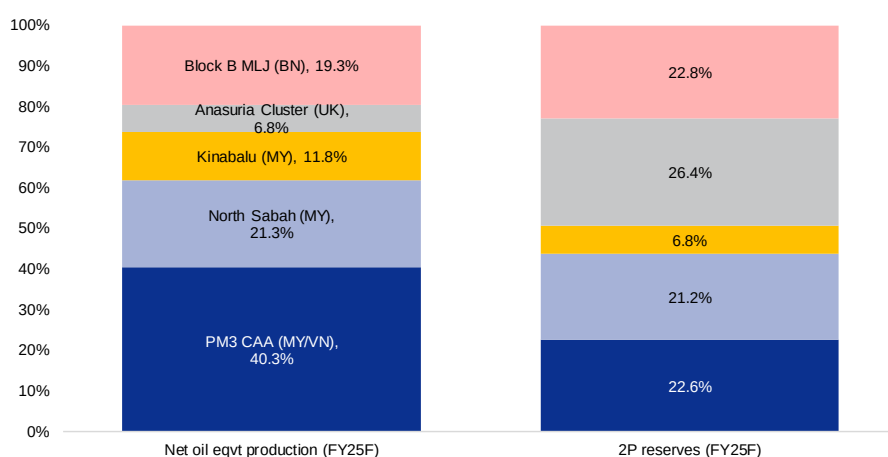
In 2015, Hibiscus changed its strategy to focus on acquiring mature and producing oil and gas assets; these were assets that various oil majors had wanted to dispose after already extracting a large portion of the reserves. At the right price, Hibiscus saw value in these assets, which could be operated for many more years.

In Aug 2015, Hibiscus agreed to buy 50% stake in the **Anasuria Cluster**, in the UK North Sea, from Shell and Esso. A year later in Oct 2016, Hibiscus agreed to buy 50% of the **North Sabah PSC**, Malaysia, from Shell.

Four years after that in Jun 2021, Hibiscus agreed to buy a group of assets from Repsol, which mainly comprise a 35% interest in the **PM3 CAA PSC** in the Malaysia-Vietnam Commercial Arrangement Area (CAA) and a 60% interest in the **Kinabalu PSC** in Sabah.

The latest acquisition happened when, in Jun 2024, Hibiscus agreed to buy a 37.5% interest in the **Brunei Block B MLJ** concession from TotalEnergies. These assets are now the key contributors to Hibiscus's production and 2P reserves (Figure 1).

Figure 1: Breakdown of FY25F net oil equivalent production rate and 2P reserves by asset



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

The acquisitions of the above assets have contributed to the Hibiscus group's production growth over time (Figure 2), with growth in FY22 from PM3 CAA and Kinabalu (acquisition completed 24 Jan 2022). We expect another round of production growth in FY25F from the completion of the Brunei MLJ acquisition on 14 Oct 2024.

Figure 2: Hibiscus group: Net oil equivalent production rate (boepd)

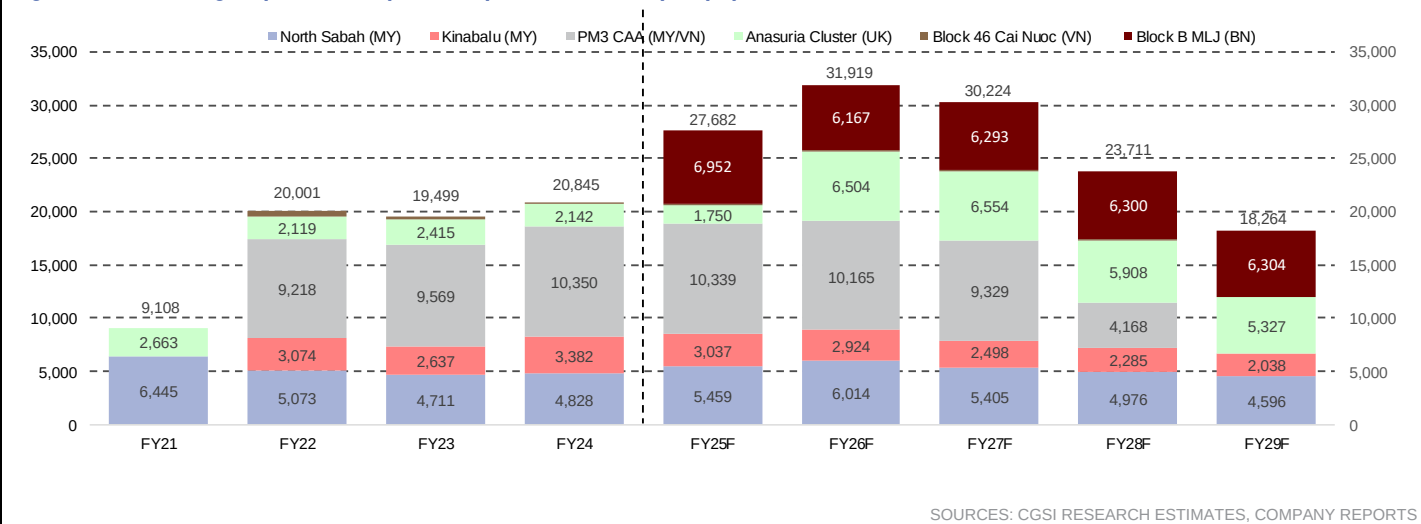
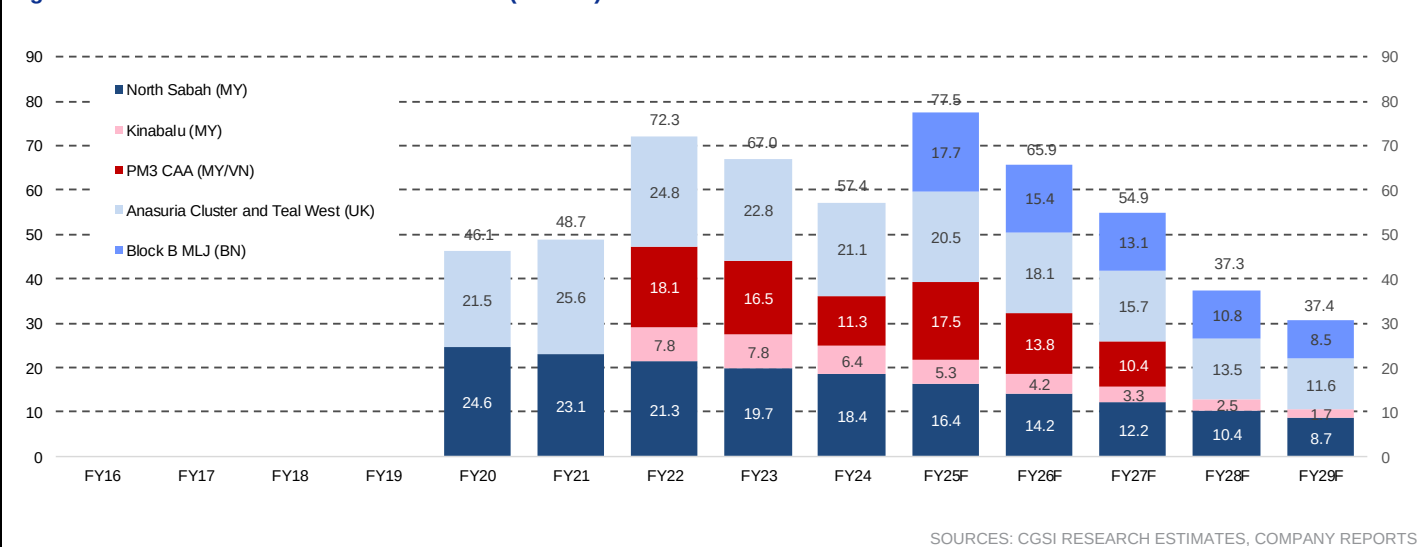


Figure 3: Movement in Hibiscus's 2P reserves (MMboe)



Hibiscus has also been actively working to add value to its assets, and some examples are listed below:

1. At the **PM3 CAA PSC**, Hibiscus successfully executed the 6-well infill drilling campaign at the North Bunga Orkid H4 reservoir in FY22-24, and drilled the Bunga Lavatera-1 gas exploration well and the Bunga Aster-1 oil exploration well in FY23-24; all of these contributed to additional production and reserves.
2. At the **North Sabah PSC**, Hibiscus already started the process of drilling five oil producer infill wells and six water injector wells between Oct 2024 and Jun 2025F at the South Furious 30 platform (also called the 'SF30 Water Flood Phase 2' project), to increase the volume of oil production and reserves recovery via pressure support from water injection. Hibiscus had also drilled three exploration wells in 2023-2024 at the North Sabah PSC, with two wells declared as uneconomic to develop and one more well still in the process of evaluation.

3. At the **Kinabalu PSC**, Hibiscus is currently executing a project to improve the efficiency and capacity of the low-pressure compressor (LPC) and the high-pressure compressor, which can increase the production of oil due to reduced backpressure to the well at the processing facilities. This project will be completed in FY25F, according to Hibiscus.
4. At the **Anasuria Cluster**, Hibiscus has arranged to drill one well in the Teal West field in 2Q or 3Q of CY25F, then moving to install the umbilical and pipeline back to the Anasuria FPSO in 2HCY25F, with first oil planned for end-2025F or early-2026F.
5. If Hibiscus secures an **extension of the PM3 CAA PSC** beyond the current expiry date of 31 Dec 2027F, which is likely in our view, we believe that Hibiscus will move quickly to develop the proximate PKNB Cluster, which holds sizeable gas resources that can be produced via tie-back to the PM3 CAA production facilities.

Initiate coverage with an Add; why investors should look at Hibiscus ➤

We initiate coverage on Hibiscus with an **Add** rating, and highlight that Hibiscus is priced attractively relative to our **end-CY25F DCF valuation of the company at RM2.81**, which is where we have set our target price (Figure 4). We believe that our valuation is conservative in terms of both the discount rate that we have used as well as our cashflow forecasts.

We have applied a high **cost of equity of 16%** as our discount rate, using a risk-free rate of 4%, equity risk premium of 6%, and a high beta of 2, which is higher than Hibiscus's 5-year beta of 1.87 against the FBMKLCI Index.

In terms of our cashflow forecasts:

- We have **not assumed any PSC extensions**; hence, our cashflow forecasts for PM3 CAA end on 31 Dec 2027F; we will only incorporate additional cashflows beyond that date once the PSC is officially extended by Petronas and PetroVietnam. We have similarly ended our DCF estimates for other PSCs on the expiry dates of their respective tenures.
- We have **only assumed contribution to future production from Hibiscus's existing projects**, such as the SF30 Water Flood Phase 2 project at North Sabah, and the Teal West development at the Anasuria Cluster. Beyond these projects, we have adopted the **'No Further Activity' (NFA) assumption** in our cashflow projections, which means that no incremental production is assumed for projects that have not been announced or disclosed by Hibiscus. This NFA assumption is the reason why our production forecasts progressively decline yoy from FY27F onwards (Figure 2).
- Meanwhile, our **absolute cash opex forecasts are generally sticky and do not decline even if production declines**; consequently, the cash opex per boe of production increases rapidly as production declines with age and maturity.
- Also, our **long-term selling price assumptions are conservative**. Our Brent oil price assumption of US\$70/bbl and long-term spot Asian JKM LNG price assumption of US\$8/MMBtu, from 2026-2027F onwards (Figure 5), are conservative relative to the International Energy Agency's (IEA) estimates of oil prices at US\$79/bbl in 2030F and US\$77/bbl in 2040F, and Japan LNG prices of US\$8.30/MMBtu in 2030F and US\$8.80/MMBtu in 2040F, under its Stated Policies Scenario (STEPS).

As mentioned earlier, we highlight that our production estimates for FY27F and beyond are based on the **'No Further Activity' (NFA) assumption**, which means that we have not incorporated Hibiscus's potential efforts in the future to increase production from its existing assets; rather we have assumed that the assets' production rates will be left to decline naturally. This is also the reason why our core net profit forecasts decline after the FY26F peak (Figure 6).

This assumption may not ultimately bear out, as we think that Hibiscus will always evaluate opportunities for infill drilling projects to produce more hydrocarbons at its existing assets. However, for the purposes of our model, we do not assume that Hibiscus will execute those projects until we have been so guided by the company. We have only incorporated the contribution to production from the projects that Hibiscus has told the market that it is currently executing in FY25-26F, which is why we expect Hibiscus group's production rate to rise in FY26F, but then decline thereafter. Furthermore, the PM3 CAA PSC tenure expires on 31 Dec 2027F, which means we assume production to cease thereafter; we have not assumed an extension, although we are confident that a 10- or 20-year extension will be granted, based on the merits of Hibiscus's application for extension. If the PM3 CAA PSC is extended, we believe that the decline in production seen in our FY28-29F forecasts will likely be gentler, even in an NFA scenario.

Therefore, investors should view our production forecasts (and our revenue and earnings forecasts that flow from that), as forming the minimum achievable for Hibiscus, assuming that there are no catastrophic equipment failures or other imponderables.

Based on our cashflow model, **the current Hibiscus market price of c.RM2 represents a long-term Brent oil price of slightly less than US\$60/bbl from 2027F onwards.** As we do not expect oil prices to fall to below US\$60/bbl, given OPEC+ output discipline, Hibiscus's share price has discounted a lot of negatives and is attractively valued, in our view.

Figure 4: DCF valuation breakdown

	End-Jun 2025F	End-Jun 2026F	End-Jun 2026F	End-Jun 2026F
Total present value of cashflows to equity (RM m)	1,771.6	1,790.1	1,404.8	1,018.6
- North Sabah	617.9	558.3	394.0	284.6
- Kinabalu	155.1	153.6	79.4	45.5
- PM3 CAA	262.5	221.0	49.0	-2.2
- Anasuria Cluster	1,227.7	1,086.9	769.7	532.3
- Block 46 Cai Nuoc	0.5	-0.5	-1.2	-0.1
- Brunei MLJ	474.7	411.6	278.6	182.5
- Investment holding	-923.8	-620.9	-164.8	-24.1
Add: Unrestricted cash (RM m)	131.3	301.5	658.7	1,104.1
Add: Restricted cash (RM m)	406.3	455.0	497.9	536.6
* Non-current	328.3	377.0	419.9	458.6
* Current	78.0	78.0	78.0	78.0
Add/(less): Net working capital (RM m)	-205.5	-337.3	-92.2	-107.0
Total equity value (RM m)	2,103.7	2,209.2	2,469.1	2,552.3
No of ordinary shares (m)	768.4	768.4	768.4	768.4
Target price (RM) - end of financial years	2.74	2.88	3.21	3.32
Target price (RM) - end-CY25F / CY26F / CY27F		2.81	3.04	3.27
Exchange rate (RM:US\$1)	4.20	4.20	4.20	4.20
Cost of equity calculation				
Risk-free rate (Rf)	4.0%			
Equity risk premium (ERP)	6.0%			
Equity Beta	2.00			
Cost of equity (Ke)	16.0%			

SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 5: CGSI's estimates for Brent oil prices (US\$/bbl) and Asia JKM spot LNG prices (US\$/MMBtu)

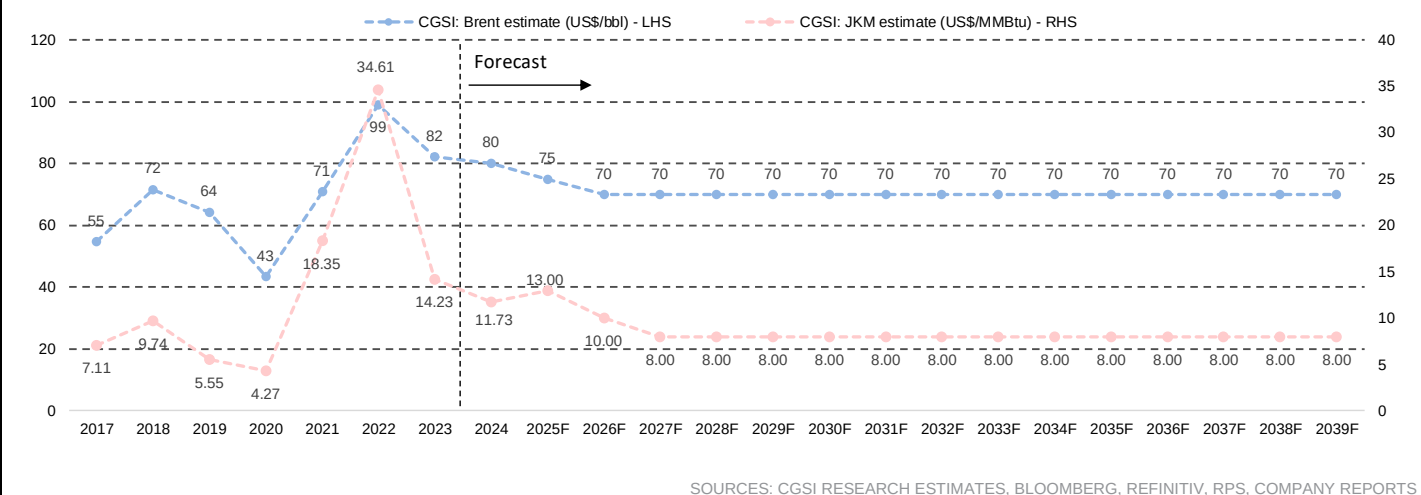
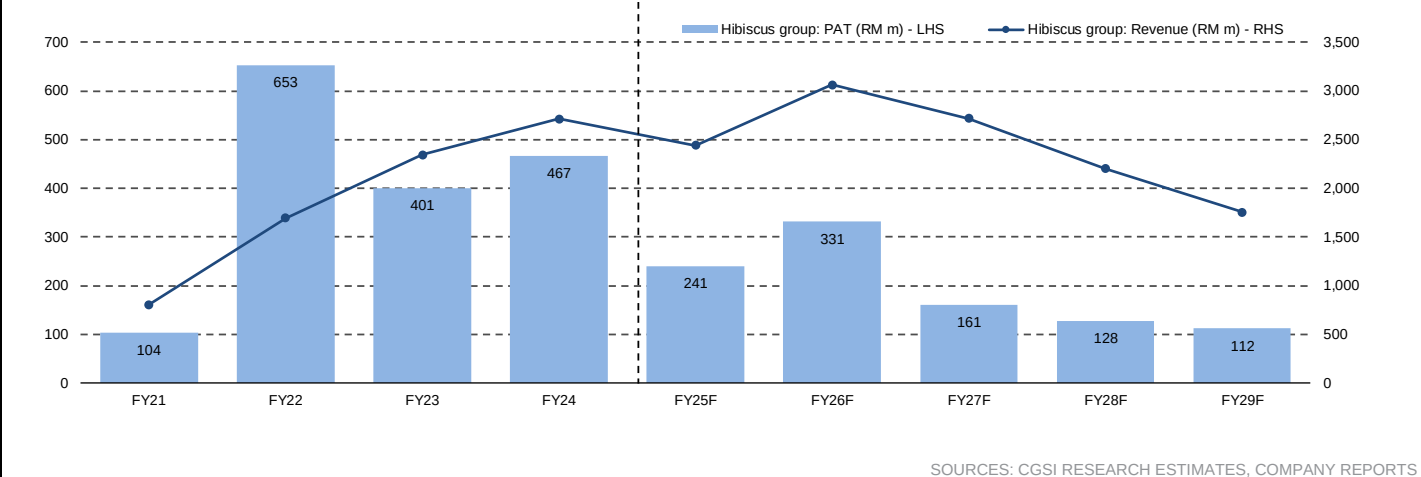


Figure 6: Hibiscus group: Revenue and PAT (RM m)



Why has Hibiscus shares been sold down since Apr 2024? ➤

Despite the long-term growth opportunities for Hibiscus, and despite the announcement of its acquisition of TotalEnergies Brunei in Jun 2024, Hibiscus's share price has been sold down almost 30% from its recent peak of RM2.80 in mid-Apr 2024. We think the main reason is the **share price's high correlation of 0.83 against the Brent crude oil price** (Figure 7).

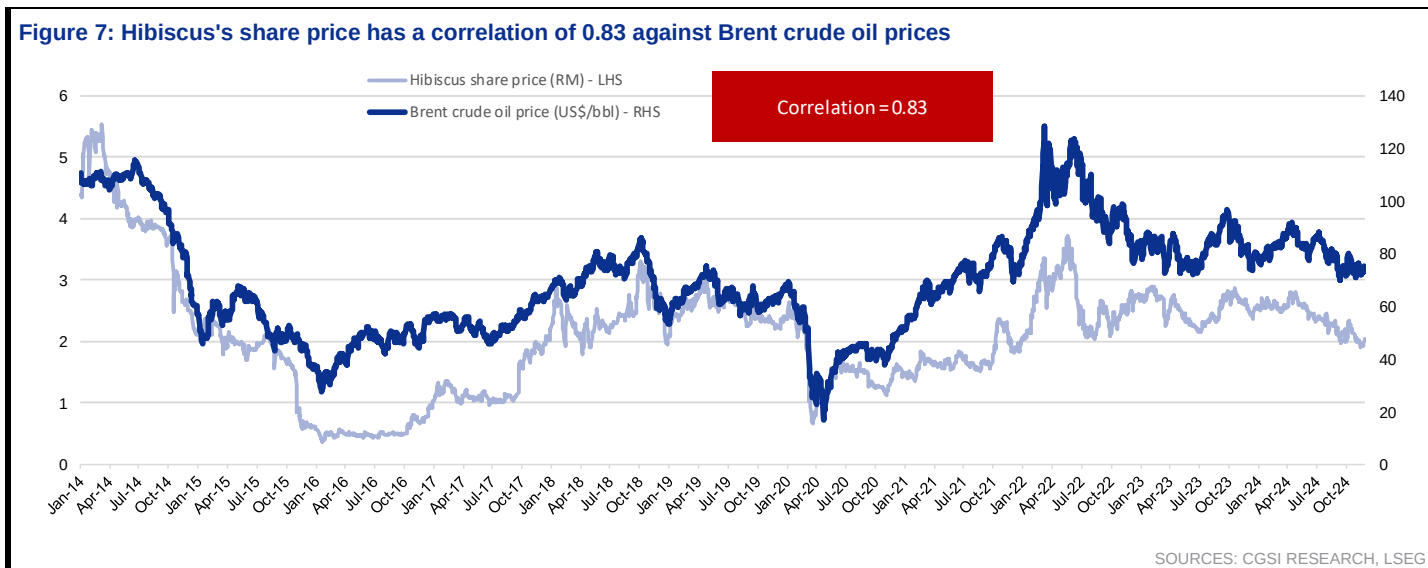
The **depreciation of the US\$ against the ringgit** from a peak of RM4.80 in Feb-Apr 2024 to RM4.10 in late-Sep and early-Oct 2024 also spooked investors, as the overwhelming majority of Hibiscus's revenue is denominated in US\$, while only 30-40% of opex is denominated in US\$ with the remaining 60-70% denominated in local currencies such as ringgit, GBP, and the Bruneian dollar.

We believe the share price has baked-in investor expectations of lower oil prices and also the weaker US\$ that will likely **negatively impact Hibiscus's earnings performance in FY25F**. Our core net profit forecast for FY25F is RM241m, lower than FY24's RM467m (Figure 6).

Another possible reason is investors' perception that **Hibiscus had purchased TotalEnergies Brunei at a relatively high valuation** when compared against its three previous acquisitions; namely the purchase of Repsol's assets as announced in Jun 2021, North Sabah in Oct 2016, and Anasuria Cluster in Aug 2015 (Figure 48). Brent oil prices had averaged US\$84/bbl in the 12 months

preceding the TotalEnergies deal announcement in Jun 2024, higher than the 12-month averages preceding the previous three acquisitions; hence, future oil prices need to remain at least as high in the long run to make the TotalEnergies acquisition work financially for Hibiscus, in our view. Oil prices have instead weakened to the US\$70-75/bbl range in recent months.

Figure 7: Hibiscus's share price has a correlation of 0.83 against Brent crude oil prices



Capital management initiatives and dividends ➤

What could help Hibiscus's share price is Hibiscus's capital management initiatives, including **share buybacks and cancellation of its treasury shares**. Between 26 Jul 2024 and 27 Nov 2024, Hibiscus had bought back 36.8m ordinary shares from the open market, and proceeded to cancel 36.6m of the treasury shares on 27 Nov 2024. This reduced by 4.5% the previous outstanding share base of 805m shares to 768.4m shares.

Hibiscus has also been proactive in guiding for **higher absolute dividends** over time, if oil prices remain supportive, even though it does not have a dividend payout policy.

Hibiscus declared its maiden dividend per share (DPS) of 3.75 sen in FY21, followed by 5 sen in FY22, 6.25 sen in FY23 and 8.5 sen in FY24.

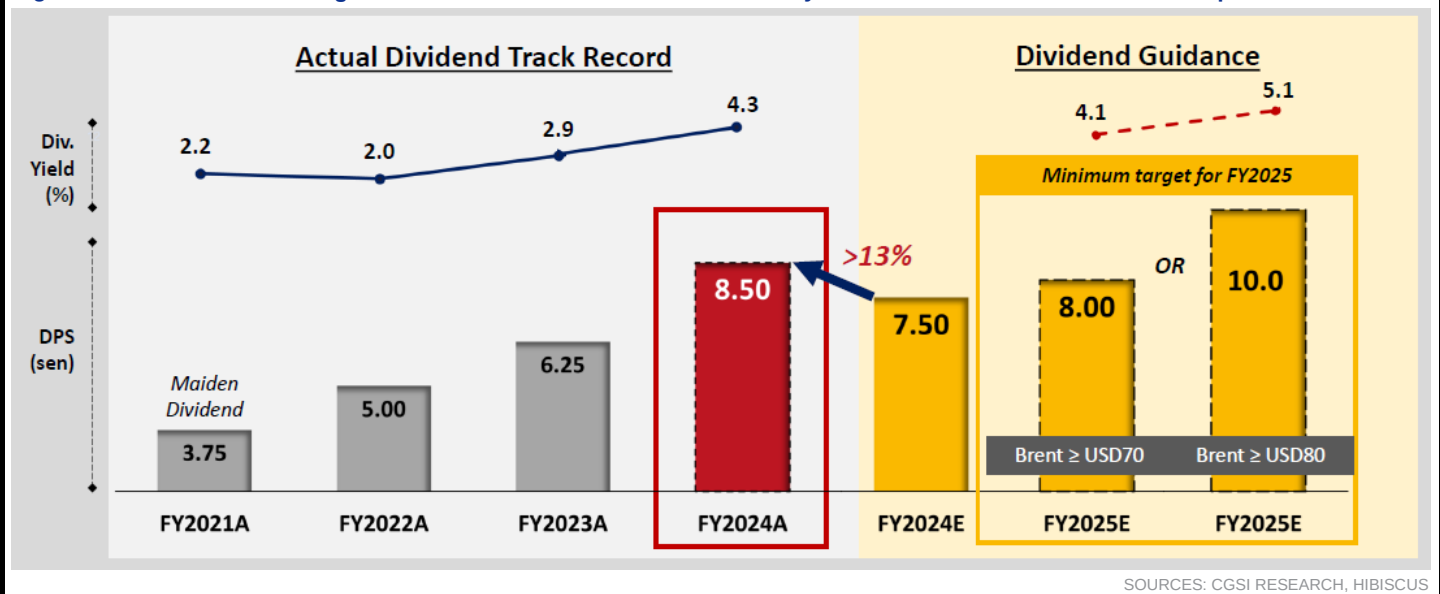
The FY24 DPS was originally 7.5 sen, but Hibiscus announced a surprise 1 sen extra on 12 Sep 2024, taking the total to 8.5 sen. Hibiscus had already declared four interim dividends during FY24, but topped it off with an extra final dividend of 1 sen. The FY24 DPS of 8.5 sen represented a payout ratio of 14.6%.

For FY25F, Hibiscus has guided that:

- DPS of 8 sen will be paid if the Brent oil price averaged at least US\$70/bbl; and
- DPS of 10 sen will be paid if the Brent oil price averaged at least US\$80/bbl.

With Brent oil prices holding above US\$70/bbl during the Jul-Sep 2024 quarter (Hibiscus's 1QFY25), Hibiscus already declared a 2 sen interim DPS earlier this month. We have pencilled-in a DPS of 8 sen for FY25F given that the Brent oil price from 1 Jul 2024 to 26 Nov 2024 had averaged US\$77/bbl. An 8 sen DPS represents c.4% dividend yield at a share price of around RM2.

Figure 8: Hibiscus's dividend guidance for FY25F – the forecast dividend yields for FY25F are based on a share price of RM1.96



Potential re-rating catalysts ➤

- We expect higher production from two ongoing projects to help drive a **41% yoy improvement in our FY26F core net profit forecast to RM331.5m**.
 - The **SF30 Water Flood Phase 2 project** is currently ongoing — all five oil producer wells will be drilled by end-2024F and all six water injector wells should be drilled by mid-2025F, according to Hibiscus. We believe that this project may be able to contribute to higher production by some c.1,200 bopd in 2025F, or c.4% of Hibiscus group production in FY25F.
 - The **Teal West project** at the Anasuria Cluster in the UK North Sea is also progressing, with first oil targeted for end-2025F or early-2026F. This project may increase the production rate from 3,835 boepd in 2025F to 7,793 boepd in 2026F, according to Hibiscus, an increment of almost 4,000 boepd in 2026F, or c.14% of Hibiscus group production in FY25F.
- A **potential extension of PM3 CAA PSC tenure, which may be announced by end-2024F**, will be good news for Hibiscus, as it has the potential to increase our DCF valuation due to the longer runway with which to monetise the available resources. There may also be **upside catalysts to our earnings forecasts** arising from a potential extension of the PSC tenure. This is because once the PSC term is extended, we expect Hibiscus to revise higher its estimate of 2P reserves at PM3 CAA. This directly leads to lower depreciation and amortisation expense in the P&L, based on the Unit of Production (UOP) accounting method that uses 2P reserves as the denominator of the UOP calculation and the production for the year as the numerator.
- The **US\$ rebound** from a low of RM4.10 in late-Sep and early-Oct 2024 to the current level of c.RM4.44 may also help Hibiscus deliver better operating results for the Oct-Dec 2024F quarter (2QFY25F).
- Also, if US president-elect **Trump tightens sanctions on Iran** after he takes power on 20 Jan 2025F, Iranian oil exports of some 1.12 MMbbl/d during 11M24 could come under pressure, which may be positive for oil prices.

We also believe that **there may be upside to our DCF valuation for Hibiscus** for a few reasons:

1. We have **more conservative estimates of production** than Hibiscus's public guidance. For example, we have assumed production of 31,919 boepd in FY26F and 30,224 boepd in FY27F, but Hibiscus has guided for average production of 35,000 boepd in CY26F.
2. Hibiscus had guided for capex of US\$283m in FY25F and US\$150m in FY26F, which we have fully incorporated into our model. We understand from Hibiscus that some **exploration capex for the PM3 CAA PSC has already been included in model** on the assumption that the PSC will be extended beyond 31 Dec 2027F. However, our cashflow forecasts end on 31 Dec 2027F and do not assume that the PSC tenure will be extended. Similarly, the capex to be spent on the PM327 PSC and the PKNB Cluster have been included in Hibiscus's guidance, but the cashflow forecasts from those fields have not yet been included as Hibiscus is not yet ready to disclose the details.
3. A **potential extension of the PM3 CAA PSC licence** by 10 years to 31 Dec 2037F or by 20 years to 31 Dec 2047F will be positive for our DCF valuation, as Hibiscus has a longer runway to extract value from the PSC and the 2P reserve estimates for PM3 CAA will naturally be increased. We can only make an estimate of the potential incremental valuation once Hibiscus makes the necessary disclosures.
4. The Bunga Aster-1 exploration well at PM3 CAA was drilled in FY24 and achieved first oil in May 2024. However, the incremental 2P reserves from this reservoir have not yet been included in Hibiscus's disclosures, as the first well was not drilled down to the oil-water contact. This means that the potential 2P reserves could potentially be fairly sizable, and we estimate that **Hibiscus's net 2P reserves from this Bunga Aster reservoir could be between 4.2 MMbbl and 16.8 MMbbl**, depending on the outcome of an appraisal well that Hibiscus plans to drill in 2025F. This compares against Hibiscus's total 2P reserves as at 1 Jul 2024 of 57.4 MMboe. Given the potential sizable reserves, we expect Hibiscus to drill more development wells in the foreseeable future.
5. Hibiscus disclosed **sizeable 2C gas reserves from the PKNB Cluster of 47 MMboe**. Hibiscus intends to develop and monetise the gas reserves from 2028F onwards via tie-backs to the PM3 CAA production infrastructure, assuming that the PM3 CAA PSC is extended.
6. Hibiscus believes that RPS, which is the reserves auditor and valuer for the TotalEnergies acquisition, has offered a very **conservative assessment of the volume of the Brunei MLJ 2P reserves**. If Hibiscus is correct, more gas and condensate can be extracted from this asset than what we have currently imputed into our model.
7. Hibiscus is also enthusiastic about the **many medium-term prospects for hydrocarbon resource monetisation in Brunei**. Although the TotalEnergies Brunei acquisition may be perceived by many investors as being 'expensive', Hibiscus sees this as an opportunity to step foot into Brunei, gradually gain the trust of the national oil and gas regulator, and eventually secure the award of new concessions that can be developed via tie-back to the Brunei MLJ production infrastructure.

Downside risks ►

Downside risks include:

1. A **sizeable deferred tax provision for Anasuria Cluster may be booked in by Hibiscus in its 2QFY25F results** (the Oct-Dec 2024F quarter), in our view, because the UK has increased the Energy Profits Levy (EPL) rate from 35% to 38% effective 1 Nov 2024, removed enhance tax deductions on certain categories of capex, and extended the duration of the EPL regime from 31 Mar 2028F to 31 Mar 2030F. We are unclear on the amount of the deferred

tax provision, as we are waiting for guidance from Hibiscus. In our estimate, this deferred tax provision may offset the potential earnings uplift in 2QFY25F from a qoq uptime recovery at the Anasuria Cluster, after it had experienced both planned and unplanned outages in 1QFY25 that caused uptime to fall to only 46%.

- Separately, there is potential in 3QFY25F (Jan-Mar 2025F quarter) for a **write-off of the costs incurred to drill the South Furious Ungu well** in 2023-2024 previously. Hibiscus guided that an assessment of the subsurface data can only be completed in early-2025F. If the well is not viable to develop, a gross amount of RM46.4m may be written off, or a net-of-tax amount of RM28.6m, according to Hibiscus.
- Hibiscus is exposed to the risk of lower oil prices and of a weaker US\$.
 - We estimate that every **US\$5/bbl rise or fall in the Brent oil price** will impact our FY25F core net profit forecast by **25%**.
 - Every 10% depreciation in the US\$** exchange rate against the ringgit can negatively impact our FY25F core net profit forecast by **30%**.
- Hibiscus negotiated during 2022-2024 the purchase of TotalEnergies Brunei when oil prices were high** in the aftermath of the Russia-Ukraine war, compared to the prevailing oil prices today. If the Brunei MLJ production volumes disappoint Hibiscus's expectations, Hibiscus may not be able to fall back on oil prices to make up the difference in revenue expectations.

Sector comparisons table ➤

Figure 9: Sector Comparisons

Company	Bloomberg Ticker	Recom.	Price	Target Price	Market Cap (US\$ m)	Core P/E (x)		3-year EPS CAGR (%)	P/BV (x)		Recurring ROE (%)			EV/EBITDA (x)		Dividend Yield	
						CY24F	CY25F		CY24F	CY25F	CY24F	CY25F	CY26F	CY24F	CY25F	CY24F	CY25F
Hibiscus Petroleum Bhd	HIBI MK	Add	RM2.03	RM2.81	350	4.6	5.5	-15.2%	0.5	0.5	11.5%	8.7%	7.1%	1.7	1.6	4.1%	3.9%
Medco Energi Internasional	MEDC IJ	Add	Rp1,090	Rp1,750	1,729	3.9	4.4	-1.2%	0.8	0.7	22.2%	16.7%	13.6%	3.5	3.4	5.2%	4.5%
PTT	PTT TB	Reduce	THB32.25	THB32.00	26,869	10.5	10.4	-11.4%	0.8	0.8	7.8%	7.4%	7.2%	4.9	4.6	3.8%	3.9%
PTT Exploration & Production	PTTEP TB	Add	THB127.50	THB180.00	14,765	6.8	8.1	-6.6%	0.9	0.9	14.1%	11.4%	10.9%	1.9	2.0	7.3%	6.2%
Average E&P group - under CGSI coverage						8.3	8.9	-9.0%	0.8	0.8	10.4%	9.1%	8.6%	3.7	3.6	5.1%	4.7%
BP plc	BP/ LN	Not Rated	GBP384.65	n.a.	78,404	4.9	4.5	-21.7%	0.68	0.64	13.9%	14.6%	15.2%	2.2	2.1	10.3%	11.0%
Chevron	CVX US	Not Rated	US\$161.93	n.a.	291,003	15.4	13.4	-0.4%	1.88	1.89	12.1%	14.1%	16.1%	6.8	6.5	4.0%	4.1%
ConocoPhillips	COP US	Not Rated	US\$108.34	n.a.	140,145	13.9	13.3	-0.6%	2.25	2.28	17.5%	17.0%	18.5%	5.6	5.1	2.9%	2.9%
Eni S.p.A.	ENI IM	Not Rated	€13.41	n.a.	46,533	6.8	6.8	-10.0%	0.76	0.73	10.6%	10.9%	11.3%	2.9	3.1	8.3%	8.6%
Equinor	EQNR NO	Not Rated	NOK267.20	n.a.	67,589	7.6	7.3	-15.7%	1.48	1.39	19.9%	19.6%	18.3%	1.8	1.9	10.9%	6.7%
ExxonMobil	XOM US	Not Rated	US\$117.96	n.a.	518,445	14.6	15.0	-3.6%	1.96	1.98	14.4%	13.1%	14.7%	7.3	6.9	3.3%	3.4%
Shell	SHEL LN	Not Rated	GBP2,532	n.a.	198,241	4.8	4.8	-2.2%	0.65	0.62	13.8%	13.2%	12.6%	2.5	2.7	6.9%	7.3%
TotalEnergies	TTE FP	Not Rated	€54.97	n.a.	139,287	6.4	6.2	-9.5%	0.98	0.91	15.5%	15.1%	14.7%	3.4	3.5	6.5%	7.0%
Average E&P group - supermajors						10.0	9.8	-7.9%	1.4	1.4	14.2%	14.1%	14.7%	4.3	4.3	4.8%	4.8%
CNOOC	883 HK	Not Rated	HK\$17.10	n.a.	108,698	5.2	5.2	1.1%	1.01	0.95	21.1%	18.9%	17.1%	2.5	2.3	8.0%	7.9%
Indian Oil Corp Ltd	IOCL IN	Not Rated	INR138.63	n.a.	23,154	4.4	11.2	29.0%	1.14	0.96	10.1%	9.3%	11.3%	4.0	7.4	10.7%	3.7%
ONGC	ONGC IN	Not Rated	INR256.70	n.a.	38,196	7.0	7.0	7.7%	1.04	0.89	9.8%	13.7%	13.3%	3.7	3.8	5.0%	4.9%
Petrobras	PBR US	Not Rated	US\$14.28	n.a.	89,664	5.3	4.2	-24.2%	1.06	0.85	27.8%	22.5%	18.2%	2.3	2.3	18.0%	12.6%
Petrochina	857 HK	Not Rated	HK\$5.51	n.a.	194,583	5.6	5.7	-4.0%	0.61	0.58	11.4%	10.5%	10.1%	2.5	2.5	8.5%	8.1%
PetroVietnam	PVS VN	Not Rated	VND38,000	n.a.	715	17.4	13.0	16.2%	1.31	1.24	7.9%	9.8%	11.6%	14.6	12.1	2.0%	2.0%
PTT	PTT TB	Reduce	THB32.25	THB32.00	26,869	10.5	10.4	-11.4%	0.8	0.8	7.8%	7.4%	7.2%	4.9	4.6	3.8%	3.9%
PTT Exploration & Production	PTTEP TB	Add	THB127.50	THB180.00	14,765	6.8	8.1	-6.6%	0.9	0.9	14.1%	11.4%	10.9%	1.9	2.0	7.3%	6.2%
Saudi Aramco	ARAMCO AB	Not Rated	SAR27.45	n.a.	1,768,469	16.4	16.6	-4.7%	4.53	4.23	11.6%	26.4%	26.1%	7.5	7.6	6.6%	5.0%
Sinopec	386 HK	Not Rated	HK\$4.16	n.a.	98,345	8.0	7.4	-0.1%	0.57	0.55	7.2%	7.6%	8.0%	3.0	2.8	8.4%	9.0%
Average E&P group - NOCs						12.9	13.0	-6.0%	2.4	2.2	11.5%	17.9%	17.5%	5.5	5.6	7.0%	5.4%
Brava Energia	BRAV3 BZ	Not Rated	BRL19.88	n.a.	1,534	30.1	4.4	na	0.76	0.69	2.9%	16.4%	15.2%	5.3	2.1	0.6%	13.0%
Capricorn Energy	CNE LN	Not Rated	GBP237.00	n.a.	213	16.2	31.8	na	0.25	0.24	1.2%	0.8%	0.2%	0.9	0.3	57.5%	44.1%
EnQuest	ENQ LN	Not Rated	GBP11.20	n.a.	266	1.6	1.5	na	0.31	0.27	21.1%	19.0%	13.0%	0.7	0.6	11.4%	17.1%
Genel Energy	GENL LN	Not Rated	GBP85.00	n.a.	302	na	na	5.4%	0.44	0.39	-8.1%	-0.1%	3.5%	1.4	0.5	6.7%	9.0%
Hibiscus Petroleum Bhd	HIBI MK	Add	RM2.03	RM2.81	350	4.6	5.5	-15.2%	0.5	0.5	11.5%	8.7%	7.1%	1.7	1.6	4.1%	3.9%
Jadestone Energy	JSE LN	Not Rated	GBP25.00	n.a.	172	na	2.9	na	na	28.97	-96.2%	-704.3%	430.4%	1.8	0.6	0.0%	0.0%
Medco Energi Internasional	MEDC IJ	Add	Rp1,090	Rp1,750	1,729	3.9	4.4	-1.2%	0.8	0.7	22.2%	16.7%	13.6%	3.5	3.4	5.2%	4.5%
OKEA	OKEA NO	Not Rated	NOK19.99	n.a.	188	4.2	3.4	-31.8%	1.67	1.23	30.0%	41.8%	29.0%	0.2	0.3	0.0%	14.3%
OMV AG	OMV AV	Not Rated	€37.92	n.a.	13,115	5.5	5.8	12.8%	0.65	0.64	12.0%	11.2%	11.6%	1.8	2.1	13.0%	12.2%
Pharos Energy	PHAR LN	Not Rated	GBP21.80	n.a.	115	2.7	na	na	0.22	0.20	8.5%	-4.9%	-3.7%	0.6	0.2	5.8%	7.0%
Santos	STO AU	Not Rated	A\$6.61	n.a.	14,001	24.7	25.8	-5.7%	2.07	2.00	8.5%	7.9%	9.8%	10.2	9.9	2.3%	2.0%
Serica Energy	SQZ AU	Not Rated	GBP128.60	n.a.	639	2.2	2.6	-24.1%	0.35	0.40	19.1%	14.4%	11.3%	0.7	0.4	36.6%	29.4%
Woodside Petroleum	WDS AU	Not Rated	A\$24.51	n.a.	30,352	22.2	34.5	-34.8%	2.02	2.01	8.8%	5.8%	4.8%	8.3	8.7	3.5%	2.3%
Average E&P group - independents						15.9	18.5	-12.4%	1.6	1.5	9.8%	8.3%	8.2%	5.5	5.5	4.2%	3.5%

SOURCES: CGSI RESEARCH ESTIMATES, BLOOMBERG, COMPANY REPORTS; DATA AS AT 29 NOV 2024; NON-RATED COMPANIES' ESTIMATES ARE BASED ON BLOOMBERG CONSENSUS ESTIMATES (NR COMPANIES SHOW REPORTED NET PROFIT)

Abbreviations used in this report ➤

Fiscal systems

PSC: Production Sharing Contract

DRO: Discovered Resource Opportunity

NOC: National oil company, referring to Petronas in Malaysia

POC: Private oil companies

Production assets

2P reserves: Proved and probable reserves; 50% probability that the volume of hydrocarbons recovered will be equal to or exceed this number

2C resources: Best estimate of contingent resources; 50% probability that the quantity of hydrocarbons recovered will be equal to or exceed this number

FPSO: Floating Production Storage Offload vessel

FSO: Floating Storage Offload vessel

OSV: Offshore support vessels

Measurements

bbl: barrels (of oil)

bbl/day: barrels (of oil) per day

Bcf: Billion standard cubic feet, referring to the volume of natural gas

boe: barrels of oil equivalent, a measure of the heating value of fossil fuels; natural gas volumes are converted into barrels of oil equivalent whereby 1 boe is approximately 5,000 scf (5 Mscf) of natural gas

K: Thousand, as in kboe (thousands of barrels of oil equivalent)

M: Thousand, as in Mscf (thousands of standard cubic feet of gas)

MM: Million

MMBtu: Million British Thermal Units, referring to the heating value of natural gas whereby 1 boe is equivalent to 5.8 MMBtu

Greenhouse gases and emissions

CCS: Carbon capture and storage

CH₄: Methane gas, which is also called natural gas

CO₂: Carbon dioxide, referring to CO₂ present in natural gas or emissions of CO₂

CO₂e: Carbon dioxide equivalent, referring to emissions, whereby CH₄ and H₂S are converted into a CO₂e measure by multiplying against the Global Warming Potential (GWP) values relative to CO₂

tCO₂e: tonnes of CO₂e

GHG: Greenhouse gases

GWP: Global Warming Potential of various non-CO₂ gaseous emissions relative to CO₂ over a 100-year time horizon; for instance, CH₄ has a GWP value of 25, which means it is 25 times more powerful than CO₂ over a 100-year time horizon

H₂S: Hydrogen sulfide, referring to natural gas contaminants or emissions

ETS: Emissions trading system

UKA: United Kingdom Allowance; 1 UKA must be purchased and surrendered for every tCO₂ emitted by UK entities above the permitted free allowances

N₂O: Nitrous oxide

HFC: Hydrofluorocarbons

SECTION 2: BRIEF HISTORY OF HIBISCUS

Early history ►

Initial Public Offer (IPO)

Hibiscus was listed under Special Purpose Acquisition Company (SPAC) rules on the main market of Bursa Malaysia on 25 Jul 2011. Hibiscus raised RM234m via the issue of new shares and warrants. According to Hibiscus's prospectus, "SPACs are companies which have no operations or income generating business at the point of IPO but undertake an IPO for the purposes of raising funds to acquire operating companies, businesses or assets, otherwise known as qualifying acquisition(s)... we intend to establish our Company as a junior independent oil and gas exploration and production (E&P) player in the near to medium term. Initially, our focus will be to identify and acquire the rights to develop small- and medium-sized oil and gas fields in the South Asia, Middle-East, East Asia and Oceania regions."

Lime Petroleum and HiRex

The first asset which Hibiscus purchased was a 35% equity interest in Lime Petroleum Plc on 18 Apr 2012 for US\$55m; Lime Petroleum owned various upstream concessions in the Middle East, including in Oman and the UAE. Following the above 'qualifying asset acquisition', Bursa Malaysia reclassified Hibiscus from a SPAC to an oil and gas company. Lime Petroleum was then 65% owned by Rex International, which is listed on the Singapore Exchange.

In 2013, Lime Petroleum drilled a non-commercial well discovery in Oman, and in 2014, a second Omani well was drilled which turned out to be successful. Lime Petroleum had other Middle East exploration concessions in the UAE and separately acquired various stakes in Norway exploration assets and blocks in 2013-2014.

In 2013, Hibiscus entered into a JV with Rex South East Asia Ltd (unlisted wholly-owned subsidiary of Rex International) to form HiRex Petroleum Sdn Bhd (unlisted), which had the ambition of acquiring mature concessions in Southeast Asia and Australia.

In 2015, Rex International completed capital injection exercises into various subsidiaries of Lime Petroleum, which significantly diluted Hibiscus's stakes in Lime Petroleum's Norwegian and Middle Eastern assets. Hibiscus subsequently filed an court application in the Isle of Man against three directors of Lime Petroleum for breach of trust and breach of fiduciary duty. The judge ruled in Lime Petroleum's favour, and Hibiscus ultimately decided to cease further legal proceedings and eventually wrote off its investments in Lime Petroleum. In 2016, Hibiscus's investments in HiRex were also fully written off after the disagreement with Rex International.

Australia assets

In 2013, Hibiscus's wholly-owned subsidiary, Carnarvon Hibiscus Pty Ltd, became the operator and majority owner of the VIC/P57 permit area in the Bass Strait, Australia for A\$13.5m via a farm-in exercise with 3D Oil Limited (presently known as 3D Energi Limited), and also became a 13.04% shareholder of 3D Oil for A\$2m. Carnarvon Hibiscus drilled its first exploration well in Nov 2015 in Australia – the Sea Lion-1 – but this was not commercially viable. The VIC/P57 permit was surrendered back to the Australian government in 2022.

In 2019, Carnarvon Hibiscus farmed into the VIC/P74 permit by buying a stake from 3D Oil, but Carnarvon Hibiscus transferred it back to 3D Oil at zero cost in 2022 after finding that the 3D seismic did not yield promising results.

Separately, in 2013, Hibiscus was awarded the VIC/L31 production licence by the Australian oil and gas regulator National Offshore Petroleum Titles Administrator (NOPTA). This licence contains the West Seahorse discovery which has 2C oil resources of 8 MMbbl. Because no development happened after five years, Carnarvon Hibiscus applied to convert this licence into the VIC/RL17 retention lease in 2018, and this was approved by NOPTA in 2022, with Carnarvon Hibiscus given another five years to develop the asset. However, Hibiscus has since

assessed that it will not likely develop the asset, and hence its investments in Australia have been fully written off. Hibiscus is currently in the process of decommissioning the abandoned wells and will return the VLC/RL17 permit to NOPTA by late-2026F.

Change of strategy to focus on producing assets ►

In 2015, Hibiscus decided to change its strategy from pursuing exploration opportunities to acquiring producing assets. Hibiscus continues to maintain this strategy to this day.

This subsequently led to the acquisition of interests in several producing assets, namely the Anasuria Cluster, UK; North Sabah, Malaysia; acquisition of Repsol's assets in Malaysia and Vietnam; and the recent acquisition of TotalEnergies Brunei.

(A) Acquisition of Anasuria Cluster

In Aug 2015, Hibiscus tied up with Ping Petroleum and signed an agreement with Shell and Esso to buy the Anasuria Cluster in the UK North Sea; this transaction was completed on 11 Mar 2016 and gave Hibiscus a 50% working interest in the Anasuria Cluster. The effective date of the acquisition was 1 Jan 2015, which meant that all the economics benefits and risks of the Anasuria Cluster belonged to the acquiring parties from that date onwards.

Hibiscus later built on its UK presence by buying a 50% interest in the Marigold West and Sunflower fields in Oct 2018. Hibiscus secured direct awards of several licences by the North Sea Transition Authority (NSTA), which is the UK oil and gas regulator, at the 32nd Offshore Licensing Round in 2019 (Teal West, Cook West, Kildrummy fields) and the 33rd Offshore Licensing Round in 2023-2024 (Crown, Cross fields). Also, Hibiscus farmed into a licence that contained the Fyne field in 2023.

(B) Acquisition of North Sabah

In Oct 2016, Hibiscus signed an agreement to buy a 50% participating interest in the North Sabah PSC from Shell; this transaction was completed on 31 Mar 2018, with an effective date of 1 Jan 2017.

(C) Acquisition of Repsol's assets

In Jun 2021, Hibiscus entered into an agreement with Repsol to buy its assets in Southeast Asia; this included the PM3 CAA PSC in the Malaysia-Vietnam Commercial Arrangement Area (35% interest), the Kinabalu PSC in Malaysia (60% interest), the PM305 and PM314 PSC blocks in Malaysia (60% interest), and Block 46 Cai Nuoc in Vietnam (70% interest). This transaction was completed on 24 Jan 2022, with an effective date of 1 Jan 2021.

(D) Acquisition of TotalEnergies Brunei

In Jun 2024, Hibiscus signed an agreement with TotalEnergies to buy 100% equity stake in TotalEnergies Brunei, which holds a 37.5% working interest in Block B in Brunei that contains the MLJ field; this transaction was completed on 14 Oct 2024, with an effective date of 1 Jan 2023.

In addition to the above acquisitions, Hibiscus also recently expanded its Malaysia portfolio via:

- Award by Petronas to Hibiscus of a 65% participating interest in the **PKNB Cluster**, with an effective date of 1 Jul 2024; and
- Farm-in to secure a 30% participating interest in the **PM327 PSC**, with an effective date of 5 Jul 2024.

Hibiscus plans to ultimately produce the reserves and resources from the PKNB Cluster and the PM327 PSC to the PM3 CAA production facilities.

Figure 10: Hibiscus's asset purchases and company acquisitions since 2016 - the key assets are highlighted in blue

No	Description	Location	Hibiscus's participating interest	Buyer	Seller	Date of agreement	Legal completion date	Effective economic date
1	Anasuria Cluster concession asset purchases							
	> Licence No P013: Guillemot A, Teal, Teal South fields	UK North Sea	50%	Anasuria Hibiscus UK *	Shell, Esso	6-Aug-15	11-Mar-16	1-Jan-15
	> Licence No P185: Cook field	UK North Sea	19.325%	Anasuria Hibiscus UK *	Shell, Esso	6-Aug-15	11-Mar-16	1-Jan-15
	> Licence No P2451: Fyne	UK North Sea	42.5%	Anasuria Hibiscus UK *	Rapid Oil	30-Aug-23	20-Nov-23	20-Nov-23
2	North Sabah PSC asset purchase	Sabah, Malaysia	50%	SEA Hibiscus *	Shell	12-Oct-16	31-Mar-18	1-Jan-17
3	Greater Marigold Area Development (GMAD) - asset purchases							
	> Licence No P198: Marigold Wes	UK North Sea	87.5%	Anasuria Hibiscus UK *	Caldera Petroleum	9-Oct-18	16-Oct-18	16-Oct-18
	> Licence No P198: Sunflower	UK North Sea	87.5%	Anasuria Hibiscus UK *	Caldera Petroleum	9-Oct-18	16-Oct-18	16-Oct-18
4	Fortuna International Petroleum Corporation (FIPC) - company acquisition							
	> Kinabalu Oil PSC	Sabah, Malaysia	60%	Peninsula Hibiscus *	Repsol	2-Jun-21	24-Jan-22	1-Jan-21
	> PM3 CAA PSC	Malaysia-Vietnam Commercial Arrangement Area	35%	Peninsula Hibiscus *	Repsol	2-Jun-21	24-Jan-22	1-Jan-21
	> PM305 and PM314 PSCs	Peninsular Malaysia	60%	Peninsula Hibiscus *	Repsol	2-Jun-21	24-Jan-22	1-Jan-21
	> Block 46 Cai Nuoc PSC	Vietnam	70%	Peninsula Hibiscus *	Repsol	2-Jun-21	24-Jan-22	1-Jan-21
5	TotalEnergies Brunei - company acquisition							
	> Block B MLJ	Brunei	38%	Simpur Hibiscus *	TotalEnergies	13-Jun-24	14-Oct-24	1-Jan-23
* all wholly-owned (unlisted) subsidiaries of Hibiscus Petroleum Bhd								
SOURCES: CGSI RESEARCH, COMPANY REPORTS								

Figure 11: Hibiscus's PSC and concession awards and farm-ins - the key assets are highlighted in blue

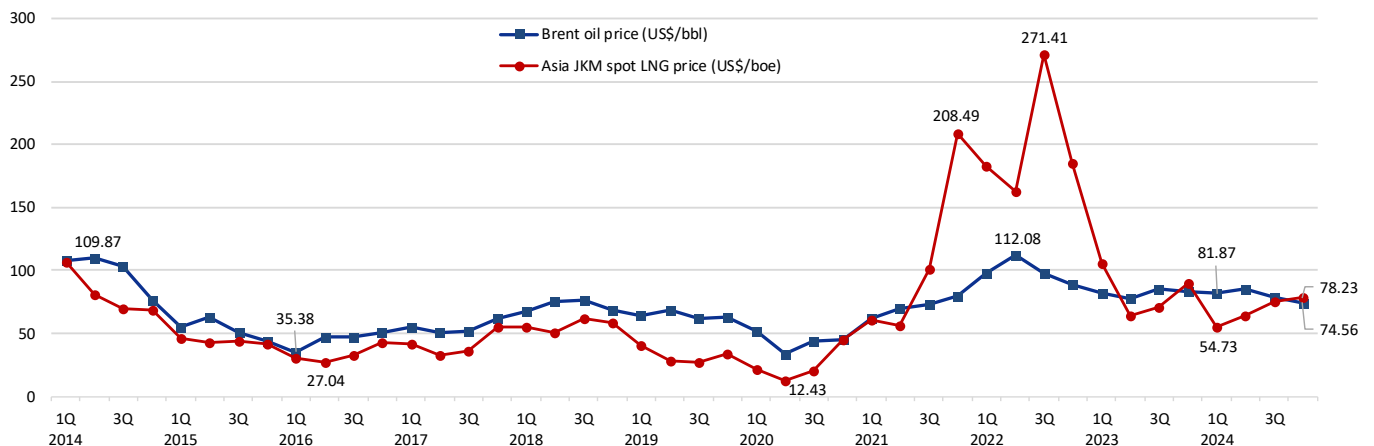
No	Description	Location	Hibiscus's participating interest	Buyer / Holder of licence	Seller / Awarded by	Date of agreement	Award / purchase date	Effective economic date
1	Anasuria Cluster concession licence awards							
	> Licence No P2535: Teal West	UK North Sea	100%	Anasuria Hibiscus UK *	NSTA, 32nd licencing round	-	3-Sep-20	19-Jan-21
	> Licence No P2532: Cook West, Cook North	UK North Sea	19.325%	Anasuria Hibiscus UK *	NSTA, 32nd licencing round	-	3-Sep-20	2-Feb-21
2	Greater Marigold Area Development (GMAD) - licence awards							
	> Licence No P2518: Kildrummy	UK North Sea	100%	Anasuria Hibiscus UK *	NSTA, 32nd licencing round	-	3-Sep-20	19-Jan-21
	> Licence No P2608: Crown	UK North Sea	100%	Anasuria Hibiscus UK *	NSTA, 33rd licencing round	-	30-Oct-23	23-Feb-24
	> Licence No P2608: Cross	UK North Sea	100%	Anasuria Hibiscus UK *	NSTA, 33rd licencing round	-	31-Jan-24	4-Jun-24
3	PKNB Cluster PSC award	Peninsular Malaysia	65%	Peninsula Hibiscus *	Petronas, Malaysia Bid Round Plus in 2024	-	26-Jul-24	1-Jul-24
4	PM327 PSC farm-in	Peninsular Malaysia	30%	Straits Hibiscus *	Petronas Carigali	23-Aug-24	30-Sep-24	5-Jul-24
* all wholly-owned (unlisted) subsidiaries of Hibiscus Petroleum Bhd								
NSTA: North Sea Transition Authority								
SOURCES: CGSI RESEARCH, COMPANY REPORTS								

SECTION 3: THE MACRO ENVIRONMENT

Oil price outlook ►

The near-term outlook for Brent oil prices look slightly weakish on fundamental grounds. Brent oil prices have already moderated from an average of US\$81.87/bbl in 1Q24 to US\$78.23/bbl so far in 4Q24F, despite geopolitical tensions in the Middle East, and despite the Organization of the Petroleum Exporting Countries (OPEC) curtailing output by a cumulative 5.8 MMbbl/d since Oct 2022 (2 MMbbl/day of production cuts from Oct 2022; an additional 1.6 MMbbl/d from May 2023; and a further 2.2 MMbbl/d in voluntary cuts from Jan 2024 by eight member countries).

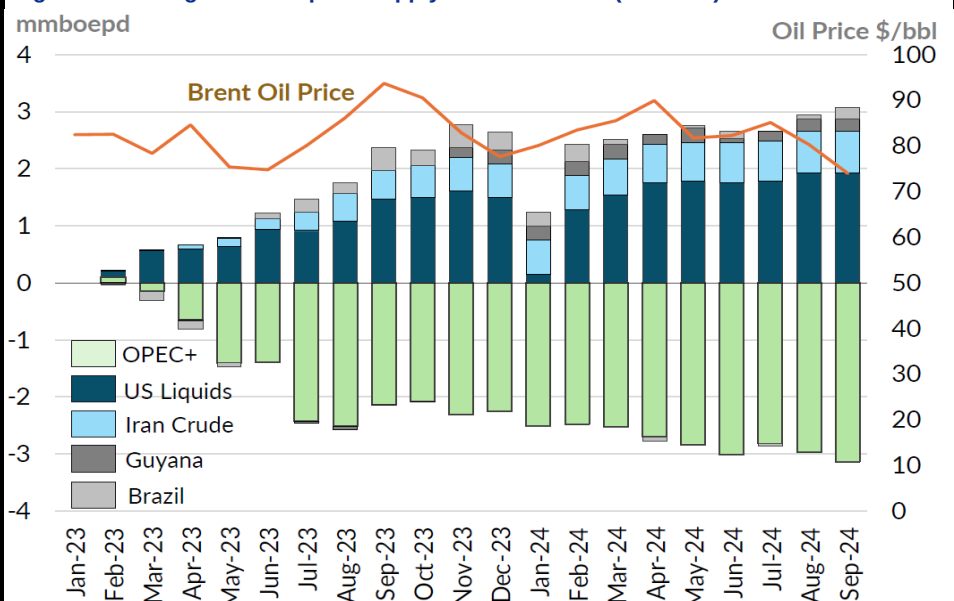
Figure 12: Brent oil price (US\$/bbl) and Asia JKM spot LNG price (US\$/boe) – the US\$/MMBtu gas price is converted to US\$/boe on the basis that 1 boe = 5.8 MMBtu



SOURCES: CGSI RESEARCH, LSEG

Without OPEC+ controlling their aggregate supply of oil to the market, Brent oil prices would have corrected more sharply (OPEC+ comprises OPEC and its partner countries like Russia, Kazakhstan, Mexico, etc.) In Figure 13, we can see how **OPEC+ has given up market share in favour of other producers such as the US, Iran, Guyana and Brazil** (Iran is part of OPEC but is exempt from the output cuts imposed on other OPEC members).

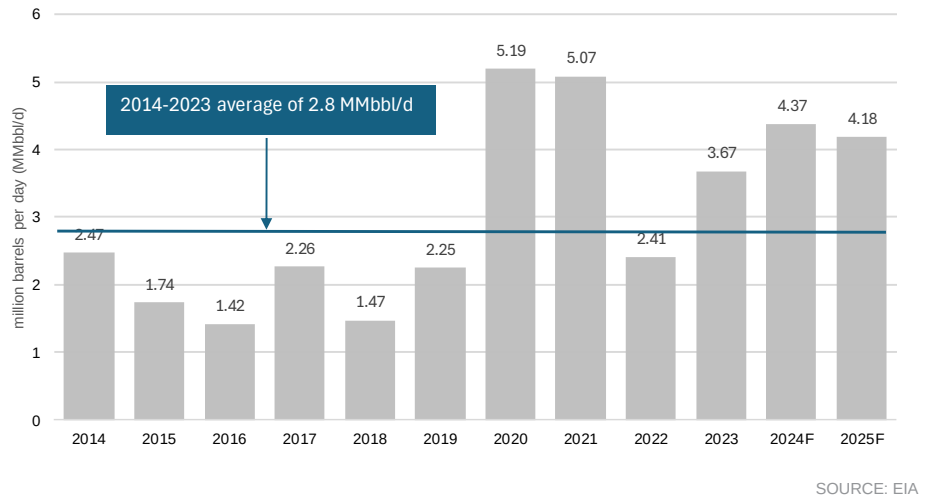
Figure 13: Changes in oil liquids supply since Jan 2023 (MMbbl/d)



SOURCE: WESTWOOD GLOBAL ENERGY

As a result, OPEC by itself may have spare crude oil production capacity of 4.37 MMbbl/d by end-2024F, according to the US Energy Information Administration (EIA), vs. the 2014-2023 average of 2.8 MMbbl/d. **OPEC+ had spare production capacity of 6.2 MMbbl/day in Oct 2024**, according to the International Energy Agency (IEA), double the level in 2019.

Figure 14: OPEC surplus crude oil production capacity (MMbbl/d)



Not helping the oil price is the 3.1% yoy **decline in China's crude oil imports** in terms of MMbbl/d during 10M24 vs. 2023 (Figures 15-16); this was probably due to China's relatively weak economic growth, the growing penetration of electric vehicles (EV), and possibly a slowdown in the stockpiling of crude that had been particularly aggressive in 2023 upon the post-Covid reopening, with Reuters reporting in Nov 2024 that "the volume of crude refined [in China] is well short of the total available from imports and local output."

In their latest Nov 2024 reports, both **OPEC and the IEA have reduced their demand projections for 2024F and 2025F**, from projections made earlier this year (Figure 17). OPEC remains the most optimistic for demand growth in 2025F, with the IEA the most conservative, and the US EIA in between, but closer to the IEA numbers (Figure 18).

Figure 15: China crude oil imports (MMbbl/d)

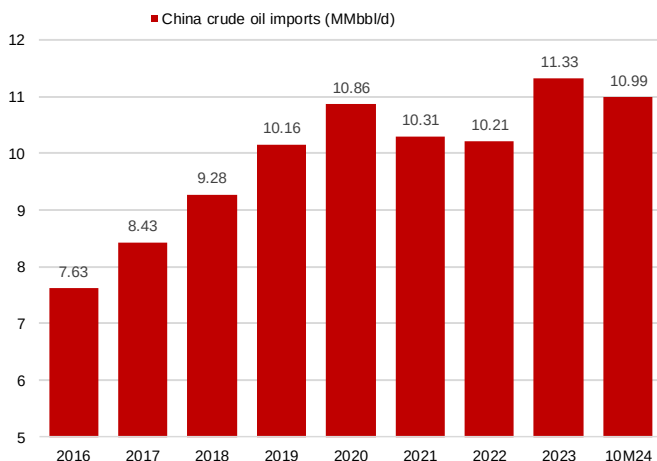


Figure 16: China crude oil imports (yoy change)

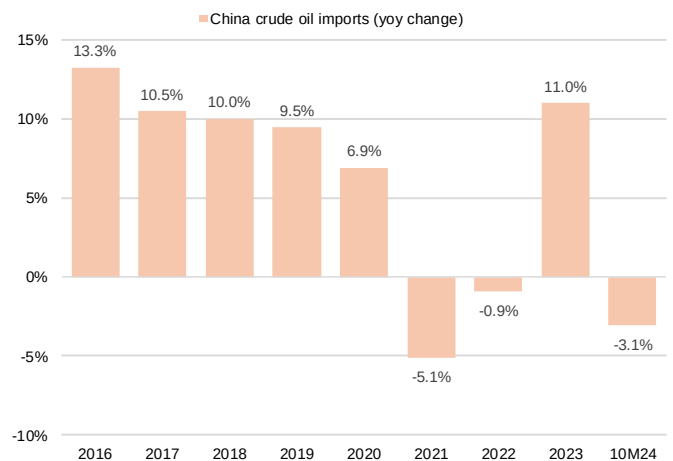
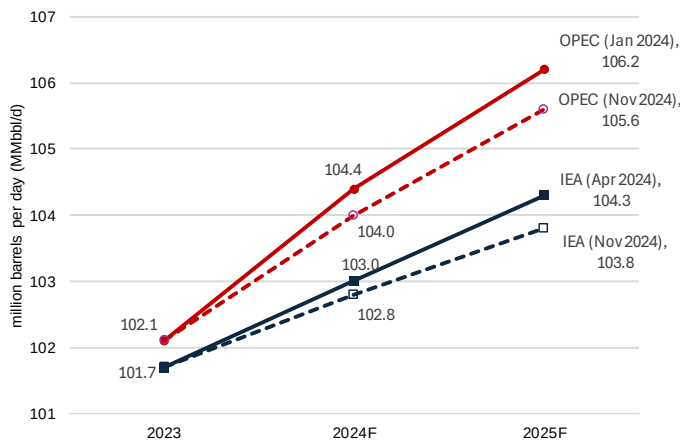
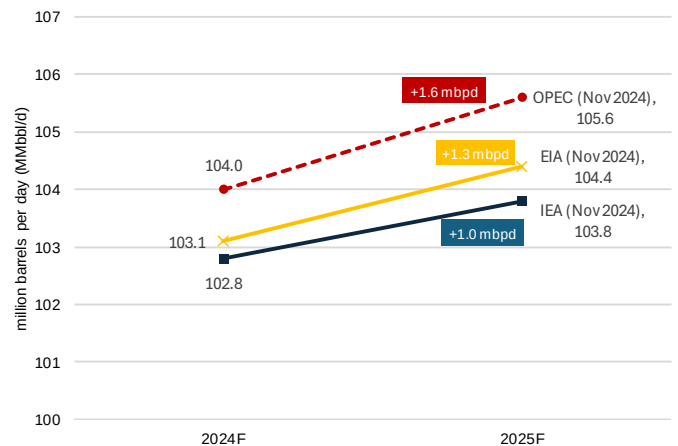


Figure 17: OPEC and IEA world oil demand forecasts have been revised lower; IEA's 2025F demand forecast is 1.8 MMbbl/d lower than OPEC's forecast



SOURCES: CGSI RESEARCH, IEA, OPEC

Figure 18: The US EIA's world oil demand forecasts are in between OPEC and IEA



SOURCES: CGSI RESEARCH, IEA, OPEC, EIA

The fundamental outlook for 2025F suggests that oil prices could moderate further in the absence of more OPEC+ production cuts. The US EIA is forecasting average non-OPEC+ production growth of 1.5 MMbbl/d in 2025F, against demand growth of 1.3 MMbbl/d, suggesting that OPEC+ will need to curtail production by a further 0.2 MMbbl/d next year in order to balance the market (Figure 19).

EIA data show that the key contributors to non-OPEC+ production growth in 2023-2024F have been North America (US and Canada) and Central and South America (Guyana and Brazil). The EIA also expects these countries to contribute to production growth in 2025F, with Europe (Norway) joining in.

Looking now at the IEA data, and assuming that its forecasts are correct, OPEC+ may need to curtail its production by an even larger 0.5 MMbbl/d, as the IEA expects oil demand growth of just 1 MMbbl/d in 2025F (Figure 20).

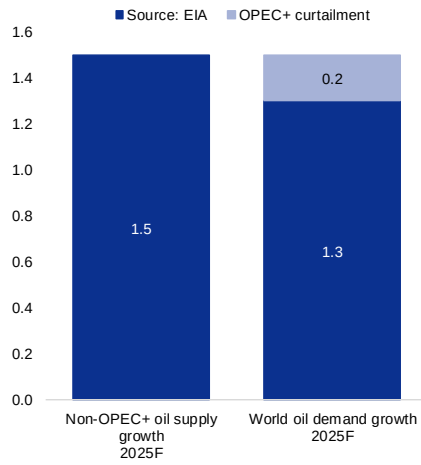
However, we gather that reducing collective output further is not OPEC+'s intention. The group had planned to progressively raise output from 1 Sep 2024, but delayed it to 1 Dec 2024F, and delayed it again to 1 Jan 2025F. We are not yet certain what OPEC+ will do next year, but it seems necessary for OPEC+ to at least extend the duration of the current curbs, in our view.

OPEC itself forecasts global oil demand to grow at a much higher rate of 1.6 MMbbl/d in 2025F compared to the IEA and EIA estimates; and OPEC forecasts non-OPEC+ output to grow just 1.1 MMbbl/d, lower than either IEA or EIA.

Despite OPEC's bullish forecasts for oil demand, **our base-case view is that OPEC+, and especially Saudi Arabia, will be disciplined in its collective output decisions**, as lower oil prices will have a very damaging impact to their members' national budgets, in our view. The International Monetary Fund (IMF) estimated in Apr 2024 that Saudi Arabia requires an oil price of US\$96.20/bbl to balance its national budget in 2024F, given its heavy spending programme to diversify the economy; this is an increase from IMF's May 2023 breakeven estimate of US\$80.90/bbl.

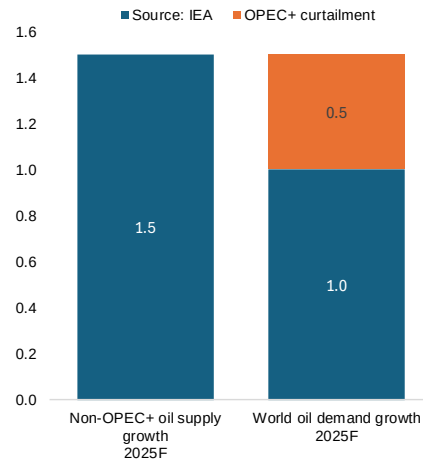
The key risk to oil prices is whether OPEC+ can stay together as a group, and remain willing to sacrifice market share to non-OPEC+ producers. Already, Qatar (in 2019), Ecuador (2020), and Angola (2024) have left OPEC. The UAE had also expressed unhappiness over its production quotas in the past few years, although it did manage to secure an increase in its quota by 0.3 MMbbl/d that will be phased in over the first nine months of 2025. On balance, we think that the major OPEC producers will not likely leave the group, as the consequences of non-cooperation are severe as oil prices could plunge.

Figure 19: EIA expects that OPEC+ may have to curtail output by 0.2 MMbbl/d in 2025F to balance the market



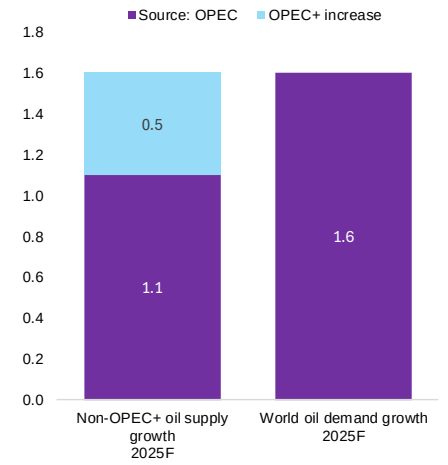
SOURCE: EIA

Figure 20: IEA expects that OPEC+ may have to curtail output by 0.5 MMbbl/d in 2025F to balance the market



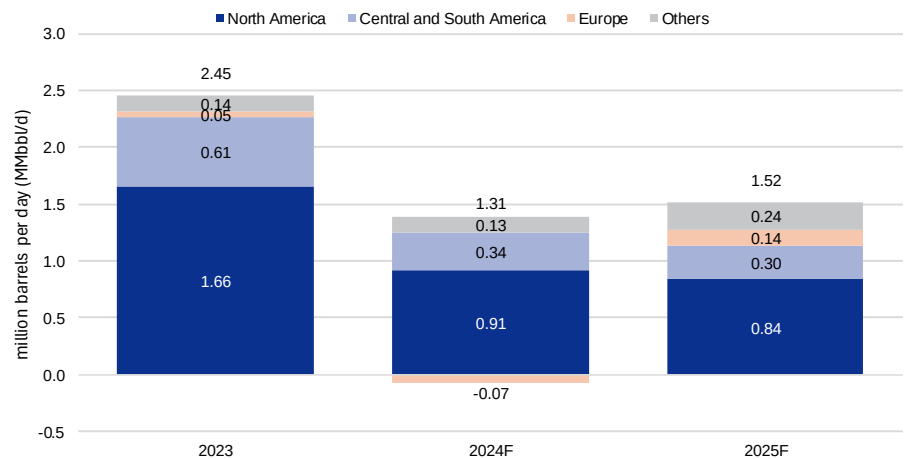
SOURCE: IEA

Figure 21: OPEC expects that OPEC+ may have to raise output by 0.5 MMbbl/d in 2025F to balance the market



SOURCE: OPEC

Figure 22: Contribution to non-OPEC+ supply growth (MMbbl/d)

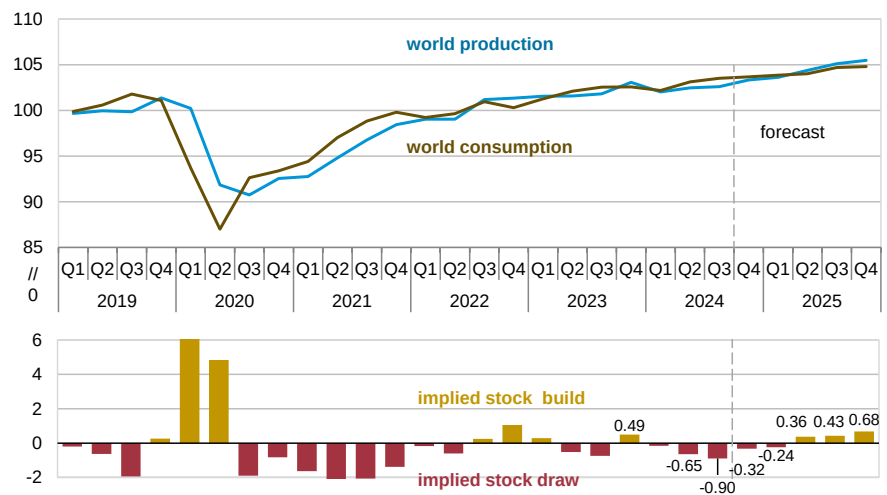


SOURCE: EIA

The EIA expects global oil inventories to build up in 2025F, because it expects oil demand growth to lag total OPEC+ and non-OPEC+ supply growth next year. The EIA forecasts 2Q25F global inventories to accumulate by 0.36 MMbbl/d, by 0.43 MMbbl/d in 3Q25F, and by 0.68 MMbbl/d in 4Q25F (Figure 23). If the EIA is correct, Brent oil prices could moderate in 2025F vs. average 2024F prices, in our view.

The EIA is forecasting Brent oil price to average US\$76/bbl in 2025F, vs. US\$81/bbl in 2024F.

Figure 23: World liquid fuels production and consumption balance (MMbbl/d)



SOURCE: EIA

‘Drill, baby, drill’? Not so fast....

Another downside risk to oil prices is the US president-elect Trump’s ‘Drill, baby, drill’ mantra, which **may eventually increase US oil production**.

This is premised on Trump’s nomination of North Dakota Governor Doug Burgum to head the Interior Department; North Dakota is the third-largest oil producing state in the US. Meanwhile, Trump has nominated Chris Wright, the current CEO of US fracking contractor Liberty Energy, to head the Energy Department; he was one of the pioneers of hydraulic fracturing in the US.

According to a Wall Street Journal (WSJ) article in Nov 2024, Doug Burgum’s first priority will be to roll back the Biden regulations that have hampered resource development, including:

- Possibly scrapping Biden’s restrictions on the leasing of federal lands for offshore drilling in the US Gulf of Mexico and for fracking onshore, and increasing the number of auctions of the federal lands moving forward;
- Potentially opening up the Arctic region for oil and gas leasing; and
- Reducing red tape for securing government permits to build new pipelines and terminals for the transportation and export of oil.

Meanwhile, Chris Wright’s priority will be to restart permitting for LNG exports, which the Biden team had paused in Jan 2024. The Energy Department has the authority to approve gas exports, and Biden had disrupted the US energy companies’ plans to build more LNG liquefaction terminals when he declared a moratorium on new LNG exports. This moratorium may be lifted in the early days of the upcoming Trump presidency.

Despite the headlines, we do not think that the ‘Drill, baby, drill’ mantra will make a big overall difference to the existing trajectory of US oil and gas production.

According to the US Bureau of Ocean Energy Management, it may take 4-10 years from the time a permit is secured to drill in the Gulf of Mexico, to the time production actually begins. The Gulf of Mexico currently accounts for about 15% of US crude oil production, according to the EIA.

Also, according to the WSJ last month, some of the US oil and gas executives that donated to the Trump campaign “grimace when they hear Trump promise that under his watch, crude-oil producers would open the floodgates” because oil companies have been squarely pressured by their US investors to focus on dividends and share buybacks, rather than to plough cash into more drilling. “Our stocks will be absolutely crushed if we start growing our production the way Trump is talking about it,” said Bryan Sheffield, a Texas oilman who contributed more than US\$1 million to Trump’s latest campaign,” WSJ wrote.

The WSJ also noted in an article in 2022 that for geological reasons, US drillers are “running out of premium wells, and many don’t have the runway to pump more oil than they are already.” This limits the frackers’ ability to increase production too dramatically, for fear of running out of inventory too quickly. WSJ noted that “the limited inventory suggests that the era in which US shale companies could quickly flood the world with oil is receding, and that market power is shifting back to other producers, many overseas.”

Data from US oilfield services company Baker Hughes about the number of working drilling rigs in the US shows a drop from almost 800 rigs in late-2022 to below 600 in late-Nov 2024. The EIA is forecasting US oil production growth to slow from 1.36 MMbbl/d in 2022 and 1.59 MMbbl/d in 2023, to much slower pace of 0.64 MMbbl/d in 2024F and 0.46 MMbbl/d in 2025F.

‘Maximum pressure 2.0’ on Iran?

There is one scenario that may provide support to oil prices. President-elect Trump could launch a crackdown on Iranian oil exports, which have ballooned from 0.29 MMbbl/d in 2022 to 1.12 MMbbl/d in 11M24 due to non-enforcement of sanctions on Iran by the current Biden administration in the US (Figure 24).

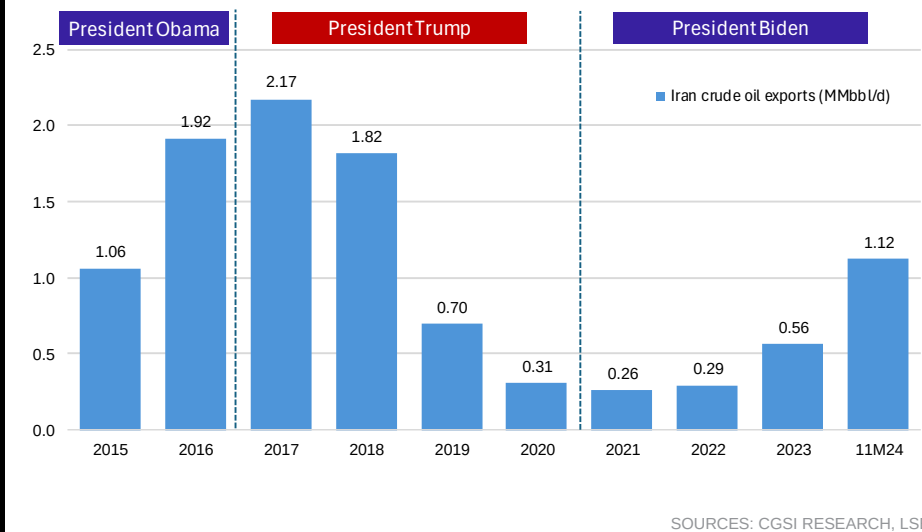
As a historical backdrop, Iranian oil exports rose in the aftermath of ex-US president Obama's nuclear deal with Iran in mid-2015, which removed both US sanctions and international sanctions on Iran.

His successor, ex-US president Trump withdrew from the Obama deal in 2018 and reimposed US sanctions on Iran, causing Iranian oil exports to plunge in 2019. However, most international sanctions remain formally suspended from the Obama era, allowing Russia, China and other countries to legally trade with Tehran, according to the WSJ. Also, current US president Biden has maintained the Trump-era sanctions on the US side, but has not enforced them. Hence, Iran has been able to assemble a fleet of ‘shadow tankers’ to export rising volumes of its oil to the Chinese independent ‘teapot’ refineries and other buyers.

In his first presidency between Jan 2017 and Jan 2021, Trump had enforced a ‘maximum pressure’ campaign against Iran, increasing sanctions and curbing its oil exports in the process. The WSJ reported on 8 Nov 2024 that “president-elect Donald Trump plans to drastically increase sanctions on Iran and throttle its oil sales as part of an aggressive strategy to undercut Tehran’s support of violent Mideast proxies and its nuclear program, according to people briefed on his early plans... the new team would move rapidly to try to choke off Iran’s oil income, including going after foreign ports and traders who handle Iranian oil.” The WSJ also reported on 19 Nov 2024 that Iran had sharply increased its stockpile of nearly weapons-grade uranium amid its confrontation with Israel.

We are not certain what actions president-elect Trump will take against Iran. However, if ‘maximum pressure 2.0’ happens, we expect a small positive impact on oil prices due to the potential reduction in the volume of Iranian oil exports. While any Iranian export cuts may be substantially offset by OPEC+ tapering down its production cuts, this may still be positive for oil prices as OPEC+ now has the means to increase its oil production without misbalancing the oil markets.

Figure 24: Iran crude oil exports (MMbbl/d)



Our conclusion is that for the next 1-2 years, oil prices could trade at the US\$70/bbl level +/- 5 if OPEC+ continues production discipline. The key upside risks are if the US resumes the 'maximum pressure' campaign against Iran, or if Chinese demand for oil imports picks up due to potential future stimulus measures. Downside risks include a possible proliferation of trade wars launched by the US against its many trading partners that may curb consumer spending due to inflation, and which may curtail global trade and GDP growth; these factors may ultimately lead to reduced oil demand.

The longer-term outlook for oil demand is significantly more uncertain. If the IEA and OPEC cannot agree on oil demand projections for 2025F, the expectations gap is even wider further ahead. Surprisingly, OPEC has revised up its long-term oil demand forecasts over the past two years, while the IEA has revised down its forecasts; hence the already-wide gap in expectations has widened even more this year (Figures 25-27).

For 2030F, the gap in demand forecasts between the two agencies is 11.6 MMbbl/d (OPEC's 113.3 MMbbl/d minus the IEA's 101.7 MMbbl/d in the STEPS scenario).

But the gap rises to 17.3 MMbbl/d in 2035F and to 27 MMbbl/d in 2050F, as the IEA is forecasting stagnation and then decline in oil demand after 2030F, whereas OPEC believes that oil demand will keep growing.

OPEC believes that demand from India, Africa and other developing countries will drive fossil fuel demand, while renewable energy (RE) developments will face financing constraints and issues with intermittency and storage, and the electric vehicle (EV) industry will somehow fail to address supply-chain bottlenecks. Conversely, the IEA believes in opposing scenarios.

Consultancy Rystad's forecasts fall in between OPEC and IEA, for the period up to 2040F, with **Rystad expecting peak oil demand of 111 MMbbl/d in 2033F**. If Rystad's forecasts are accurate, this implies that **oil demand may continue to grow up to 2030F, then stagnate at c.110 MMbbl/d until 2035F, and decline thereafter**.

In the 2041-2050F decade, Rystad is more conservative than the IEA's STEPS scenario as Rystad expects oil demand to fall to 89 MMbbl/d in 2045F, and to as low as 67 MMbbl/d in 2050F. We would substantially discount OPEC's bullish oil demand trajectory in the final 10 years to 2050F as technological innovation is proceeding at a fast pace.

For instance, **nuclear energy may be the solution to intermittency of solar and wind**, and experimental nuclear fusion technology is purportedly safe and promising, according to the International Atomic Energy Agency (IAEA).

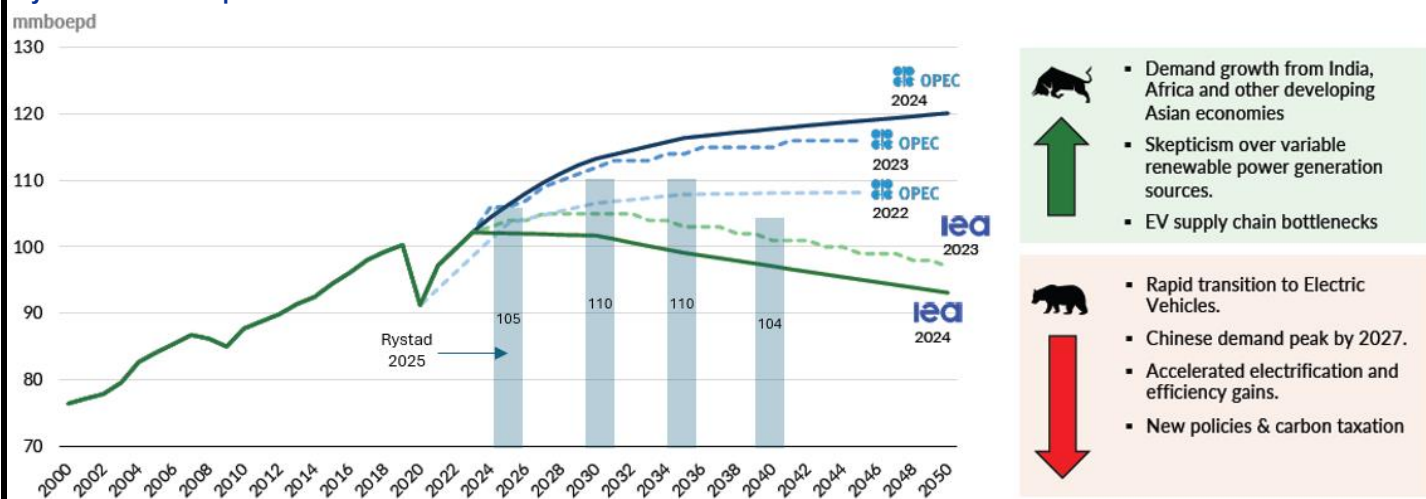
According to an article by The Straits Times in Oct 2024, “nuclear fusion has been touted as the Holy Grail for clean energy, producing immense amounts of energy with no long-term radioactive waste, a problem which is associated with conventional nuclear fission plants, where a uranium atom is split in two to generate power.” Instead of splitting the uranium atom, nuclear fusion fuses two isotopes of hydrogen (deuterium and tritium) to produce heat from the reaction, similar to processes in the sun, without GHG emissions. Nuclear fusion works to produce energy, although the technical challenge is to be able to produce a reaction that will last long enough for it to be commercially viable. As a fairly experimental technology that was only conceptualised in 1985, it may take decades for the technology to be implemented commercially, probably around 2040-2050F, according to the scientific experts interviewed by The Straits Times.

But before nuclear fusion becomes operational, Small Modular Reactors (SMR) are already in advanced stages of development and they have significantly lower risks of unsafe radioactive leaks, according to the IAEA. SMRs are also compact and can be installed in dense urban areas. Our view is that once nuclear power installations becomes more widespread in the decades ahead (timing uncertain), fossil fuel demand will inevitably decline.

Figure 25: The gap between OPEC and IEA on the future of oil demand (MMbbl/d) is widening

Rystad's oil demand forecasts are in between OPEC and IEA, with 2025F at 105 MMbbl/d; 2030F: 110; 2035F: 110; 2040F: 104

Rystad's forecasts peak oil in 2033F at 111 MMbbl/d



SOURCE: WESTWOOD GLOBAL ENERGY, OPEC, IEA, RYSTAD

Figure 26: OPEC's oil demand projections

	2023	2030	2035	2040	2045	2050	Growth 2023-2050
OECD Americas	25.0	25.6	24.9	23.5	22.2	21.1	-3.8
OECD Europe	13.4	13.1	12.1	11.0	10.0	9.2	-4.2
OECD Asia-Pacific	7.2	7.2	6.7	6.1	5.7	5.2	-2.0
OECD	45.7	45.9	43.7	40.6	37.9	35.6	-10.1
China	16.4	18.6	19.0	19.2	19.1	18.9	2.5
India	5.3	7.1	8.6	10.2	11.8	13.3	8.0
Other Asia	9.3	11.2	12.3	13.1	13.8	14.5	5.2
Latin America	6.7	8.0	8.8	9.2	9.5	9.7	3.0
Middle East	8.6	10.7	11.5	12.1	12.6	13.0	4.4
Africa	4.5	5.4	6.2	7.0	7.9	8.9	4.4
Russia	3.8	4.1	4.1	4.1	4.1	4.0	0.2
Other Eurasia	1.2	1.4	1.5	1.5	1.6	1.6	0.4
Other Europe	0.8	0.8	0.8	0.8	0.8	0.7	-0.1
Non-OECD	56.6	67.4	72.7	77.2	81.1	84.6	28.0
World	102.2	113.3	116.4	117.8	118.9	120.1	17.9

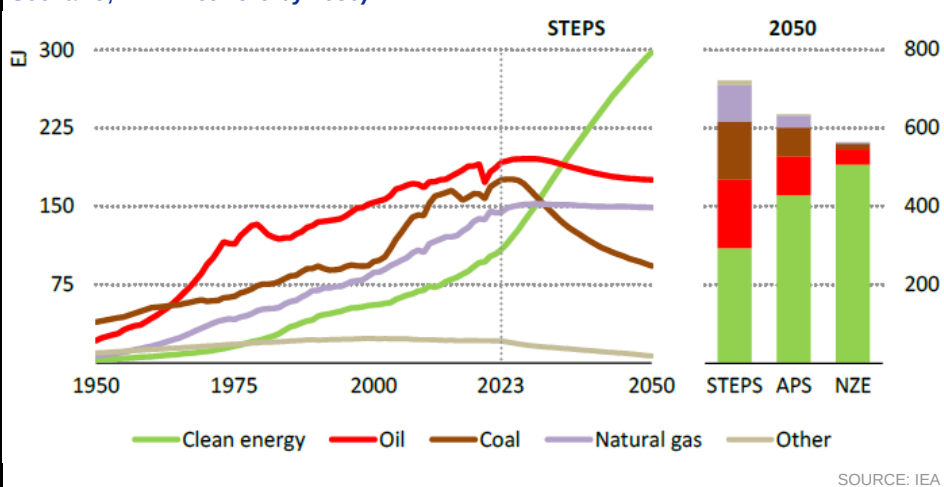
SOURCE: OPEC

Figure 27: The IEA's oil demand projections under the 'Stated Policies' framework

	2010	2022	2023	Stated Policies			Announced Pledges		
				2030	2035	2050	2030	2035	2050
World	87.2	97.1	99.1	101.7	99.1	93.1	92.8	82.0	53.7
North America	22.2	22.0	22.1	21.0	18.6	14.5	18.8	14.7	6.3
United States	17.8	18.1	18.2	17.2	15.1	11.3	15.6	12.1	4.8
Central and South America	5.5	5.5	5.6	5.8	6.0	6.6	5.2	4.8	2.9
Brazil	2.2	2.4	2.5	2.5	2.6	2.8	2.3	2.1	1.2
Europe	13.6	12.4	12.1	10.7	9.0	5.3	9.6	7.0	2.4
European Union	10.3	9.3	9.0	7.8	6.3	3.0	6.9	4.9	1.4
Africa	3.3	4.3	4.2	4.9	5.6	7.9	4.8	5.1	5.8
Middle East	7.0	8.1	8.1	8.1	8.5	10.2	7.7	7.8	7.4
Eurasia	3.5	4.3	4.4	4.6	4.7	5.0	4.3	4.2	3.9
Russia	3.0	3.5	3.5	3.6	3.6	3.6	3.4	3.3	2.9
Asia Pacific	25.1	33.3	34.8	38.1	37.9	34.4	35.2	32.0	20.2
China	8.8	14.8	16.2	17.4	16.4	11.8	16.1	14.1	7.8
India	3.3	5.0	5.2	6.6	7.1	7.6	6.2	6.1	4.5
Japan	4.2	3.1	3.1	2.6	2.3	1.7	2.3	1.7	0.7
Southeast Asia	4.0	4.9	5.0	6.0	6.4	7.0	5.5	5.2	3.8
International bunkers	7.0	7.1	7.7	8.6	8.9	9.3	7.1	6.4	4.9

SOURCE: IEA

Figure 28: The IEA's forecast of global energy mix by scenario to 2050F (STEPS: Stated Policies Scenario, of various governments; APS: Announced Policies Scenario; NZE: Net Zero by 2050)



SOURCE: IEA

LNG prices are strongish now, but is there a looming gas surplus? ➤

As shown on Figure 12, the spot Asian LNG price as depicted by the Japan-Korea Marker (JKM) published by data provider S&P Global Platts, has increased from a recent low of US\$9.44/MMBtu (US\$54.73/boe) in 1Q24 to US\$12.96/MMBtu (US\$78.23/boe) so far in 4Q24F. Forward JKM prices for Jan-Mar 2025F are priced at around US\$15/MMBtu currently.

While European LNG storage is now very full and the continent is seemingly prepared for winter, LNG prices have risen due to **fears of a colder-than-expected winter in the Northern Hemisphere** in 2025-2026F. Spot LNG prices have also rallied due to the high likelihood that **Russian pipeline gas transit flows via Ukraine will be disrupted from 1 Jan 2025F** as Ukraine does not want to renew the current 5-year deal with Russia's state-owned natural gas supplier Gazprom that allows Gazprom to send pipeline gas via Ukraine to Slovakia, the Czech Republic and until recently, Austria. Reuters estimated the total volume supplied to Europe by this pipeline transiting Ukraine at 15 Bcm in 2023, or about 5% of total European imports of natural gas, in our calculation.

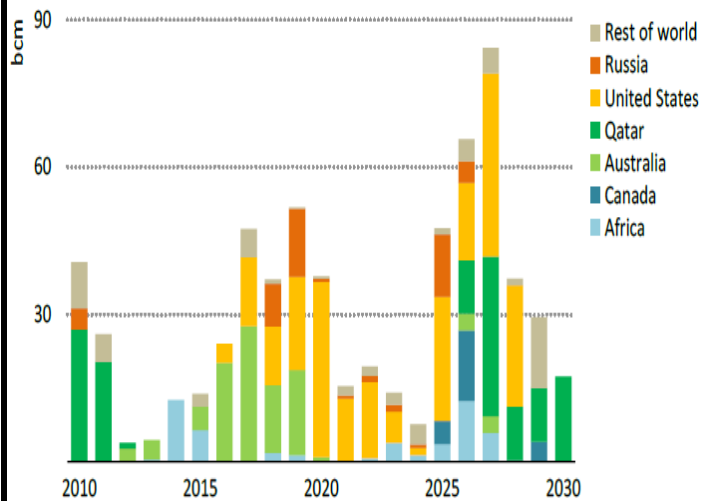
Beyond the current winter, however, **JKM futures prices are now reflecting a weakening to below US\$10/MMBtu by 2027F** due to the ample liquefaction export capacity projects that are currently undergoing construction; the IEA's forecasts are shown in Figure 29, while shipbroker Clarksons' forecasts are shown in Figure 30. They differ in the sense that the IEA's capacity addition forecasts peak in 2027F, whereas Clarksons' forecasts peak in 2026F as it excluded projects that it excludes under-construction projects that are deemed as being unlikely to start-up in the forecast period (due to project delays, etc.)

In Figure 32, the IEA is forecasting a significant increase in available LNG supply (shaded areas) in 2026-2027F, which may then open a wider gap against LNG demand (as depicted in the lines) in all of its three climate scenarios, i.e. the Stated Policies Scenario (STEPS), the Announced Pledges Scenario (APS), and the Net Zero 2050 Scenario (NZE). According to the IEA, if all projects that are under construction are completed on time, available liquefaction capacity is expected to rise globally from 580 Bcm p.a. today to 850 Bcm p.a. in 2030F, led by a near-doubling of export capacity in the United States and Qatar. Natural gas markets could be affected by a LNG surplus of around 130 Bcm in 2030F in the STEPS scenario, according to the IEA.

The IEA is concerned that LNG demand may not rise by as much as supply, because Europe and China are both investing in renewable energy (RE) buildups. Also, China may not want to be overly dependent on LNG imports in the current geopolitical competition with the US, preferring instead to be self-reliant on its RE and coal-power capacities.

As a result, the **IEA is forecasting LNG import prices in Japan to fall from US\$13/MMBtu in 2023** (which is typically contractually linked to the Japan Crude Cocktail or JCC price) **to US\$8.30/MMBtu by 2030F** in the STEPS scenario (Figure 33). OPEC, despite releasing a bullish World Oil Outlook 2050 report in Sep 2024, did not provide any price forecasts in the 290-page report.

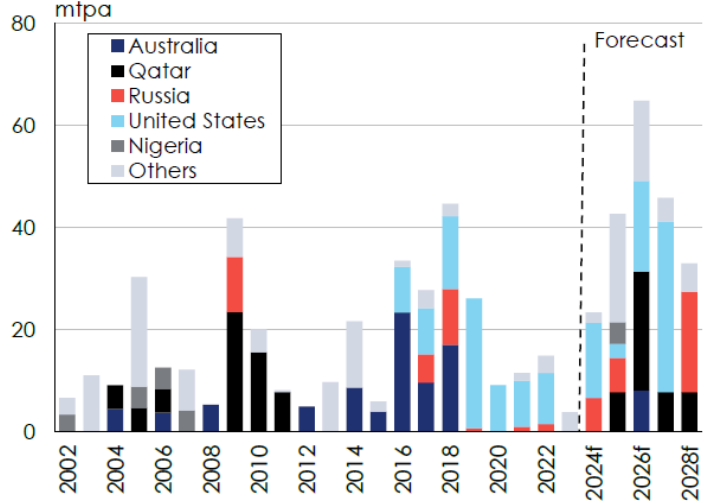
Figure 29: The IEA's forecast LNG export capacity additions by country to 2030F (billion cubic metres, Bcm)



SOURCE: IEA

NOTE: Bcm is a volume measure of LNG when regasified back into its natural gaseous state. Tonnes of LNG refer to the weight of LNG when in liquid form. Hence, 1 tonne of LNG = 48.7 Bcf of gas = 1.379 Bcm of gas

Figure 30: Clarkson's forecast LNG export capacity additions by country to 2028F (million tonnes p.a. or mtpa)



SOURCE: CLARKSON RESEARCH SERVICES

NOTE: Tonnes of LNG refer to the weight of LNG when in liquid form. Bcm is a volume measure of LNG when regasified back into its natural gaseous state. Hence, 1 tonne of LNG = 48.7 Bcf of gas = 1.379 Bcm of gas

Figure 31: Clarkson's forecasts of the growth of liquefaction capacity (million tonnes p.a. or mtpa) – the total capacity under construction of 270.5 mtpa amounts to 56% of the Oct 2024 liquefaction capacity of 478.9 mtpa

Liquefaction	Liquefaction Capacity, End (mtpa)						5 Yr CAGR	U/C (mtpa)				FEED	
	2019	2020	2021	2022	2023	Oct-24		2024	2025	2026	2027+	Total	Total
Australia	88.2	88.2	88.2	88.2	88.2	88.2	0%			8.0		8.0	2.0
% utilisation	85%	88%	90%	89%	90%								
Qatar	77.1	77.1	77.1	77.1	77.1	77.1	0%		7.8	23.4	31.6	62.8	
% utilisation	101%	100%	101%	103%	101%								
US	57.6	66.8	75.8	85.8	85.8	85.8	9%	14.7	2.8	17.7	60.6	95.8	159.7
% utilisation	75%	74%	97%	96%	101%								
Malaysia	30.5	30.5	32.0	32.0	32.0	32.0	1%				2.5	2.5	
% utilisation	86%	78%	81%	86%	84%								
Russia	28.0	28.0	28.9	30.4	30.4	37.0	6%		6.6		19.6	26.2	23.4
% utilisation	106%	106%	104%	113%	103%								
Nigeria	22.3	22.3	22.3	22.3	22.3	22.3	0%		4.2	3.6		7.8	
% utilisation	93%	92%	74%	64%	58%								
Others	127.4	127.4	127.4	130.8	134.6	136.6	1%	21.3	15.8	30.3		67.4	71.0
Global Total	431.0	440.2	451.6	466.5	470.3	478.9	2%	14.7	42.7	68.5	144.6	270.5	256.1
% utilisation	85%	83%	85%	87%	87%								
Start-Ups^	26.1	9.1	11.5	14.9	3.8	8.6		23.3	42.7	64.9	78.7	209.5	

SOURCE: CLARKSON RESEARCH SERVICES

Note: 'U/C' stands for under construction; 'FEED' refers to projects that are currently undergoing front-end engineering and design prior to final investment decision; '2027+' refers to all capacity additions in 2027F and beyond

Figure 32: LNG trade by scenario relative to existing and under construction export capacity to 2050

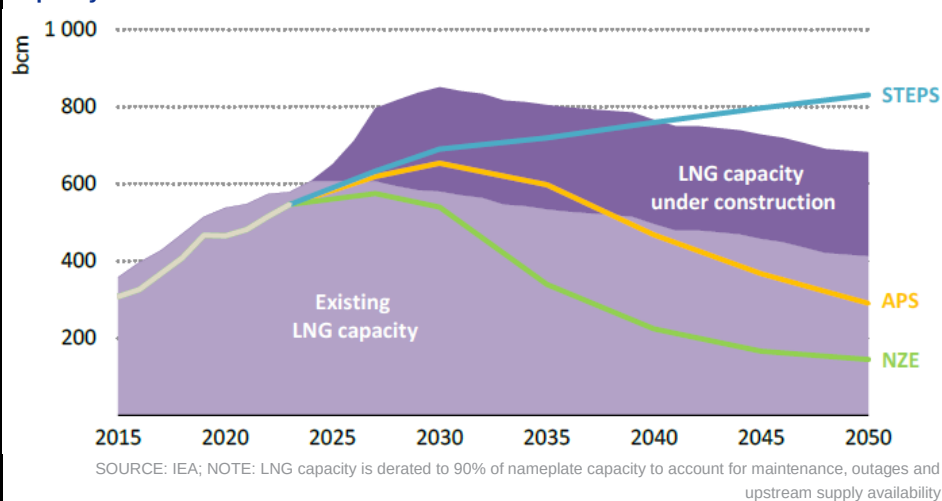


Figure 33: Wholesale fossil fuel prices by scenario (note that the IEA's 'MBtu' represents million BTU, or what we represent as 'MMBtu')

USD (MER, 2023)	2023	STEPS			APS			NZE Scenario		
		2030	2040	2050	2030	2040	2050	2030	2040	2050
IEA crude oil (USD/barrel)	82	79	77	75	72	63	58	42	30	25
Natural gas (USD/MBtu)										
United States	2.7	3.9	4.1	4.2	3.2	3.0	2.9	2.1	2.0	2.0
European Union	12.1	6.5	7.6	7.7	6.0	5.2	5.2	4.4	4.1	4.0
China	11.5	7.2	8.2	8.3	6.9	6.2	6.2	5.0	4.8	4.8
Japan	13.0	8.3	8.8	8.7	6.8	6.1	6.2	5.0	4.8	4.8

SOURCE: IEA

Despite the looming oversupply of LNG, the market can be self-correcting. In South Asia, LNG demand will pick-up at US\$5/MMBtu, which is the level at which LNG can compete with the cost of coal-fired power generation, according to the IEA. The IEA noted that existing low-cost LNG projects (i.e. in Qatar, Malaysia, Brunei, etc.) can sell LNG at US\$3-5/MMBtu to make a profit, but this breakeven rises to US\$8/MMBtu for newer export projects and those under construction, due to capex cost inflation. Therefore, if spot LNG prices fall towards US\$5-6/MMBtu, we expect price-sensitive South Asian buyers to support demand, coupled with possible curtailment of output by the newer export projects.

SECTION 4: ACQUISITION OF TOTALENERGIES BRUNEI

Background of the Brunei Block B MLJ ➤

On 13 Jun 2024, Hibiscus's wholly-owned subsidiary Simpor Hibiscus Sdn Bhd signed a Sales and Purchase Agreement (SPA) with TotalEnergies Holdings International B.V. (the seller) to acquire 100% of TotalEnergies EP (Brunei) B.V. for a cash consideration of **c.US\$259.4m**. TotalEnergies Brunei is incorporated in the Netherlands with a branch in Brunei. The acquisition was completed on **14 Oct 2024**, with an **effective date of 1 Jan 2023**.

TotalEnergies Brunei holds a **37.5%** participating interest in Block B Maharajalela Jamalulalam (MLJ) field and is currently the operator of the field.

Other partners include **Shell Deepwater Borneo B.V.** with a 35% stake, and **Brunei Energy Exploration Sdn Bhd** with a 27.5% stake (the latter company is owned by the Brunei state government). The JV partners are collectively referred to as the **BBJV Partners**. TotalEnergies Brunei was the operator of the Brunei MLJ field, but Hibiscus has assumed the role of **operator** of the MLJ field post-acquisition.

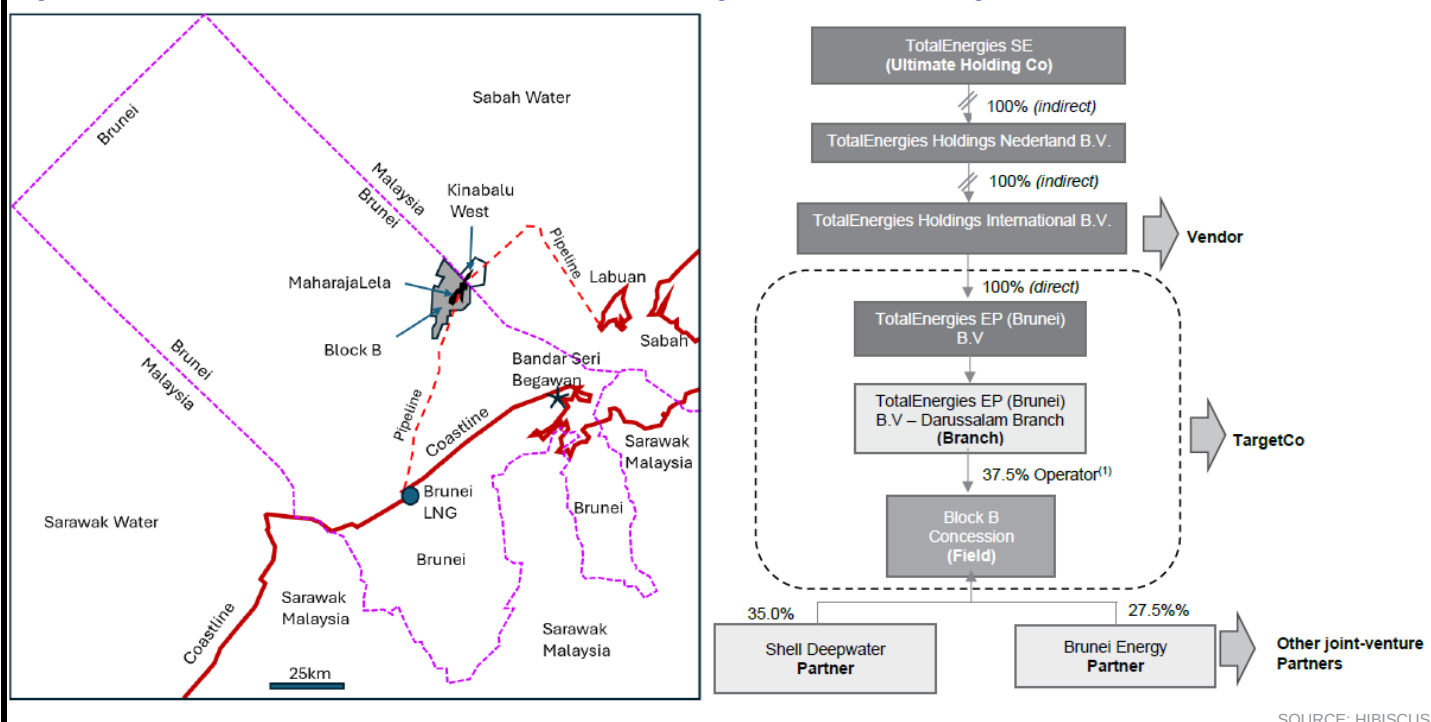
History and tenure of concession

Block B offshore Brunei contains MLJ field and was discovered in 1989. It was appraised and developed during the 1990s with first gas in 1999. It has a total area of 276 sq km and is approximately 50 km offshore Brunei. Since 1999, the field has been producing gas and condensate from three unmanned platforms in relatively shallow waters of less than 100m depth.

TotalEnergies Brunei has been operating in Brunei since 1986 and purportedly has a proven track record in operating the MLJ field in Brunei with no lost time injury for over 24 years.

The concession was awarded on 23 Nov 1989 (production began in 1999) with an initial expiry date of 23 Nov 2019 (30 years duration), subsequently extended by 10 years to **23 Nov 2029F**, with the option to extend for an additional 10 years until **23 Nov 2039F** subject to mutual agreement of the BBJV Partners. Approval from the Brunei government is not required to secure the extension to 2039F.

Figure 34: Location of the Brunei Block B MLJ field / Shareholding structure of TotalEnergies Brunei



Production infrastructure and schematic

Gas accounted for **88%** of the total production in boe terms from Brunei MLJ in 2023, with condensate making up the remaining 12%.

The three unmanned platforms at Brunei MLJ are named MLJ1 (four producing wells), MLJ2 (five wells) and MLJ3 (six wells).

No processing occurs offshore and the produced gas and condensate are transported via an 85km pipeline to the **Onshore Processing Plant (OPP)** at Lumut, Brunei.

The OPP separates the gas, condensate and water; the gas is processed to remove mercury and traces of H₂S, and then sent via pipeline to the **Brunei LNG (BLNG)** liquefaction plant, where it is turned into LNG for export. The BLNG plant has enjoyed high uptime in recent years, according to Hibiscus.

Meanwhile, the condensate and water are exported to the **Seria Crude Oil Terminal (SCOT)**, where the condensate is dewatered, stored and periodically exported on crude oil tankers.

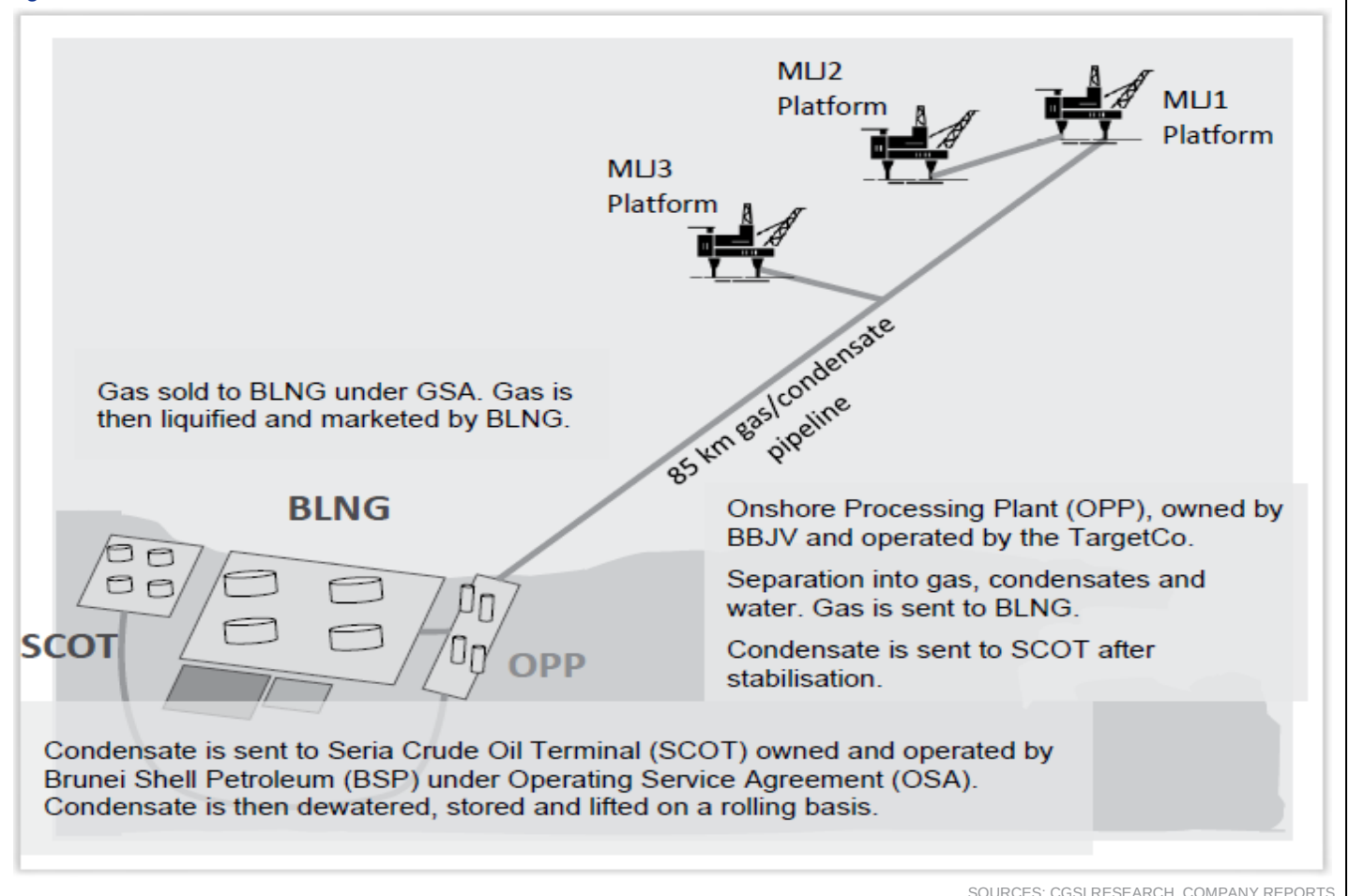
Ownership of infrastructure

The OPP belongs to the BBJV partners and was operated by TotalEnergies Brunei, but Hibiscus has since taken over the ownership and operations post-acquisition.

SCOT is owned and operated by Brunei Shell Petroleum (BSP), which is a 50:50 JV between the Government of Brunei and Shell.

BLNG is owned by the Government of Brunei (50%), Shell (25%) and Mitsubishi Corporation (25%).

Figure 35: Production infrastructure at the Brunei Block B MLJ field



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Commercial arrangements ►

Condensate

For Hibiscus's share of condensate produced at the Brunei MLJ field, it will continue to engage **TotalEnergies** as its sales agent. This was an agreement that was entered into in 2023 that is valid for five years to 2028F and has an automatic 1-year extension.

Hibiscus receives the spot price for condensate, which is sold at an average **2% premium to Brent**, according to RPS.

Natural gas

BLNG is the purchaser of all the natural gas produced at Brunei MLJ, under the Gas Sale Agreement (GSA), on a **take-or-pay basis** for the Annual Contract Quantity (ACQ) of the gas produced. There is no other physical means of evacuating and selling the gas produced at MLJ except to sell it to BLNG.

The current GSA was dated 16 Dec 2013 and its term expires on **31 Mar 2033F**, having been renewed for 20 years after the initial expiry in 2013. If the Brunei MLJ concession is extended to 23 Nov 2039F, we expect the GSA for Brunei MLJ to be also extended until then.

The GSA specifies an **Annual Contract Quantity (ACQ)** for delivery by the BBJV Partners to BLNG. The first ACQ period ended in Mar 2023 and the second ACQ period started in April 2023 and will last until 31 Mar 2032F.

In the event of operating downtime at BLNG and it is unable to purchase the ACQ, BLNG will still have to pay for the ACQ shortfall (calculated as the ACQ purchased minus the ACQ not yet purchased) in that same year at a price **premium** of 10-15%, in our estimate. BLNG will then take delivery of the ACQ shortfall in future periods.

Similarly, if Brunei MLJ fails to produce and deliver the contracted ACQ, the BBJV Partners will have to deliver the ACQ shortfall to BLNG in future periods, but would be penalised with a 10-15% **discount** on the gas selling price, in our estimate, when the ACQ shortfall is delivered.

To provide a buffer for both buyer and seller, the ACQ is typically slightly lower than the actual volumetric demand by BLNG, and also slightly lower than what the Brunei MLJ field can actually produce on a regular basis.

The gas selling price received by the BBJV Partners is called the **wellhead gas price (WGP)**. Hibiscus disclosed that the actual realised WGP in 2023 was US\$4.70/Mscf, after taking into account:

- The **Domestic Gas Supply Obligation (DGSO)** to sell 10% of the gas produced at a fixed price of US\$0.33/MMBtu; while
- The remaining 90% of the gas produced can be sold at the **Contracted Wellhead Gas Price (CWGP)**.

According to PwC, the DGSO commenced on 1 Jan 2021 and the DGSO price is fixed until 31 Dec 2039F. The BBJV Partners will pay to the Government of Brunei the DGSO volume multiplied by the difference between the CWGP and the prevailing DGSO price of US\$0.33/MMBtu.

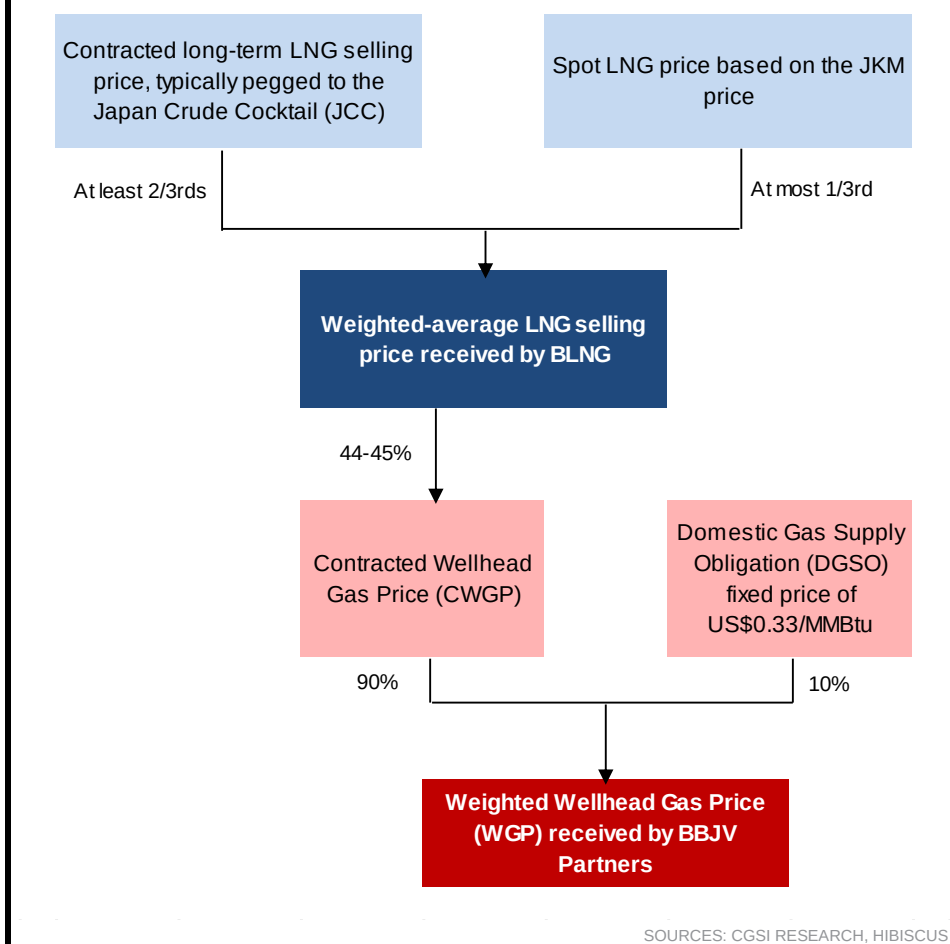
We estimate that Brunei MLJ's CWGP is pegged to a ratio of c.44-45% multiplied by BLNG's weighted average realised LNG price.

BLNG's realised price of LNG is the weighted average of:

1. Its long-term LNG sale contracts (which are typically pegged to the Japan Crude Cocktail (JCC) price); and
2. The spot LNG price that is correlated to the Japan Korea Marker (JKM) price that is published by data provider S&P Global Platts.

We believe that BLNG sells at least two-thirds of its LNG based on long-term contracts, with less than one-third sold at the spot market.

Figure 36: How Brunei MLJ's gas selling price is calculated



Details of the acquisition transaction ➤

The independent valuer, RPS, calculated a DCF value of Brunei MLJ at **US\$250m**; this represented the cashflows from the effective acquisition date of 1 Jan 2023 to the to the end of the concession on 23 Nov 2029F, and also inclusive of the potential option to extend for an additional 10 years until 23 Nov 2039F.

Although the acquisition was only completed on 14 Oct 2024, all the cashflows of the asset belong to Hibiscus from the effective date of 1 Jan 2023.

Hibiscus negotiated a purchase price of **US\$245m** with respect to the above cashflows.

To this is added the net working capital of US\$14.4m as at 31 Dec 2022, since the effective date was 1 Jan 2023, and since Hibiscus is acquiring the entire company.

A US\$17m estimated time value amount was added, to account for the time value of money of the purchase price of US\$245m between the effective date and the actual completion of the transaction on 14 Oct 2024.

A total deduction of US\$80.6m was made against the closing amount, to reflect the cash removed from the target company prior to transaction completion.

Since a deposit of US\$49m was already paid on 13 Jun 2024, the closing settlement amount on the completion date of 14 Oct 2024 was US\$146.8m.

Figure 37: Amounts paid by Hibiscus to acquire TotalEnergies Brunei

	US\$ m	Notes
Purchase price	245.0	This was the purchase price for the cashflows from 1 Jan 2023 (effective date) to the end of the concession on 23 Nov 2029F, and also inclusive of the potential option to extend for an additional 10 years until 23 Nov 2039F. These cashflows were valued by RPS, the independent valuer, at US\$250m.
Add: Net cash as at 31 Dec 2022	44.9	The net current assets of US\$14.4m as at 31 Dec 2022 were included in the purchase consideration, because Hibiscus was purchasing the entire company, and the effective date was 1 Jan 2023.
Less: Net working capital as at 31 Dec 2022	-30.5	
Purchase consideration	259.4	
<u>Agreed adjustments:</u>		
Add: Estimated time value amount	17.0	To reflect time value of money of the purchase consideration from 31 Dec 2022 to 14 Oct 2024 when the transaction was completed.
Less: Estimated pre-closing dividend	-65.0	This US\$80.6m was deducted from the estimated closing amount, as it was removed from the target company prior to transaction completion.
Less: Estimated leakage	-15.6	
Less: Deposit	-49.0	Deposit was paid on 13 Jun 2024
Closing amount	146.8	The closing amount was settled on 14 Oct 2024.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Funding the acquisition ►

Of the total cash consideration of **US\$195.8m** (the deposit of US\$49m paid on 13 Jun 2024 and the closing amount of US\$146.8m paid on 14 Oct 2024), Hibiscus has stated that it will:

- Fund US\$100m from an external trade facility, and
- Fund US\$95.8m from its internal cash balances.

The external trade facility is with an unnamed offtaker of its hydrocarbons, which Hibiscus will gradually pay down from the proceeds of its oil and gas sales.

No new equity was raised to fund the purchase of TotalEnergies Brunei.

Transition services ►

On 23 Sep 2024, Simpor Hibiscus (the buyer) entered into a transition services agreement with TotalEnergies Holdings (the vendor) for the provision of various services by TotalEnergies Holdings to Simpor Hibiscus in order to facilitate a smooth handover of the business and operations of Total Energies EP (Brunei) B.V. (the acquired company). Hibiscus estimated the total fees payable by Simpor Hibiscus to be US\$5m-8m.

Carry arrangement ➤

Under the carry arrangement, Hibiscus, as the party holding 37.5% working interest in the Brunei MLJ field, and Shell Deepwater holding 35% working interest, shall carry Brunei Energy's 27.5% participating interest of capex in the BBJV.

Hibiscus and Shell Deepwater will then recoup the carried capex monthly by taking a share from Brunei LNG's base gas sales.

What this means is that Hibiscus's balance sheet will reflect 51.72% of the development capex of the BBJV, and Hibiscus's P&L will reflect 51.72% share of the gas sales arising from the recoupment of the Brunei LNG's capex borne by Hibiscus on Brunei LNG's behalf. The calculations are shown in Figure 38.

Figure 38: Carry arrangement

All in %	Original Working Interest	Split of Brunei Energy share	Financing Interest (i.e. Interest with Carry)
Hibiscus	37.50	14.22	51.72
Shell Deepwater	35.00	13.28	48.28
Brunei Energy	27.50	-	-
TOTAL	100.00	27.50	100.00

SOURCE: HIBISCUS

Capex spending at Brunei MLJ ➤

Hibiscus guided that there is minimal capex to be incurred on the MLJ field in the near term, as the MLJ field is producing and cashflow generating.

The only ongoing project is the upgrading of the **low-pressure compressor (LPC)** at the OPP, which started in Jan 2022 and is expected to come on stream in 3QCY25F (1QFY26F). We suspect that a large portion of the capex has already been spent, as this project was already in the process of execution by TotalEnergies Brunei prior to the sale to Hibiscus.

The LPC project is intended to enhance production and extend field life, as it will reduce the gas backpressure at the OPP facilities, which will then allow more gas and condensate to flow from the wells. Separately, regular low-cost well intervention and workover campaigns have also been planned for this year to increase monetisation of the 2P reserves, according to Hibiscus.

RPS pencilled in capex cost of **US\$42.2m** for the above **2P capex projects**, of which US\$33.6m was to be spent in 2024F and US\$8.6m in 2025F. Hibiscus guided that it will spend US\$21m in FY25F and US\$5m in FY26F for this LPC project.

Hibiscus also guided that **maintenance capex** is **US\$1m-2m p.a.**

With regard to the monetisation of **2C resources of 6.8 MMboe** (as at 1 Jan 2023), the capex spending will only take place in 2028-2029F, according to Hibiscus. This includes one well-deepening activity in the unitised MLJ North field area, and the drilling of one new high pressure well. RPS has pencilled in a total 2C monetisation capex of **US\$51.7m in 2029F**. RPS has also assumed that regular well production enhancement activities will take place every two years from 2028F onwards until the end of production in 2039F, at a cost of c.US\$6m-10m p.a.

The **decommissioning liability** for MLJ field of US\$180m-190m for both wells and facilities, of which Hibiscus's share is **US\$72m** (undiscounted), which will be incurred in 2040F. In Brunei, there is no need for operators to pay abandonment cess on an annual basis unlike in Malaysia; abandonment costs will be incurred in a lump-sum at the end of field life.

The basis for RPS's DCF valuation of US\$250m ➤

RPS's DCF valuation net to Hibiscus of **US\$250m** as at 1 Jan 2023 (undiscounted US\$329m) was derived from:

- RPS's estimates of the remaining recovery of hydrocarbons as represented by the 2P reserves discounted by WACC discount rate of 10%, and the 2C resources discounted by WACC of 12%;
- The RPS Brent price and gas price forecasts (see Figure 39);
- Cashflows from 1 Jan 2023 to 23 Nov 2039F, assuming that the BBJV Partners agree to extend the concession from the current expiry date of 23 Nov 2029F; and
- Inclusive of the DCF value of third-party gas processing of US\$67m up to 23 Nov 2039F (at WACC of 10%).

The breakdown of RPS's NPV valuation of US\$250m is:

- **US\$169m** valuation for **2P reserves** (using WACC of 10%);
- **US\$67m** present value of the future cashflows from **third-party gas processing** (using WACC of 10%); and
- The remaining **US\$14m** for **2C resources** (using WACC of 12%).

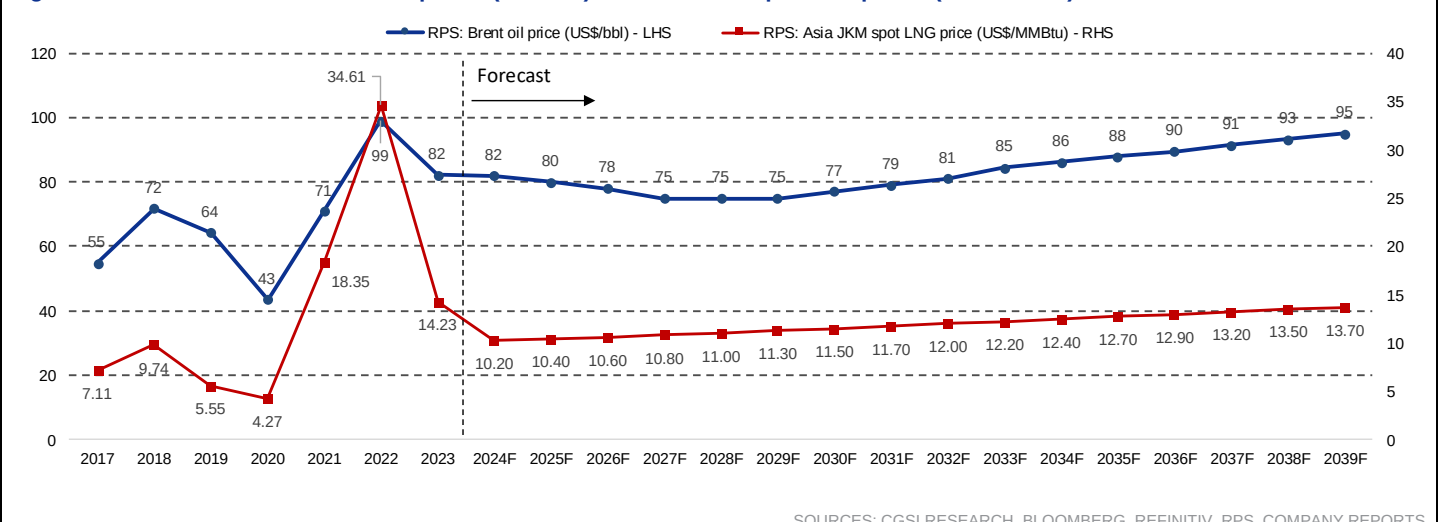
RPS noted that the DCF valuation as at 1 Jan 2023 would have been US\$177m in the event the concession is not extended by the BBJV Partners (i.e. expiry on 23 Nov 2029F).

RPS's price assumptions are as follows:

- MLJ condensate is sold at a 2% premium to Brent (Brent assumptions in Figure 39);
- JKM LNG prices at US\$10/MMBtu, with 2% annual inflation (JKM assumptions in Figure 39);
- JCC prices are at a US\$1.60/bbl premium to Brent, which are used to forecast BLNG's LNG selling price on JCC-pegged long-term contracts; and
- Domestic Gas Supply Obligation (DGSO) gas price of US\$0.33/MMBtu, applicable to 10% of the gas sold.

Separately, RPS also assumes opex cost inflation at 2% p.a. and transportation cost for the condensate at US\$2.60/bbl.

Figure 39: RPS forecasts for Brent oil prices (US\$/bbl) and Asia JKM spot LNG prices (US\$/MMBtu)



Valuation of the 2C resources

The 2C resources were valued into the deal pricing, because the 2C resources arise from projects already identified by TotalEnergies previously, with the drilling to be undertaken in 2028-2029F after FID is taken. The projects could have been executed earlier, but TotalEnergies had to wait for the existing production rate to decline first, as there is currently not enough gas processing and production capacity at the OPP. This is a departure from the Peninsula Hibiscus acquisition of the Repsol assets in Malaysia and Vietnam (the deal was announced in 2021 and completed in 2022), because at that time, there were no projects that were identified or sufficiently mature for the 2C resources to be included in the valuation of the deal, according to Hibiscus.

Third party gas processing

According to Hibiscus, the northern panel of the MLJ field (MLJ North) extends into an unnamed third party's licensed area. Since late-2023, the gas production by this third party has been sent to the OPP for processing, which involves stripping out condensate and water from the gas, with the gas sold to BLNG and the condensate sent to SCOT.

Hibiscus disclosed that the third-party gas gross production volume of condensate and gas was 0.7 MMboe in CY22 and 3.2 MMboe in CY23. However, forecast volumes were not disclosed.

The commercial details of the third-party gas processing have not been officially disclosed. The commercial risks of third-party gas processing have also not been discussed by Hibiscus in substantive detail. Hence, we are unable to make a detailed assessment of the operating and financial risks of the third-party gas processing.

RPS has attributed a DCF value of US\$67m from third-party gas processing into the valuation of the Brunei MLJ acquisition. We have included our own assessment of the third-party gas processing into our valuation model, albeit at a lower value of US\$56m as we have applied a higher cost of equity discount rate of 16% vs. RPS's WACC assumption of 10%.

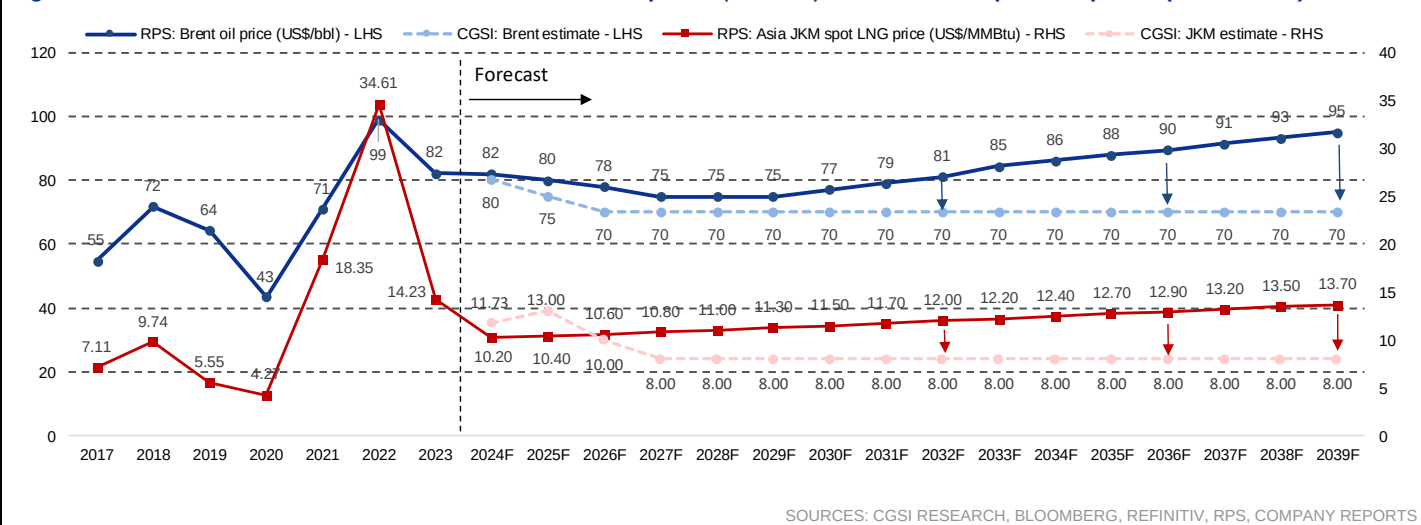
CGSI's valuation of Brunei MLJ ➤

Our DCF valuation of Hibiscus's 37.5% working interest in Brunei MLJ's future cashflows as at 1 Jan 2023 is **US\$200m**, lower than the US\$245m purchase consideration which Hibiscus paid, and also lower than the RPS valuation of US\$250m.

Our lower valuation is on account of the application of more conservative Brent oil and JKM LNG prices, as shown in Figure 40. We have used the same production forecasts that were published by RPS, on a 2P-plus-2C basis.

The difference between our lower valuation of the Brunei MLJ asset and the price paid by Hibiscus of US\$45m represents **26 sen/share** at an assumed end-CY25F exchange rate of RM4.20:US\$1, and has been deducted from our DCF-based target price for Hibiscus.

Figure 40: RPS forecasts vs. CGSI's estimates for Brent oil prices (US\$/bbl) and Asia JKM spot LNG prices (US\$/MMBtu)



Implied acquisition valuation multiples ➤

The implied multiples of the purchase consideration against 2P reserves and 2C resources are calculated as follows.

Net price paid for 2P reserves and 2C resources

= Purchase price of US\$245m

– DCF value of third-party gas processing of US\$67m up to 2039F

= US\$178m

Valuation against 2P reserves as at 1 Jan 2023

= US\$178m / (2P reserves of 24.3 MMboe)

= **US\$7.4/boe of 2P reserves**

Valuation against 2P reserves and 2C resources as at 1 Jan 2023

= US\$178m / (2P reserves + 2C resources of 31 MMboe)

= **US\$5.7/boe of 2P reserves + 2C resources**

Based on the information summarised in Figure 41 of comparable M&A transaction multiples, for which data was sourced from Hibiscus, the implied dollar per 2P barrel ranges between US\$6.2/boe and US\$17.3/boe. Hence, the valuation of the Brunei MLJ transaction of US\$7.4/boe of 2P reserves falls at the lower end of the range.

The implied dollar per 2P plus 2C barrels ranges between US\$5.9/boe and US\$10.7/boe, according to the data in Figure 41. Brunei MLJ's acquisition multiple US\$ 5.7/boe also falls within this range.

Figure 41: Comparable transaction multiples of Southeast Asian upstream E&P acquisitions

No	SPA date	Asset	Buyer	Seller	Price	2P reserves		2P price		2P + 2C		Avg Brent price 12 months prior
						US\$ m	MMboe	US\$/boe	MMboe	US\$/boe	US\$/bbl	
1	May 2018	Acquisition of Santos's Southeast Asian production licences	Ophir Energy Plc	Santos Limited	205		23.3	8.8	-	-		59
2	Nov 2018	Acquisition of 50% interest in SEB Upstream Sdn Bhd	OMV	Sapura Energy Bhd	800		46.1	17.3	74.7	10.7		72
3	Jan 2019	Acquisition of Ophir Energy Plc	PT Medco Energi	Ophir Energy Plc	517		70.1	7.4	-	-		71
4	Mar 2019	Acquisition of Murphy Oil's interests in Malaysia	PTTEP Limited	Murphy Oil	2,127		169.3	12.6	-	-		70
5	Jun 2021	Acquisition of Repsol's assets in Malaysia and Block 46 Vietnam	Hibiscus	Repsol	213		34.5	6.2	35.8	5.9		51
6	Jun 2022	Concession L53/48	Dialog	Pan Orient Energy Corp	39		4.6	8.4	-	-		87
7	Jun 2024	Acquisition of TotalEnergies Brunei	Hibiscus	TotalEnergies	1 178	2 24.2		7.4	2 31.0	5.7		84

① Purchase consideration used for valuation calculation
 = Purchase price of US\$245m
 - DCF value of third-party gas processing of US\$67m up to 2039F

② 2P reserves and 2C resources as as at 1 Jan 2023, the effective date of the TotalEnergies Brunei acquisition.

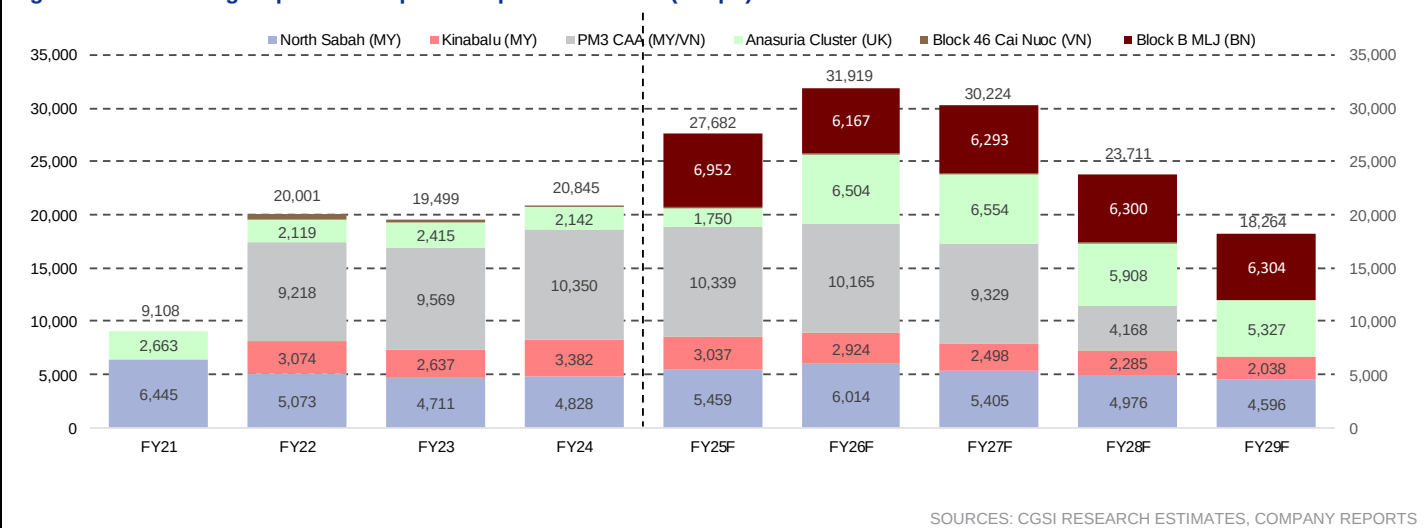
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Contribution of Brunei MLJ to Hibiscus group production ➤

As Brunei MLJ is now included in the group effective from 14 Oct 2024, the enlarged net boepd production rate is shown in Figure 42. We are expecting a 34% uplift in net production in FY25F (with Brunei MLJ contributing to earnings for 260 days), a 24% uplift in FY26F, a 26% uplift in FY27F, etc. against the levels excluding Brunei MLJ in each respective year.

On a separate note, Hibiscus's FY29F production rate is much lower than for FY28F, mainly because of the expiry of the PM3 CAA licence on 31 Dec 2027F. However, if the licence is extended, the production decline in FY29F may not be so steep.

Figure 42: Hibiscus group: Net oil equivalent production rate (boepd)



Brunei MLJ will increase the proportion of gas production in the Hibiscus group from 35.9% in FY24 to 43.9% in FY25F, in our estimate (Figure 43). However, we expect the proportion of gas production to decline in FY26F because of the pick-up in Anasuria Cluster oil production with the Teal West field targeted to begin production from late-2025F.

Figure 43: Hibiscus group oil and gas production (boe) - including Brunei MLJ

	FY24	FY25F	FY26F	FY27F
Oil and condensate (bbl)	4,929,001	5,256,729	7,279,058	6,864,901
North Sabah oil	1,767,170	1,992,670	2,195,278	1,972,957
Kinabalu oil	1,232,255	1,108,436	1,067,183	911,863
PM3 CAA oil	1,176,901	1,252,106	1,314,711	1,248,976
Anasuria Cluster oil	699,729	568,426	2,298,179	2,320,209
Block 46 Cai Nuoc oil	52,946	53,088	53,088	53,088
Block B MLJ condensate		282,003	350,619	357,810
Gas (boe)	2,754,936	4,120,196	4,371,431	4,166,877
PM3 CAA gas	2,670,912	2,521,632	2,395,551	2,155,995
Anasuria Cluster gas	84,024	70,324	75,599	71,819
Block B MLJ gas		1,528,239	1,900,281	1,939,063
Total oil, condensate and gas (boe)	7,683,937	9,376,925	11,650,489	11,031,778
<u>Proportion of production</u>				
Oil and condensate	64.1%	56.1%	62.5%	62.2%
Gas	35.9%	43.9%	37.5%	37.8%

SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

In terms of 2P oil and gas reserves, we forecast the gas portion to increase from 15.9% at end-FY24 to 27.7% at end-FY25F (Figure 44).

Figure 44: Hibiscus group 2P oil and gas reserves (boe) - including Brunei MLJ

	FY24	FY25F	FY26F	FY27F
Oil and condensate - 2P (bbl)	48.3	56.1	48.8	41.9
North Sabah oil	18.4	16.4	14.2	12.2
Kinabalu oil	6.4	5.3	4.2	3.3
PM3 CAA oil	3.1	11.8	10.5	9.3
Anasuria Cluster oil	20.2	19.6	17.3	15.0
Block 46 Cai Nuoc oil	0.2	0.1	0.1	0.0
Block B MLJ condensate		2.8	2.4	2.0
Gas - 2P (boe)	9.1	21.4	17.1	12.9
PM3 CAA gas	8.2	5.7	3.3	1.1
Anasuria Cluster gas	0.9	0.8	0.8	0.7
Block B MLJ gas		14.9	13.0	11.1
Total oil, condensate and gas 2P (boe)	57.4	77.5	65.9	54.8
<u>Proportion of 2P reserves</u>				
Oil and condensate	84.1%	72.3%	74.1%	76.5%
Gas	15.9%	27.7%	25.9%	23.5%

SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

We forecast Brunei MLJ to deliver net oil equivalent production of between 6,000 boepd and 7,000 boepd between FY25-29F, and operating spreads of US\$20-22/boe sold.

Figure 45: Brunei MLJ: Net oil equivalent production rate (boepd)

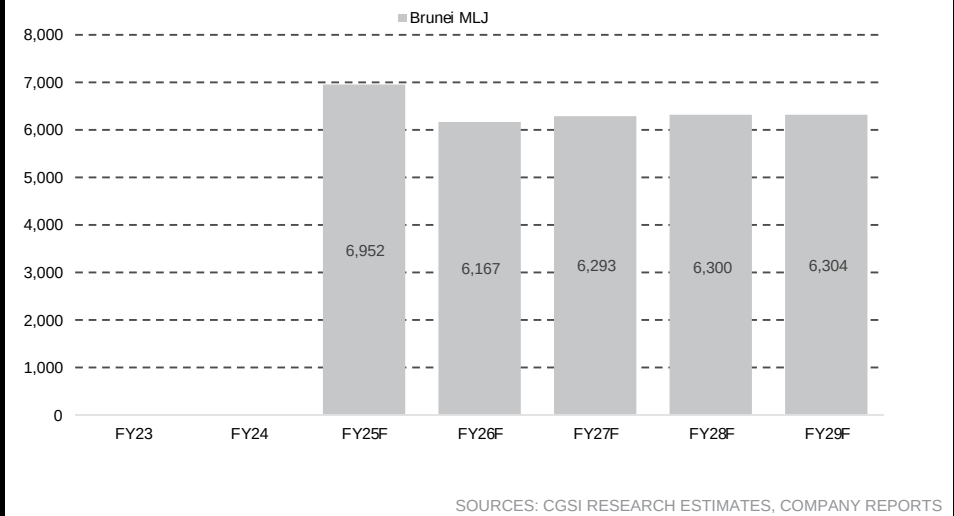


Figure 46: Brunei MLJ: Revenue and PAT (RM m)

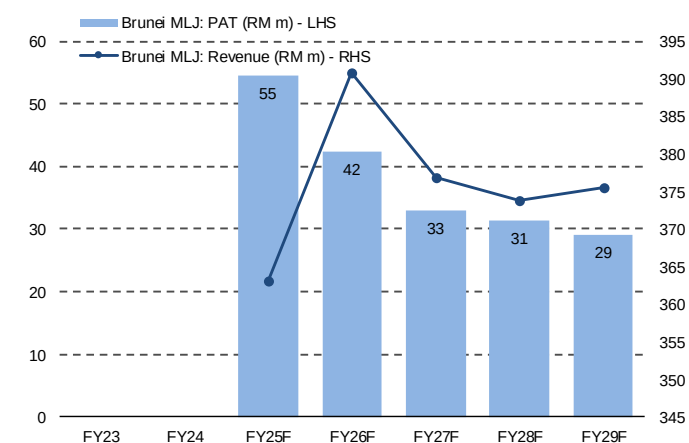
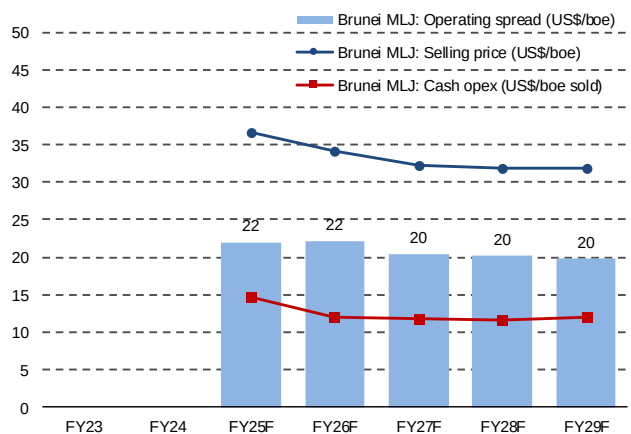


Figure 47: Brunei MLJ: Operating spread = Selling price - Cash opex (US\$/boe sold)



Upside risks for Hibiscus in Brunei ►

(A) Upside to MLJ field's 2P reserves and 2C resources

As at 1 Jan 2023, RPS estimated that:

- 2P reserves for the MLJ field stood at 24.2 MMboe (21.7 MMboe as at 1 Jan 2024); and
- 2C reserves stood at 6.8 MMboe.

This totals 31 MMboe.

Based on Hibiscus's internal estimates, it believes that the 2P reserves and 2C resources are potentially more than 31 MMboe. This is on the back of Hibiscus's confidence that it can add value to the Brunei MLJ asset by exploring various methods of enhanced recovery, such as better reservoir management, additional well completions and well interventions, etc.

Meanwhile, TotalEnergies (the seller) claimed that the hydrocarbon volumes are even higher than Hibiscus's internal estimate.

If Hibiscus's or TotalEnergies' estimates turn out to be correct, there may be upside to the Brunei MLJ DCF estimate.

(B) Brunei has many development prospects that are not being exploited by the supermajors

Oil and gas production in Brunei is dominated by **Shell** working alongside the Brunei state entities. **Hibiscus** has since taken over TotalEnergies' MLJ asset in Brunei. Meanwhile, **Petronas** is working to bring to production various gas and condensate developments in Brunei with 2028F as the earliest first gas date, including that of the Kelidang field that will be developed with a Floating, Production, Storage and Offload (FPSO) vessel.

Hibiscus purchased TotalEnergies' stake in the MLJ field as a means to step into Brunei, but it will not stop there. Proximate to the MLJ field are many other **potential development clusters** that can be developed via tie-back to the production infrastructure at MLJ. This means that once ullage at the OPP is available, due to natural production decline at MLJ, Hibiscus may be able to exploit proximate fields to keep the utilisation of the OPP high.

Many of these clusters are currently not being developed because their resource potentials fall below the materiality threshold of the oil majors in Brunei. According to consultant Rystad Energy, Brunei gas production has declined by c.35% over the past 10 years to 2024F; we believe that this is a cause for concern for the Brunei government as its economy depends heavily on hydrocarbons. As such, we think that Brunei will welcome having an operator like Hibiscus in the country, because Hibiscus is willing to develop smaller resource accumulations that the oil majors will pass over.

Hibiscus thinks that it will need some time to gain the trust of the oil and gas regulators in Brunei. As such, Hibiscus believes that it will need 2-3 years to secure a development licence and be awarded a cluster in Brunei to develop, and 2-3 years after that to bring a development to production.

Downside risks for Hibiscus in Brunei ►

(A) Actual MLJ field production may fall below RPS expectations

In the shareholder circular dated 13 Dec 2021 relating to Hibiscus's acquisition of Repsol's assets in Malaysia and Vietnam, RPS had published production profile forecasts.

However, we notice that the actual production from both the Kinabalu and the PM3 CAA fields underperformed RPS's expectations in 2022 and 2023, and Kinabalu is on track to underperform again in 2024F (Figures 51-52). Hibiscus attributed the underperformance to Covid-related maintenance delays and postponements, and even though Hibiscus had finally caught up with the maintenance work in

2022 and 2023, it may have been too late to arrest the negative impact to production rates, in our view.

Given that the Brunei MLJ field is a mature asset that has been producing for the last 25 years since 1999, we think that there is some risk that the future production decline may turn out to be steeper than expected, and the actual production levels could also disappoint, as had been the case for the Repsol assets. Hibiscus's own view is that Brunei MLJ is a well-maintained asset and its production rate should not disappoint, but only time can tell if this assertion is valid.

(B) Hydrocarbon prices were high when the Brunei MLJ SPA was inked

Hibiscus signed the Sale and Purchase Agreement (SPA) for the Brunei MLJ field in Jun 2024 when oil and gas prices were relatively high when compared to the oil and gas prices that prevailed in its previous three acquisitions. In the 12 months prior to the signing of the SPA, Brent crude had averaged **US\$84/bbl**, while JKM had averaged **US\$12.22/MMBtu** (Figure 48).

By comparison, the SPA for Hibiscus's acquisition of Repsol's assets in Malaysia and Vietnam was signed in Jun 2021, and Brent averaged just **US\$51/bbl** in the preceding 12 months, while JKM averaged just **US\$6.62/MMBtu**.

Although production fell below original expectations post-acquisition, Hibiscus still profited handsomely from the Repsol deal, as oil and gas prices appreciated materially after the purchase completion date of 24 Jan 2022 due to the Russian invasion of Ukraine in Mar 2022.

However, we are unclear if Hibiscus will enjoy something similar for the Brunei MLJ acquisition. If the actual MLJ production underperforms RPS's expectations, Hibiscus may not have the benefit of higher oil and gas prices to make up for the production shortfall.

Figure 48: Average Brent and JKM prices 12 months prior to Hibiscus's previous acquisitions

No	SPA date	Asset	Buyer	Seller	Avg Brent price 12 months prior US\$/bbl	Avg JKM price 12 months prior US\$/MMBtu
1	Jun 2024	Acquisition of TotalEnergies Brunei	Hibiscus	TotalEnergies	84	12.22
2	Jun 2021	Acquisition of Repsol's assets in Malaysia and Block 46 Vietnam	Hibiscus	Repsol	51	6.62
3	Oct 2016	Acquisition of North Sabah PSC in Malaysia	Hibiscus	Shell	42	5.67
4	Aug 2015	Acquisition of Anasuria Cluster in the UK	Hibiscus	Shell, ExxonMobil	69	9.54

SOURCES: CGSI RESEARCH, COMPANY REPORTS

(C) RPS's forecasts for Brent oil and JKM gas prices may be high

RPS forecasted Brent oil prices to bottom at US\$75/bbl in 2027-2029F, before rising annually to US\$95/bbl in 2039F. Meanwhile, RPS forecasted JKM prices to average US\$10.2/MMBtu for 2024F, before consistently rising by 2% p.a. to US\$13.7/MMBtu in 2039F (Figure 40).

Long-term hydrocarbon price forecasts are unreliable, in our view, as prices depend on a mix of many factors that cannot be reliably forecasted. In addition, the International Energy Agency (IEA) has a particularly bearish view on oil prices in its Stated Policies Scenario (STEPS), which assumes that nations and governments follow through on their pledges to reduce hydrocarbon consumption in favour of renewable and clean energy sources. Having said that, the IEA noted that governments have not always followed their own pledges.

As shown in Figure 40, our strategy is to use lower hydrocarbon price assumptions in order to reflect a more conservative valuation of Brunei MLJ into our DCF-based target price for Hibiscus.

RPS's Brent price assumption of US\$80/bbl for 2025F also look high when juxtaposed against weak import demand from China this year, ample spare production capacity at OPEC of 5.9 MMbbls as at end-Sep 2024 (according to the IEA), and OPEC+'s current plans to gradually raise production from 1 Jan 2025F. **We have applied Brent oil prices of US\$75/bbl for 2025F, and US\$70/bbl from 2026F onwards.**

The upside risk to our assumption is if the US president-elect Trump tightens the sanctions on Iran after he takes office on 20 Jan 2025F; Iran has been exporting 1.5 million barrels per day (mbpd) of oil mainly to China, and this flow could be curtailed if the US merely enforces the sanctions already in place. If Iran's oil exports decline, that would give room for OPEC+ to progressively restore its production without roiling the oil markets.

Conversely, **RPS's JKM price assumption of US\$10.4/MMBtu for 2025F looks low** when compared against the YTD average of US\$11.56/MMBtu up to the last week of Nov 2024; the JKM has traded above US\$13/MMBtu since mid-Aug 2024 in the run-up to the Northern Hemisphere winter, which is typical price behaviour if the market expects that winter may turn out to be colder than normal. **We have applied JKM price of US\$13/MMBtu for 2025F.**

We highlight that **crude oil price movements make a bigger impact on the cashflows and valuation of Brunei MLJ than the variability in spot gas prices.** Although Brunei MLJ mainly produces gas, the wellhead gas price received by Brunei MLJ is directly correlated with the price that BLNG receives for its LNG exports, and the latter price is at least two-thirds weighted to the Japan Crude Cocktail (JCC) price and less than one-third weighted to spot JKM gas prices.

For the medium term, the IEA has warned about the impending oversupply of LNG given the significant build-up of liquefaction capacity in the US and Qatar, and a significant loosening of market conditions from 2026-2027F onwards. The IEA expects the Japan LNG price to bottom at US\$8.3/MMBtu in 2030F, before recovering slightly after that. **From a JKM price assumption of US\$13/MMBtu for 2025F, we have assumed a lower price of US\$10/MMBtu in 2026F, and US\$8/MMBtu from 2027F onwards.**

(D) Downtime at BLNG's facilities may affect timing of revenue recognition

On 20 Nov 2024, BLNG issued a statement that it was managing an "operational upset" to its gas liquefaction plant. The BLNG plant came back online on 28 Nov 2024, according to Hibiscus, and the MLJ asset returned to full production.

Gas production from the Brunei MLJ asset is sold to BLNG as the sole buyer, hence, any operational downtime at BLNG could temporarily affect the gas sale revenues at Brunei MLJ. Unplanned outages at BLNG mean that no gas can be delivered to BLNG, hence, Brunei MLJ cannot recognise any gas sale revenues during the BLNG outage period. However, once BLNG comes back online, there may be catch-up gas purchases that could augment the Brunei MLJ gas revenues in the period immediately following the outage. Ultimately, Brunei MLJ is protected by the take-or-pay clause that require BLNG to purchase the Annual Contracted Quantity (ACQ) for any specific year.

In the event of a lengthy outage at BLNG, Brunei MLJ's gas sales volume could still be impacted. This is because BLNG usually purchase all of the gas produced by Brunei MLJ, and the total volume of gas purchased is typically more than the ACQ. Therefore, a lengthy downtime at BLNG could impact the total volume of purchased gas above the ACQ threshold, or even push the fulfilment of the current year's ACQ volume to the following year.

SECTION 5: THE PENINSULA HIBISCUS ASSETS IN MALAYSIA AND VIETNAM

Background of the acquisition of Repsol's Southeast Asian assets ➤

On 2 Jun 2021, Peninsula Hibiscus (wholly owned by Hibiscus) entered into an SPA with Repsol Exploración, S.A. to buy the entire equity interest in Fortuna International Petroleum Corporation (FIPC) and its subsidiary companies for a **cash consideration of US\$212.5m**.

The effective date of the transaction was **1 Jan 2021**. This meant that the economic benefits and risks from the acquisition, and the cashflows and profits from the acquired companies, belonged to Hibiscus since 1 Jan 2021.

The acquisition was legally completed on **24 Jan 2022**, upon which the acquired companies were consolidated into Hibiscus's financial statements.

The acquisition gave Hibiscus participating interests and operatorship in the following PSCs:

- 60% interest in the **2012 Kinabalu Oil PSC** located offshore Sabah, Malaysia;
- 35% interest in the **PM3 CAA PSC** located within the Commercial Arrangement Area (CAA) between Malaysia and Vietnam;
- 60% interest in each of the **PM305 and PM314 PSCs** located off the east coast of Peninsular Malaysia; and
- 70% interest in the **Block 46 PSC (Cai Nuoc)** offshore Vietnam, for which production is tied-back to the PM3 CAA PSC.

Of the purchase price of US\$212.5m, Hibiscus ended up paying a final purchase consideration of US\$138.7m after netting off US\$78m pre-closing dividends extracted out of FIPC by Repsol, among other adjustments. However, because FIPC was acquired with US\$18.5m in cash balances, the net cash outflow from the acquisition was only US\$120.2m (or RM503.3m based on the exchange rate as at the legal completion date of 24 Jan 2022).

The **final purchase consideration of US\$138.7m** was funded through:

- An US\$80m drawdown of Hibiscus's prepayment facility with Trafigura Pte Ltd ^① in Dec 2021;
- RM196.1m (US\$46.8m) from the first and second tranches of the CRPS private placement (see Section X for more details); and
- The remaining amount of c.US\$12m from internally generated funds.

Note: ^① Trafigura is the party to which Hibiscus sells all of its North Sabah crude oil output, and Hibiscus fully settled the above US\$80m prepayment facility drawdown via North Sabah crude oil offtake proceeds between Jul 2022 and Dec 2022.

FIPC was valued by RPS at US\$285m, which compared favourably to the purchase price of US\$212.5m; this led to a **negative goodwill of RM317.3m** that was booked in Hibiscus's 3QFY22 P&L as the transaction was completed on 24 Jan 2022.

Figure 49: Peninsula Hibiscus is wholly owned by Asia Hibiscus, which is wholly owned by Hibiscus Petroleum Bhd

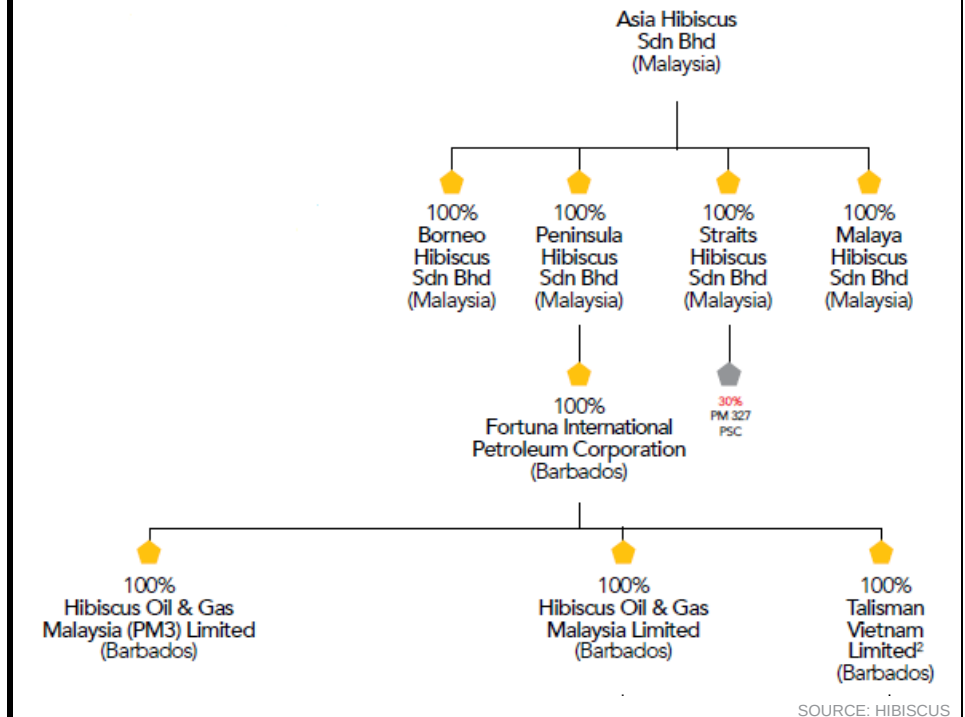
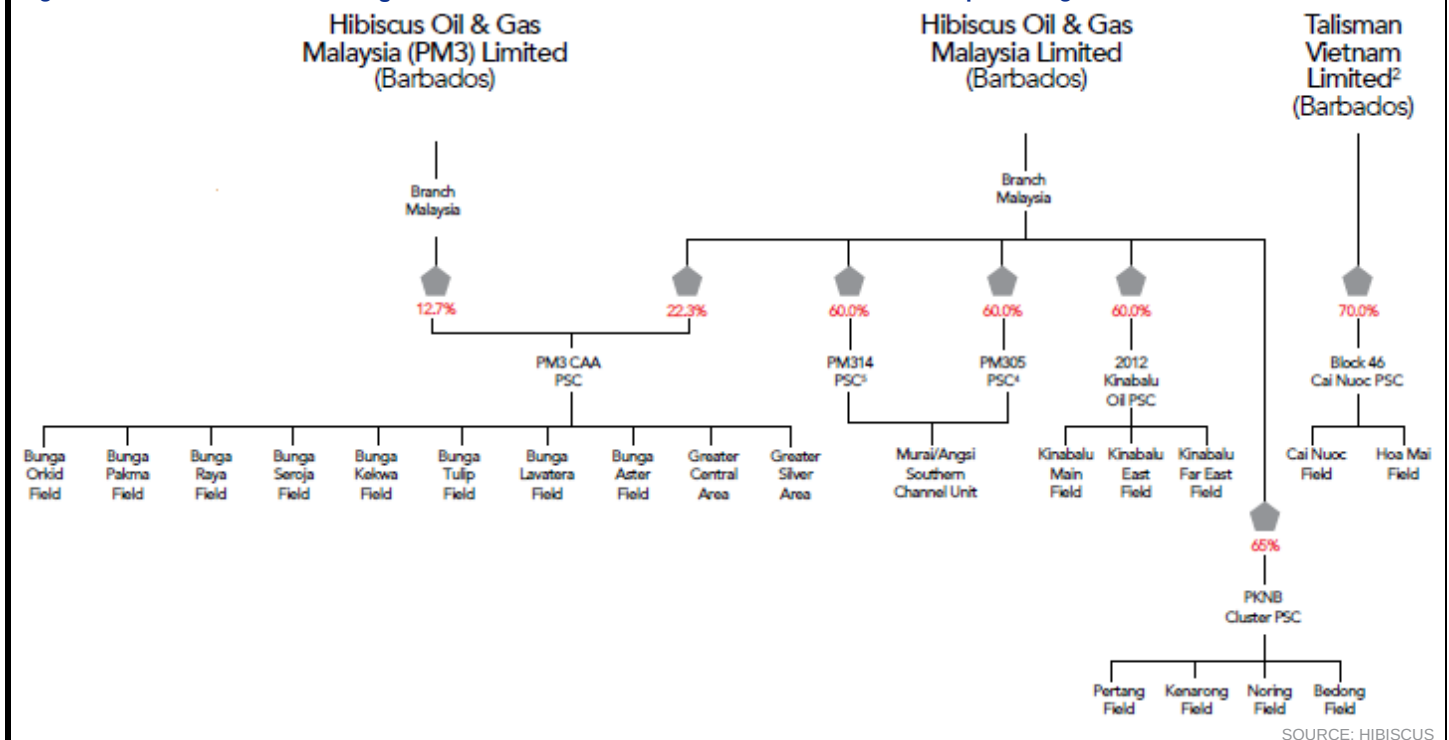


Figure 50: Hibiscus's 35% working interest in the PM3 CAA PSC asset is held via two separate legal entities



Peninsula Hibiscus production disappointed Hibiscus's expectations ►

Hibiscus noted in its Jul-Sep 2021 quarterly results (released in Nov 2021) that “based on third party expert reports, upon completion of the Proposed Acquisition [of FIPC], it is forecasted that the Group’s daily production rate will increase almost three-fold to circa **26k boe per day** while our 2P net entitlement reserves will increase by more than 1.5 times.”

However, the actual production numbers came below Hibiscus’s guidance above. In the Jan-Mar 2022 quarter, the group net oil equivalent production rate rose to **19,405 boepd** (from 8,333 boepd in the Oct-Dec 2021 quarter), and was 18,584 boepd in the Apr-Jun 2022 quarter. A year after the acquisition was completed, production was at 21,489 boepd. These production numbers came below Hibiscus’s expectations of 26,000 boepd.

Hibiscus did deliver on the increase in the 2P net entitlement reserves, which rose 1.77x as a result of the acquisition, using the reserves data as at 1 Jul 2022. But we wonder if RPS would have stated the reserves as high as that had RPS known about the subsequent production shortfalls against its expectations. The shortfall can be seen in Figures 51-52, where we compare the actual production for the two main PSC blocks – PM3 CAA and Kinabalu – against expectations set out by RPS in the shareholders’ circular dated 13 Dec 2021.

For PM3 CAA, the actual gross gas **production rate** and the gross oil and condensate production rate **fell below RPS expectations for CY22 and CY23**. While the gross gas production rate in the Jan-Sep 2024 period has risen to above RPS expectations for CY24F, this was only achievable because of **heavier capex spending** put in by Hibiscus compared to that modelled-in by RPS. Specifically, Hibiscus had spent capex to drill the Bunga Lavatera gas exploration well in 2023 (as well as the Bunga Aster oil exploration well in 2024), both of which turned out to be successful and productive wells.

For Kinabalu, it was the also same story whereby its gross oil production rate for CY22 and CY23 fell below the RPS forecasts. For Jan-Sep 2024, Kinabalu’s gross oil production rate was still 13% below the RPS expectations for CY24F, despite Hibiscus spending significantly more capex in CY23 than that estimated by RPS.

A key factor behind the shortfall against RPS’s expectations was because during the Covid period, Repsol had paused a lot of non-essential offshore maintenance, which directly led to lower production when Hibiscus took over the assets. In the post-acquisition period, Hibiscus had needed to catch up on the deferred maintenance work, which may have also impacted production due to the greater frequency of maintenance shutdowns. The higher level of maintenance also led to **net opex being higher than RPS expectations** in CY23 for both PM3 CAA and Kinabalu, which continued into Jan-Sep 2024.

Figure 51: Comparisons of PM3 CAA actuals against RPS forecasts in shareholder circular dated 13 Dec 2021

PM3 CAA PSC	CY22	CY23	CY24F *
Gross gas production rate (boepd)			
- Projected by RPS	35,833	31,833	24,333
- Actual	31,564	31,538	31,084
Variance (absolute)	-4,270	-295	6,751
Variance (%)	-12%	-1%	28%
Gross oil and condensate production rate (bopd)			
- Projected by RPS	19,109	21,782	18,240
- Actual	13,555	19,430	18,164
Variance (absolute)	-5,554	-2,352	-76
Variance (%)	-29%	-11%	0%
Net opex (US\$ m)			
- Projected by RPS	77	77	76
- Actual / Annualised for CY24F	77	84	96
Variance	0	7	20
Net capex (US\$ m)			
- Projected by RPS	48	2	2
- Actual / Annualised for CY24F	39	25	40

* CY24F production data for Jan-Sep 2024 only; opex and capex data for CY24F is annualised from the Jan-Sep 2024 actuals.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 52: Comparisons Kinabalu actuals against RPS forecasts in shareholder circular dated 13 Dec 2021

Kinabalu PSC	CY22	CY23	CY24F *
Gross oil production rate (bopd)			
- Projected by RPS	12,254	11,209	8,771
- Actual	8,924	7,181	7,633
Variance (absolute)	-3,330	-4,028	-1,138
Variance (%)	-27%	-36%	-13%
Net opex (US\$ m)			
- Projected by RPS	33	27	26
- Actual / Annualised for CY24F	25	28	30
Variance	-8	1	4
Net capex (US\$ m)			
- Projected by RPS	35	11	1
- Actual / Annualised for CY24F	8	50	13

* CY24F production data for Jan-Sep 2024 only; opex and capex data for CY24F is annualised from the Jan-Sep 2024 actuals.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

The combination of higher-than-expected level of capex and opex, and the lower-than-expected gross production rates would have negatively impacted Hibiscus's financials if not for the **significant increase in oil prices** after the completion of the acquisition on 24 Jan 2022, which was due to the post-Covid recovery in oil demand and the onset of the Russia-Ukraine war in Mar 2022.

In the shareholders' circular dated 13 Dec 2021:

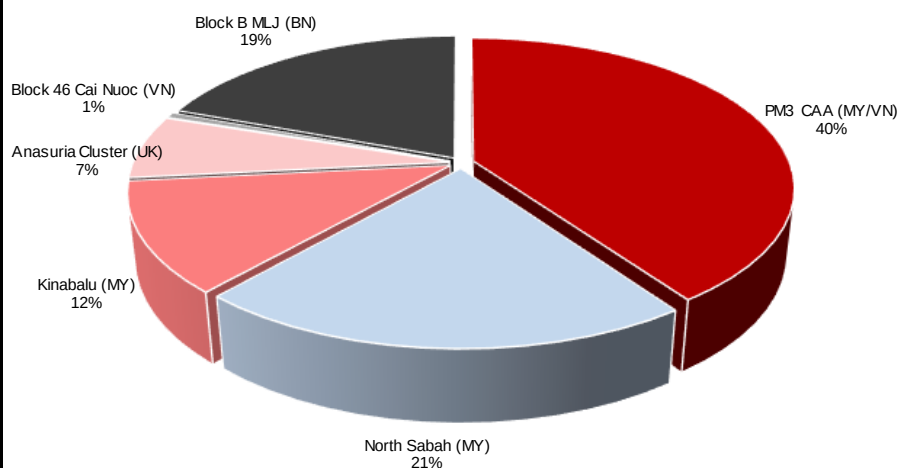
- RPS had forecast average Brent oil price of US\$57/bbl for CY22, but the actual average Brent oil price was substantially higher at US\$99/bbl.
- For CY23, RPS forecast US\$55/bbl, but the actual was US\$82/bbl.
- For CY24F, RPS expected US\$53/bbl, but the actual YTD Brent oil price up to end-Nov 2024 was US\$80/bbl.

The higher-than-expected oil prices also spilled over into higher realised gas prices for PM3 CAA, as its gas prices are pegged to the price of Singapore High Sulphur Fuel Oil (HSFO) which is intrinsically linked to oil.

In our assessment, higher oil prices had more than compensated for the post-acquisition shortfall in production of the Repsol assets. Hibiscus was fortunate to have negotiated the deal when oil prices were low and were still recovering from the Covid-related demand destruction, in our view.

Of the Peninsula Hibiscus assets, PM3 CAA and Kinabalu are the key producing assets, totalling 66% of Hibiscus group's net oil equivalent production in FY24, but declining to 52% with the contribution of Brunei MLJ in FY25F (Figure 53). Block 46 Cai Nuoc PSC produces very little, while production from PM305/PM314 PSCs have already ceased.

Figure 53: Share of net oil equivalent production (boe) by block in FY25F



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

PM3 CAA PSC, at the Malaysia-Vietnam Commercial Arrangement Area (CAA) ➤

Location, PSC licence, and production infrastructure

The PM3 CAA PSC is located in the Malaysia-Vietnam Commercial Arrangement Area (CAA), off the coast of Malaysia and Vietnam in shallow waters of 184 feet depth (Figure 54).

Hibiscus holds a **35%** participating interest in the PSC, with Petronas Carigali holding 35% and PetroVietnam Exploration Production Corporation holding the remaining 30%.

The PSC licence was awarded in Feb 1989 and will expire on **31 Dec 2027F**. Hibiscus and its PSC partners are negotiating to extend the PSC term, possibly by 10 years to 31 Dec 2037F, or by 20 years to 31 Dec 2047F. Hibiscus hopes to make an announcement by end-2024F.

Although the PM3 CAA PSC lies in the Malaysia-Vietnam CAA, the applicable PSC framework is that of the **Malaysian PSC regime** (not the Vietnamese PSC regime) and the regulator of the PSC is Petronas (not PetroVietnam).

The PM3 CAA development is split into the 'Northern Fields' and the 'Southern Fields'. Oil and gas production from the PM3 CAA PSC comes from eight fields, namely Bunga Orkid, Bunga Pakma, Bunga Raya, Bunga Seroja, Bunga Kekwa, Bunga Tulip, Bunga Lavatera, and Bunga Aster. First gas was achieved in Jul 1997, while first oil in Oct 2003.

The existing production infrastructure comprises 14 fixed platforms, 143 wells, and two Floating Storage Offload (FSO) units, i.e. the FSO Orkid which is leased from its owner MISC (located in the 'Northern Fields'), and the FSO PM3 CAA (located in the 'Southern Fields') which is owned by the three PSC participants.

The oil is produced and exported via the two FSOs. Oil production from the Block 46 Cai Nuoc PSC, for which Hibiscus has a 70% participating interest, is tied-in to and exported via the production facilities at PM3 CAA.

Gas pipelines from the platforms in the 'Southern Fields' transport the gas to Kerteh (a city in Terengganu, Peninsular Malaysia) via the offshore Resak platform operated by Petronas Carigali, and to Ca Mau (a city in southern Vietnam), where it is used to fulfil domestic gas demand in the two countries. Gas produced in the 'Northern Fields' is transported via pipeline to the 'Southern Fields' before it is piped to onshore Malaysia and Vietnam.

Because of the high content of contaminants in the natural gas produced at PM3 CAA, the mercury must first be removed from the gas, and the CO₂ content must also be substantially reduced from 44-45% content to a maximum of 8%, as

specified by the buyers of the gas. The CO₂ removal is achieved through the Acid Gas Removal Unit (AGRU) which is located on one of the offshore platforms.

The PM3 CAA hub strategy

Hibiscus has a 65% participating interest in the **PKNB Cluster PSC**, which comprises four Discovered Resource Opportunities (DRO), namely the Pertang, Kenarong, Noring and Bedong (PKNB) fields. The PKNB Cluster is currently not yet developed, and it can be developed via tie-back to the PM3 CAA production facilities due to its proximity (Figures 54-56). Hibiscus guided that production from the PKNB Cluster may begin in 2028F.

In addition, Hibiscus has a 30% participating interest in the **PM327 PSC**. This is a sizable exploration block for which no discoveries have yet been made. According to Hibiscus, developments of any future discoveries will also be made via tie-backs to the proximate PM3 CAA production facilities.

In short, the economic viability of the PM3 CAA production hub can be extended by feeding-in hydrocarbons from the PKNB Cluster and the PM327 PSC.

Hibiscus has guided that in the next 4-5 years it will likely **prioritise capital allocation to the development of the PM3 CAA production hub**, in order to take advantage of the opportunities within PM3 CAA itself, and also the opportunities for the development of the PKNB Cluster and the future PM327 discoveries. This is in addition to the ongoing projects at the UK Teal West field and the North Sabah SF30 Water Flood Phase 2 project, which should be largely completed in the next 12-18 months.

Figure 54: Hibiscus's PM3 CAA hub strategy – PM3 CAA is shaded orange and is comprised of the Northern and Southern Fields; “B-46 CN” shaded yellow refers to Block 46 Cai Nuoc PSC which is located to the north of PM3 CAA PSC; the PKNB Cluster PSC is marked by the two dashed-line circles; and the PM327 PSC is shaded green and located to the south of PM3 CAA PSC

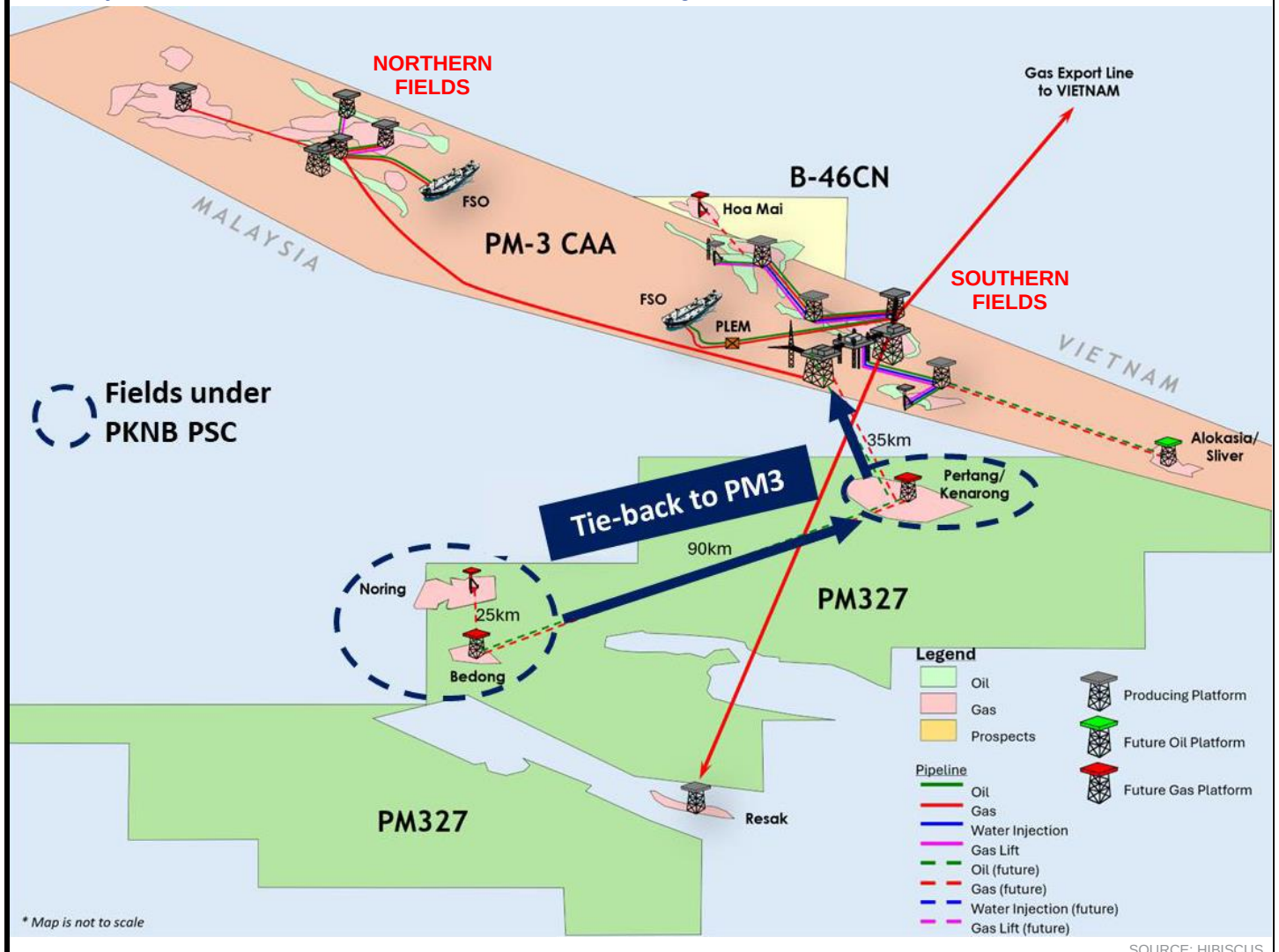
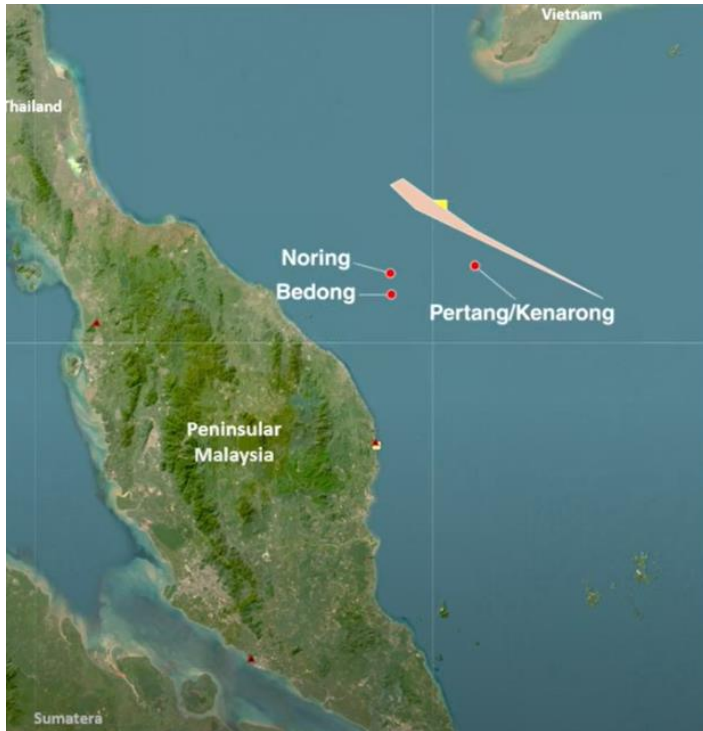
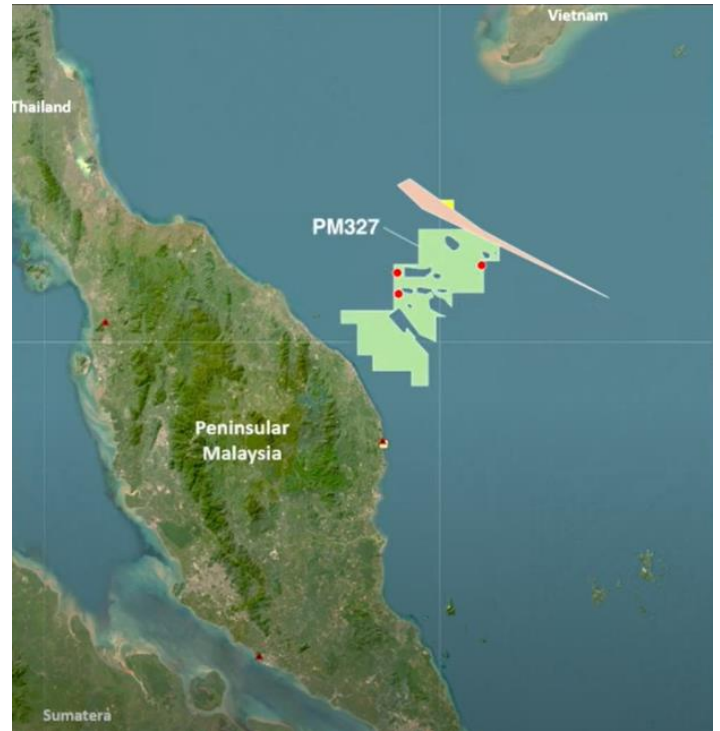


Figure 55: Location of the PKNB discovered fields offshore Terengganu to the south of PM3 CAA PSC (shaded orange)



SOURCE: HIBISCUS

Figure 56: Location of the PM327 exploration block offshore Terengganu (red dots represent the PKNB fields)



SOURCE: HIBISCUS

Commercial terms

The oil produced at PM3 CAA is sold to **Petronas Trading Corporation Sdn Bhd (PETCO)**, the trading arm of Malaysia's national oil company, Petronas. The oil is typically sold at a premium to the price of Brent, due to higher quality specifications; for the Jan-Mar 2024 quarter, Hibiscus disclosed that the PM3 CAA oil was sold at a **4% premium** to Brent.

Under the **Gas Sale Agreement (GSA)**, the gas produced at PM3 CAA is sold to Petronas and PetroVietnam. The gas produced at PM3 CAA is subject to Annual Delivery Quantities (ADQ), which is shared equally between the two buyers. A shortfall in gas delivery by the PSC participants to the buyers will have to be made up for in future periods but at 10-15% lower prices. However, if the buyers Petronas and PetroVietnam request for gas offtake below the ADQs, the buyers will have to pay a 10-15% price premium for the gas in the year that the differential gas volumes were to have been delivered, with the differential volumes physically delivered in future periods.

The wellhead gas price is linked to the price of **Singapore High Sulphur Fuel Oil (HSFO)**. In FY23 and FY24, the wellhead gas price on a US\$ per boe basis was 47-48% of the Singapore HSFO price. This worked out to between US\$5/MMBtu and US\$6/MMBtu, in our estimate.

Peninsula Hibiscus is obligated to pay a supplementary payment to Petronas under the terms of its PM3 CAA PSC if the realised price of the PM3 CAA crude exceeds the stated threshold; the latter increases by a mid-single-digits percentage annually. However, the threshold is very high and no supplementary payment has been paid by Peninsula Hibiscus since it acquired the PM3 CAA asset on 24 Jan 2022. No supplementary payment is applicable on PM3 CAA's gas production.

Extension of the PSC term; variation on PSC terms and CCS requirements

As noted above, the PM3 CAA PSC participants are negotiating with Petronas and PetroVietnam for an extension of the PSC term which currently ends on 31 Dec 2027F. The PSC term was last extended in 2016 for an additional 10 years to 31 Dec 2027F.

Hibiscus is seeking an **extension of up to 20 years**, although a shorter extension of 10 years is also possible. We sense that Hibiscus is confident of an extension, with a potentially positive announcement by end-2024F.

As noted above, the **PM3 CAA production facilities will function as a hub for future production from the PKNB Cluster and the PM327 PSC**. The PKNB Cluster PSC is for a duration of 24 years to 2048F, while the PM327 PSC is for a duration of 28 years to 2051F. As such, we are reasonably confident that the PM3 CAA PSC licence term can be ultimately extended by up to 20 years to 2047F, even if it may be first extended by an initial period of 10 years to 2037F.

Given the very high greenhouse gas (GHG) emissions from the production of high-CO₂ gas (see Appendix 5 for more details), Hibiscus is preparing to execute a **Carbon Capture and Storage (CCS) solution** for PM3 CAA, likely by 2028-2029F. The CCS solution capex is likely to be very costly, in our view; Hibiscus has not yet provided guidance on the quantum. The proposed CCS capex will be shared among the three PSC participants based on their respective working interests.

Although the CCS capex will almost certainly be cost recoverable by the three PSC participants from the production of the PM3 CAA fields, we believe that the elevated capex spending in the extension period will directly result in lower absolute profits for the PSC participants, based on the technicality of the PSC fiscal terms (which we explain in detail in Appendix 5), assuming production levels and selling prices are unchanged. Also, in a situation where capex spending is stepped-up, all else being equal, the PSC participants' share of production profits will fall by a greater percentage than the share of production profits attributed to the NOCs, Petronas and PetroVietnam. In other words, the PSC participants indirectly bear a greater burden of the CCS capex than the NOCs.

Furthermore, if the PSC term is extended, and even if there is no CCS capex spending, the PSC participants may face poorer economics due to the natural decline in production rates and the resulting increase in opex per boe, since absolute opex is typically quite sticky irrespective of production levels.

As a result of the above situation, we think that it would be natural for Hibiscus, on behalf of the PSC participants, to **seek an improvement in the PSC fiscal terms** for the extension period, so that the heavy CCS capex cost can be more equitably shared between the PSC participants and the NOCs. Improved fiscal terms may involve raising the PSC participants' share of the profit oil tranche and profit gas tranche, with the NOCs share consequently reduced. The impact of this would be to increase the PSC participants' net entitlement to the production of PM3 CAA.

Another possibility is for the PSC participants to **seek better wellhead gas pricing**, which is currently being sold to the NOCs on a US\$/boe basis at 47-48% of the Singapore HSFO price, in our view. Higher wellhead gas pricing can improve the profits of the PSC participants, even if the PSC participants' aggregate net entitlement to production is not raised.

We believe that it is highly likely for Petronas and PetroVietnam to improve the commercial and fiscal terms for the PSC in the extension period, due to the importance of the CCS initiative for the NOCs' own GHG emissions targets, and because a continuation of production from PM3 CAA can help both Malaysia and Vietnam maintain employment on the platforms and facilities, and also to maintain the flow of royalties and taxes to the two countries.

Financial impact to Hibiscus of the potential PSC extension

As of 1 Jul 2024, Hibiscus disclosed its share of PM3 CAA 2P reserves at 11.3 MMboe, comprising 3.1 MMboe of oil reserves and 8.2 MMboe of gas reserves.

Once the PSC term is extended by another 10 years or up to 20 years, we expect Hibiscus to **revise higher its estimate of 2P reserves** at PM3 CAA.

This is because the 2P reserves are stated as the net economically recoverable quantities from the currently producing wells, but only up to the end of the current PSC term of 31 Dec 2027F. Once this time cut-off is extended, 2P reserves can be added just from the existing wells alone.

Additionally, from the new exploration drilling campaigns that Hibiscus will execute only if the PSC duration is extended, **prospective hydrocarbons may be discovered as 2C resources**, which may be subsequently transformed into 2P reserves once its Field Development Plan (FDP) is approved by the national regulators and after Hibiscus and its PSC partners take the Final Investment Decision (FID) to proceed with the development. Hibiscus did not disclose any 2C resources that are attributable to PM3 CAA as at 1 Jul 2024.

Once the 2P reserves are restated higher, we expect depreciation period of oil and gas equipment and the amortisation period of intangible assets at PM3 CAA to be extended up to the end of the new PSC term (rather than only to 31 Dec 2027F), or to the end of the useful life of the assets, whichever is earlier. This means that the periodic **depreciation and amortisation expense in the P&L should be reduced**, in our opinion.

We expect the lengthening of the depreciation and amortisation period to take place as soon as the PSC term is extended; hence, if the PSC term is extended by, say, an additional 10 years and an official announcement is made to that effect on 1 Jan 2025F, Hibiscus should be able to extend the depreciation and amortisation period to a maximum of 13 years effective 1 Jan 2025F up to the end of the extended PSC term of 31 Dec 2037F.

Recent and ongoing drilling programmes

Between FY22 and FY24, Hibiscus completed the 6-well **North Bunga Orkid H4 reservoir** infill drilling programme, comprising two oil producer wells and four water injector wells. This infill drilling increased the production of oil.

In FY23-24, Hibiscus drilled the **Bunga Lavatera-1 gas exploration well** from the Bunga Pakma A platform, and achieved first gas in FY24 with an estimated incremental 2P reserves of 1.6 MMboe.

In FY24, Hibiscus also drilled the **Bunga Aster-1 oil exploration well** from the Bunga Orkid-D platform, and achieved first oil in May 2024, with Hibiscus's net entitlement to production at **400-450 bopd** from that one well in 2HCY24F (1HFY25F). The original flow rate was higher, but the production was deliberately choked back to avoid having sand enter the well, according to Hibiscus.

The incremental 2P reserves from Bunga Aster have not yet been included in Hibiscus's reserve disclosures, as Hibiscus plans to drill one appraisal well in 2025F to assess the actual size of the incremental reserves. This is because the first exploration well was not drilled down to the oil-water contact, or the 'oil down to' depth. This means that the size of the potential 2P reserves could potentially be fairly large, and if so, would imply that additional development wells could be drilled in the future to increase the rate and volume of production.

Hibiscus's preliminary estimate for the Bunga Aster reservoir is for an initial gross oil in-place volume of between 21 MMbbl and 84 MMbbl, as disclosed in Annual Report 2024. Hibiscus's participating interest in PM3 CAA is 35%, but its net entitlement to production under the PSC fiscal regime is c.20%.

This means that **Hibiscus's 2P reserves could potentially be enhanced by between 4.2 MMbbl and 16.8 MMbbl** (20% x 21-84 MMbbl), although we note that not all of the incremental reserves can be produced before the current expiry of the PSC on 31 Dec 2027F, and Hibiscus will need the PSC term to be extended to be able to include all of the above into its 2P reserves.

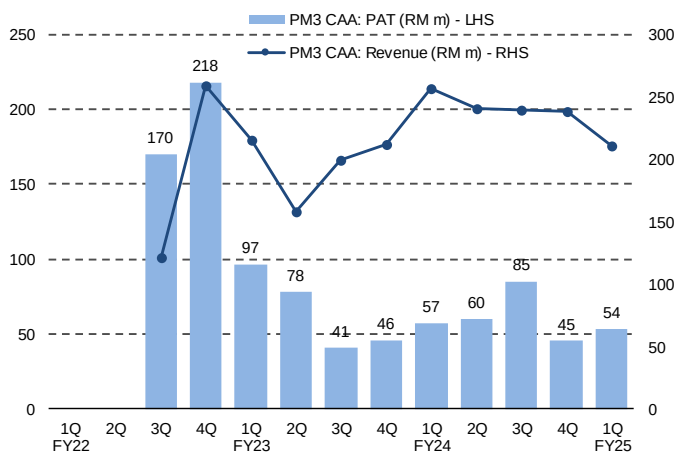
Assuming PSC extension, on a proforma basis, the reserves under the Bunga Aster well(s) would increase PM3 CAA's 2P reserves significantly from the 11.3 MMboe as at 1 Jul 2024. Hibiscus group's total 2P reserves would also increase materially, from 57.4 MMboe as at 1 Jul 2024.

Quarterly financial and operating data

Maintenance shutdowns typically affect production from PM3 CAA for approximately two weeks in the 3Q of every calendar year. As a result, facilities uptime rates and production rates are typically the lowest in the 1Q of every financial year. In FY23, the maintenance shutdown was for 14 days from 20 Aug to 2 Sep 2022. In FY24, the maintenance shutdown was for 11 days between 16 Aug and 26 Aug 2023. In FY25F, the maintenance shutdown took place over 12 days from 17 Aug to 28 Aug 2024.

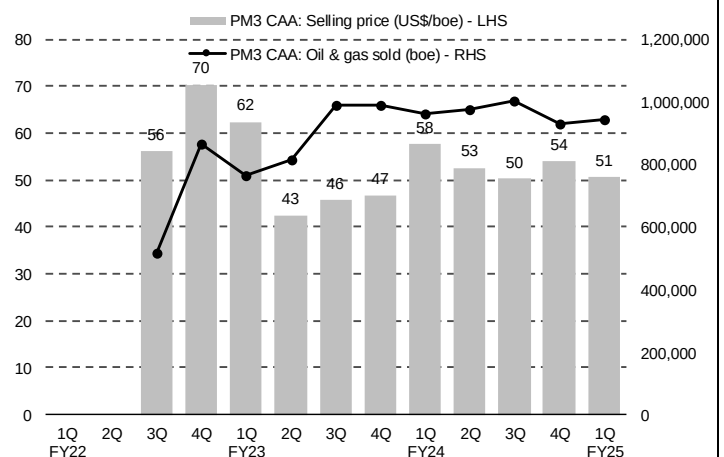
During the maintenance shutdown quarter, cash opex per boe may also be higher than for other quarters, as the maintenance costs are charged into the P&L.

Figure 57: PM3 CAA: Revenue and PAT (RM m)



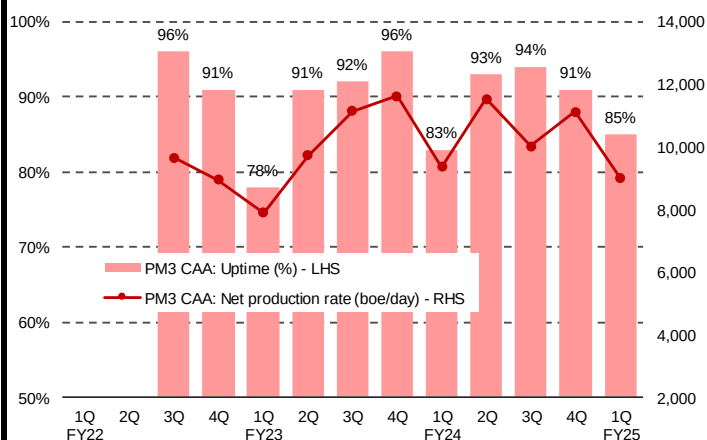
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 58: PM3 CAA: Oil and gas sold (boe) and Selling price (US\$/boe)



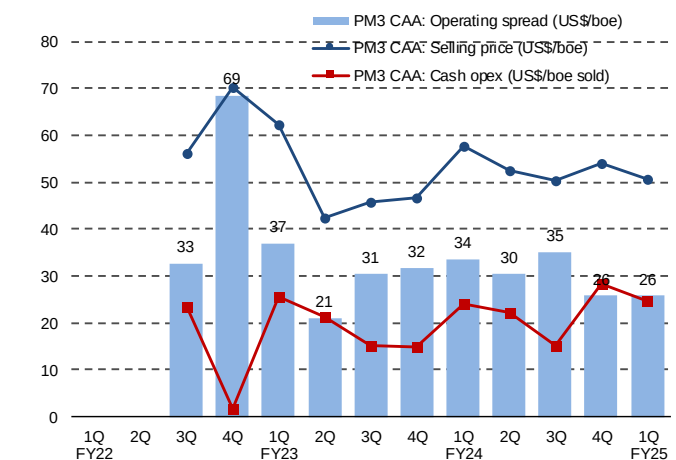
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 59: PM3 CAA: Uptime (%) and Net production rate (boe/day)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 60: PM3 CAA: Operating spread = Selling price - Cash opex (US\$/boe sold)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Annual forecasts for financial and operating data

Our **production forecasts** are on the basis of 'No Further Activity' (NFA), which means that we have not assumed any additional development drilling work unless it has been specifically sanctioned by Hibiscus.

As noted earlier, Hibiscus's net entitlement to production from the **Bunga Aster-1 oil well** was at **400-450 bopd** from 2HCY24F (1H FY25F) onwards. This has already been incorporated into our production forecasts (Figure 61).

Hibiscus disclosed that a **second Bunga Aster oil producer well** may be drilled in 2HCY25F (1H FY26F), but this drilling campaign has not been sanctioned yet, although it has been included in Hibiscus's capex guidance for FY26F. This second oil producer well may raise net production by a further **400-450 bopd** from 1HCY26F (2H FY26F) onwards. In the years ahead, Hibiscus may also put in more drilling investment to produce even more volumes. For perspective, PM3 CAA net oil production in FY24 was 3,200 bopd. We have not yet incorporated any further enhancements to production rates pending finalisation of Hibiscus's capex and drilling plans, hence there is potential upside to our production estimates.

Hibiscus guided for **capex spending** at PM3 CAA of US\$47m in FY25F and US\$40m in FY26F; however, some of the capex spending in FY26F is on the basis that the PSC expiry date will be extended.

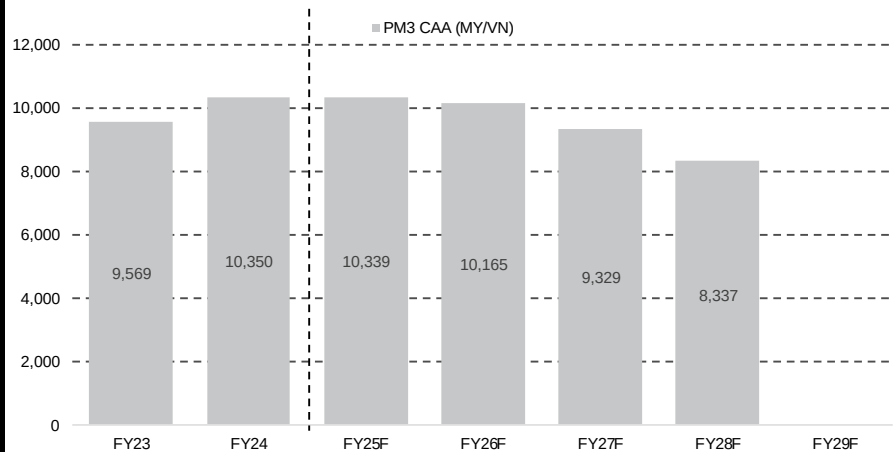
We have assumed that PM3 CAA will produce only until the end of its current PSC term on 31 Dec 2027F, which means that FY28F only reflects half a year of production.

We expect the PM3 CAA **absolute opex** to remain elevated as we head into the PSC expiry of 31 Dec 2027F, because Hibiscus is expecting extension of the PSC by 10 years or by 20 years; hence, we expect Hibiscus to keep the asset in good shape. However, given the gradually reducing production rates, we expect the **opex per boe** to be in a rising trend in our forecast period. However, the opex per boe at PM3 CAA may decline in the future (even as absolute opex rises), if and when the production from PKNB Cluster is tied into PM3 CAA facilities, since PM3 CAA will allocate some of the infrastructure and opex costs to the PKNB Cluster.

We expect the **PM3 CAA PAT in FY25F to decline** from the FY24 level due to the combination of lower average selling prices, and higher absolute opex and opex per boe, that result in a squeeze in operating spreads per boe. In addition, PM3 CAA had written back tax overprovisions in FY24, and if this does not recur, we expect the effective tax rate to rise to 35% in FY25F, from 27.4% in FY24.

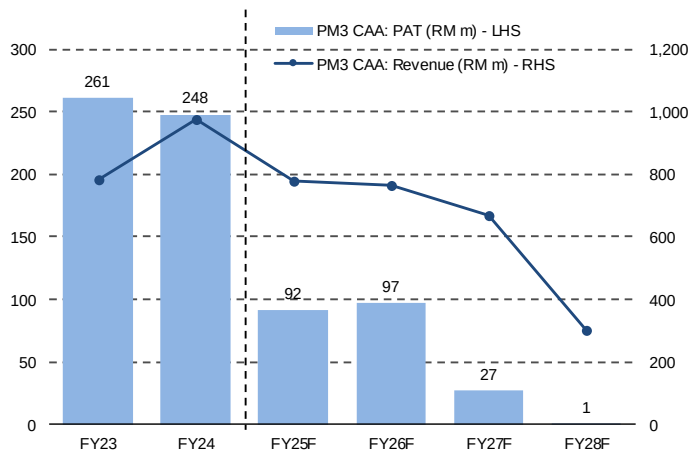
If the PM3 CAA PSC term is extended, we anticipate that our PAT forecasts will be revised higher to reflect lower depreciation and amortisation expense, because the depreciation and amortisation expense is calculated using the **Unit of Production (UOP) method** and because the 2P reserves will almost certainly be revised higher. Our current estimate for depreciation and interest expense is RM246m in FY25F. We are not yet able to estimate the post-extension level of depreciation and amortisation expense until we receive information on the new 2P reserves estimate.

Figure 61: PM3 CAA: Net oil equivalent production rate (boepd)



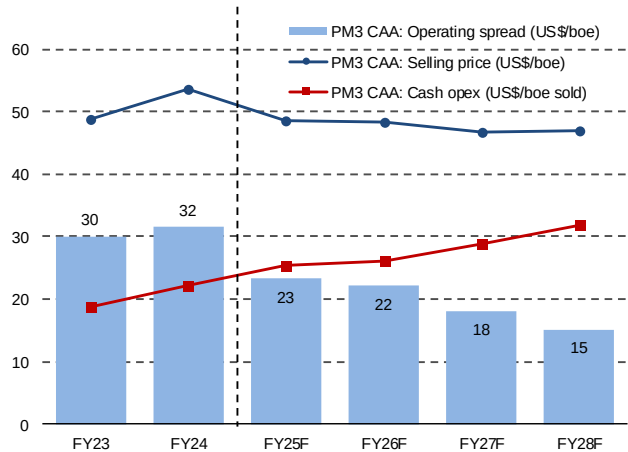
SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 62: PM3 CAA: Revenue and PAT (RM m)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 63: PM3 CAA: Operating spread = Selling price - Cash opex (US\$/boe sold)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

PKNB Cluster, Malaysia ➤

Location, PSC licence, and production infrastructure

On 1 Jul 2024, Hibiscus was awarded by Petronas a **65%** participating interest and operatorship of the Pertang, Kenarong, Noring and Bedong (PKNB) fields, which are Discovered Resource Opportunities (DRO) located offshore Terengganu in shallow waters of 213-246 feet and proximate to the PM3 CAA PSC. For this privilege, Hibiscus paid a one-off fee of RM0.7m to Petronas.

Industry paper Upstream wrote that Petronas had conducted its maiden Malaysia Bid Round Plus (MBR+) offering earlier this year, which complements the annual Malaysia Bid Round (MBR) acreage offerings by providing an additional avenue for investors to participate in DRO and late-life assets in Malaysia. It was under this year's MBR+ offering that Hibiscus was awarded its participating interest and operatorship in the PKNB Cluster.

According to Hibiscus, Petronas awarded this PSC to Hibiscus without an open tender, as Petronas has now accepted Hibiscus as an equal to other more established oil and gas exploration and production companies. Another possible reason may be because Hibiscus is the operator of the PM3 CAA facilities, which could offer the most cost-efficient way of developing the PKNB Cluster, in our view.

The effective date of the PKNB Cluster PSC was 1 Jul 2024, with a contract duration of 24 years to **30 Jun 2048F**. The other PSC partner is Petronas Carigali with 35% participating interest.

Hibiscus disclosed that the PKNB Cluster may be developed via three platforms and 16 wells. Gas produced at the PKNB Cluster is intended to be tied-back to the PM3 CAA facilities for processing, before export via gas pipelines to Peninsula Malaysia and Vietnam.

Historically, the Pertang, Kenarong, Noring and Bedong (PKNB) fields were part of the PM311 PSC block that was previously held by Murphy Oil (75%) and Petronas Carigali (25%). Gas resources at Pertang were discovered by Murphy Oil in 2004, while gas at Kenarong was discovered in 2005. For some reason, neither field was developed by Murphy Oil, which subsequently relinquished its rights to PM311 back to Petronas, and exited Malaysia entirely in 2019.

Commercial terms

The PKNB Cluster DRO PSC will come under the '**Improved Revenue Over Cost**' terms. This means that the R/C index will be applied in a way that will improve the net entitlement and profitability to the PSC participants, relative to the traditional PSC terms. This is necessary to encourage oil and gas companies to develop the smaller opportunities, in our view.

For instance, we expect that the PSC participants of the PKNB Cluster will have a **net entitlement of c.86%** of the gross production volume. This means that the Petronas will only have a net entitlement of 4%, after accounting for 10% royalty.

By comparison, in FY24, the PSC participants of the PM3 CAA PSC only enjoyed a net entitlement of c.58%, a net entitlement of c.69% at the Kinabalu PSC, and a net entitlement of c.73% at the North Sabah PSC, based on the terms of their respective PSC contracts.

Please refer to Appendix 5 for a detailed explanation of the concept of 'net entitlement' in the context of the Malaysian PSC regime.

Hibiscus has commenced negotiations to improve the basis of the pricing of the PKNB gas sales to be better than that for PM3 CAA gas. As a recap, PM3 CAA gas is sold at a price that is pegged to the price of Singapore HSFO at a ratio of 47-48%. In FY23 and FY24, we estimate that the PM3 CAA wellhead gas price was sold at between US\$5/MMBtu and US\$6/MMBtu.

Development plan

Hibiscus is confident that the PKNB Cluster will be economically viable to develop. It expects the primary production of the PKNB Cluster to be gas as well as condensate, but also oil.

Hibiscus is working with Petronas for approval of its **Field Development Plan (FDP) by 2HCY26F**, which is c.18 months away.

In the meantime, Hibiscus does not expect to perform any drilling work at the PKNB Cluster in the next two years. For FY25-26F, Hibiscus has allocated **capex** at PKNB Cluster of just US\$5m p.a. for pre-FID costs.

Hibiscus will likely only begin **significant development capex spending in CY27-28F**, according to the company. The full development capex has not been disclosed. Hibiscus hopes to fund 50-60% of the capex with bank borrowings, given that this is a gas asset (hence cleaner from the ESG perspective) and because Petronas (strong counterparty) will be the main offtaker for the gas.

The gross 2C gas resources for the Pertang and Kenarong fields were estimated by Murphy Oil at 500 Bcf, of which **Hibiscus's net entitlement was disclosed as 282 Bcf (47 MMboe)**. The 2C gas resources for the Noring and Bedong fields are not publicly available.

Hibiscus is targeting to commence **first gas production in 2028F** to use up the ullage that will likely be available at the PM3 CAA processing facilities by that time, as the existing production at the PM3 CAA fields progressively decline. Feeding PKNB gas into PM3 CAA will help keep the unit production costs at PM3 CAA under control.

We have not incorporated any potential PKNB production into our earnings model or DCF-based target price, pending further guidance from Hibiscus on the likely development capex spending as well as the production flow rates.

PM327, Malaysia ➤

Location, PSC licence, and production infrastructure

On 23 Aug 2024, Hibiscus signed an agreement to acquire a **30%** participating interest in the Block PM327 PSC, which is a sizable exploration block with an area of 12,500 sq km, located offshore Terengganu in shallow waters of 66-246 feet. The acquisition price for the farm-in was **US\$9.9m**, of which US\$7.4m was not yet paid as at 30 Sep 2024; this will be capitalised as intangible assets on the balance sheet.

The effective date of the farm-in agreement was 5 Jul 2024, which involved Petronas Carigali paring down its participating interest from 90% to 60%. The other PSC participant is E&P Malaysia Venture, another subsidiary of Petronas, with a 10% working interest.

The PM327 PSC was originally awarded to Petronas Carigali and EPMV effective 1 Feb 2023 in the Malaysia Bid Round 2022 and has a term of 28 years to **31 Jan 2051F**.

The PSC is operated by Petronas Carigali, who will be responsible for arranging and executing the exploration work programme; Hibiscus will contribute its share of the capex in line with its 30% working interest.

The first four years of the PSC licence between 2023 and 2027F has been set aside for exploration drilling, the subsequent four years between 2027F and 2031F will be allocated for development activities (if it passes the threshold of economic viability), and the remaining 20 years for production.

Production, if assessed to be viable, may not begin until 2032F, although it is possible that production may begin earlier, in our opinion. This is because given the proximity of PM327 to the PM3 CAA PSC, Hibiscus anticipates that the hydrocarbons will be developed via tie-back to PM3 CAA facilities.

Commercial terms

Most of the potential PM327 output will likely be that of **gas**, given the predominance of gas reservoirs in the surrounding geographical area, but oil and condensate volumes are also likely to be present, according to Hibiscus.

The commercial terms regarding the wellhead selling price for the oil, gas and condensate have not been disclosed.

Recent and ongoing drilling programmes

Exploration activities have commenced since 2023, according to Bernama news agency, and the programme includes the acquisition of new 3D seismic data, the reprocessing of existing seismic data, and the phased drilling of exploration wells.

Hibiscus has set aside **capex** of US\$16m in FY25F and US\$17m in FY26F for the PM327 exploration, representing its 30% participating interest of the total exploration drilling capex at PM327.

Hibiscus's participation in this exploration block carries **higher risks** than its participation in the PKNB Cluster. This is because the resources at the PKNB Cluster are already discovered, but the PM327 PSC is still in exploration stage. This means that the exploration drilling capex at PM327 will not be cost recoverable unless the to-be-discovered 2C resources are ultimately monetised as 2P reserves and result in actual production. If the exploration yields dry holes or hydrocarbons that are economically unviable to recover, Hibiscus will have to write-off its portion of the exploration capex without any opportunity for recovery.

We have not incorporated any potential PM327 production into our earnings model or DCF-based target price, pending discovery of actual 2C resources.

Block 46 Cai Nuoc PSC, Vietnam ►

The Block 46 Cai Nuoc PSC was acquired by Peninsula Hibiscus alongside the other assets sold by Repsol in 2022. Hibiscus is the operator of the PSC and holds a **70%** participating interest, with PetroVietnam Exploration Production (PVEP) holding the remaining 30%. The PSC is located offshore Vietnam in shallow waters of 184 feet directly north of the PM3 CAA; there are no platforms or facilities located at Block 46 itself, and oil production from its nine wells is produced via tie-in to the PM3 CAA facilities. The Block 46 Cai Nuoc PSC is governed by the **Vietnamese PSC regime** with PetroVietnam as the regulator. The PSC will terminate on **31 Dec 2027F**. Oil production from this PSC is very minimal at just 0.7% of Hibiscus group's net oil equivalent entitlement in FY24; hence, we are unclear if Hibiscus will seek an extension of the PSC term.

Kinabalu PSC, Malaysia ►

Location, PSC licence, and production infrastructure

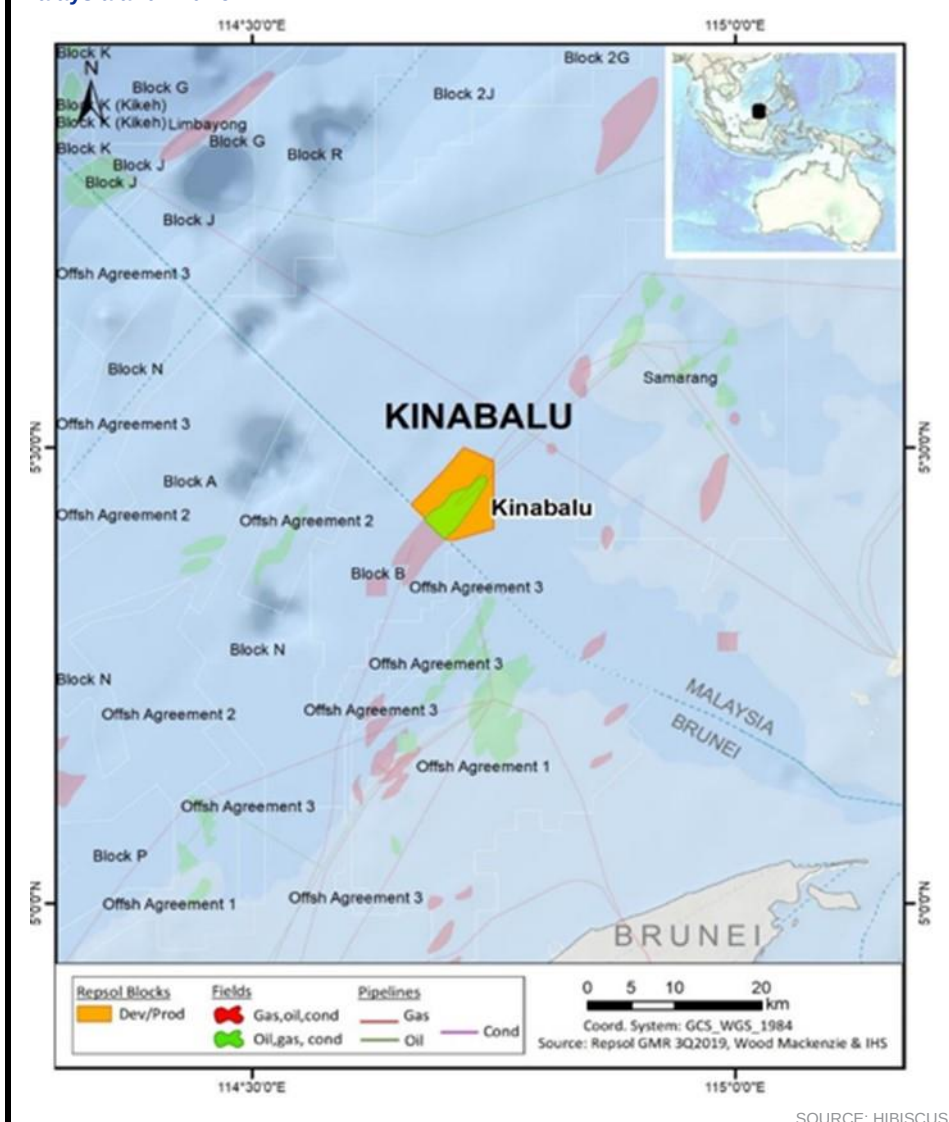
The Kinabalu PSC is located at the maritime border between Malaysia and Brunei, in shallow waters of 184 feet offshore Sabah. Hibiscus is the operator and has a **60%** participating interest, with Petronas Carigali holding the remaining interest. The 20-year PSC licence will end on **25 Dec 2032F**.

Production of **crude oil** is from two fixed platforms over three oil fields, namely Kinabalu Main, Kinabalu East and Kinabalu Far East. The oil is piped to the Labuan Crude Oil Terminal (LCOT) where it is sold by Hibiscus.

There is also the production of associated gas alongside the oil production, but the rights to the associated gas production at Kinabalu were relinquished to Petronas; hence, Hibiscus does not have the right to monetise the associated gas. Some of the associated gas is used for gas lift operations to enhance the production of oil, but the produced associated gas is subsequently piped to the Petronas-operated Semarang platform offshore Sabah, where it will be ultimately piped to the Labuan Gas Terminal (LGAST) for processing. Separately, Petronas

also produces non-associated gas from a third platform at Kinabalu; this also does not involve Hibiscus.

Figure 64: Location of the Kinabalu PSC at the maritime border between Sabah, Malaysia and Brunei



Commercial terms

PETCO is the offtaker for the produced oil, which is usually sold at a premium to the Brent oil price. For the Jan-Mar 2024 quarter, Hibiscus disclosed that the Kinabalu crude oil was sold at an **11% premium** to Brent. PETCO uplifts the oil from LCOT in parcel sizes of c.300,000 bbls each, and there is typically one offtake per quarter.

Hibiscus (via Peninsula Hibiscus) pays a **5% Sabah sales tax (SbST)** to the state government out of the oil sold by Kinabalu. The SbST was extended to the sale of crude, condensate, natural gas and LNG from Sabah from 1 Apr 2020 onwards. At that time, the Kinabalu asset was under the operatorship of Repsol, which had paid the SbST up to the point when the sale to Hibiscus was concluded in early-2022. However, Hibiscus did not agree to continue paying the SbST, arguing that the point of sale of North Sabah and Kinabalu crude is at Labuan, which is part of the Federal Territories and outside the jurisdiction of the Sabah state government. The New Straits Times reported in Jul 2022 that the Sabah state government had threatened to cancel the work permits of crew at North Sabah and Kinabalu if the SbST was not paid. On 21 Sep 2022, Hibiscus agreed to pay the SbST on the sale of crude oil by North Sabah and Kinabalu, and the issue was essentially settled. Hibiscus retrospectively provided for the Kinabalu SbST of RM13.5m

inclusive of RM4.5m in penalties in the Apr-Jun 2022 quarter (4QFY22), comprising outstanding payments since early-2022.

Peninsula Hibiscus also pays a **supplementary payment** to Petronas under the terms of its Kinabalu PSC, since the realised price of the Kinabalu crude since Hibiscus's acquisition on 24 Jan 2022 has exceeded the stated threshold; the latter increases by a mid-single-digits percentage annually.

Recent and ongoing projects

Kinabalu PSC is currently implementing a project to improve the efficiency and capacity of the **low-pressure compressor (LPC)** and **high-pressure compressor (HPC)** to increase the amount of produced associated gas that can be transported to the Semarang platform. This will increase the volume of monetisable associated gas, and also increase the production of oil due to reduced backpressure to the well at the processing facilities. The capex cost of the project is therefore repaid via increased production of oil and increased monetisation of the gas (for Petronas); this also reduces the flaring of gas and reduces GHG emissions. Implementation work on the Kinabalu LPC/HPC project began in Mar 2022 and will be completed in FY25F, according to Hibiscus.

Hibiscus disclosed in its 2024 Annual Report that it had successfully drilled **two infill oil development wells** at Kinabalu, which were completed with Autonomous Inflow Control Valves (AICVs) to reduce excessive gas production. The wells had initially flowed at a total oil rate of 2,000 bopd, but one of the wells subsequently experienced higher-than-expected water production and the oil production rate has since declined from the initial level.

Meanwhile, **two wells are currently undergoing a workover programme** that will see each well completed with Wireline Retrievable Electrical Submersible Pump systems that will raise production rates from Nov 2024F onwards.

Quarterly financial and operating data

Hibiscus succeeded in **raising oil production rates** in 2Q-3QFY24 (Oct 2023 to Mar 2024) due to first oil from the two infill oil development wells from Aug 2023 and Oct 2023 respectively, successful gas lift optimisation executed in prior periods, and successful rectification in Jul 2023 of the issues encountered with the HPC that had led to insufficient gas lift supply to the oil wells since Jan 2023.

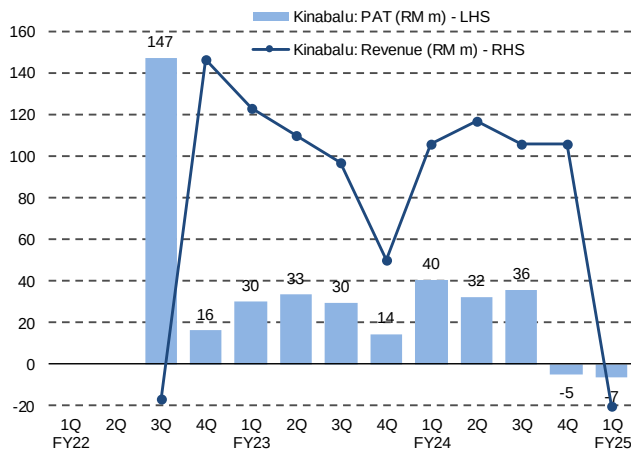
However, the **production rate dropped sharply qoq in 4QFY24** (Apr-Jun 2024) due to various technical issues, including reliability issues on the HPC, limited production enhancement work due to crane unavailability, and higher-than-expected water production from one of the two newly-drilled oil development wells. As a result, Hibiscus noted in Annual Report 2024 that **Kinabalu had underperformed internal expectations for production rates in FY24**.

Kinabalu suffered a net loss after tax in 4QFY24 after an **impairment charge** of RM61m relating to the write-off of capitalised costs of efforts to recover a well in FY23, which unfortunately did not turn out to be successful.

The **annual maintenance campaign** at Kinabalu this year took place over 10 days between 26 Jun and 5 July 2024 during which the production facilities were shut down; this affected the facilities uptime in 4QFY24 and 1QFY25. Post-maintenance production start-up was delayed by 12 days as the Kinabalu PSC experienced an outage at a high pressure compressor in Jul 2024. Meanwhile one well experienced higher sand and water production between Jun 2024 and Oct 2024; these issues in combination caused a qoq decline in uptime for 1QFY25. As a result of the lower production levels, there was no crude oil offtake in 1QFY25.

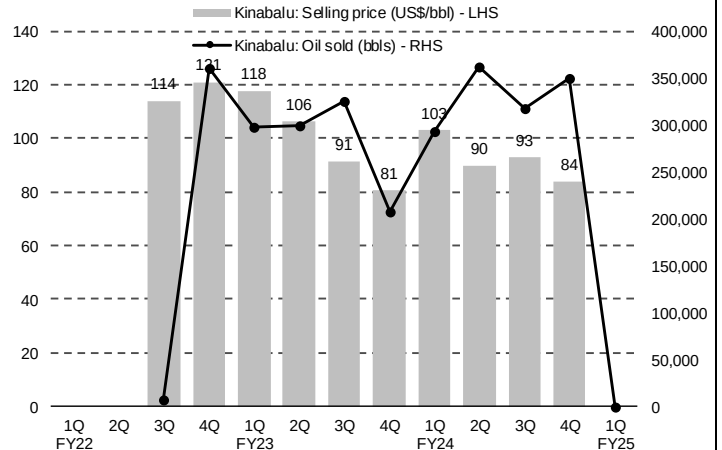
Previous maintenance campaigns had taken place over 8 days between 29 Jul and 5 Aug 2023 (1QFY24), and over 12 days between 29 Jul and 9 Aug 2022 (1QFY23), during which quarterly uptime rates were also lower.

Figure 65: Kinabalu: Revenue and PAT (RM m)



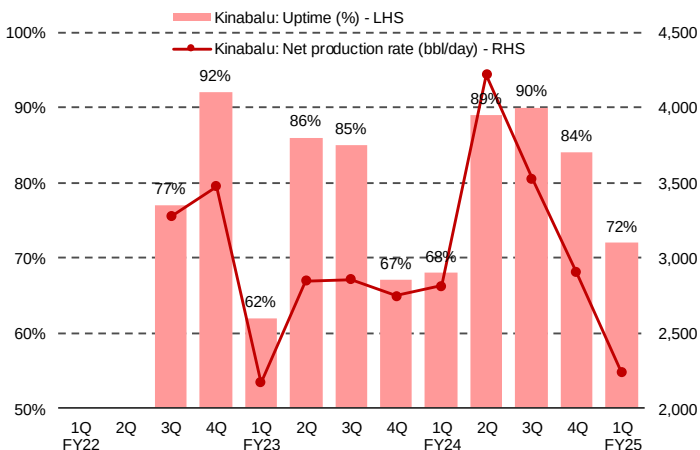
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 66: Kinabalu: Oil sold (bbls) and Selling price (US\$/bbl)



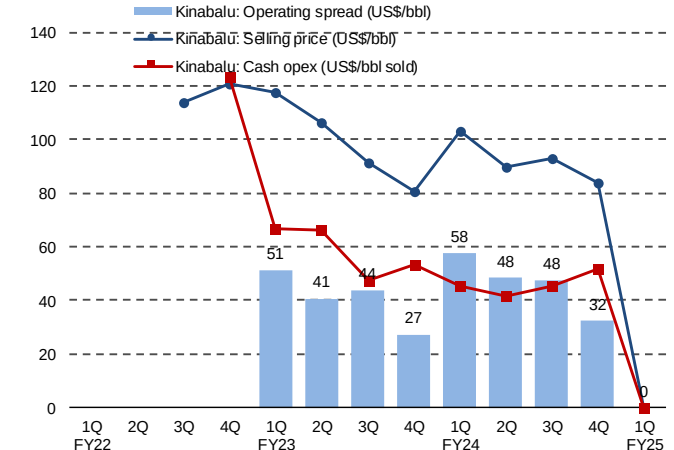
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 67: Kinabalu: Uptime (%) and Net production rate (bbl/day)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 68: Kinabalu: Operating spread = Selling price - Cash opex (US\$/bbl sold)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

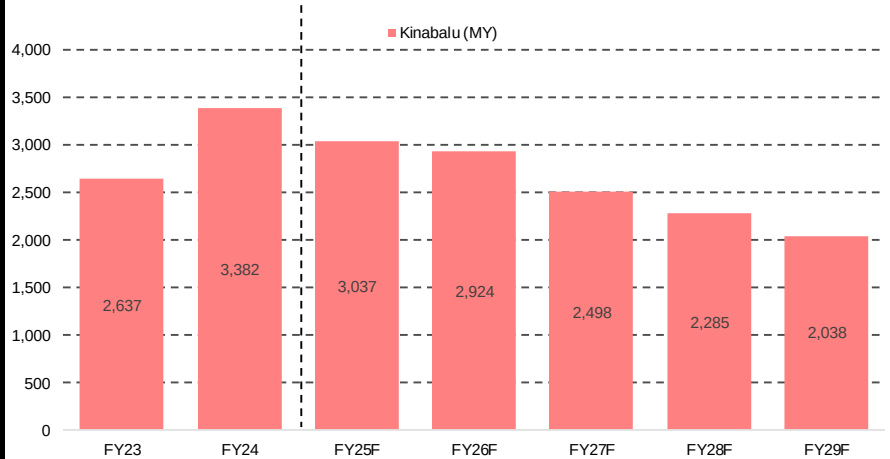
Annual forecasts for financial and operating data

Our **production forecasts** are on the basis of 'No Further Activity' (NFA), which means that we have not assumed any additional development drilling work unless it has been specifically sanctioned by Hibiscus. We believe that Hibiscus is less enthusiastic about Kinabalu than it is about PM3 CAA and PKNB Cluster. As a result, we expect that Hibiscus will not focus capex on Kinabalu.

Hibiscus guided for **capex** at Kinabalu of US\$30m in FY25F relating primarily to the LPC/HPC upgrading project, and US\$25m in FY26F relating to various projects that are intended to increase production rates. However, the FY26F capex may be deferred if Hibiscus decides to prioritise spending at PM3 CAA instead, especially given Hibiscus's disappointment with the outcome of its various production enhancement activities at Kinabalu in FY24.

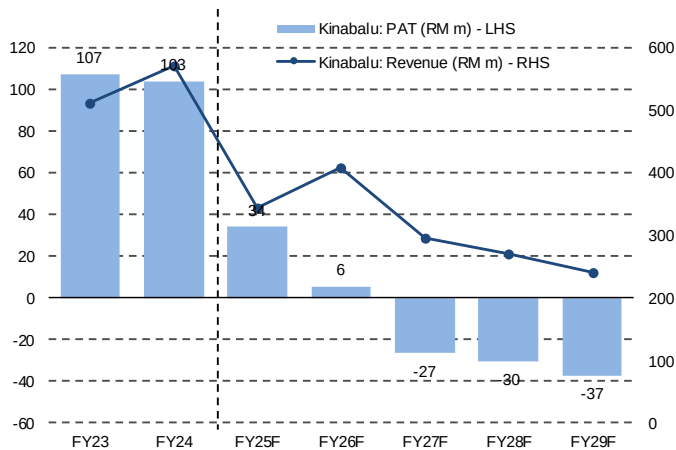
We forecast **Kinabalu's PAT to decline yoy in FY25F** from the combination of lower production, lower selling prices and higher cash opex per boe. In addition, Kinabalu's PAT in FY24 benefitted from a RM23.7m tax overprovision writeback, but we assume that the effective tax rate will normalise in FY25F.

Figure 69: Kinabalu: Net oil equivalent production rate (boepd)



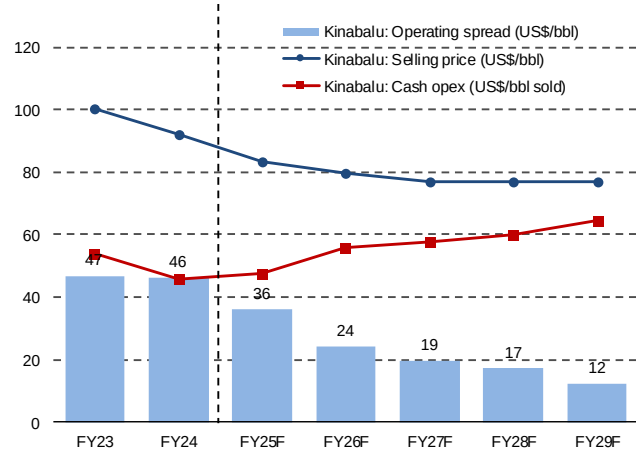
SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 70: Kinabalu: Revenue and PAT (RM m)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 71: Kinabalu: Operating spread = Selling price - Cash opex (US\$/bbl sold)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

PM305 and PM314 PSCs, Malaysia ►

The PM305 and PM314 PSCs are located offshore Terengganu. Hibiscus previously held a working interest of 60% in both PSCs, with Petronas Carigali holding the remaining 40%. However, Hibiscus's interests in the PSCs have since been handed back to Petronas.

The PM314 PSC was to have expired on 30 Mar 2033F, but production of oil ceased since Sep 2019 and the three wells have been plugged and abandoned.

The PM305 PSC was to have expired on 26 Nov 2029F, but production ceased earlier this year, and Hibiscus relinquished its interest in PM305 in Mar 2024. As a result, we do not expect any further oil production from PM305. The facilities have been partially decommissioned, and the removal of the platform topsides and jackets scheduled for completion in Sep 2025F.

Decommissioning work is to be undertaken by Petronas if the PSC term has expired, but because the PSC term for PM305 has not yet expired, the decommissioning work must be undertaken by the erstwhile operator, Hibiscus. Hibiscus disclosed that the estimated costs have already been accrued for in FY24, and subsequent to the completion of the decommissioning works, the costs will be reimbursed by Petronas to Hibiscus out of the accumulated abandonment cess payments that were made in previous years.

SECTION 6: NORTH SABAH

North Sabah PSC acquisition ►

On 12 Oct 2016, Hibiscus (via wholly-owned SEA Hibiscus) entered into an SPA to acquire **50%** working interest in the North Sabah Enhanced Oil Recovery PSC for **US\$25m** (excluding post-completion adjustments) from Shell.

The **effective date** of the acquisition was **1 Jan 2017**, upon which all the risks and rewards of the asset belong to Hibiscus.

The transaction was only **formally completed on 31 Mar 2018**.

Of the US\$25m purchase consideration, US\$2.5m was paid on 12 Oct 2016 (SPA date) while US\$12.5m was paid on 31 Mar 2018 (completion date). The cashflows accruing to Hibiscus between the effective date of 1 Jan 2017 and the completion date of 31 Mar 2018 were used to partially pay for the purchase price. A deferred consideration of US\$5m was paid on 31 Mar 2019 (one year after completion) while the final US\$5m was paid on 31 Mar 2020 (two years after completion).

The average Brent oil price 12 months prior to the Oct 2016 SPA date was only US\$42/bbl, and the pricing of the transaction likely reflected the oil prices prevailing at that time; hence, we believe that Hibiscus secured a good asset at a very affordable price.

Location, PSC licence, and production infrastructure

Hibiscus has a 50% participating interest in the North Sabah PSC, with Petronas Carigali holding the remaining 50%. The PSC duration is until **31 Dec 2040F**.

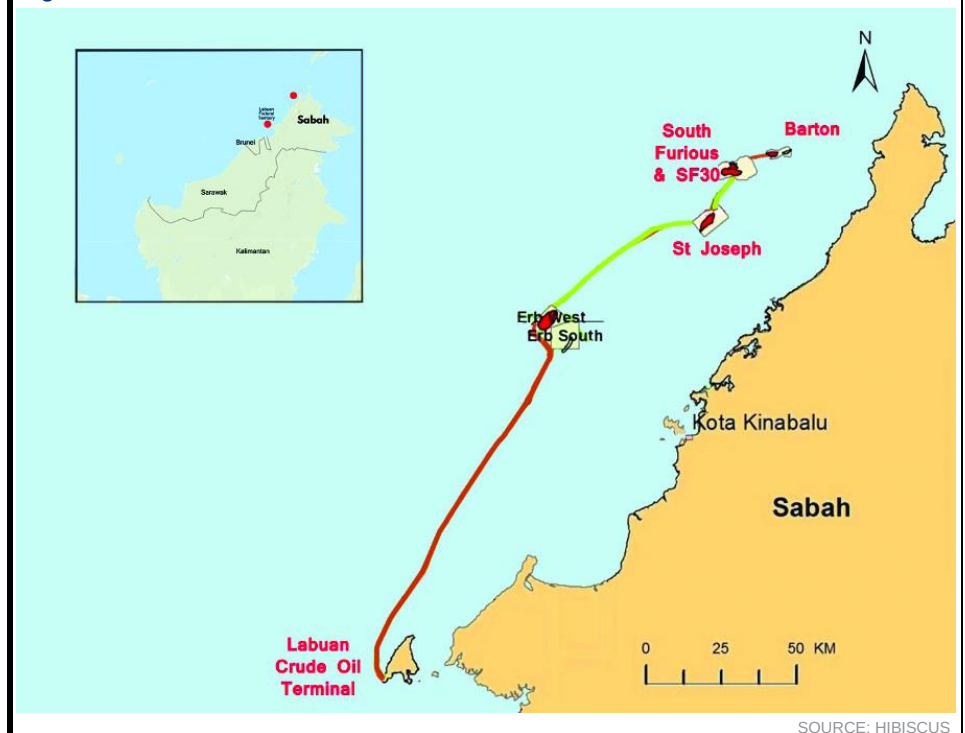
The North Sabah PSC is located in shallow waters of 59-197 feet offshore Sabah, and is made up of **four producing oil fields**, i.e. St Joseph, South Furious, South Furious 30 (SF30), and Barton where 21 fixed platforms and 146 wells are situated.

The PSC also contains pipeline infrastructure and the **Labuan Crude Oil Terminal (LCOT)**, which is an onshore processing plant and oil export terminal. The LCOT receives the produced oil from the North Sabah and Kinabalu PSCs via pipeline, and stores the oil in tanks while waiting for the buyers to uplift the oil via crude oil tankers. All of the facilities including LCOT are owned by the PSC participants.

The associated gas produced alongside the North Sabah oil is not sold, but rather is being used by Hibiscus for internal fuel requirements for the platforms, and also to reinject into the reservoir to enhance reservoir pressure and increase oil production.

Hibiscus is the operator for the North Sabah PSC, and is also responsible for operating and managing the LCOT.

Figure 72: Location of the North Sabah PSC and the Labuan Crude Oil Terminal



Commercial terms

Trafigura is the offtaker for Hibiscus's portion of the produced oil, which is usually sold at a premium to the Brent oil price. For the Jan-Mar 2024 quarter, Hibiscus disclosed that its North Sabah crude oil was sold at an **11%** premium to Brent.

Hibiscus (via SEA Hibiscus) pays a **5% Sabah sales tax (SbST)** to the state government. The SbST was extended the sale of crude, condensate, natural gas and LNG from Sabah from 1 Apr 2020 onwards. At that time, Hibiscus did not agree to pay the SbST, arguing that the point of sale of North Sabah and Kinabalu crude is at Labuan, which is part of the Federal Territories and outside the jurisdiction of the Sabah state government. The New Straits Times reported in Jul 2022 that the Sabah state government had threatened to cancel the work permits of crew at North Sabah and Kinabalu if the SbST was not paid. On 21 Sep 2022, Hibiscus agreed to pay the SbST on the sale of crude oil by North Sabah and Kinabalu, and the issue was essentially settled. Hibiscus retrospectively provided for the North Sabah SbST of RM101.2m inclusive of RM33.7m in penalties in the Apr-Jun 2022 quarter (4QFY22), comprising outstanding payments since 1 Apr 2020.

SEA Hibiscus also pays a **supplementary payment** to Petronas under the terms of its North Sabah PSC, as the realised price of the North Sabah crude has regularly exceed the specified threshold; this threshold rises by a mid-single-digits percentage annually.

The South Furious drilling campaign between 29 Oct 2023 and 5 Mar 2024

In late-2023, Hibiscus commenced a drilling campaign to drill three exploration wells at the South Furious field, namely the SF Ungu, SF Ungu Side Track (ST) and SF Merah wells. The SF Ungu ST and the SF Merah wells were assessed to be commercially unviable, and Hibiscus wrote-off RM82.6m in 2HFY24 (mainly in the Jan-Mar 2024 quarter), representing its 50% portion of the drilling capex. However, as the write-off is tax deductible, the net-of-tax impact was **RM51.2m** (after accounting for the 38% petroleum income tax rate).

The subsurface data for the SF Ungu well is still be analysed and an assessment will only be completed in early-2025F. If the well is not viable to develop, a gross

amount of RM46.4m will be written off, or **RM28.6m** net of tax. We have not assumed any write-off in our FY25F forecast.

Under the PSC terms and conditions, the gross pretax drilling costs incurred of RM129m for all three exploration wells are cost recoverable from the cost oil tranche of the North Sabah production.

The South Furious 30 (SF30) Water Flood Project Phase 2

Hibiscus is currently undertaking the **South Furious 30 (SF30) Water Flood Project Phase 2**. This entails the drilling of a total of 11 wells, comprising six water injector wells and five oil producer infill wells at the SF30 field. The purpose of this project is to increase the volume of oil production and reserves recovery via pressure support from water injection and sweep into existing and new oil producers.

The drilling was originally planned for execution over two years in CY23 and CY24, but the drilling of the first oil producer well was only performed in Sep 2024, with **first oil from this one well on 31 Oct 2024**. With each well taking slightly less than a month to complete, the drilling of all 11 wells will likely only be **completed in Jun 2025F**, in our estimate.

As the first oil producer well achieved first oil on 31 Oct 2024, we expect contribution to Hibiscus's production from Nov 2024F onwards (2QFY25F), and as the remaining four oil producer wells are drilled and connected to production infrastructure, the oil production rate from the SF30 Water Flood Phase 2 project should progressively increase, in our view.

Hibiscus disclosed in early-Sep 2024 that it expects the SF30 Water Flood Phase 2 project to contribute an **incremental net production of 1,197 bopd in 2025F**, raising the net production rate at North Sabah to 6,007 bopd in 2025F, or a 25% uplift from the 4,810 bopd level in 2024F.

The 2P reserves associated with the project was estimated by Hibiscus at 5.6 MMbbls; this was reclassified from 2C resources to 2P reserves on 1 Jul 2023. As at 1 Jul 2024, North Sabah disclosed its total 2P reserves at 18.4 MMbbls.

The total capex for the SF30 Water Flood Phase 2 project was estimated by Hibiscus at **US\$100m**, involving not just the drilling capex, but also the capex to fabricate a new wellhead platform and the transportation and installation of that platform at the SF30 field.

Separately, Hibiscus has signed a 5-year agreement with Uzma Berhad to lease a Mobile Offshore Drilling Unit (MODU) that will house a water injection facility (WIF) at the SF30 field. The WIF is currently undergoing conversion in at the Malaysia Marine and Heavy Engineering (MMHE) yard with a targeted start of water injection in mid-2025F.

This SF30 Water Flood Phase 2 project follows the Phase 1 project that was executed in 2020, involving the drilling of just one water injector well (capex of RM54m).

Quarterly financial and operating data

The quarterly North Sabah oil sales and revenues fluctuate widely from quarter to quarter, depending on the **number of offtakes** in that quarter. In FY23, there were five offtakes, with one quarter having two offtakes, while the remaining three quarters only having one offtake each. In FY24, there were six offtakes, with two quarters enjoying two offtakes each, and the remaining two quarters having one offtake each. For instance, 4QFY24 saw two offtakes, which led to a jump in sales volume and revenue, vs. the immediately-preceding 3QFY24 that saw only one offtake. The reason for the variability in the number of offtakes is because each offtake must range between 250,000 and 350,000 bbls in order to optimally use up the cargo carrying capacity of the panamax-sized crude oil tankers that berth at LCOT, which can typically carry a minimum of 350,000 bbls fully laden.

The **annual maintenance programme** for North Sabah is usually executed in the Apr-Jun quarter and Jul-Sep quarter of every year. In 2023, the maintenance

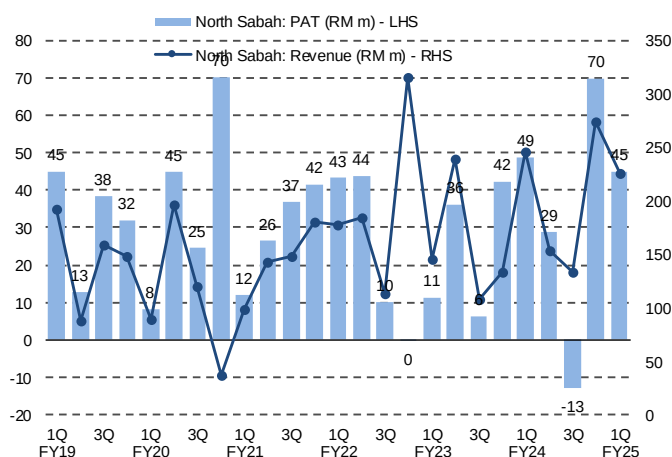
shutdowns took place over Apr to Aug, while this year, the maintenance shutdown took place between Mar and Jul 2024. As a result, uptime rates decline in the quarter when the maintenance is performed, while opex per bbl sequentially rises. Because there are 21 fixed platforms over four fields, production activities at North Sabah continue to take place during maintenance season, because Hibiscus shuts down the platforms for maintenance by batches and not all simultaneously.

As noted above, Hibiscus booked in an **SbST expense of RM101.2m in 4QFY22** to settle all of the SbST attributed to the crude oil sales made by North Sabah since 1 April 2020; this resulted in zero PAT in that quarter.

The **write-off of the exploration drilling costs** of the South Furious wells hit the P&L in **3QFY24**, and caused the North Sabah segment to deliver a loss after tax.

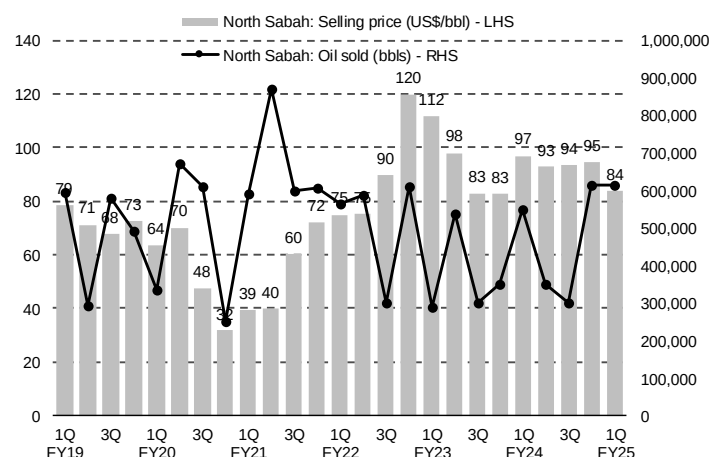
In 1QFY25, North Sabah's PAT fell qoq due to lower oil selling prices, coupled with several technical issues that caused opex per bbl to increase, i.e. the unavailability of a compressor at the St Joseph field between Jun and Oct 2024, and an 8-day wells shutdown in Sep 2024 caused by a delay of a drilling rig entry into the South Furious 30 field due to unfavourable weather conditions.

Figure 73: North Sabah: Revenue and PAT (RM m)



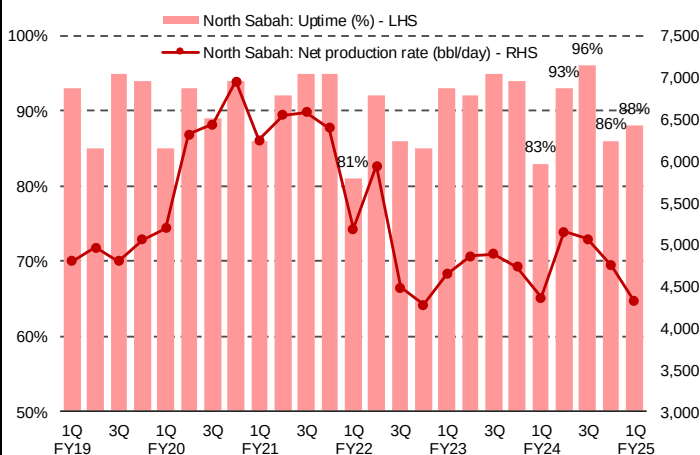
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 74: North Sabah: Oil sold (bbls) and Selling price (US\$/bbl)



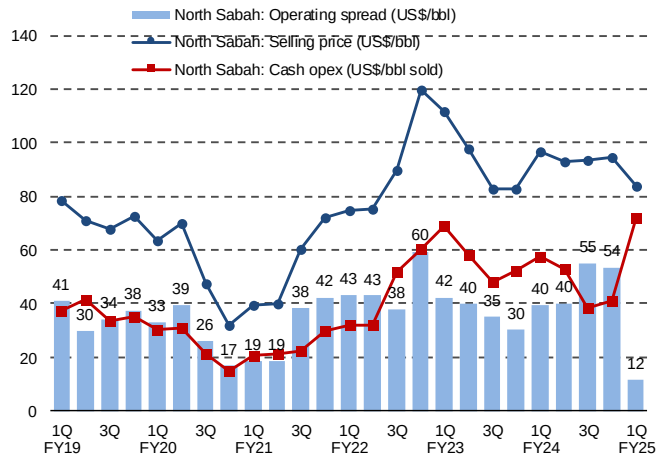
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 75: North Sabah: Uptime (%) and Net production rate (bbl/day)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 76: North Sabah: Operating spread = Selling price - Cash opex (US\$/bbl sold)



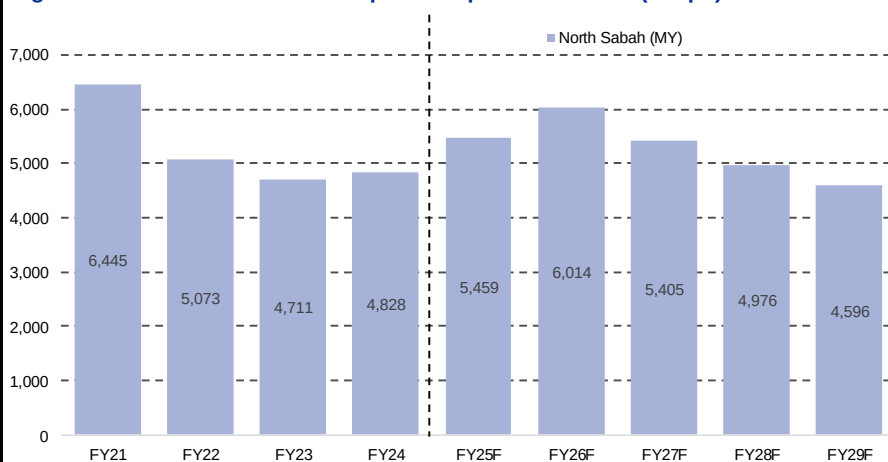
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Annual forecasts for financial and operating data

The net production rate for North Sabah peaked at 6,445 bpd in FY21 at an uptime of 92%, then declined sharply to 5,073 bpd in FY22 at a reduced uptime of 86%; this was caused by Covid-related restrictions that had prevented contractors from accessing the platforms to perform the requisite maintenance work. Production stabilised in FY23 as Hibiscus caught up on its maintenance backlog, but even with a better uptime rate of 94%, production did not improve back to the FY22 level, probably due to natural production decline. Production improved slightly in FY24 due to various well intervention campaigns, partly offset by a lower uptime of 90%.

Moving forward, the contribution to **production from the SF30 Water Flood Project Phase 2** should be felt from late-2024F onwards. In early-Sep 2024, Hibiscus guided for North Sabah net production rate to be 4,810 bpd in 2024F, rising to 6,007 bpd in 2025F, before moderating to 5,791 bpd in 2026F. We have incorporated this guidance into our production forecasts.

Figure 77: North Sabah: Net oil equivalent production rate (boepd)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

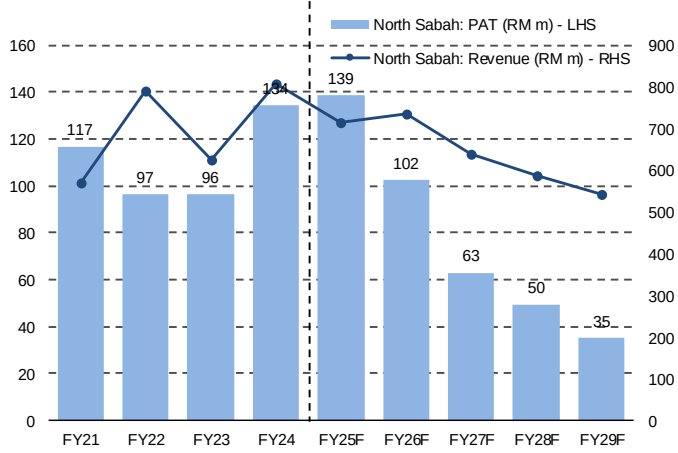
The North Sabah PAT in FY24 rose sharply yoy because there were six crude oil offtakes that year, compared to five in FY23. We expect the North Sabah PAT to rise again in FY25F, due to the higher production levels forecast for the current financial year.

We expect the North Sabah PAT to decline yoy in FY26F, despite higher production and lower cash opex per bbl, due to our forecast for lower crude oil selling prices, and higher depreciation and amortisation expense.

We forecast North Sabah's depreciation and amortisation charges to increase yoy in FY26F because of the higher production levels from the SF30 Water Flood Phase 2 project in FY25-26F. The 5.6 MMbbls of 2P reserves attributed to this project were reclassified from 2C resources to 2P reserves on 1 Jul 2023. Under the Unit of Production (UOP) method, the denominator of the depreciation and amortisation calculations is the 2P reserves. Hence, for North Sabah, the depreciation and amortisation expense in FY24 (1 Jul 2023 to 30 Jun 2024) and in FY25F reflected or will reflect the increased denominator, but the numerator (i.e. actual production) will only be partially reflected in FY25F and will be fully reflected only in FY26F upon the completion of the 11-well drilling programme in Jun 2025F. This would explain our forecast for higher depreciation and amortisation charges in FY26F, relative to FY25F, which we think will cause the North Sabah PAT to decline yoy in FY26F.

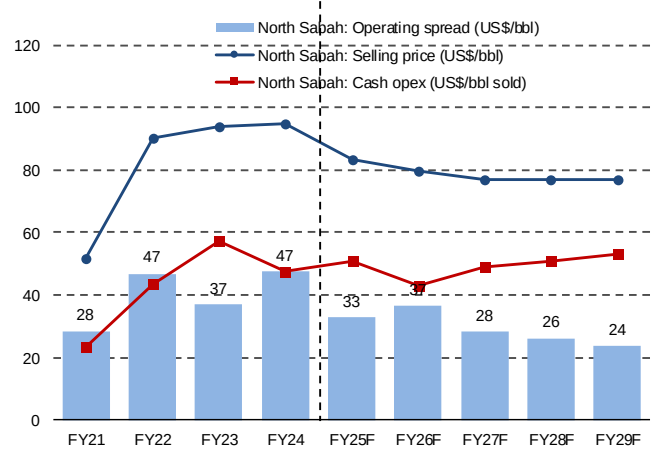
Separately, Hibiscus has budgeted a **capex** of US\$62m in FY25F for the SF30 Water Flood Project Phase 2, and US\$18m in FY26F for other items.

Figure 78: North Sabah: Revenue and PAT (RM m)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 79: North Sabah: Operating spread = Selling price - Cash opex (US\$/bbl sold)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

SECTION 7: THE UK ASSETS

Overview of Hibiscus's exposure to the UK ➤

Hibiscus has two main sets of assets in the UK North Sea area, which is the **Anasuria Cluster**, and the **Greater Marigold Area Development (GMAD)**. Each set is made up of five separate licences, as shown in Figure 80.

The Anasuria Cluster is currently producing from two licence areas, with a third licence area (Teal West) to produce from end-2025F. Hibiscus expects production to last until 2035F. The GMAD is not expected to produce until at least 2028F, according to Hibiscus, as it has not taken the Final Investment Decision (FID); production should last some 7-8 years once it begins.

In terms of 2P reserves, the Anasuria Cluster had **21.1 MMboe of 2P reserves** as at 1 Jul 2024, mainly of oil.

Hibiscus's 2C resources in the UK are mainly located at the GMAD (46.4 MMboe of oil), with Anasuria Cluster holding a smaller quantity (4 MMboe of oil).

Hibiscus secured its licences in the UK via a mix of acquisitions, farm-ins, and awards from the UK regulator, the North Sea Transition Authority (NSTA). *Note that the NSTA adopted its current name on 21 Mar 2022; it was previously known as the Oil and Gas Authority of the United Kingdom (OGA).*

Acquisitions

- Hibiscus's maiden entry into the UK was in 2016, via an acquisition from Shell and Esso of
 - Licence No P013 (comprising the Teal, Teal South and Guillemot A fields), and
 - Licence No P185 (Cook).
- In 2018, it acquired interests in Licence No P198 (Marigold West and Sunflower) from Caldera Petroleum.
- In 2019, Hibiscus acquired an interest in Licence No P2366 (Crown) from United Oil & Gas and Swift Exploration, although this licence expired before a solution for the field development was finalised (this licence is not listed in Figure 80).

Farm-ins

- In 2023, Hibiscus farmed-into Licence No P2451 (Fyne), acquiring a stake from Rapid Oil.

Awards from the NSTA

- In 2020, Hibiscus was awarded several licences via the UK's 32nd Offshore Licensing Round, i.e.
 - Licence No P2532 (Cook West, Cook North, etc.);
 - Licence No P2535 (Teal West);
 - Licence No P2518 (southern part of Kildrummy, Block 15/17a).
- In 2023-2024, Hibiscus was awarded several licences and blocks via the UK's 33rd Offshore Licensing Round, i.e.
 - Licence No P2518 (northern part of Kildrummy, Block 15/12a);
 - Licence No 2608 (Crown); and
 - Licence No 2635 (Cross, and northwest of Marigold field).

Hibiscus's immediate focus in the coming year is to **bring Teal West into production** at the Anasuria Cluster.

Figure 80: An overview of Hibiscus's UK assets

		Production rate			2P reserves **		2C resources **				
	Hibiscus's equity interest	CY24	CY25F	CY26F	Oil	Gas	Oil	Gas	To contribute to production by	Production to last until	
	%	boepd	boepd	boepd	MMboe	MMboe	MMboe	MMboe			
(A) Anasuria Cluster					20.2	0.9	4.0	-			
1	Licence No P013 - Teal, Teal South and Guillemot A (Block 21/25a and Block 21/30a)	50%	2,086	3,835	7,793	15.9	0.9	-	-	-	2035F
2	Licence No P185 - Cook (Block 21/20a)	19.325%									
3	Licence No P2535 - Teal West (Block 21/24d)	100%				-	4.3	-	-	-	
4	Licence No P2451 - Fyne (Block 21/28b)	42.5%	-	-	-	-	4.0	-	-	Development unclear	
5	Licence No P2532 - Cook West, Cook North, etc. (Block 21/19c and Block 21/20c)	19.325%	-	-	-	-	-	-	-	Development unclear; still considered a prospective resource	
(B) Greater Marigold Area Development (GMAD)					-	-	46.4	-			
1	Licence No P198 - Marigold West (Block 15/13a) *	87.5%	-	-	-	-	33.0	-	From 2028F onwards thereabouts, as GMAD may have an economic life of 7-8 years	2036F	
2	Licence No P198 - Sunflower (Block 15/13b)	87.5%	-	-	-	-	5.1	-			
3	Licence No P2518 - Kildrummy southern part (Block 15/17a) and Kildrummy northern part (Block 15/12a)	100%	-	-	-	-	3.9	-			
4	Licence No P2608 - Crown (Block 15/18a and Block 15/19a)	100%	-	-	-	-	4.4	-			
5	Licence No P2635 - Cross (Block 15/18c) and Northwest of Marigold field (Block 15/13c)	100%	-	-	-	-	-	-	-	Development unclear; still considered a prospective resource	
* to be developed together with Licence No P2158 - Marigold East (Block 15/18b)											
** as at 1 Jul 2024											

SOURCES: CGSI RESEARCH, COMPANY REPORTS

In the UK, exploration and development licences are granted with specific expiry dates which determines the time period provided for the licence holder to secure the Field Development Plan (FDP) approval and the production consent from the NSTA. This is intended to prevent licence holders from sitting on the licence indefinitely without developing it. However, once a licence area enters into production, the licence holders are permitted to continue production indefinitely, or until it is no longer economically feasible to extract the hydrocarbons.

In Hibiscus's case, production from Licence No P013 (Teal, Teal South and Guillemot A), Licence No P185 (Cook), and in the near future from Licence No P2535 (Teal West) can continue until indefinitely or until the end of field economic life. However, Licence No P198 (Marigold West and Sunflower) will expire on 31 Dec 2024F if its FDP approval and production consent has not been received by the NSTA before then; Hibiscus is currently in negotiations with NSTA to extend the licence validity by five years to 31 Dec 2029F. Similarly, Licence No P2451 (Fyne) will expire on 30 Sep 2026F. Licence expiry dates can be extended subject to application to and approval by NSTA.

Taxation of UK hydrocarbons production is currently very heavy at **78%**, comprising:

- Ring Fence Corporate Taxation (RFCT) of 30%;
- Supplementary Charge (SC) of 10%; and
- Energy Profits Levy (EPL) of 38% until 31 Mar 2030F.

Before the EPL was first implemented on 26 May 2022, the UK taxation was only at 40%, comprising the RFCT and SC.

We believe that Hibiscus may reprioritise its future capex away from the UK to focus on opportunities in the PM3 CAA hub and in Brunei. As a result, the development of the 2C resources at the Anasuria Cluster (Fyne) and at GMAD remain work-in-progress and is unlikely to materialise in the near future, in our view.

At the end of the field life, or at the end of the block licence tenure in the UK, the concession participants will have the obligation to **decommission the facilities** and plug and abandon the wells. Concession participants are required to fund their decommissioning liabilities during the course of production, by periodically placing deposits into an escrow account, which is classified on the balance sheet as 'restricted cash'. As at 30 Sep 2024, Hibiscus had RM262.24m in restricted cash set aside for future decommissioning work at the Anasuria Cluster.

For more details on the UK upstream fiscal and taxation regime, please refer to Appendix 7.

Anasuria Cluster ►

Location, licence, and production infrastructure

On 6 Aug 2015, Anasuria Operating Company Limited (AOCL) signed an SPA with Shell and Esso to acquire for US\$105m a cluster of UK North Sea oil and gas fields, located c.175 kilometres east of Aberdeen in shallow waters of 308 feet. The legal completion date was **11 Mar 2016**, with the **effective date being 1 Jan 2015**.

AOCL is the 50:50 JV company between Anasuria Hibiscus UK Limited (AHUK), which is a wholly owned subsidiary of Hibiscus, and Ping Petroleum UK (a subsidiary company of Dagang NeXchange Berhad or DNeX).

AOCL has 100% interest in **Licence No P013** which consists of:

- The Guillemot A field and the related field facilities;
- The Teal field and the related field facilities;
- The Teal South field and the related field facilities; and

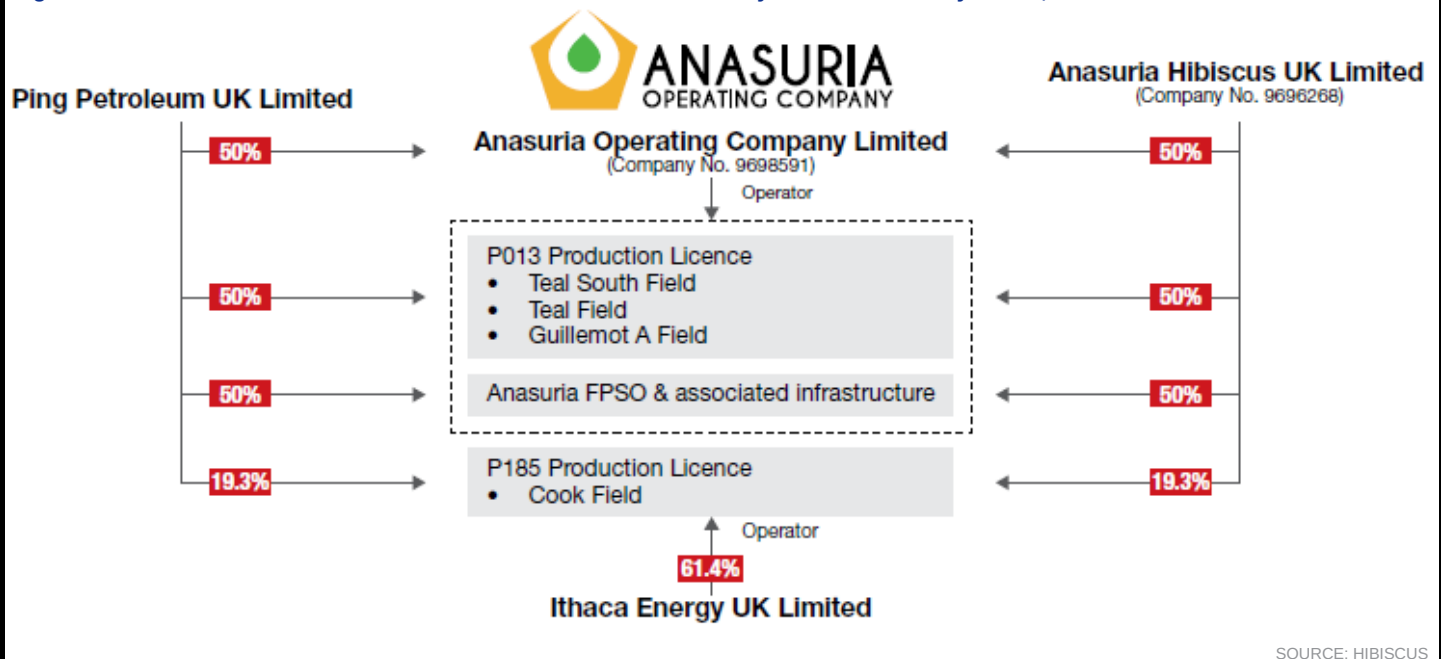
AOCL also has 38.65% interest in **Licence No P185**, which contains the Cook field, and 100% ownership of the Anasuria FPSO vessel which produces oil and gas from the above fields.

Therefore, via Hibiscus's 50% equity stake in AOCL, Hibiscus has 50% interest in Licence No P013, 50% interest in the Anasuria FPSO, and 19.325% interest in Licence No P185.

AOCL has been the operator at Licence No P013 since 10 Mar 2016 (taking over from Shell), although Ithaca Energy (UK) Limited is the operator at Cook as it owns a 61.35% interest in Licence No P185. AOCL appointed Petrofac as the manager of the facilities at Anasuria Cluster.

The Anasuria Cluster has been producing since 1996 via the **Anasuria FPSO**, to which is connected 13 subsea wells. The FPSO was ordered by Shell in 1994 and constructed by Mitsubishi Heavy Industries in Japan in 1996. The FPSO has an oil storage capacity of 850,000 bbls, seven cargo tanks and can accommodate 60 crew on board. The Anasuria FPSO is already 28 years old, but was built to last for 60 years. While there should not be any need for an FPSO drydock before production ends in 2035F (Hibiscus's expectations), regular maintenance is required.

Figure 81: Hibiscus has interests in the Anasuria Cluster via its wholly-owned subsidiary AHUK, which owns 50% in AOCL



Commercial terms

BP Oil International Limited is the offtaker for the produced oil and condensate, which is usually sold at a premium to the Brent oil price. For the Jan-Mar 2024 quarter, Hibiscus disclosed that the Anasuria crude oil was sold at an **2% premium** to Brent. The appointment of BP as the marketing agent lasts until 2026F, but Hibiscus plans to continue this arrangement.

Shell and **Esso** are the offtakers for the produced gas at Anasuria.

Gas prices for the respective fields in the Anasuria Cluster, are as follows:

- Cook field – gas is priced at the landing point of the Fulmar Gas Line at the St Fergus Terminal at 40% (prior to the Oct-Dec 2021 quarter) and **75%** (from Oct-Dec 2021 quarter onwards) of the **Heren National Balancing Point (NBP) index**;
- Guillemot A, Teal and Teal South fields – gas is priced at the point where the gas leaves the fields and enters the Shell-Esso Gas and Liquids (SEGAL) System for a price of **85%** of the Heren NBP index.

We expect the gas from to-be-developed Teal West field (see below) to be priced at 85% of the Heren NBP index.

According to Wikipedia, “the National Balancing Point (NBP) is a virtual trading location for the sale and purchase and exchange of natural gas in the UK. It is the second most liquid gas trading point in Europe after the Title Transfer Facility (TTF) which is a virtual trading point for natural gas in the Netherlands.”

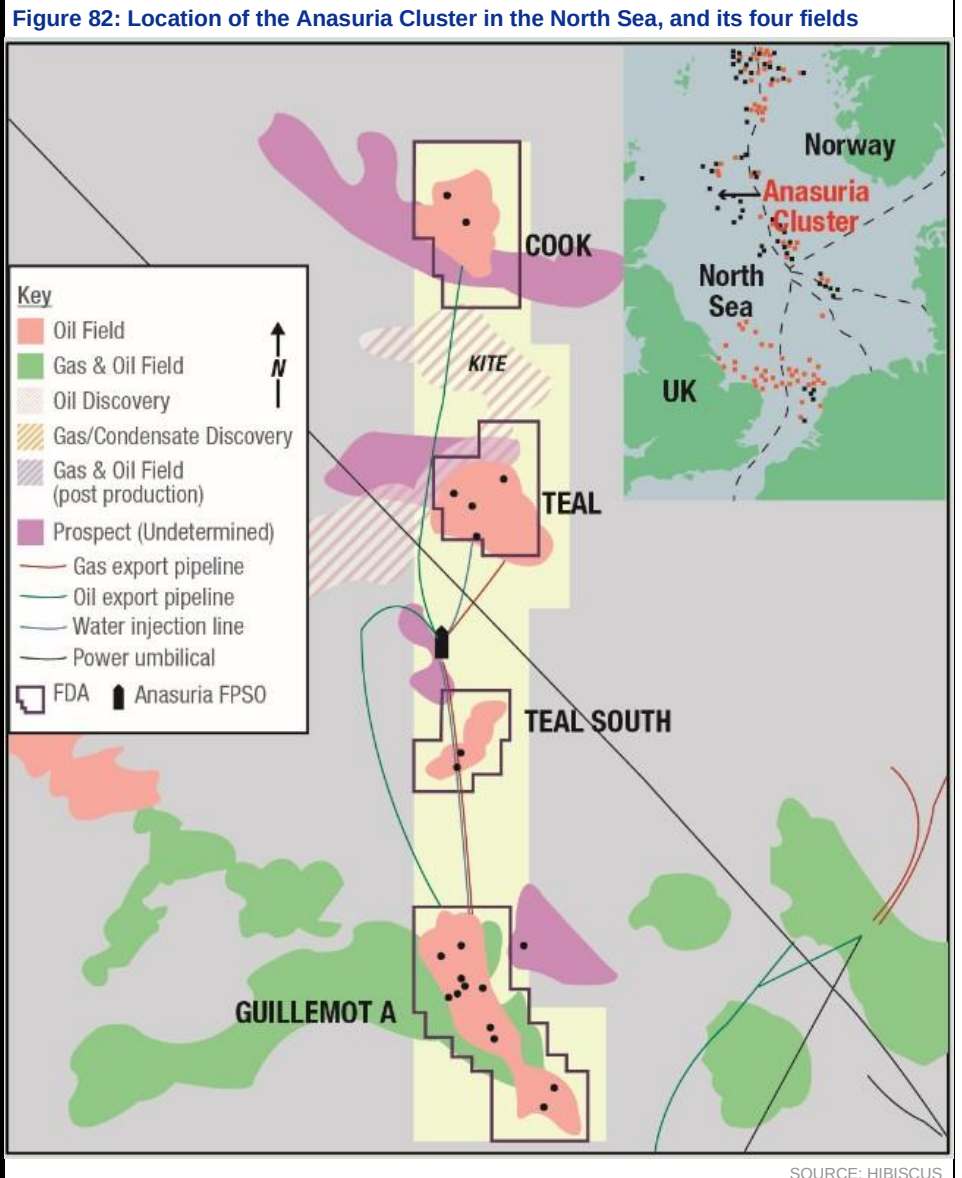
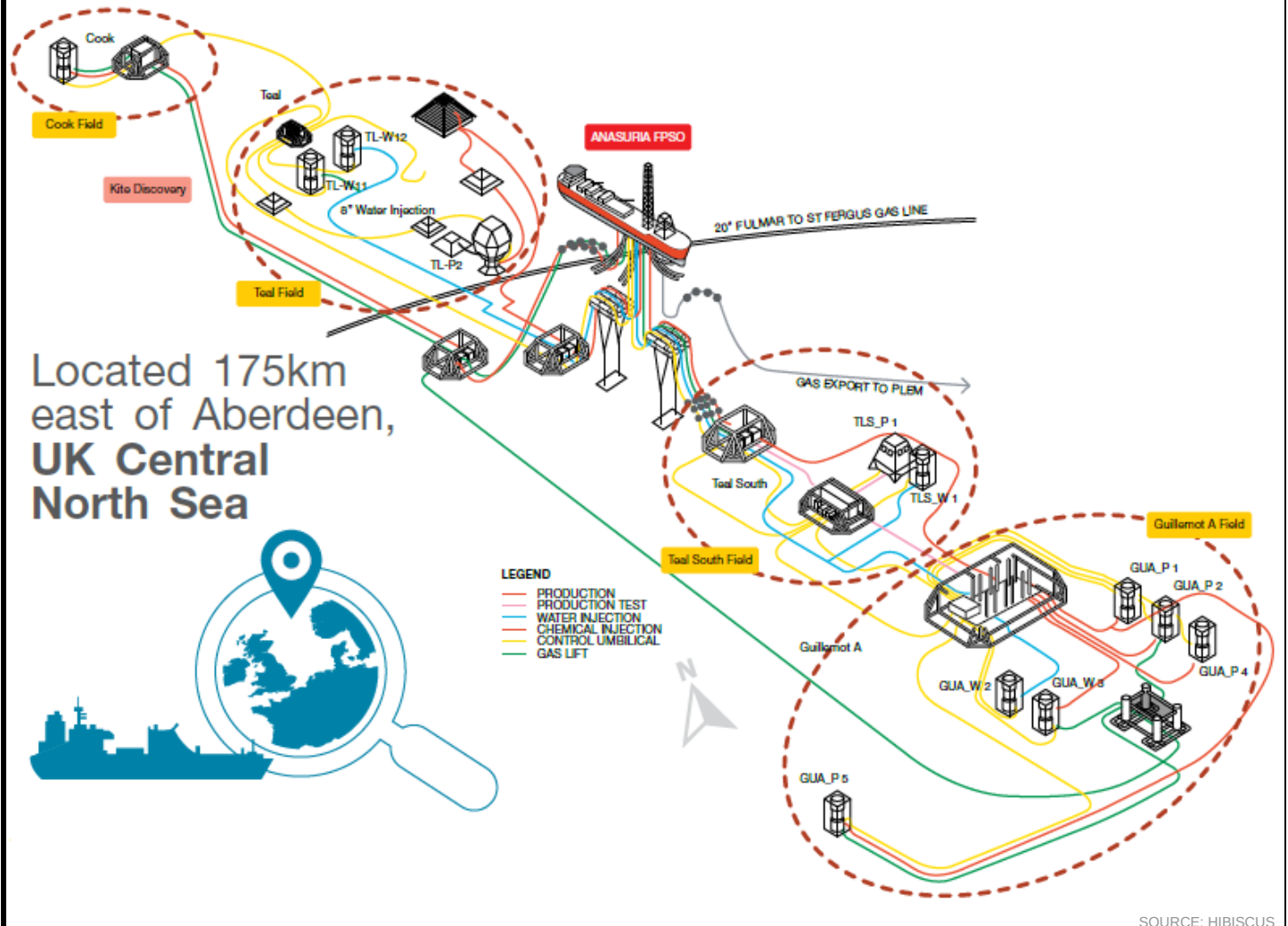


Figure 83: Subsea wells at the Anasuria Cluster are linked to the Anasuria FPSO for production



Licence No P2535 – Teal West (Block 21/24d)

Brief history: AHUK and NEO Energy (ZPL) Limited were awarded 70% and 30% interest respectively in Licence No P2535 (Teal West) during the UK's 32nd Offshore Licensing Round on **3 Sep 2020**. On 8 Jul 2022, NEO Energy advised AHUK of its intention to withdraw from Licence No P2535, and AHUK took over 100% of the licence without any compensation to NEO Energy.

The Teal West discovery is contiguous to the Teal field and is currently AOCL's focus project. Hibiscus guided in early-Sep 2024 that its 50% share of the Teal West **capex will amount to US\$88m in FY25F and US\$29m in FY26**, in addition to the US\$30.4m already spent in FY22-24.

AOCL is pushing the Teal West project because production from the Anasuria Cluster has been declining rapidly.

Prior to malfunction of FPSO production riser between May 2021 and Sep 2022, Hibiscus's net production from Anasuria Cluster was 2,500-2,700 bopd.

In the Oct-Dec 2022 quarter, after the riser was returned to service, net production recovered to 2,700 bopd, but since then it averaged only 2,300 bopd in Jan-Jun 2023, and then declining further to 1,926 bopd in Jul-Dec 2023, and 1,900 bopd in Jan-Jun 2024.

The continuing decline in Anasuria Cluster production, even with the reinstatement of the production riser, has led AOCL to pursue the Teal West project.

The latest guidance is for spudding the Teal West oil producer well in the 2Q or 3Q of CY25F, installing the umbilical and pipeline back to the Anasuria FPSO in 2HCY25F, with **first oil planned for end-2025F or early-2026F**. Hibiscus does not expect the Anasuria FPSO to be shut down when Teal West well is tied-back to the FPSO. Production from Teal West will complement the existing production at the Anasuria Cluster. Hibiscus has guided for the **Anasuria Cluster production to last until 2035F**.

The Teal West Field Development Plan (FDP) was submitted to the NSTA in Aug 2022 and approved in Aug 2023 with production consent also given at the same time. In Jul 2023, the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) had issued their Environmental Approval for the Teal West project. AHUK gave FID approval in Sep 2023.

Hibiscus's target for Teal West first oil was originally in 2023, but it was delayed several times due to supply chain constraints, principally due to the tightness in the global supply of jack-up drilling rigs, but also because of slow delivery of specific items needed for hook-up and commissioning.

As a footnote, the NSTA has granted the application by AHUK to surrender part of License P2535, thereby reducing the acreage held from approximately 58 square km to about 17 square km. The partial relinquishment was sought as an internal assessment determined that there was no economic prospectivity in the acreage outside the Teal West Field Determination Area and to reduce associated costs.

Licence No P2532 – Cook West, Cook North, etc. (Block 21/19c and Block 21/20c)

AHUK was awarded 19.3% in Licence No P2532 during the UK's 32nd Offshore Licensing Round on 3 Sep 2020. Ithaca Energy (UK) Limited (operator) holds 61.35% interest; Ping Petroleum holds 19.325% interest.

This licence was secured as 'protection acreage', because if some other party developed this licence, the reserves from the existing Cook field could flow out. Cook West and Cook North remain in exploration for now, but if they are developed, they may be tied back to the Anasuria FPSO for production.

Due to the lack of economic prospectivity, AHUK had sought to relinquish part of the licence, i.e. the northern and southern areas of Block 21/19c and the whole of Block 21/20c. This relinquishment was approved by the NSTA on 8 Sep 2024. However, AHUK retained the acreage covering the western extension of the Cook field into Licence No P2532.

Licence No P2451 – Fyne field

On 30 Aug 2023, AHUK and Ping Petroleum each entered into a separate but identical farm-in agreements with Rapid Oil, in order to each take 42.5% equity interest in Licence No P2451, with the balance 15% equity interest to remain with Rapid Oil. AHUK paid less than US\$1m for its 42.5% stake.

Licence No P2451 holds an undeveloped oil field, the Fyne field, for which Hibiscus reported net 2C oil resources of 4 MMbbl as at 1 Jul 2024. The NSTA has extended the licence validity to 30 Sep 2026F, by which time AHUK is required to have achieved an approved FDP and production consent from NSTA.

Hibiscus had previously disclosed that AHUK and its partners planned to submit the draft FDP to NSTA in 2024F. If production goes ahead, first oil is expected in 2027-2028F, whereupon AOCL will take over as operator of the Fyne production from AHUK.

However, we are unsure if Hibiscus will proceed with the development of the Fyne field, as it has other options including at the new PM3 CAA hub, PKNB Cluster and potentially at Brunei in the future. Furthermore, the NSTA may require AHUK to undertake efforts at decarbonisation at the Anasuria FPSO, which may be costly and technically challenging as the FPSO was built 28 years ago. As such, Hibiscus noted recently that the Fyne development has been put on hold.

Quarterly financial and operating data

Between May 2021 (4QFY21) and Sep 2022 (1QFY23), a production riser that transports produced crude oil to the Anasuria FPSO malfunctioned; the riser was subsequently isolated from the primary production system, which resulted in a lower overall daily production rate from the Anasuria Cluster until the failed component was returned to service in Sep 2022. This was the main reason for the weak production rates in FY22. When the production riser was reinstated, output jumped in 2QFY23, but has since trended lower in subsequent quarters.

Despite weaker production rates when the riser malfunctioned, the Anasuria Cluster delivered strong profits in the aftermath of the Russian invasion of Ukraine in Mar 2022, due to the steep increase in both oil prices and UK gas prices, which substantially boosted the operating spreads. Since 2HFY23, spreads have broadly normalised, even though they remain slightly above the pre-Ukraine war period.

The Anasuria Cluster reported a deep loss of RM79m in 2QFY23. This was because of the:

- Introduction of the EPL from 26 May 2022, which then required AHUK to recognise a RM106.7m non-cash deferred tax liability relating to all taxable temporary differences arising from the future amortisation and depreciation expenses that will be fully reversed within the EPL regime period, which at that time was up to 31 Mar 2028F.
- Another small, deferred tax liability provision was made in 3QFY23 because the EPL tax rate was raised from 25% to 35% effective 1 Jan 2023 and the enhance capital allowance (CA) deductions were reduced from 180% of capex to 129% of capex.
- A further deferred tax liability provision of RM5.7m was made in 3QFY24 when the EPL regime was extended to 31 Mar 2029F.

The Anasuria FPSO undergoes a major turnaround once every two years (biennially), which takes around one month.

- In 2022, the FPSO turnaround occurred over 30 days between 17 Jun and 17 Jul 2022; hence in 1QFY23, uptime fell to only 53%.
- In 2024, the FPSO went through a major turnaround over 38 days from 3 Aug 2024 to 10 Sep 2024.
- The next major turnaround will take place in 2026F.

In between each turnaround year, the FPSO is shut down for shorter maintenance periods of 1-2 weeks. Hence, in 2023 the Anasuria FPSO was shut down for 15 days in Oct 2023 to execute planned maintenance, which impacted uptime in 2QFY24.

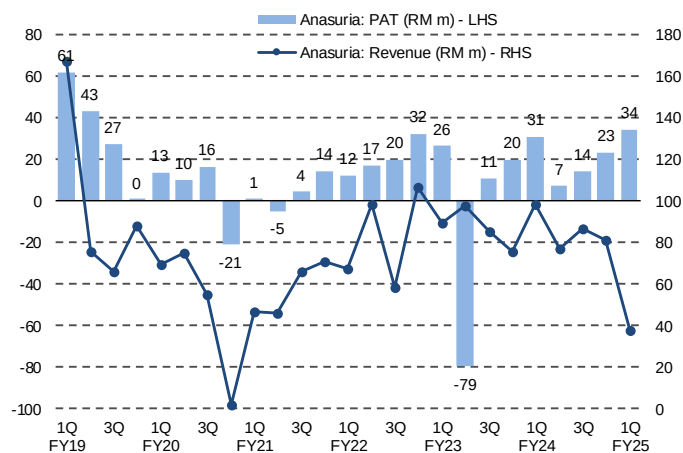
During the FPSO major turnarounds and shorter maintenance shutdowns, all production from the Anasuria Cluster pauses because the hydrocarbons from all 13 subsea wells at the Anasuria Cluster are linked to and processed at the FPSO.

The Anasuria Cluster's uptime in 1QFY25 dropped to just 46% because of the 38-day major turnaround in Aug-Sep 2024, and also because due to certain technical issues affecting production from the wells that were supported by gas lift operations. The gas compression system was offline from 24 Sep to 25 Oct 2024; these technical issues were finally resolved 25 Oct 2024 and full production has resumed.

In 1QFY25, the Anasuria Cluster reported a negative operating spread of US\$36/boe (based on the boe sold), due to the heavy maintenance costs incurred in that quarter from the 38-day major turnaround and the subsequent technical issues encountered, and the corresponding reduction in sales volume. This caused the Anasuria Cluster to report a loss before tax of RM32m in 1QFY25. Despite this, the Anasuria Cluster reported a PAT of RM34m in 1QFY25 due to a RM65m deferred tax income credit, which is non-cash in nature.

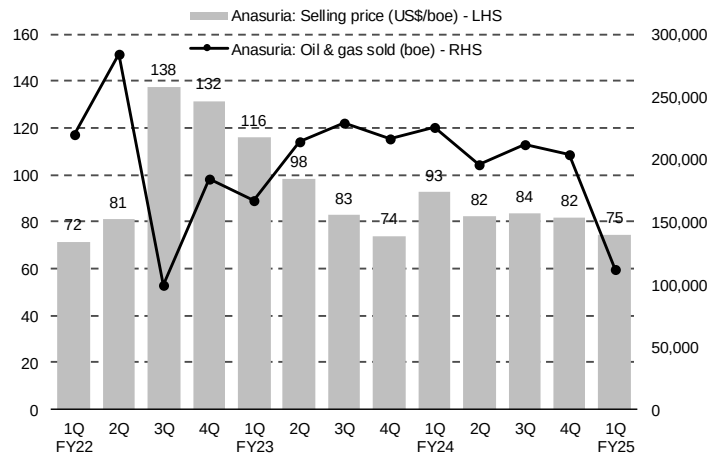
As the technical issues stretched into Oct 2024, we expect some negative effect on Anasuria Cluster's uptime in 2QFY25F.

Figure 84: Anasuria: Revenue and PAT (RM m)



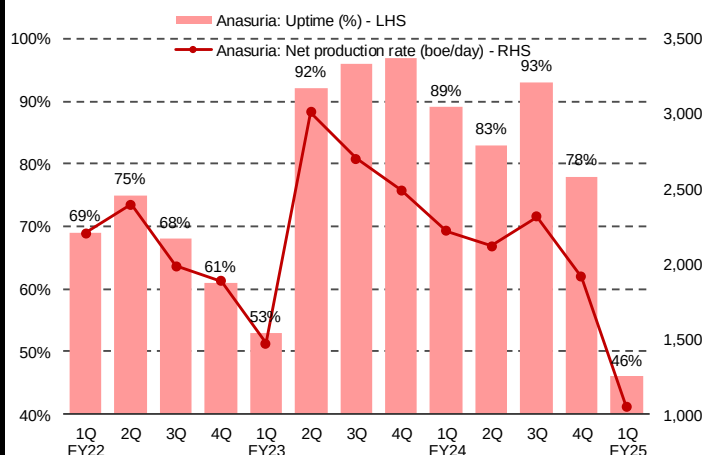
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 85: Anasuria: Oil and gas sold (boe) and Selling price (US\$/boe)



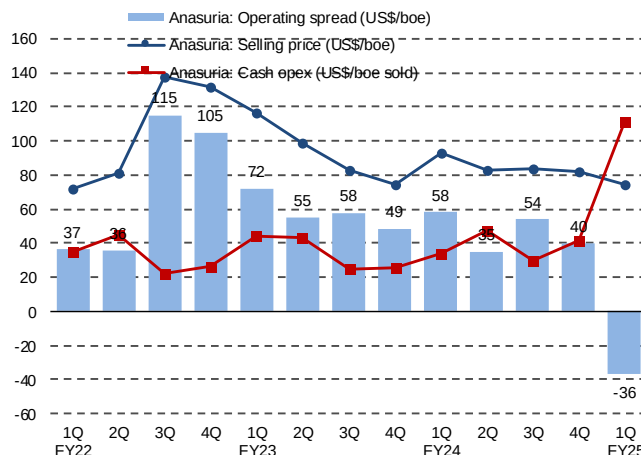
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 86: Anasuria: Uptime (%) and Net production rate (boe/day)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 87: Anasuria: Operating spread = Selling price - Cash opex (US\$/boe sold)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

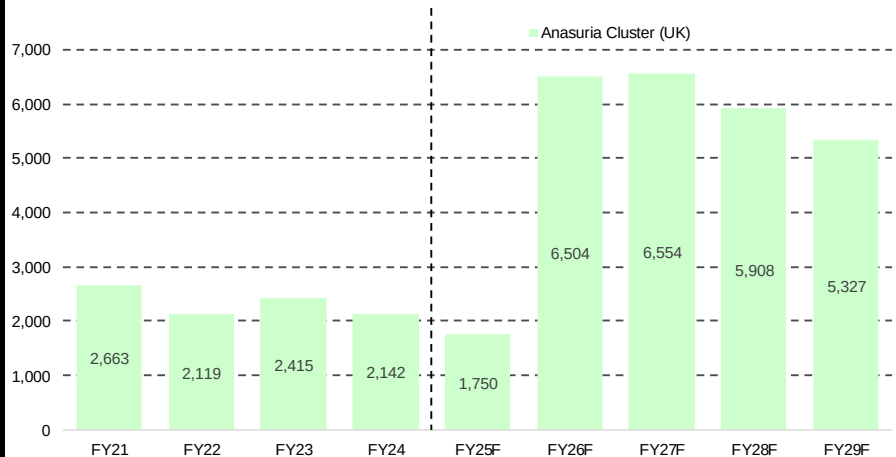
Annual forecasts for financial and operating data

The latest guidance is for spudding the Teal West oil producer well in 2QCY25F, installing the umbilical and pipeline back to the Anasuria FPSO in 2HCY25F, with **first oil planned for end-2025F or early-2026F**. Hibiscus does not expect the Anasuria FPSO to be shut down when Teal West well is tied-back to the FPSO.

In May 2024, Hibiscus guided that Teal West may add an **incremental net 4,000-5,000 bopd in 2026F** to the Anasuria Cluster production. The Teal West volume guidance appears to have been raised to **5,000-6,000 bopd in 2026F**, based on our interpretation of Hibiscus's investor presentation in early-Sep 2024, and we have used the latest volume guidance in our forecasts.

Hibiscus also guided in May 2024 that there is no significant incremental opex from operating the Teal West field, and once Teal West begins producing, the average net production opex for Anasuria Cluster should fall from c.US\$30/boe to US\$20/boe. However, our forecasts may be conservative because we have assumed a rise in absolute opex nevertheless.

Figure 88: Anasuria Cluster: Net oil equivalent production rate (boepd)

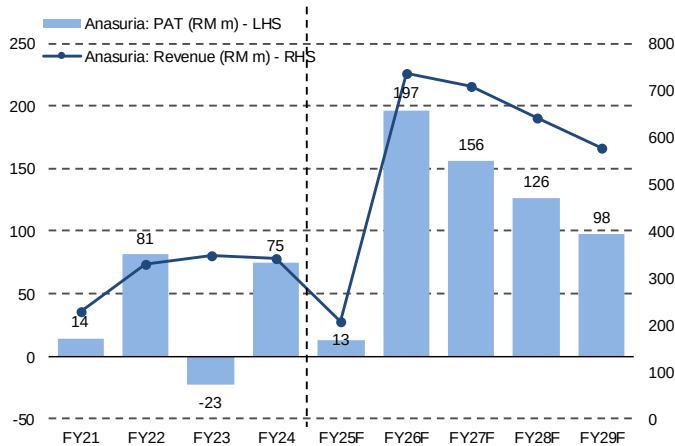


SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Effective 1 Nov 2024, the EPL regime was extended further to 31 Mar 2030F, while the EPL tax rate was raised to 38%, and the enhanced CA deductions were removed (except for certain decarbonisation capex). Consequently, **we expect Hibiscus to make EPL-related deferred tax liability provisions in 2QFY25F**. This is the reason why we are forecasting a PAT of only RM13m for the Anasuria Cluster in FY25F, despite reporting a PAT of RM34m in 1QFY25.

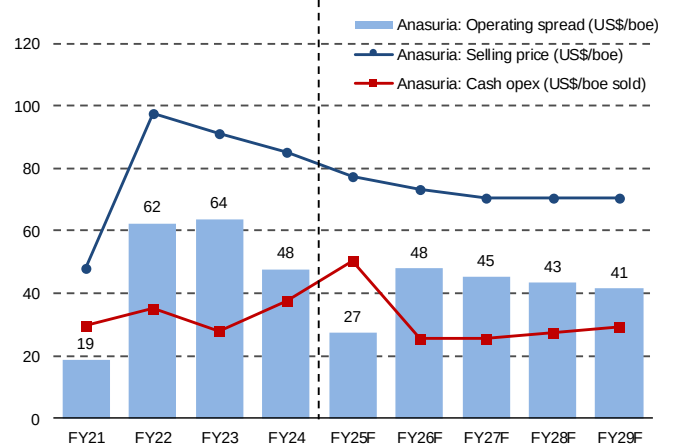
In the 2QFY23 earnings release, Hibiscus had claimed that it did not “expect a significant income tax liability arising from the EPL regime as currently enacted as AHUK foresees there will be significant enhanced capital allowances in the future allowed in the EPL regime to offset any income chargeable to EPL.” However, given that the enhanced CA deductions were removed from 1 Nov 2024, this may result in AOCL and AHUK having to make actual cash tax payments in the future, although we are waiting for Hibiscus to provide guidance on this.

Figure 89: Anasuria: Revenue and PAT (RM m)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 90: Anasuria: Operating spread = Selling price - Cash opex (US\$/boe sold)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Greater Marigold Area Development (GMAD) ➤

The history of Hibiscus's involvement in GMAD started from 16 Oct 2018 when AHUK completed the acquisition of a 50% interest in Licence No P198, which contained the **Marigold West field (Block 15/13a)** and the **Sunflower field (Block 15/13b)**, c.250 km northeast of Aberdeen in the UK Central North Sea.

This 50% interest was purchased from Caldera Petroleum, when at that time held the remaining 50% interest. Subsequently on 20 Jan 2021, Caldera Petroleum agreed to transfer a 37.5% interest in the licence to AHUK, which raised AHUK's interest to the current level of **87.5%**. In return, AHUK agreed to pay all capex amounts attributable to Caldera Petroleum's retained interest of 12.5% up to first oil delivered from the fields. This is captured as a 'contingent consideration' liability that is booked at its discounted present value in Hibiscus's balance sheet; as at 30 Sep 2024, Hibiscus booked in RM38m as contingent consideration.

In 2020, AHUK was awarded Licence No P2518, which contained the **southern part of the Kildrummy field (Block 15/17a)** via the UK's 32nd Offshore Licensing Round.

In 2023-2024, AHUK was awarded several licences and blocks via the UK's 33rd Offshore Licensing Round, i.e.

- Licence No P2518, which contains the **northern part of the Kildrummy field (Block 15/12a)**;
- Licence No 2608, which contains the **Crown field (Block 15/18a and Block 15/19a)**; and
- Licence No 2635, which contains the **Cross field (Block 15/18c)**, and the area **northwest of Marigold field (Block 15/13c)**.

All of the above fields are now categorised under the GMAD grand plan, and may be developed via tie-backs to a common set of production infrastructure. None are producing as yet, and assuming that Hibiscus takes FID on the GMAD project, it only expects production to begin in 2028F at the earliest, via progressive and sequential development of the fields.

Despite the imposition of high EPL tax burden of 38% from 1 Nov 2024 up to 31 Mar 2030F, Hibiscus believes that the impact of EPL on GMAD's profitability will be minimal given that the start-up in production is not forecast until 2028F at the earliest.

We note that Licence No P198 (Marigold West and Sunflower) will expire on 31 Dec 2024F if its FDP approval and production consent has not been received by the NSTA before then; Hibiscus is currently in negotiations with the NSTA to extend the licence validity by five years to 31 Dec 2029F.

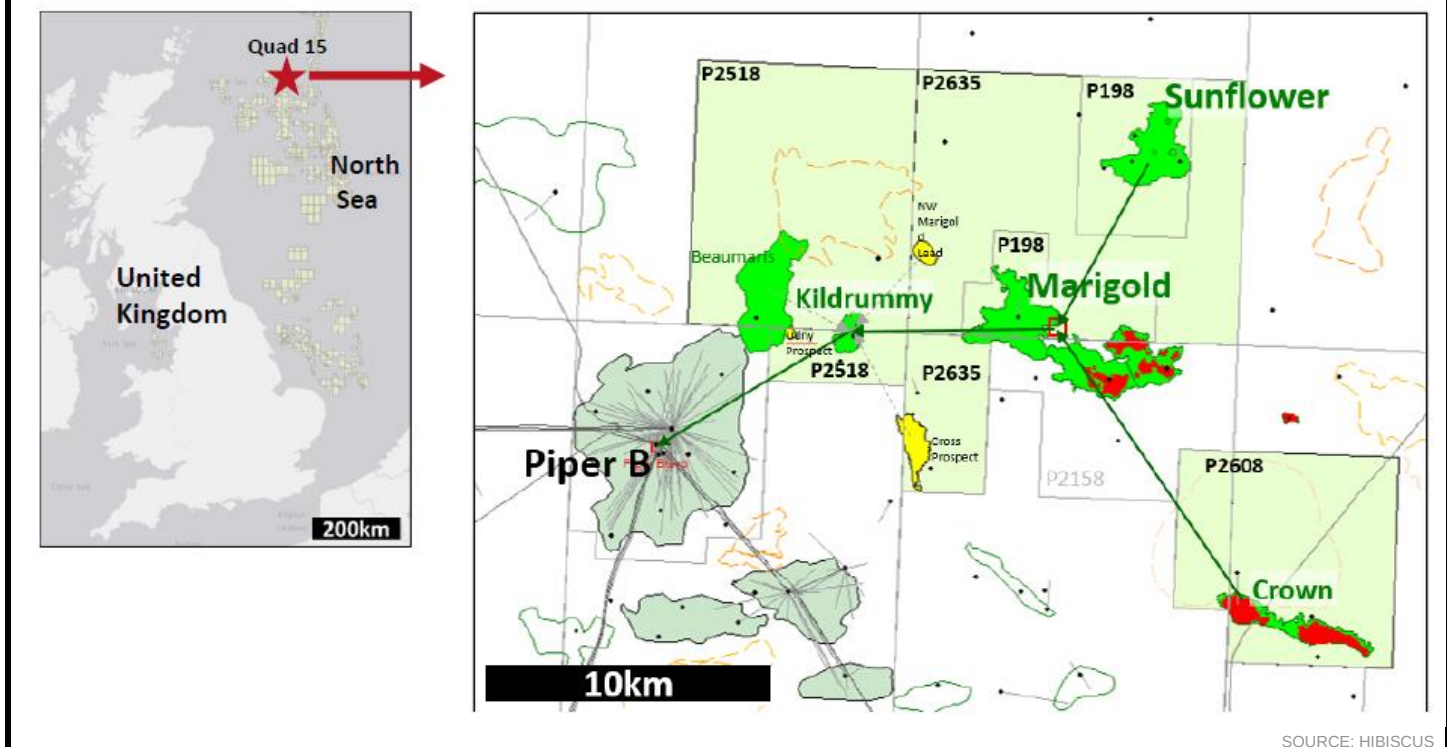
AHUK had originally wanted to develop Marigold West and Sunflower on its own by utilising a redeployed FPSO solution, but this did not materialise due to the disruption from the Covid-19 pandemic.

In any case, the NSTA requested In Jan 2021 that AHUK work with Ithaca Energy Limited for a joint development solution for the Marigold West and the Marigold East fields as they are adjacent to each other. Ithaca is the holder of Licence No P2158 which contains the Marigold East field (Block 15/18b).

The NSTA had also requested that a **Unitisation and Unit Operating Agreement (UUOA)** be entered into by the participants for the joint development; this was concluded on 15 Sep 2023 whereby AHUK's interest in the unitised Marigold unit (which is the combined Marigold West and Marigold East fields) was determined at 61.25%, with Caldera Petroleum holding 8.75%, and Ithaca holding the remaining 8.75%. AHUK is the operator of the unitised Marigold field.

AHUK's interest in the Sunflower field remains at 87.5%, as the Sunflower field is not part of the UUOA.

Figure 91: Location of the Greater Marigold Area Development (GMAD) in the UK North Sea



Ultimately, AHUK and Ithaca agreed to develop Marigold West and Marigold East via a 16 km **tieback to the Piper Bravo ('Piper B') platform**, which is operated by Repsol Sinopec in a proximate field. AHUK recently agreed with Repsol Sinopec a very competitive tariff that the Piper B platform will charge for processing the oil production from the unitised Marigold field. According to Hibiscus, this was possible because Repsol Sinopec may be able to defer the decommissioning of the Piper B platform for many more years if production from Marigold is tied-back to Piper B in the future. The economics of the Marigold development may also be enhanced by the unitisation of Marigold West and Marigold East, as the larger, combined volume of production may help reduce production opex per boe, in our view.

Hibiscus has not taken FID on any of the GMAD development fields. If and when it does, the current guidance from Hibiscus is for a **2028F** production commencement. The development concept will involve drilling multiple wells across the Marigold, Sunflower and Kildrummy fields and mixing up the different crude flows so that the viscosity of the produced Marigold oil can be diluted by the lighter sources of crude from Sunflower and Kildrummy (also possibly also Crown). In this way, the flow of oil via pipeline to the Piper B platform can be improved, resulting in lower overall capex spending for AHUK.

The Marigold FDP was submitted in early-2024, but has not yet been approved by the NSTA. An FDP for Sunflower was submitted independently of Marigold as Sunflower does not form part of the Marigold UUOA.

SECTION 8: RISKS

Risk 1: 2P reserves may be restated lower ➤

Hibiscus's reserves are reassessed periodically, including by its appointed reserves auditor, RPS. Hibiscus restated downwards its 1 Jul 2023 2P reserves by **7.8 MMboe** to 67 MMboe; the latter was 10% lower than it would have been without the reassessment (Figure 92). This downward restatement in 2P reserves was mainly on account of a reduction in 2P oil reserves at North Sabah and the Anasuria Cluster, partially offset by a small upward revision in 2P gas reserves at PM3 CAA and the Anasuria Cluster.

There was another downward revision for the 1 Jan 2024 2P reserves by **2.2 MMBoe**, comprising 1.2 MMboe for PM3 CAA, and 1 MMboe for Anasuria Cluster.

These downward restatements may have been due to observations of the actual flows from the reservoirs; the data is then used to refine the technical estimates of the probability of recoverability based on the 1P, 2P and 3P assessment framework.

We have used Hibiscus's 2P reserves estimates to determine our production profile that feeds into our earnings forecasts and DCF valuation. If Hibiscus or its reserves auditor, RPS, unexpectedly revises its 2P reserves estimates, we may also have to revisit our forecasts.

Figure 92: 2P reserves movement schedule

	North Sabah	Kinabalu	PM3 CAA	Anasuria Cluster	Block 46 Cai Nuoc	Total	Notes
2P oil and condensate reserves (MMboe)							
Balance as at 1 Jan 2023	20.4	7.3	6.2	22.9	0.3	57.1	
Less: Production	-0.9	-0.5	-0.7	-0.4	0.0	-2.5	
Add/(less): Reclassification from 2C to 2P	5.6			4.3		9.9	5.6 MMboe of 2P reserves added to North Sabah , as the SF30 Water Flood Phase 2 project was reclassified from 2C resources to 2P reserves; 4.3 MMboe of 2P reserves added to Anasuria Cluster , as the Teal West project was reclassified from 2C resources to 2P reserves.
Add/(less): Reassessment of reserves	-5.4	1.0	0.2	-5.9	-0.1	-10.2	2P oil and condensate reserves reassessed lower by 10.2 MMboe in the 1 Jul 2023 review.
Balance as at 1 Jul 2023	19.7	7.8	5.7	20.9	0.2	54.3	
Less: Production	-0.9	-0.6	-0.6	-0.4	0.0	-2.5	
Add/(less): Reclassification from 2C to 2P							
Add/(less): Reassessment of reserves		-0.1	-1.8			-1.9	2P oil and condensate reserves reassessed lower by 1.9 MMboe in the 1 Jan 2024 review.
Balance as at 1 Jan 2024	18.8	7.1	3.3	20.5	0.2	49.9	
Less: Production	-0.9	-0.6	-0.6	-0.3	0.0	-2.4	
Add/(less): Reclassification from 2C to 2P							
Add/(less): Reassessment of reserves	0.5	-0.1	0.4			0.8	
Balance as at 1 Jul 2024	18.4	6.4	3.1	20.2	0.2	48.3	
2P gas reserves (MMboe)							
Balance as at 1 Jan 2023			10.3	1.4		11.7	
Less: Production			-1.4	0.0		-1.4	
Add/(less): Reassessment of reserves			1.9	0.5		2.4	2P gas reserves reassessed higher by 2.4 MMboe in the 1 Jul 2023 review.
Balance as at 1 Jul 2023			10.8	1.9		12.7	
Less: Production			-1.3	0.0		-1.4	
Add/(less): Reassessment of reserves			0.6	-1.0		-0.3	
Balance as at 1 Jan 2024			10.1	0.9		11.0	
Less: Production			-1.3	0.0		-1.3	
Add/(less): Reassessment of reserves			-0.6			-0.6	
Balance as at 1 Jul 2024			8.2	0.9		9.1	
Total 2P reserves (MMboe)							
Balance as at 1 Jan 2023	20.4	7.3	16.5	24.3	0.3	68.8	
Less: Production	-0.9	-0.5	-2.1	-0.5	0.0	-3.9	
Add/(less): Reclassification from 2C to 2P	5.6			4.3		9.9	
Add/(less): Reassessment of reserves	-5.4	1.0	2.1	-5.3	-0.1	-7.8	Total 2P oil, condensate and gas reserves reassessed lowered by a net 7.8 MMboe in the 1 Jul 2023 review.
Balance as at 1 Jul 2023	19.7	7.8	16.5	22.8	0.2	67.0	
Less: Production	-0.9	-0.6	-1.9	-0.4	0.0	-3.9	
Add/(less): Reassessment of reserves		-0.1	-1.2	-1.0		-2.2	Total 2P oil, condensate and gas reserves reassessed lowered by a net 2.2 MMboe in the 1 Jan 2024 review.
Balance as at 1 Jan 2024	18.8	7.1	13.4	21.4	0.2	60.9	
Less: Production	-0.9	-0.6	-1.9	-0.4	0.0	-3.7	
Add/(less): Reassessment of reserves	0.5	-0.1	-0.2			0.1	
Balance as at 1 Jul 2024	18.4	6.4	11.3	21.1	0.2	57.4	

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Risk 2: Disruption to equipment uptime ►

Hibiscus's current business model is to acquire mature, producing oil and gas fields from their previous operators that may want to focus on more lucrative prospects elsewhere. By their very nature, the mature and producing fields have old production infrastructure that may have been operating for several years. Consequently, there is a higher risk of unplanned production downtime caused by various unexpected technical issues affecting the equipment.

At the **Kinabalu PSC**, Hibiscus has had reliability issues with the high pressure compressor (HPC) in the Jan-Jul 2023 and the Apr-Jul 2024 periods, which naturally affected production rates.

At the **Anasuria Cluster**, a production riser that transports produced crude oil to the Anasuria FPSO malfunctioned between May 2021 and Sep 2022, which resulted in a lower overall daily production rate from the Anasuria Cluster until the failed component was returned to service in Sep 2022. Recently, production from several oil wells that utilise gas lift operations declined as the gas compression system was offline from 24 Sep to 25 Oct 2024.

Meanwhile, on 20 Nov 2024, Brunei LNG (BLNG) issued a statement that it was managing an "operational upset" to its gas liquefaction plant. Gas production from the **Brunei MLJ** asset is sold to BLNG as the sole buyer, hence, any operational downtime at BLNG could affect the gas sale revenues at Brunei MLJ. Brunei MLJ is protected by the take-or-pay clause that require BLNG to purchase the Annual Contracted Quantity (ACQ), but unplanned outages at BLNG may shift the timing of revenue recognition to the right, and/or impact the total volume of purchased gas above the ACQ threshold. The BLNG plant restarted on 28 Nov 2024.

Risk 3: Sensitivity to oil and gas price changes ►

Hibiscus has a much greater sensitivity to oil prices compared to gas prices. North Sabah, Kinabalu, PM3 CAA and Anasuria Hibiscus all produce oil. Meanwhile, PM3 CAA's gas output is priced against Singapore HSFO, which is closely linked to oil price.

Natural gas prices in the UK (the Heren NBP index) will determine the pricing for Anasuria Cluster's gas output, but the Anasuria Cluster's production of gas only accounted for 11% of its overall production in FY24, which represented just **1.1%** of Hibiscus group's total production in boe terms.

Once Brunei MLJ is consolidated into the group accounts, Hibiscus's sensitivity to gas prices will increase, but not by much. Brunei MLJ's production of condensate is sold at prices linked to oil, and RPS estimates that condensate will represent 15.6% of Brunei MLJ's production in CY24F.

The remaining 84.4% of Brunei MLJ's production is gas. A 10% portion of the gas volume is sold at a fixed price of US\$0.33/MMBtu under the Brunei Domestic Gas Supply Obligation (DGSO). The remaining 90% of the gas volume is sold to BLNG at a contracted ratio to BLNG's realised price of LNG. We believe that BLNG sells at least two-thirds of its LNG based on long-term contracts that are pegged to the Japan Crude Cocktail (JCC) price and less than one-third sold is sold at the spot Japan Korea Marker (JKM) price.

Consequently, we estimate that:

- 10% of Brunei MLJ's wellhead gas is sold at a fixed domestic price;
- c.60% of Brunei MLJ's wellhead gas is ultimately linked to oil prices [90% x 2/3]; and
- Only c.30% of Brunei MLJ's wellhead gas is leveraged to spot JKM prices [90% x 1/3].

Overall, we estimate that on a full-year basis, **only an average of about 7% of Hibiscus's total production on a boe basis is exposed to spot gas prices**, using proforma FY25F data as if Brunei MLJ had been consolidated into Hibiscus from the start of the financial year. Without Brunei MLJ, the direct exposure to spot gas prices is only c.1%.

For FY25F, we have assumed Brent oil price of US\$75.97/bbl. **Every US\$5/bbl rise or fall in the Brent oil price will impact our FY25F core net profit forecast by 25%.**

Risk 4: Sensitivity to US\$ ➤

With the majority of revenues denominated in US\$, but with only 30-40% of opex denominated in US\$, Hibiscus is **net long US\$** and will benefit from a rising US\$ exchange rate environment relative to the ringgit, GBP and B\$. Conversely, Hibiscus may experience a margin squeeze if the US\$ depreciates relative to those currencies.

For FY24, we estimate that **if the US\$ had been 10% lower** against the ringgit and GBP:

- The core EBITDA would have been lower by 17%; while
- The **PAT would have been lower by 30%** relative to the actual numbers disclosed by Hibiscus.

Risk 5: Overlapping South China Sea claims ➤

China views the Nine Dash line as representing its territorial claims in the South China Sea, while all ten ASEAN member states are signatories to the United Nations Convention on the Law of the Sea (UNCLOS), which states that a nation's Exclusive Economic Zone (EEZ) stretches 200 nautical miles from its coast.

The exploration and development of oil and gas fields in the areas of overlap between the Nine Dash Line and the EEZ of the ASEAN member states may need to be managed by the respective governments in the future.

In our discussions with Hibiscus, the company believes that its assets in Sabah (North Sabah and Kinabalu) and its Brunei MLJ asset lie outside of the Nine Dash Line. We believe that Hibiscus may have to pay attention to geopolitical risks should it choose to venture into the areas of overlap in the future.

Figure 93: ASEAN member states' EEZ juxtaposed against China's Nine Dash Line



SOURCES: OBSERVER RESEARCH FOUNDATION (AS QUOTED BY 'THE REBIRTH OF QUAD 2.0: NAVIGATING ASEAN DIRECTIVES IN THE MIDST OF GEOPOLITICAL RIVALRY')

SECTION 9: SWOT ANALYSIS

SWOT Analysis ►

Strengths

1. The PM3 CAA PSC tenure will end on 31 Dec 2027F, but Hibiscus has applied for an extension of 10 years or up to 20 years. If this application is successful, the PM3 CAA will be able to book an increase in its 2P reserves.
2. Hibiscus intends to develop the PM3 CAA PSC as a tie-back hub for the future development of the PKNB Cluster and the PM327 exploration block.
3. Hibiscus has experienced management, and a low net gearing of less than 30% even after acquisition of TotalEnergies Brunei.

Weaknesses

1. Hibiscus's mature, late-life assets may experience rapid production decline and elevated maintenance requirements.
2. The acquisition of Brunei MLJ was negotiated in an environment of high oil prices, which could leave Hibiscus exposed if production volumes fall short of Hibiscus's expectations, or if oil prices moderate.
3. The PM3 CAA PSC has a very high absolute GHG emissions and high emissions intensity.

Opportunities

1. Hibiscus has 46.4 MMboe of 2C oil resources at the potential Greater Marigold Area Development (GMAD) in the UK North Sea, and a further 4 MMboe of 2C oil resources at the Fyne field in the Anasuria Cluster (as at 1 Jul 2024); these could be developed in the future.
2. Brunei has many discovered resource opportunities which are below the oil majors' minimum threshold for development; these could be a source of future growth for Hibiscus.
3. The proposed carbon capture and storage (CCS) project promises to significantly reduce GHG emissions at PM3 CAA; the addition of Brunei MLJ into the portfolio of assets also reduces Hibiscus's emissions intensity.

Threats

1. The UK Energy Profits Levy (EPL) may affect the profitability and returns from the Teal West project.
2. Any future extension of the UK EPL regime could affect Hibiscus's forecast returns from the potential Greater Marigold Area Development (GMAD) in the UK North Sea.
3. A potential surplus of oil in 2025F and potential surplus of LNG supplies from 2026F onwards could pressure Hibiscus's profitability.

SECTION 10: FINANCIALS

Quarterly financial performance ►

Hibiscus's 1QFY25 (Jul-Sep 2024) quarterly net profit declined to RM76m, because:

- Production from the Anasuria Cluster was offline for 38 days during a major turnaround in Aug-Sep 2024, and subsequently, the gas compression system was offline from 24 Sep to 25 Oct 2024. These factors caused the Anasuria Cluster to report a loss before tax of RM32m in 1QFY25. The impact to the Hibiscus group would have been worse if it did not book in a RM65m non-cash deferred tax income provision, which enabled it to report a PAT of RM34m last quarter.
- Hibiscus's other assets also went through their usual annual maintenances, with the North Sabah maintenance taking place between Mar and Jul 2024, and the Kinabalu maintenance taking place over 10 days between Jun and Jul 2024. Kinabalu also experienced a 12-day gas compressor outage in Jul 2024. Meanwhile, the PM3 CAA operations went through a maintenance shutdown over 12 days in Aug 2024.
- The above planned and unplanned outages caused Hibiscus's overall production uptime to decline to 81% in 1QFY25, vs. 88% in the immediately-preceding 4QFY24.
- The production issues encountered at Kinabalu also resulted in zero crude oil sales in 1QFY25, although one sale of 304,528 bbls took place in Oct 2024 (2QFY25F).
- Finally, Hibiscus booked in RM33.8m in realised and unrealised forex losses in 1QFY25 due to the depreciation of the US\$ against the ringgit, against RM2m of forex gains in 4QFY24.

Figure 94: Hibiscus group's Revenue and Core net profit (RM m)

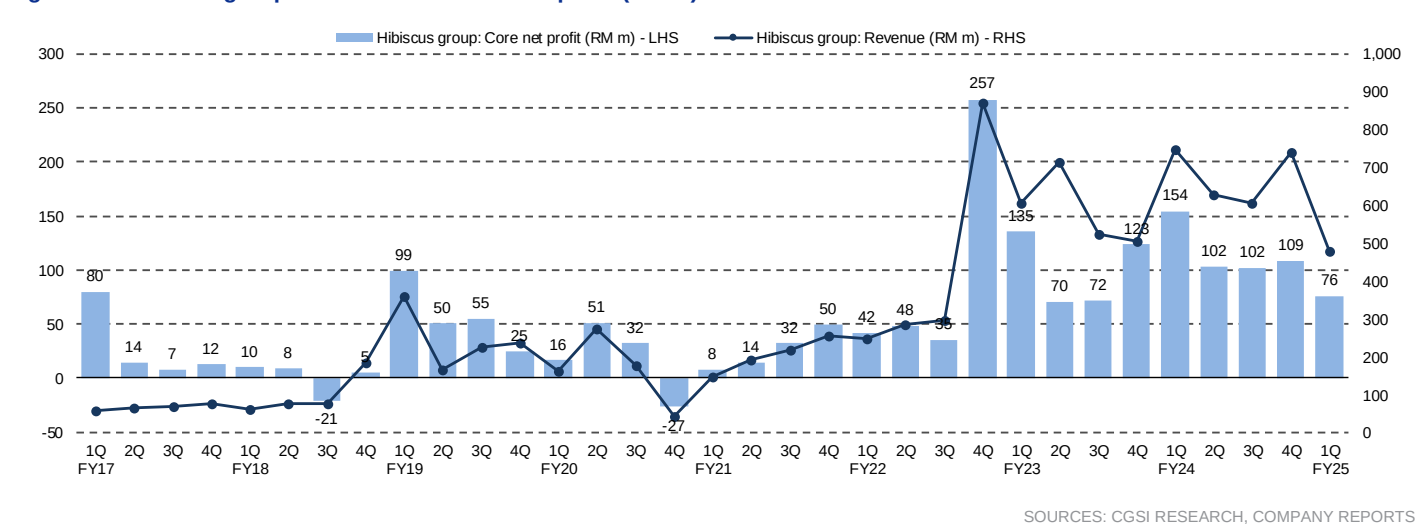
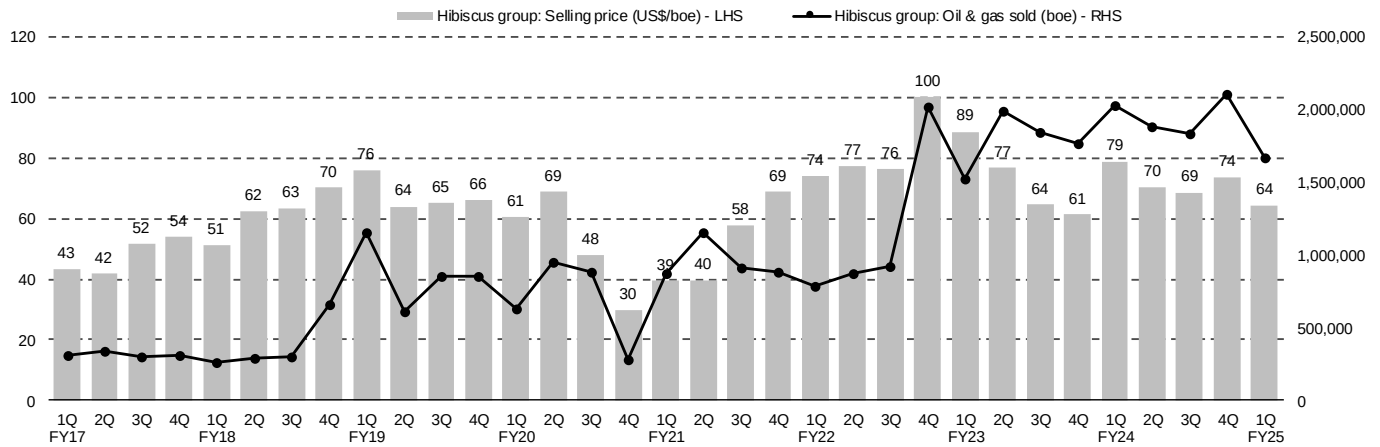
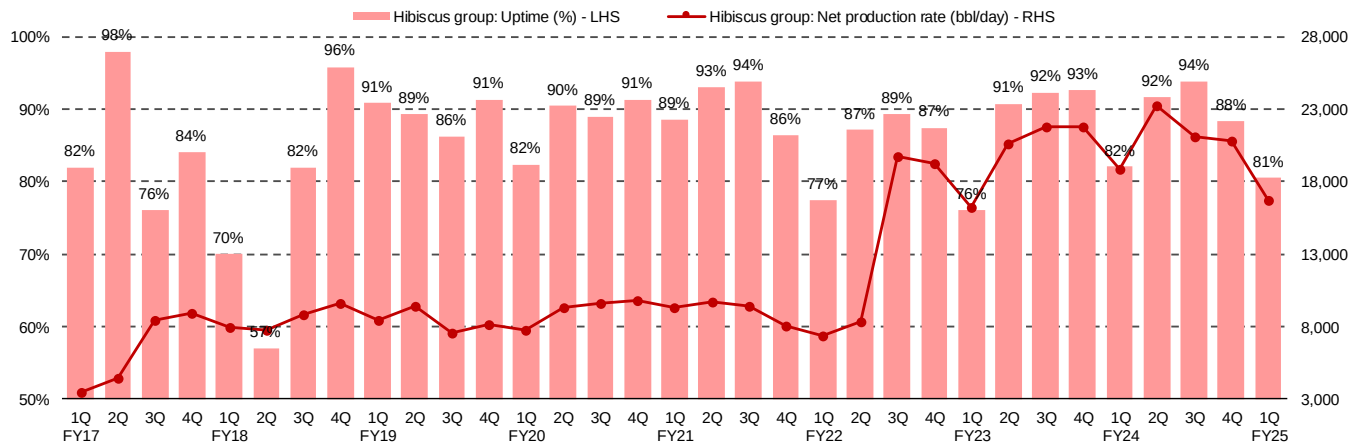


Figure 95: Hibiscus group: Oil & gas sold (boe) and Selling price (US\$/boe)



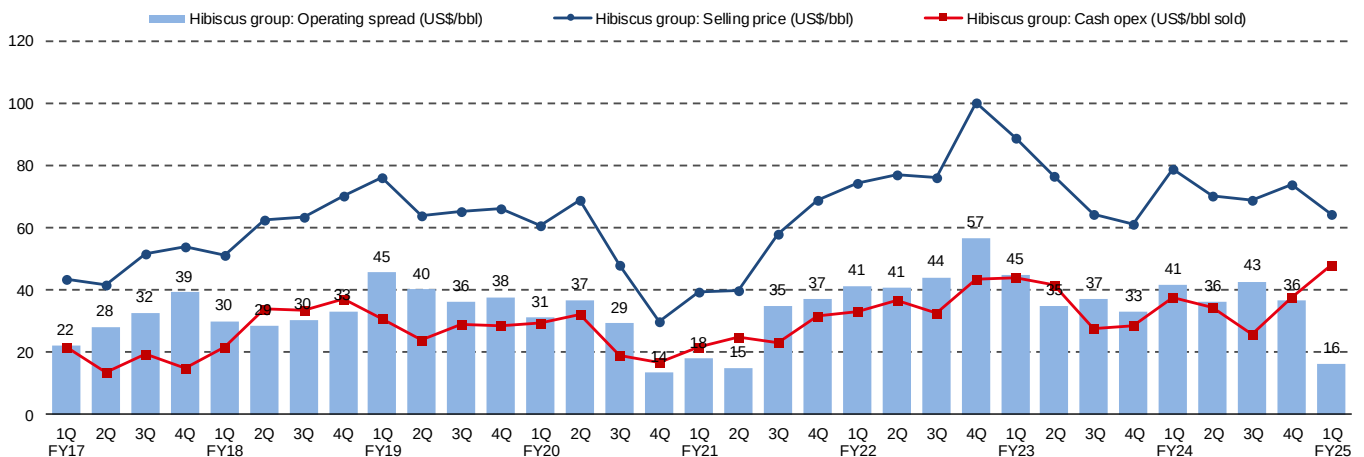
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 96: Hibiscus group: Uptime (%) and Net production rate (bbl/day)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 97: Hibiscus group: Operating spread = Selling price - Cash opex (US\$/bbl sold)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Annual forecasts for financial and operating data ►

We expect **FY25F** core net profit to decline to RM241m, from RM467m in FY24, because:

- We forecast a lower average selling price of US\$59/boe in FY25F, vs. US\$73/boe in FY24, as a result of the softer Brent crude oil prices due to weak demand from China and ample production growth from non-OPEC+ sources;
- We have pencilled-in an average US\$ exchange rate of RM4.30 in FY25F, vs. RM4.73 in FY24;
- Unplanned production issues were encountered at the Anasuria Cluster and at Kinabalu during 1QFY25;
- Hibiscus is likely to make a large deferred tax expense provision in its 2QFY25F results, according to the company, to reflect the intensified EPL rules; and
- Hibiscus may write-off a net of tax amount of RM28.6m in 3QFY25F relating to the South Furious Ungu well in the North Sabah PSC, if the outcome of the earlier exploration drilling programme is determined to be unfavourable by Hibiscus; however
- The above negative impacts are partially offset by incoming contribution from the Brunei MLJ acquisition that was completed on 14 Oct 2024.

Our forecast for **FY26F** is a rise in core net profit to RM331m, driven by a 24% yoy growth in net oil equivalent production, mainly based on guidance from Hibiscus that:

- The Teal West project will contribute significant volume growth for the Anasuria Cluster from late-2025F onwards;
- Production growth at North Sabah due to the SF30 Water Flood Project Phase 2 from late-2024F onwards; and
- A full year's contribution from the Brunei MLJ acquisition.

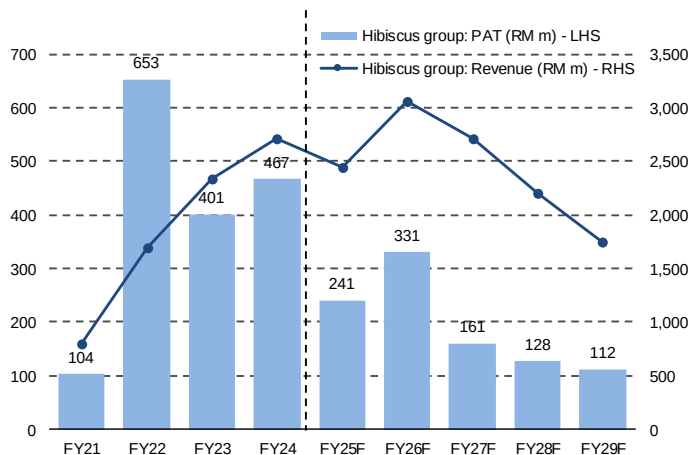
We currently expect Hibiscus to deliver lower core net profits of RM161m in **FY27F**, as:

- We are forecasting a 5% yoy decline in production due to natural well depletion partially offset by full-year impact from the Teal West project, and
- A 5% decline in average selling prices from US\$60.20/boe in FY26F to US\$57/boe in FY27F.

We have also assumed that absolute cash opex at the Anasuria Cluster will rise by 50% yoy in FY26F and sustain into FY27F on the back of the incoming uplift in production from Teal West. Hibiscus itself has guided the market that incremental costs from the extra Teal West volumes are not significant, but we have opted for a more conservative approach and to leave upside opportunities for our forecasts.

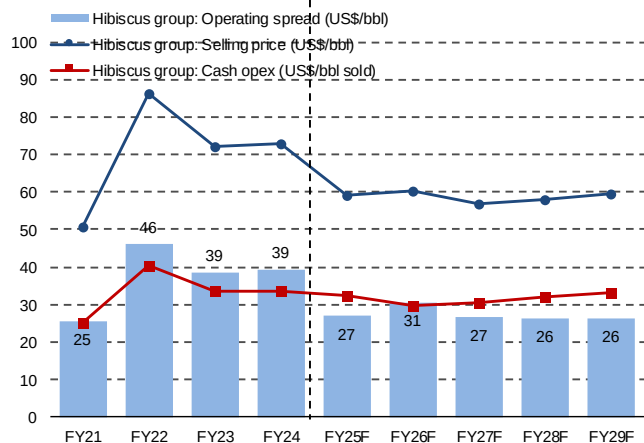
Our FY27F forecasts are on the basis of the PM3 CAA PSC tenure expiring on 31 Dec 2027F; if it is extended, Hibiscus will likely reduce the annual depreciation and amortisation charges under the UOP accounting method of calculating depreciation and amortisation, in our view.

Figure 98: Hibiscus group: Revenue and PAT (RM m)



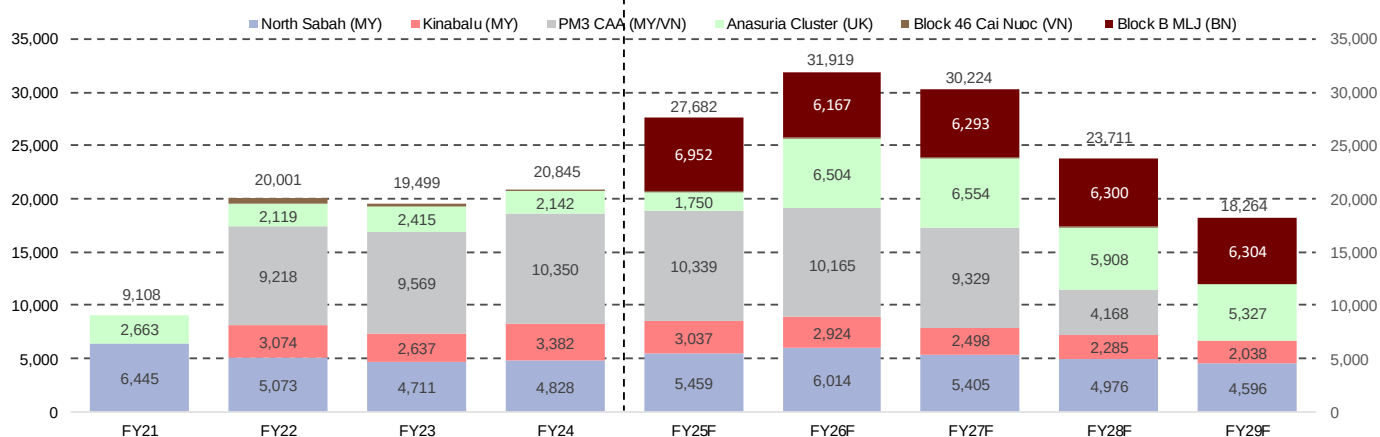
SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 99: Hibiscus group: Operating spread = Selling price - Cash opex (US\$/boe sold)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Figure 100: Hibiscus group: Net oil equivalent production rate (boepd)



SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

Capex spending ➤

The latest Hibiscus capex guidance is set out below; we have reflected these numbers in our forecasts. We note that the capex estimate of US\$283m in FY25F is very heavy at more than RM1.2bn at an exchange rate of RM4.40.

Our FY25F operating cashflow estimate is RM0.8bn, excluding the RM430m (US\$100m) prepayment facility that Hibiscus had drawn down to pay for the TotalEnergies Brunei acquisition. We have assumed that Hibiscus will borrow RM500m this year to cover its dividend commitments, pay for the share buybacks, and to top up its cash balances that were previously drawn down to pay for the remaining RM200m in purchase consideration for TotalEnergies Brunei.

Figure 101: Hibiscus's capex spending guidance, as released on 12 Sep 2024

Asset	Key Highlights	CAPEX (USD m)	
		FY2025	FY2026
UK: Teal West	Teal West Development	88	29
Malaysia-Vietnam: PM3 CAA	Bunga Aster Appraisal Well + Exploration Wells	47	40
Malaysia: North Sabah	SF30 Waterflood Phase 2	62	18
UK: Anasuria	Upgrade & Replacements of Facilities on FPSO	14	11
Malaysia: Kinabalu	Redevelopment Project	30	25
Malaysia: PKNB	Pre-FID costs	5	5
Malaysia: PM327	Exploration Activities	16	17
Brunei: Block B MLJ	LP Compression Project + Well Intervention Activities	21	5
TOTAL CAPEX		283	150

SOURCE: HIBISCUS

Sales and pricing ➤

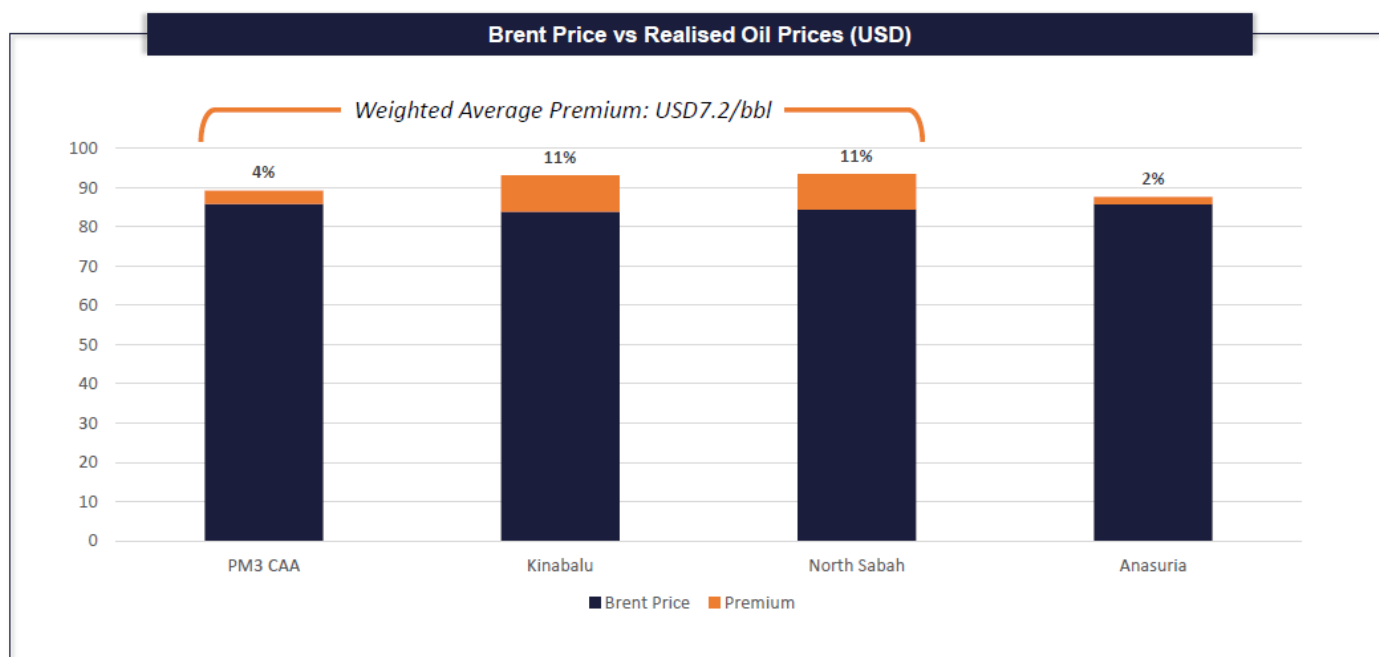
Hibiscus sells its oil production at a premium to Brent, as shown in Figure 102. The premium depends on the source of the crude, with Malaysian crude types (North Sabah and Kinabalu) commanding the highest premiums, while PM3 CAA and the Anasuria Cluster premiums are relatively modest.

Figure 102: Hibiscus's oil production was sold at a premium to Brent prices for the Jan-Mar 2024 quarter

SELLING AT A PREMIUM TO BRENT



Oil sold in Q3FY24 was at a premium of between USD2-9 per barrel



SOURCE: HIBISCUS

Gas selling prices are based on specific contractual terms, as summarised below:

- UK gas: selling price is linked to the Heren National Balancing Point (NBP) index
- PM3 CAA gas: selling price is linked to the price of Singapore High Sulphur Fuel Oil
- Brunei MLJ gas: selling price is linked to the price that Brunei LNG obtains for the sale of its liquefied natural gas (LNG)

Hibiscus sells its production to various offtakers:

- UK oil and condensate: BP is the offtaker until 2026F; Hibiscus expects the contract to be extended
- UK gas: Shell and Esso
- North Sabah oil and condensate: Trafigura until 2026F; to be extended
- PM3 CAA oil and condensate: PETCO until 2027F; to be extended
- PM3 CAA gas: Petronas and PetroVietnam, based on the long-term gas sale agreement
- Kinabalu oil and condensate: PETCO until 2027F; to be extended
- Brunei MLJ condensate: TotalEnergies
- Brunei MLJ gas: Brunei LNG

Anasuria Cluster, UK

The oil produced from the Anasuria Cluster is sold to BP, which is the marketing agent until 2026F; Hibiscus expects to extend the validity of this marketing agreement. This oil is sold at a premium to Brent; for the Jan-Mar 2024 quarter, Hibiscus disclosed that the Anasuria Cluster oil was sold at a 2% premium to Brent. The gas produced from the Cook field is priced at 75% of the Heren National Balancing Point (NBP) index, whereas the gas from the Guillemot A, Teal and Teal South fields is priced at 75% of the Heren NBP index. The gas is sold to Shell and Esso.

North Sabah

The oil produced at North Sabah is sold to Trafigura, who will market the oil for Hibiscus. The marketing agreements ends in 2026F, but Hibiscus expects to extend and continue with this contract. Hibiscus disclosed that for the Jan-Mar 2024 quarter the North Sabah oil was sold at a 11% premium to Brent.

PM3 CAA

The oil produced at PM3 CAA is sold to PETCO, which is a Petronas subsidiary, who will market the oil for Hibiscus. The marketing agreements ends in 2027F, but Hibiscus expects to extend this contract. Hibiscus disclosed that for the Jan-Mar 2024 quarter the PM3 CAA oil was sold at a 4% premium to Brent.

PM3 CAA gas is sold to Petronas and PetroVietnam under long-term Gas Sale Agreements (GSA). The price of the gas is linked to the price of Singapore High Sulphur Fuel Oil (HSFO). In FY23 and FY24, the wellhead gas price on a US\$ per boe basis was 47-48% of the Singapore HSFO price. This worked out to between US\$5/MMBtu and US\$6/MMBtu, in our estimate.

Kinabalu

The oil produced at PM3 CAA is sold to PETCO. The marketing agreements ends in 2027F, but Hibiscus expects to extend this contract. Hibiscus disclosed that for the Jan-Mar 2024 quarter the Kinabalu oil was sold at a 11% premium to Brent.

Brunei MLJ

The condensate produced at Brunei MLJ is sold to TotalEnergies as the marketing agent. Consultant RPS pencilled-in a selling price at a 2% premium to Brent for the Brunei MLJ condensate.

The wellhead gas produced at Brunei MLJ is sold to Brunei LNG (BLNG) for liquefaction and sale as LNG. The current GSA with BLNG is valid until 31 Mar 2033F.

The wellhead gas price is contracted as a proportion of the average price that BLNG receives from its sale of LNG, typically c.45% of BLNG's average LNG selling price. The Brunei MLJ wellhead gas was sold at US\$4.18/MMBtu in 2023, in our estimate.

BLNG's LNG selling price is a weighted average of its selling price it receives from selling LNG in the Asian spot market and what it receives from selling LNG at long-term contract prices. We believe that at least two-thirds of BLNG's LNG selling price is pegged to long-term contract prices (which are pegged to crude prices), with at most one-third exposed to spot prices (JKM).

Interpreting Hibiscus's disclosure of production and unit cost operating metrics ➤

Hibiscus retrospectively updates its **production disclosures** every quarter, because the quarterly production numbers are reported on a preliminary basis at the release of the quarterly results, but later amended after review by Petronas.

Using the example of the disclosures for the North Sabah PSC with respect to the Jan-Mar 2024 quarter, the gross production rate was initially reported as 13,642 bbl/day in May 2024 when the quarterly report was released, but later revised higher to 13,688 bbl/day when the 4QFY24 quarterly report was released in Aug 2024. Similarly, the net production rate was revised higher.

Consequently, the gross production opex per bbl and the net production opex per bbl calculations were revised lower, as the production volume denominators of their respective calculations had been revised higher.

Figure 103: North Sabah's operating metrics

Hibiscus's disclosure for the Apr-Jun 2024 quarter

	Unit	April to June 2024 ⁴	January to March 2024	October to December 2023	July to September 2023
Average uptime	%	86	96	93	83
Average gross oil production	bbl/day	12,715	13,688	13,914	12,845
Average net oil production	bbl/day	4,705	5,065	5,148	4,357
Total oil sold	bbl	614,570	299,584	351,350	549,134
Average realised oil price ¹	USD/bbl	94.63	93.54	92.83	97.03
Average production OPEX per bbl ²	USD/bbl	25.88	15.80	21.47	24.00
Average net OPEX per bbl ³	USD/bbl	36.11	20.83	30.69	36.01

Hibiscus's disclosure for the Jan-Mar 2024 quarter

	Unit	January to March 2024 ⁴	October to December 2023	July to September 2023	April to June 2023
Average uptime	%	96	93	83	94
Average gross oil production	bbl/day	13,642	13,914	12,845	13,728
Average net oil production	bbl/day	5,047	5,148	4,357	4,729
Total oil sold	bbl	299,584	351,350	549,134	350,845
Average realised oil price ¹	USD/bbl	93.54	92.83	97.03	82.77
Average production OPEX per bbl ²	USD/bbl	15.86	21.47	24.00	24.68
Average net OPEX per bbl ³	USD/bbl	20.90	30.69	36.01	37.61

SOURCE: HIBISCUS

The gross oil production rate reflects the production of the North Sabah PSC as a whole. The ratio of the net-to-gross oil production rate reflects **Hibiscus's net entitlement share of the production**, based on the terms of the North Sabah PSC. Using the revised Jan-Mar 2024 disclosures, Hibiscus's net entitlement would therefore be 37%, calculated as the net oil production rate of 5,065 bbl/day divided by the gross oil production rate of 13,688 bbl/day. Although Hibiscus has a 50% working interest in the North Sabah PSC, it will have less than 50% net entitlement ratio, because of the royalty deduction amounting to 10% of gross production, and also Petronas's share of the profit oil tranche following the terms of the North Sabah PSC. Please see Appendix 5 for a detailed explanation of the PSC mechanism in Malaysia.

Another point to note is the difference between "[gross] production opex per bbl" and "net opex per bbl". The gross production opex per bbl is the total opex incurred for the quarter divided by the production volume of the entire North Sabah PSC, which is derived from the gross oil production rate multiplied by the number of days in the quarter.

$$(1) \text{Average production OPEX/bbl} = \frac{\text{Gross production opex}}{\text{Gross oil, condensate and gas production}}$$

The net opex per bbl is Hibiscus's 50% share of the production opex (which is based on Hibiscus's 50% working interest in the North Sabah PSC), divided by Hibiscus's 37% net entitlement to production volume. The denominator can be calculated as the net oil production rate multiplied by the number of days in the quarter.

The **net opex per bbl is higher than the gross production opex per bbl** because Hibiscus has a smaller net entitlement share of production volume compared to its share of the production opex. This is not unique to Hibiscus, but also applies to the other PSC participants; in North Sabah's case, the other participant is Petronas Carigali.

$$(2) \text{Average net OPEX/bbl} = \frac{\text{Net production} + \text{Net development opex (based on working interest)}}{\text{Net oil, condensate and gas production (based on net entitlement)}}$$

However, we highlight that for Anasuria Cluster and for Brunei MLJ which are based on the concession regime, and not the PSC regime, the **concession participants' entitlement to production exactly matches their working interest**. Hence, for the Guillemot A field in Anasuria Cluster, AOCL has a 50% working interest and hence 50% entitlement to the production and 50% responsibility for the opex. At Brunei MLJ, Hibiscus's working interest is 37.5% and it will have the same share of both production and opex. As a result, gross production opex per bbl and net opex per bbl will match each other for the Anasuria Cluster and for Brunei MLJ.

Another reason why the calculation (2) may produce a result that is higher than calculation (1) is because Hibiscus includes the net development opex into the numerator of calculation (2). Net development opex refers to the costs spent on projects prior to FDP approval by the regulators and prior to FID by Hibiscus. For instance, the pre-FDP and pre-FID costs incurred on the SF30 Water Flood Phase 2 project at North Sabah were expensed into the P&L, and therefore included in the numerator until the FDP was received, whereupon the costs incurred would be capitalised into the balance sheet either as intangibles (e.g. drilling costs) or as fixed assets (new wellhead platform).

We highlight that the absolute net opex derived from the operating metrics disclosures (net opex per bbl x net production rate per day x number of days in the quarter), cannot be directly tallied with the cost of sales disclosure in the P&L. This is because the net opex derived from the operating metrics disclosures is based on the volume of produced bbls, whereas the P&L cost of sales is based on the volume of bbls sold. Until the produced bbls are sold, the opex spent is capitalised on the balance sheet as inventory costs, which is then charged into the P&L as cost of sales only when the bbls are actually sold. As such, we use Hibiscus's disclosures of net opex per bbl of production for information purposes only, and not directly for our P&L cost of sales or opex forecasts.

Taxation ►

Malaysia

Taxable profits from oil and gas operations at Hibiscus's Malaysian PSCs (North Sabah PSC, Kinabalu PSC, and PM3 CAA PSC) are subject to tax at a rate of **38%**, as specified under the Petroleum Income Tax Act 1967 (PITA). The PITA tax collected from the PM3 CAA PSC is shared equally between the governments of Malaysia and Vietnam.

Interest income is subject to the Malaysian corporate tax rate of 24%.

The North Sabah PSC and the Kinabalu PSC, being located geographically in the state of Sabah, are subject to the **Sabah sales tax (SbST) at 5%** of their respective revenues. There is no sales tax applicable to the revenues from the PM3 CAA PSC.

The PM3 CAA PSC is held by Hibiscus via two legal Barbados-incorporated legal entities, namely Hibiscus Oil & Gas Malaysia (PM3) Limited and Hibiscus Oil & Gas Malaysia (PM3) Limited. The Kinabalu PSC is held by Hibiscus via Hibiscus Oil & Gas Malaysia (PM3) Limited. These Barbados-domiciled entities are subject to a **flat minimum tax of 1%** against their taxable incomes.

Vietnam

The Block 46 Cai Nuoc PSC is subject to an income tax rate of **50%**. This is collected 'at source' meaning that PetroVietnam settles the income tax due to the Vietnamese tax authorities on behalf of the PSC participants. Accordingly, the oil entitlement delivered to the Block 46 Cai Nuoc participants is net of the related income tax amount and also net of royalty and export duty.

Brunei

The Brunei MLJ PSC will be subject to **55%** petroleum income tax in Brunei.

Hibiscus's 37.5% working interest in the Brunei MLJ field is held via TotalEnergies EP (Brunei) B.V., which is domiciled in the Netherlands. In the Netherlands, there is a tax rate of 19% applicable on the first €200,000 of taxable worldwide income, and 25.8% subsequently. However, we understand from Hibiscus that the income derived from the Brunei branch is exempted from tax in the Netherlands.

The UK

The Anasuria Cluster in the UK is subject to the:

- Ring Fence Corporate Taxation (RFCT) of 30%;
- Supplementary Charge (SC) of 10%; as well as the
- Energy Profits Levy (EPL).

The EPL first took effect on 26 May 2022 at a rate of 25%, which was raised to 35% from 1 Jan 2023, and raised again to 38% from 1 Nov 2024. The UK government's current intention is to retain the EPL regime until 31 Mar 2030F.

The net result is that UK oil and gas profits are now taxed at a rate of **78%**, comprising RFCT of 30%, SC of 10% and EPL of 38%.

When the UK first imposed the EPL in 2022, Hibiscus booked in a large RM104m deferred tax liability in 2QFY23 (Oct-Dec 2022 quarter), representing the tax effect of the timing differences that were expected to reverse in the period to the end of the EPL regime. We expect Hibiscus to book in another deferred tax liability in 2QFY25F (Oct-Dec 2024F quarter) as a result of the increase in the EPL rate and the removal of enhanced capital allowance deductions effective 1 Nov 2024.

Intangible assets vs. equipment ►

Hibiscus's non-current assets are mainly made up of equipment assets and intangible assets. As at 30 Jun 2024, Hibiscus had RM2.2bn on its balance sheet as equipment assets and RM1.4bn as intangible assets.

Equipment assets comprise mainly the physical assets acquired in the course of the production of oil and gas, and include the cost of the platforms, pipelines and the Anasuria FPSO. Equipment assets also include the equipment acquired via the acquisition of companies, such as the equipment assets from then-Repsol's Fortuna International Petroleum Corporation (FIPC) and from TotalEnergies EP (Brunei) BV that Hibiscus had recently acquired from TotalEnergies.

Intangible assets are made up of two components, i.e. 'rights and concessions' and 'conventional studies'.

- Rights and concessions are the costs to acquire the licence to producing, exploration or development acreage, such as the cost to acquire 50% interest in the **Marigold and Sunflower** development fields from Caldera Petroleum in 2018. Hibiscus had also acquired specific producing fields such as the **Anasuria Cluster** producing field in 2016 and the **North Sabah** producing field in 2018. Anasuria Cluster has a much larger value booked as rights and concessions compared to equipment assets, while North Sabah assets are booked only as rights and concessions (no equipment assets).
- Conventional studies are the costs directly associated with an exploration well such as licence acquisition, geological and geophysical surveys, drilling, commercial appraisal costs and other directly attributable costs of exploration and appraisal including technical and administrative costs.

Intangible assets and equipment assets are regularly reviewed for the necessity of impairments. Estimates of future cashflows for each PSC asset are computed by Hibiscus based on forecast production volumes, selling prices, operating costs, and tax expectations, and then discounted to the present value using a WACC discount rate of 10%. Commercial risk factors reflecting the probability of project commerciality and will be applied against forecast cashflows from specific planned projects. If the present value of any PSC asset is below that of the carrying value of its intangible assets and equipment assets, impairments will be made.

In FY24, Hibiscus impaired the capitalised drilling costs (booked as intangible assets) of two exploration wells in North Sabah because the forecast production volumes were assessed to be uncommercial. Hibiscus also impaired the well intervention costs for one water injection well at Kinabalu in FY24 as the "potential contribution to future cashflows from that well is now expected to be substantially lower than expected."

Depreciation and amortisation calculations ►

Hibiscus employs the **Unit of Production (UOP)** method to calculate its depreciation and amortisation expense.

Intangible assets such as rights and concessions and conventional studies are amortised using the UOP method over the duration of the PSC, where the total 2P reserves in the denominator is measured as reserves that are extractable up to the end of the PSC concession. The concept is the same for the depreciation of equipment assets.

$$\text{Amortisation} = \text{Cost of intangible assets} \times \frac{\text{Net production for the period}}{\text{Total 2P reserves}}$$

$$\text{Depreciation} = \text{Cost of O\&G equipment assets} \times \frac{\text{Net production for the period}}{\text{Total 2P reserves}}$$

Periodic depreciation and amortisation expense to fall upon extension of the PM3 CAA PSC term

Hibiscus is currently negotiating to extend its PM3 CAA PSC term from the current expiry of 31 Dec 2027F. Once the PSC term is extended by another 10 years or up to 20 years, we expect Hibiscus to revise higher its estimate of 2P reserves at PM3 CAA.

Once the 2P reserves are restated higher, we expect depreciation period of oil and gas equipment and the amortisation period of intangible assets at PM3 CAA to be extended up to the end of the new PSC term (rather than only to 31 Dec 2027F), or to the end of the useful life of the assets, whichever is earlier. This means that the periodic **depreciation and amortisation expense in the P&L should be reduced**, in our opinion.

We expect the lengthening of the depreciation and amortisation period to take place as soon as the PSC term is extended; hence, if the PSC term is extended by, say, an additional 10 years and an official announcement is made to that effect on 1 Jan 2025F, Hibiscus should be able to extend the depreciation and amortisation period to a maximum of 13 years effective 1 Jan 2025F up to the end of the extended PSC term of 31 Dec 2037F.

Provision for decommissioning liabilities ►

Hibiscus is required to estimate its future cash expenditure relating to the decommissioning of physical facilities at its production fields, and discount it back to the present value. This is booked on its balance sheet as provision for decommissioning in the liability section, with a corresponding intangible assets entry. Provision for decommissioning is not required for the cost of decommissioning wells, which is typically charged into the P&L as incurred (the exception is for North Sabah where the provision for decommissioning includes that for wells and facilities).

The future cash opex for decommissioning can either be paid progressively, or paid in a lump sum at the end of field economic life. Under the PSC regime in Malaysia, abandonment cess payments are made regularly to Petronas until the end of the PSC term and these are then discounted back to the present and booked on the balance sheet at the start of the PSC term.

Under the concession regimes in the UK and Brunei, there is no requirement to make regular decommissioning cess payments to their respective national regulators, because the concession participants only have the obligation to pay for the decommissioning costs in one lump sum at the end of field economic life. These lump sums are estimated and similarly discounted back to the present and booked on Hibiscus's balance sheet at the start of the concession.

After the initial booking of the decommissioning liabilities and its corresponding intangible assets:

- The intangible assets are regularly amortised into the P&L based on the UOP method; and
- The decommissioning liabilities in the B/S are subject to periodic accretion which is booked in the P&L under finance costs as 'unwinding of discount on provision for decommissioning costs'.
- The decommissioning liabilities balance is reduced by cash payments made for decommissioning, which in the PSC regime refers to the decommissioning cess payments made periodically to Petronas.
- In the case of the concession regimes in the UK and Brunei, there is no periodic or regular cash payment, hence the decommissioning liabilities related to the UK and Brunei will only be reduced when cash is expended on the decommissioning works at the end of their respective field lives.
- Although AOCL is required to set aside cash on a regular basis into a restricted cash account to pay for future decommissioning costs, this is not treated as a payment for decommissioning as the legal title to the cash still resides with Hibiscus.

The decommissioning liabilities on Hibiscus's balance sheet is for the Anasuria Cluster, North Sabah, and the Peninsula Hibiscus assets (PM3 CAA, Kinabalu, PM305/PM314, and Block 46 Cai Nuoc).

For FY25F, we expect the decommissioning liabilities to reflect the obligations related to the recent Brunei MLJ acquisition.

The potential extension of the PM3 CAA PSC term from 31 Dec 2027F by another 10 or 20 years may result in an increase in the provision for decommissioning of facilities at that site, since the obligation to make the annual cess payments may be extended by a further 10 or 20 years. However, we do not expect the decommissioning provision to increase significantly, if any, since Hibiscus has already been making regular cess payments on the basis that the decommissioning costs will be incurred in 2028F after the PSC term ends on 31 Dec 2027F. If Hibiscus adds CCS facilities at PM3 CAA in the future, naturally abandonment cess payments will increase to factor-in the cost to decommission those CCS facilities at the end of the PSC term; this may then lead to an increase in decommissioning liabilities.

In the future, if Hibiscus decides to proceed with the development of the PKNB Cluster and PM327, their respective decommissioning liabilities will also enter into the balance sheet.

Contingent consideration ►

Hibiscus booked a contingent consideration of RM38m as at 30 Sep 2024 as a liability on its balance sheet. This relates to the Marigold West and Sunflower fields, whereby AHUK had agreed to bear Caldera Petroleum's capex obligations with respect to its retained interest of 12.5% up to first oil arising from the fields. This arrangement came about after Caldera Petroleum had agreed in Jan 2021 to transfer a 37.5% interest in the Marigold and Sunflower fields to AHUK without consideration, which left Caldera Petroleum with a residual interest of 12.5%.

Separately, for the Fyne field at the Anasuria Cluster, in Aug 2023, AHUK had entered into a farm-in agreement with Rapid Oil to acquire 42.5% equity interest in the field. A contingent consideration is payable to Rapid Oil upon achieving first oil from the field, and is also booked as a liability on Hibiscus's balance sheet.

The contingent consideration represents the estimated amount to be paid and is dependent on the timing and amounts estimated to be incurred for the period up to first oil. Changes in estimates for contingent consideration relate to the expected value and timing of capex spending on Marigold West, Sunflower, and Fyne. The contingent consideration is booked on the balance sheet at its present value, and is subject to an unwinding that is booked into the P&L under finance costs as 'unwinding of discount on contingent consideration'.

Bank borrowings ➤

On 30 Nov 2022, Hibiscus announced that it has entered into its maiden long term debt facility agreement, with four banks namely HSBC Bank Malaysia Berhad, Bank of China Malaysia Berhad, Industrial and Commercial Bank of China (Malaysia) Berhad, and Standard Chartered Bank Malaysia Berhad for a total of **US\$120m** (the Malaysian-domiciled banks are unlisted companies). The facility comprises a US\$99m term loan and a US\$21m revolving credit facility.

This was an important milestone for Hibiscus, because Hibiscus has never had loan facilities prior to this, given the reluctance of domestic Malaysian banks to lend to upstream E&P companies.

The debt facility was signed by the banks with Hibiscus's wholly-owned subsidiary Asia Hibiscus Sdn Bhd; this is the holding company of Peninsula Hibiscus, which owns the assets acquired from Repsol in 2022. However, the funds drawn down can be used for general corporate purposes, and not restricted for use within Peninsula Hibiscus only.

As at 30 Sep 2024, Hibiscus had drawn down RM304.6m (US\$74m) in terms loans which bore an effective interest rate of **9.33% p.a.** in FY24. Therefore, Hibiscus still has the room to draw down more funds if necessary. Hibiscus did not have any outstanding revolving credit debt as at 30 Sep 2024.

Prepayment facilities ➤

Hibiscus as an **US\$80m** prepayment facility with Trafigura, which is Hibiscus's offtaker for the North Sabah crude oil sales. Hibiscus also can arrange additional prepayment facilities with its other offtakers.

In Dec 2021, Hibiscus drew down RM176.4m trade financing from Trafigura at an effective interest rate ranging from 7.08% to 8.25% p.a. This amount was fully settled via crude oil offtake proceeds received between Jul 2022 and Dec 2022.

As at 30 Sep 2024, Hibiscus had no outstanding drawdown of its prepayment facilities.

The prepayment facilities, if any, are classified under 'Other payables and accruals' on the balance sheet, rather than as borrowings. However, we would include these into our calculation of net gearing as they are interest bearing, and the proceeds from these prepayment facilities can be used for general corporate purposes.

Finance lease liabilities, finance lease receivables, and right-of-use assets ➤

At the PM3 CAA PSC, Hibiscus leases a Floating Storage Offload (FSO) unit named FSO Orkid from MISC on a long-term basis, while at the North Sabah PSC, Hibiscus also entered into long-term leases for various Offshore Support Vessels (OSV). At the commencement of the lease, the stream of committed lease payments is discounted back to the present value and booked in the balance sheet as a **Right-of-Use (ROU) asset** and as a **Finance Lease Liability (FLL)**.

The ROU asset is depreciated on a straight line basis until the end of the lease tenure. The FLL is subject to periodic accretion of finance lease expense, but reduced by the lease instalment payments. At the end of the lease tenure, both the ROU asset and the FLL will have a zero balance.

Because Hibiscus only has a 35% working interest in the PM3 CAA PSC, Hibiscus will only book in 35% of the value of the ROU asset on its balance sheet at the inception of the lease.

However, Hibiscus books in 100% of the value of the FLL on its balance sheet, but also 65% of the value of the discounted lease payments as a **Finance Lease**

Receivable (FLR); hence Hibiscus books in a net 35% of the FLL commensurate with its working interest in PM3 CAA.

Hibiscus books in 100% of the value of the FLL because as the operator at PM3 CAA, it is the party that signs the agreement with MISC for the lease of the FSO Orkid and is legally responsible for all of the lease instalments payable to MISC. On the other hand, under the terms of the Joint Operating Agreement (JOA) signed between the participants of the PM3 CAA, Hibiscus as the operator has the right to claim back opex spent on behalf of its PSC partners, which is why Hibiscus books in an FLR on its books that reflect its partners' 65% share of the FLL. **Each ROU asset is therefore associated with a pair of FLL and FLR balances.**

While the FSO Orkid FLL is subject to periodic accretion of finance lease expense, the associated FLR is also subject to periodic accretion of finance lease income. The net finance lease expense on Hibiscus's P&L represents its 35% working interest in the PM3 CAA, and is booked as a net amount into finance costs on the P&L. The P&L is also impacted by the depreciation expense arising from the ROU asset.

On the balance sheet, the **FLL balance should be netted off against the FLR balance to derive Hibiscus's net exposure to finance lease liabilities**. At 30 Jun 2024, Hibiscus had RM377.5m of FLL, and RM242m of FLRs, or a net FLL of RM135.5m, which is directly associated with the ROU balance of RM143m.

The FLL is classified in Hibiscus's balance sheet under 'Borrowings', and lumped together with Hibiscus's bank borrowings. However, **Hibiscus does not see the FLL as real borrowings** per se, and neither does it see the finance lease expense as a real cost of financing. This is because under the PSC terms and conditions, the full sum of the cash instalments of the vessel leases are cost recoverable from the cost oil tranche of the gross field production. By contrast, instalment payments on standard bank borrowings are not recoverable via the PSC. As such, Hibiscus does not consider the finance lease liabilities as 'true' debt, and **we exclude the FLL balance in our computation of Hibiscus's gearing**.

Gearing ratios ►

Based on the traditional definition of debt which includes FLL, Hibiscus had a net gearing of 2% in FY24, which we expect to rise to 25.9% in FY25F; this definition is used in our system-generated gearing calculation, which can be seen on the first page of this report, and also on the left half of Figure 104.

However, the specific circumstances of Hibiscus suggest that we should apply a modified formula for net gearing, which we show on the right half of Figure 104. The modified formula excludes FLL from the definition of debt, but includes the prepayment facilities such as that from Trafigura, etc. Based on this modified formula, Hibiscus would have a **net cash position in FY24** amounting to 10.2% of total equity, and a **net gearing in FY25F of 31.2%**.

The gearing level rises in FY25F because Hibiscus has stated that it will borrow US\$100m to part-fund the acquisition of a 100% stake in TotalEnergies Brunei; we have reflected in the RM430m prepayment balance for FY25F. We have also assumed that Hibiscus will draw down bank loans amounting to RM500m in FY25F to fund its planned capex programme. As these borrowings are repaid in future years, the gearing levels should naturally decline, although this situation could change if Hibiscus gives new guidance on its capex spending, or if Hibiscus executes another acquisition.

We have included the current restricted cash balance as a deduction in the gearing calculations because current restricted cash refers to monies set aside for future loan instalments. However, we do not deduct non-current restricted cash balances because these relate to Hibiscus's share of AOCL's decommissioning obligations at the Anasuria Cluster.

Hibiscus's strategy is **not to exceed a gross gearing ratio of 0.5x** even when pursuing acquisitions.

Figure 104: Calculation of net gearing

Based on traditional definition of debt						Based on an CGSI's adjusted definition of debt, tailored to Hibiscus's circumstances					
	FY23	FY24	FY25F	FY26F	FY27F		FY23	FY24	FY25F	FY26F	FY27F
a Prepayment facilities	0.0	0.0	430.0	330.0	0.0	a Prepayment facilities	0.0	0.0	430.0	330.0	0.0
b Short-term borrowings	214.8	214.1	338.5	289.9	294.7	b Short-term borrowings	214.8	214.1	338.5	289.9	294.7
c Finance lease liabilities (FLL)	122.9	120.9	81.6	85.4	89.4	c Finance lease liabilities (FLL)	122.9	120.9	81.6	85.4	89.4
d Term loan	91.8	93.2	256.9	204.6	205.3	d Term loan	91.8	93.2	256.9	204.6	205.3
e Revolving credit	0.0	0.0	0.0	0.0	0.0	e Revolving credit	0.0	0.0	0.0	0.0	0.0
f Long-term borrowings	647.7	534.9	707.5	490.0	258.9	f Long-term borrowings	647.7	534.9	707.5	490.0	258.9
g Finance lease liabilities (FLL)	282.7	256.6	175.1	89.7	0.3	g Finance lease liabilities (FLL)	282.7	256.6	175.1	89.7	0.3
h Term loan	365.0	278.3	532.4	400.3	258.5	h Term loan	365.0	278.3	532.4	400.3	258.5
i Cash balances	959.7	688.0	209.3	379.5	736.7	i Cash balances	959.7	688.0	209.3	379.5	736.7
Unrestricted cash	925.6	610.0	131.3	301.5	658.7	Unrestricted cash	925.6	610.0	131.3	301.5	658.7
Restricted cash - current only	34.0	78.0	78.0	78.0	78.0	Restricted cash - current only	34.0	78.0	78.0	78.0	78.0
Total equity	2,689.8	3,100.4	3,232.0	3,517.4	3,631.5	Total equity	2,689.8	3,100.4	3,232.0	3,517.4	3,631.5
b + f Total debt *	862.5	749.1	1,046.0	780.0	553.6	a + d + e + h Total debt **	456.8	371.5	1,219.3	934.9	463.8
i Total cash	959.7	688.0	209.3	379.5	736.7	i Total cash	959.7	688.0	209.3	379.5	736.7
Net debt	-97.2	61.0	836.7	400.5	-183.1	Net debt	-502.8	-316.5	1,010.0	555.4	-272.8
Gross gearing	32.1%	24.2%	32.4%	22.2%	15.2%	Gross gearing	17.0%	12.0%	37.7%	26.6%	12.8%
Net gearing	-3.6%	2.0%	25.9%	11.4%	-5.0%	Net gearing	-18.7%	-10.2%	31.2%	15.8%	-7.5%
* Total debt includes FLL, but excludes prepayment facilities						** Total debt includes prepayment facilities, but excludes FLL					

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Foreign currency exposures ►

(A) Revenue currency split

PM3 CAA: The price of the gas is sold is pegged to the US\$ as the underlying currency, but Hibiscus is paid in the ringgit equivalent by Petronas. For the remaining half of the gas sold to PetroVietnam, Hibiscus also receives the proceeds in the ringgit equivalent.

Malaysia: Oil and condensate revenue is denominated in US\$ and is also collected by Hibiscus in US\$. This applies to the oil sold by the PM3 CAA PSC and the Kinabalu PSC to PETCO; and the oil sold by the North Sabah PSC to Trafigura.

UK: The oil sold from the Anasuria Cluster to BP is denominated in US\$. The gas sold by the Anasuria Cluster is denominated in GBP, as it is pegged to the Heren National Balancing Point (NBP) index, which is expressed in terms of GBp/therm (pence per therm).

Brunei: The gas and condensate revenues at the Brunei MLJ asset are denominated in US\$. The gas sales price is pegged to the BLNG's US\$ selling price of its LNG, while the condensate is sold to TotalEnergies in US\$ terms.

Overall: For FY24, we estimate that 99% of Hibiscus's revenue is pegged to the US\$, with the remaining 1% in GBP. However, we estimate the US\$-denominated collection at 83% of group revenue since Hibiscus collects the proceeds of its PM3 CAA gas sales in ringgit. The weightage of US\$ will increase in FY25F since the Brunei MLJ has been incorporated into the group since 14 Oct 2024.

(B) Opex currency split

PM3 CAA: 30-40% of opex is denominated in US\$ (mainly relating to maintenance contracts); 60-70% is denominated in ringgit.

Malaysia: same as for PM3 CAA.

UK: Some 30% of the opex is denominated in US\$; 70% in GBP.

Brunei: The currency of the opex split in Brunei is to be confirmed, but we suspect that most of the opex is denominated in the local currency.

(C) Capex currency split

Most of the underlying currency of the capex spending is in US\$, even though Hibiscus may pay for a substantial portion of the capex in ringgit.

With the majority of revenues denominated in US\$, but with only 30-40% of opex denominated in US\$, Hibiscus is **net long US\$** and will benefit from a rising US\$ exchange rate environment relative to the ringgit, GBP and Brunei dollar (B\$). Conversely, Hibiscus may experience a margin squeeze if the US\$ depreciates relative to those currencies.

For FY24, we estimate that if the US\$ had been 10% lower against the ringgit and GBP, the core EBITDA would have been lower by 17% while the PAT would have been lower by 30% relative to the actual numbers disclosed by Hibiscus.

APPENDIX 1: BOARD OF DIRECTORS AND SENIOR MANAGEMENT

Board of Directors ➤

Figure 105: Board of Directors

Name of director	Designation	Description
Zainul Rahim bin Mohd Zain	Chairman (non-independent, non-executive)	Mr Zainul, aged 71, was appointed to the board on 14 Dec 2010. He has a B. Eng majoring in Mechanical Engineering from the University of Western Australia. He has 46 years of experience in the oil and gas exploration and production (E&P) industry.
Dr Kenneth Gerard Pereira	Managing Director	Dr Pereira, aged 66, was appointed to the board on 13 Sep 2010. He has a Doctorate in Business Administration from the University of South Australia, Australia; a Masters in Business Administration (MBA) from Cranfield University, UK; and a B.Sc (Honours) in Engineering from Bath University, UK. He has 36 years of experience in the oil and gas industry (both in services and E&P), and founded Hibiscus Petroleum in 2010. He started his career at Schlumberger Overseas (as a Field Engineer in North Africa, Asia and Europe), then moved on to various positions at the Sapura group of companies, and had held the position of chief operating officer at SapuraCrest Petroleum Berhad (now part of Sapura Energy Berhad Group). He was the managing director at Interlink Petroleum Ltd, an oil and gas E&P company for a short period before leaving to establish Hibiscus Petroleum.
Dato' Sri Roushan Arumugam	Non-Independent Non-Executive Director	Dato' Sri Roushan Arumugam, aged 52, was appointed to the board on 25 Jul 2011. He has an MBA from Imperial College Business School, UK; an MA in Law from the University of Bristol, UK; and a MA in English Language and Literature from Oxford University, UK. He has 25 years of experience in the financial services industry, previously working as an investment banker with Nomura Advisory Services, Malaysia; and with Deutsche Bank, London, UK.
Thomas Michael Taylor	Senior Independent Non-Executive Director	Mr Taylor, aged 68, was appointed to the board on 1 Aug 2016. He has an MA in Engineering from the University of Cambridge, UK and is a member of the Chartered Institute of Management Accountants. He has 40 years of oil and gas industry experience, having previously worked as the finance directors of Sakhalin Energy Investment Company, Shell Malaysia, and Brunei Shell Petroleum. He also previously held board memberships in oil and gas companies, in all sectors of the industry in Malaysia, Brunei, Russia, Hungary and France.
Dato' Dr. Zaha Rina Zahari	Independent Non-Executive Director	Dato' Dr. Zaha Rina Zahari, aged 62, was appointed to the board on 15 Sep 2017. She has a Doctorate in Business Administration from Hull University, UK; an MBA from Hull University; and a BA (Hons) in Accounting and Finance from Leeds, UK. She has more than 35 years of experience in financial (including Islamic), commodities and securities industry and the developing of the Malaysian Financial Market, as well as mergers and acquisitions in insurance and takaful companies.
Emeliana Dallan Rice-Oxley	Independent Non-Executive Director	Ms Emeliana Dallan Rice-Oxley, aged 61, was appointed to the board on 5 Oct 2022. She has a B.Sc in Geology from the University of South Carolina, USA. She has 37 years of experience in the oil and gas E&P industry, having previously worked in various roles at Petronas and Shell.
Zaidah binti Ibrahim	Independent Non-Executive Director	Ms Zaidah, aged 64, was appointed to the board on 1 Jan 2023. She has a B.Eng in Electrical & Electronics Engineering (First Class Honours) from the University of Wales, Institute of Science & Technology, UK. She has 33 years of experience in the oil and gas industry, predominantly in ExxonMobil global businesses in North America, Europe, West Africa, Middle East and Asia Pacific.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Senior management staff ➤

Figure 106: Key management staff

Name	Designation	Description
Dr Kenneth Gerard Pereira	Managing Director	Please refer to the description under the Board of Directors.
Yip Chee Yeong	Chief Financial Officer	Mr Yip, aged 50, has been CFO at Hibiscus Petroleum since 1 Jun 2019. He has a B.A (Honours) in Accounting and Finance from the Middlesex University, London, UK. Has over 30 years of accounting and finance experience in various industries, namely oil and gas, manufacturing, technology, services, risk consulting, audit and taxation. He joined Hibiscus Petroleum in Nov 2013 and held the position of Vice President, Finance and Group Controller before his appointment as CFO. Before that, he was previously CFO at Microsoft Malaysia.
Dr Pascal Hos	Country Head, Malaysia and Vietnam	Dr Hos, aged 53, has been the Country Head of Malaysia and Vietnam since 1 Jan 2024. He has a Doctorate in Mechanical Engineering from Rice University, Texas, USA; and a B.Sc in Mechanical Engineering from the same university. Joined Hibiscus Petroleum in Feb 2011 as Head of Petroleum Engineering and a co-founder. He was redesignated as the COO of HiRex Petroleum Sdn Bhd in Oct 2014, and subsequently re-designated as Vice President, New Ventures on May 2016 before being appointed as the CEO of SEA Hibiscus in Sep 2017, followed by Senior Vice President of New Ventures in March 2021 prior to commencing current role. Has over 24 years of experience in general management, field development, reservoir engineering, production technology and rock mechanics in major local and foreign companies. This includes experience in project management, field development planning, development project execution, well and reservoir management and reserves reporting. He previously worked at Schlumberger Sugar Land Technology Center, NASA Johnson Space Center, Shell International EP and Sarawak Shell Berhad.
Joyce Vasudevan	Head, Corporate Finance	Ms Vasudevan, aged 56, was appointed as the head of corporate finance at Hibiscus since 2 Sep 2020. She has a B.Economics, majoring in Accounting from the LaTrobe University, Melbourne, Australia. She joined Hibiscus Petroleum on 1 Jan 2011 as co-founder and CFO. She was subsequently re-designated as Vice President, Strategy Development in 2015, and the later assumed her current role. She has more than 33 years of experience in audit, corporate finance, finance, business planning, operations planning, debt and equity fund raising, investor relations, media relations and strategy development. She perviously worked in the Corporate Finance departments at Malaysian International Merchant Bankers Berhad and RHB Sakura Merchant Bankers Berhad. She had also previously worked at Carlsberg Brewery Malaysia Berhad and SapuraCrest Petroleum Berhad.
Deepak Thakur, CFA	Vice President, Economics and Business Planning	Mr Thakur, aged 41, was appointed to his current designation on 1 Feb 2020. He has a Chartered Financial Analyst (CFA) qualification; an MBA (Major in Finance) from the Indian Institute of Management (IIM), Bangalore, India; and a B. Tech in Petroleum Engineering from the Indian Institute of Technology (IIT), Dhanbad, India. He joined Hibiscus Petroleum in Mar 2012, and has over 17 years of experience in the oil and gas industry in a career dedicated to developing financial models and cashflows, performing valuation and sensitivity analysis, debt funding, corporate planning, financial due diligence and reservoir engineering. He previously worked with Essar Group, Morgan Stanley and Prize Petroleum Ltd in India.
Kevin Robinson	Vice President, Project Assurance & Asset Oversight	Mr Robinson, aged 68, was appointed to his current role on 1 Sep 2020. He has a M.Sc in Geochemistry, Leeds University, UK; and a B.Sc (Honours) in Geology, Sheffield University, UK. He joined Hibiscus Petroleum in Apr 2019, and has over 46 years of experience in upstream oil and gas mainly in exploration, development, new Ventures and management. He previously worked from 2004-2019 for Newfield Exploration and then Sapura E&P at its E&P business in Malaysia, and also expanded Sapura's E&P business outside Malaysia.
Chong Chee Seong	Vice President, Strategic Ventures	Mr Chong, aged 47, was appointed to his current designation on 1 Jan 2024. He has a Master in Mechanical Engineering and Master of Arts in Engineering from Cambridge University, UK. He joined Hibiscus Petroleum in Dec 2017 as COO for SEA Hibiscus and was appointed CEO in Mar 2021. He has over 23 years work experience in the oil & gas industry, including at ExxonMobil Exploration & Production Malaysia and at Newfield Malaysia.
Mohammed Farroukh Abdul Aziz	Country Head, Brunei	Mr Mohammed, aged 52, was appointed as the Country Head of Brunei on 1 Aug 2024. He has a M.Sc in International Management from King's College London, UK; and a B.Eng (Honours) in Mechanical Engineering, University of Warwick, UK. He joined SEA Hibiscus in Jan 2023, and has over 26 years of experience in the oil and gas industry in general management, strategic planning, asset management, development and production operations, financial performance management, risk mitigation and Health, Safety, Security and Environment (HSSE) management, procurement and stakeholder management. He had previously worked in ExxonMobil, Petronas Carigali, Murphy Oil and SapuraOMV Malaysia.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 107: Key management staff (continued)

Name	Designation	Description
Lim Kock Hooi	Group General Counsel	Mr Lim, aged 37, was appointed to his current role on 7 Mar 2017. He has an LLB (Honours) from the University of London, UK; a B.Sc (Honours) in Applied Geology from the University of Malaya, Malaysia, and is a Fellow of the Chartered Institute of Arbitrators, UK. He joined Hibiscus Petroleum in Oc 2014. He was a petroleum geologist for 9 years prior to retraining as a lawyer. He subsequently accumulated over 34 years of experience in oil and gas law practice, with 16 years as an external legal counsel and 18 years as an in-house legal counsel in a senior leadership team role.
Stewart McMickle	Vice President, New Ventures	Mr McMickle, aged 58, was appointed to his current role on 1 Jun 2023. He has an MBA (Finance) from the Tulane University, USA; and a B.Sc in Mechanical Engineering from Louisiana Tech University, USA. He joined Hibiscus Petroleum in Mar 2023, and has over 33 years' experience in the oil and gas industry involving upstream business analysis, LNG and gas marketing, business development and acquisition/divestment of oil and gas properties. His early career was spent in project engineering and maintenance engineering assignments in oil refineries. He previously worked with RasGas in Qatar, Chevron, Mobil and ExxonMobil.
Syarifah Aliza Syed Azauddin	Vice President, Corporate Governance and Sustainability Reporting	Ms Syarifah, aged 49, has been in her current role since 1 Aug 2024. She has an MBA from International Islamic University, Malaysia; and a B. A (Honours) in Accountancy and Finance from Lancaster University, UK. She joined Hibiscus Petroleum in Sep 2011 as Senior General Manager, Corporate Finance, Secretarial and Regulatory Compliance, but is now Vice President, Corporate Governance and Sustainability Reporting. She has over 27 years of experience in various areas of corporate finance, corporate governance, corporate sustainability, corporate strategy including Environmental, Social and Governance (ESG), private equity, asset management, audit, risk, investor relations and general management encompassing production of Annual Report. She previously worked at KFH Asset Management Sdn Bhd, a subsidiary of Kuwait Finance House (Malaysia) Berhad, at Artisan Encipta (M) Sdn Bhd (the venture capital arm of MIMOS Berhad), and at Renong Berhad.
Noor Ashiah Yang	Vice President, Group Human Capital	Ms Noor Ashiah, aged 56, has been in her current position since 1 Feb 2023. She has a B.A in Economics (Hons) from the Laurentienne University, Sudbury, Canada. She joined Hibiscus in Feb 2023, and has over 26 years' experience in various areas of human capital. She previously worked at Velesto Energy Berhad as Vice President of Human Resources, as well as at Bumi Armada, Sapura Crest, Petra Energy, Dialog, Eden Group and Renong Group.
Clifford Lang	Project Director/General Manager, Hibiscus Energy UK Limited	Mr Lang, aged 63, has been in his current role since 1 Dec 2023. He has a B.Sc (Honours) Offshore Mechanical Engineering from the Heriot-Watt University, Scotland. He joined Hibiscus in Nov 2018 as a consultant for the Marigold project before becoming staff in Jan 2023. He has over 38 years' experience in the oil and gas industry, in asset management and senior drilling and completions roles, having worked globally with extensive drilling and completions experience in the North Sea, deepwater offshore West of Shetland, Faroes Islands, Australia and Brasil, offshore in SE Asia (Indonesia/Malaysia) and India, HTHP wells offshore in UK and India together with land drilling experience in Thailand/ India/North Africa and Kurdistan regions. He was also the Project/Asset Manager for onshore PSC blocks in Indonesia. He previously worked for Marathon Oil, Hess (Project Manager, Director of Europe/Eurasia/North Africa and Kurdistan) & Cairn India (Head of Drilling).
Dr Ambrose Gerard Corray	Vice President, InfoTech and Digitalisation	Dr Corray, aged 67, was appointed to his current designation on 1 Aug 2023. He has a Doctorate in Business Administration from the Southern Cross University, Australia; an MBA from the Southern Cross University, Australia; and a B.Sc (Honours) in Mechanical Engineering, King's College London, UK. He managed the Corporate Services function (Human Capital & InfoTech) and is now focused on InfoTech & Digitalisation strategy deployment in Hibiscus Group. He was instrumental in Hibiscus Petroleum's successful North Sabah asset acquisition in 2018 and the Repsol assets acquisition in 2021, as well as the Brunei asset acquisition and integration in 2024. He has 41 years of oil and gas industry global experience, having previously worked with Schlumberger, GE Oil & Gas; oil companies as Vice President, E&P/COO at Interlink Petroleum (BSE listed) & CEO of Loyz Energy (Catalist listed); Director, Loyz Australia. He had also previously worked for SLB (Schlumberger).
Lai Wai Peng	Vice President, Business Transformation	Ms Lai, aged 47, was appointed to her current role on 6 Mar 2023. She has a B.Sc in Chemical Engineering from the National University Malaysia. She joined Hibiscus in Mar 2023, and has over 23 years' experience in the oil and gas industry working in diverse roles across commercial, mergers and acquisitions, corporate finance, economics, strategy and planning, business development and as the Head of Business Unit in Malaysia, UK and Australia. She had previously worked at Accenture, Shell UK, Woodside Energy and Ping Petroleum.
Lily Ling	Vice President, Corporate Development	Ms Ling, aged 41, was appointed to her current role on 1 May 2023. She has a B.A (Honours) in Accounting from the University of Hertfordshire, UK. She joined Hibiscus Petroleum in Jan 2020, and has 21 years of diversified experience in investment banking, corporate finance, investor relations, corporate strategy, media relations, corporate communications, advisory and investment consulting, corporate social responsibility, finance and audit. She had previously worked at Sapura Energy Berhad, CIMB Investment Bank, and Ernst & Young.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

APPENDIX 2: SHAREHOLDERS AND MOVEMENTS IN ORDINARY SHARES

Major shareholders ►

As at 30 Sep 2024, Managing Director Dr Kenneth Pereira held a 10.1% stake in Hibiscus, held directly as well as via his investment vehicles, Hibiscus Upstream Sdn Bhd and Hibiscus Energy Sdn Bhd.

The single largest shareholder is Datuk Michael Tang Vee Mun at 12% stake, held directly as well as via his investment vehicles, Polo Investments Limited and Mettiz Capital Limited (both unlisted). Datuk Tang is a private equity investor and neither holds a management role in Hibiscus, nor does he sit on the board of directors. Datuk Tang first became Hibiscus's strategic shareholder in Dec 2015.

Another significant shareholder is Dato' Sri Roushan, who holds a 2% stake in Hibiscus. Dato' Sri Roushan is a non-independent, non-executive director in Hibiscus. He is reclassified as a non-independent director on 25 Jul 2023 because his previous tenure as an independent director had reached its permitted limit of 12 years according to Bursa Malaysia listing rules.

Hibiscus's public free float is c.75%. Some notable public investors in Hibiscus include local pension funds Kumpulan Wang Persaraan (KWP) and Employees Provident Fund Board (EPF); insurance funds such as AIA Bhd, Eastspring Investments Berhad, Great Eastern Life Assurance (Malaysia) Berhad, and Tokio Marine Life Insurance Malaysia Bhd; and unit trust funds such as icapital.biz Berhad and Public Mutual Berhad. [None of these investors are listed entities.]

Figure 108: Percentage shareholding in Hibiscus

	30-Sep-16	29-Sep-17	28-Sep-18	30-Sep-19	30-Sep-20	30-Sep-21	30-Sep-22	29-Sep-23	30-Sep-24
Dr Kenneth Gerard Pereira	12.0%	11.2%	10.6%	10.6%	10.6%	8.9%	8.9%	9.1%	10.1%
Datuk Michael Tang Vee Mun	9.9%	9.2%	8.7%	8.7%	8.9%	9.1%	10.7%	11.1%	12.0%
Dato' Sri Roushan A/L Arumugam				3.4%	3.4%	2.7%	1.9%	1.9%	2.0%

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Share placements since FY16 ►

FY16

On 23 Sep 2015, Bursa Malaysia gave its approval for the listing and quotation of new ordinary shares representing 25% of the enlarged issued and paid-up ordinary share capital of Hibiscus.

Subsequently, Hibiscus issued 331m new ordinary shares during FY16 in multiple tranches, raising a total of **RM95.4m**. Note that the number of ordinary shares stated here is the original number, not retrospectively adjusted for the 2-for-5 share consolidation exercise that was completed on 20 Oct 2023, whereby every five shares was exchanged for two shares.

The proceeds were partly used for the exploration drilling campaign in Australia (the Sea Lion #1 well) that ultimately was assessed to be uncommercial. Hibiscus undertook the above share placements, despite the low prevailing share price in 2015-2016, as access to bank funding was closed to Hibiscus at that time.

Hibiscus also issued 53.8m new shares for no consideration (worth RM11m) on 25 May 2016 and 23 Jun 2016 to Ping Petroleum in order to pay for the introducer fee agreed between the parties payable upon successful completion of the acquisition of a 50% interest in the Anasuria Cluster.

FY17

Hibiscus issued 131.2m new ordinary shares during FY17, raising a total of RM28.8m in three tranches, partly used to fund the Anasuria Cluster acquisition from Shell and Esso.

FY18

Hibiscus issued 144.4m new ordinary shares during FY18, raising a total of RM91.1m in three tranches, with the proceeds partly used to fund the North Sabah PSC acquisition from Shell.

Free Warrants C ➤

On 20 Mar 2018, Hibiscus issued 317,645,723 free Warrants C on the basis of one new warrant for every five existing ordinary shares, in order to raise funds for future acquisitions.

The Warrants C were exercisable anytime during the period commencing from 20 March 2018 to 18 March 2021 at the following exercise prices:

- Year 1: 20 Mar 2018 - 19 Mar 2019: RM1.00
- Year 2: 20 Mar 2019 - 19 Mar 2020: RM1.06
- Year 3: 20 Mar 2020 - 19 Mar 2021: RM1.12

The warrants expired on 19 Mar 2021, with only 4,060 warrants converted into new ordinary shares and RM4,535 raised.

Convertible Redeemable Preference Shares (CRPS) ➤

On 9 Sep 2020, Hibiscus proposed issue up to 2bn new CRPS units by way of private placement at RM1 each to raise up to RM2bn. The purpose was to raise funds to facilitate acquisitions and/or investments in producing assets.

- 6,600 units (CRPS-T1) was issued on 18 Nov 2020 to Dr Kenneth Gerard Pereira, Managing Director of Hibiscus; and
- 203,604,500 units (CRPS-T2) was issued on 19 Nov 2020 to various investors.

In total, Hibiscus raised **RM203.6m** at an issue price of RM1 per CRPS, of which **RM196.1m** was utilised as part payment for the acquisition by Peninsula Hibiscus of FIPC from Repsol (see Section X); this acquisition was completed on 24 Jan 2022.

Hibiscus had the option to redeem in whole or part of the outstanding CRPS, but did not do so, as the entire CRPS issue was converted into new ordinary shares.

The conversion prices for CRPS-T1 and CRPS-T2 were fixed at RM0.66 and RM0.48 respectively.

During FY21 (between 18 Nov 2020 and 30 Jun 2021), 197,715,931 CRPS were converted into 411,904,400 new ordinary shares, comprising:

- 6,600 units of CRPS-T1 which were converted into 10,000 new ordinary shares at RM0.66 each; and
- 197,709,331 units of CRPS-T2 which were converted into 411,894,400 new ordinary shares at RM0.48 each.

During FY22 (between 1 Jul 2021 and 25 Mar 2022), the remaining 5,895,169 CRPS were converted into 12,281,592 new ordinary shares at RM0.48 each.

In total, **417.8m new ordinary shares** were issued upon conversion from the CRPS issue between 18 Nov 2020 and 25 Mar 2022.

Hibiscus had twice applied successfully to Bursa to extend the deadline to complete the private placement of the CRPS for six months from 22 Mar 2021 until 21 Sep 2021, and again by another six months to 21 Mar 2022. However, Bursa rejected Hibiscus's third application to extend the deadline to 21 Sep 2022, and the CRPS issuance programme has since lapsed.

Capital reduction ➤

On 4 Oct 2022, Hibiscus announced its intention to seek shareholder approval to execute a capital reduction exercise and to obtain the authority to purchase up to 10% of its outstanding shares; these were approved via EGM on 1 Dec 2022.

On 3 March 2023, Hibiscus completed its capital reduction exercise, wherein its issued ordinary share capital was reduced from RM966m to RM166m, via a transfer of RM800m from share capital to retained earnings. The number of issued ordinary shares remained the same at 2,012.4m shares.

The capital reduction was intended to eliminate the accumulated losses that was at that time on the balance sheet of the listed holding company, Hibiscus Petroleum Bhd, in order to facilitate the proposed share buybacks. This was because the Bursa Malaysia listing rules specify that share buybacks can only be made from the retained earnings of the listed entity. Although the overall Hibiscus group had accumulated profits on its consolidated financial statements, this was only because the accumulated profits of the subsidiaries of the group were more than sufficient to offset the accumulated losses on the balance sheet of the listed holding company.

Share consolidation ➤

On 20 Oct 2023, Hibiscus completed its 2-for-5 share consolidation exercise, whereby every five shares were exchanged for two share, without any change in the share capital of the company. Ultimately, 2,012.4m shares were consolidated into 805m shares.

The company's stated intention was to reduce the share price volatility, which would purportedly "create more stable trading environment for the shares" and "increase market interest to a wider pool of investors seeking share price stability and longer-term growth."

Share buybacks ➤

On 1 Dec 2022, Hibiscus's shareholders approved a mandate for the company to buy back up to 10% of its outstanding shares; this mandate was renewed on 5 Dec 2023 and renewed again at its AGM on 27 Nov 2024.

Up to 27 Nov 2024, Hibiscus had repurchased 36.8m ordinary shares (4.6% of its previous outstanding base of 805m shares) at a total cost of RM79m. On 27 Nov 2024, Hibiscus cancelled 36.6m treasury shares, which reduced its outstanding share base from 805m shares to 768.4m, or a reduction of 4.5% (Figure 109).

This leaves 0.19m treasury shares purchased on 27 Nov 2024 that have not yet been cancelled.

Figure 109: Movement in ordinary share base since 30 Jun 2020

	No of ordinary shares	Share capital	No of treasury shares	Value of treasury shares	Net ex- treasury shares	Net share capital
	m	RM m	m	RM m	m	RM m
As at 30 Jun 2020	1,588.2	765.0				
Conversion of Convertible Redeemable Preference Shares (CRPS)	411.9	194.9				
Exercise of warrants C	0.0	0.0				
As at 30 Jun 2021	2,000.1	959.9				
Conversion of CRPS	12.3	6.1				
As at 30 Jun 2022	2,012.4	966.0				
Transfer to retained earnings (capital reduction)		-800.0				
As at 30 Jun 2023	2,012.4	166.0	0.0	0.0		
Share consolidation (2-for-5)	-1,207.5					
Purchase of treasury shares			6.4	16.1		
As at 30 Jun 2024	805.0	166.0	6.4	16.2	798.6	149.8
Purchase of treasury shares			30.4	62.9		
Cancellation of treasury shares	-36.6	-78.7	-36.6	-78.7		
As at 27 Nov 2024	768.4	87.3	0.2	0.4	768.2	86.9

SOURCES: CGSI RESEARCH, COMPANY REPORTS

APPENDIX 3: HIBISCUS'S FIELD ASSETS

North Sabah, Kinabalu, Brunei MLJ ➤

Figure 110: Hibiscus's oil and gas field PSC assets: North Sabah, Kinabalu, Brunei MLJ

Jurisdiction	Malaysia	Malaysia	Brunei
Licence name	North Sabah PSC	Kinabalu PSC	Block B MLJ PSC
	2011 North Sabah Enhanced Oil Recovery (EOR) PSC	2012 Kinabalu Oil PSC	
Fields	Producing: St Joseph, South Furious, South Furious 30 (SF30), Barton	Producing: Kinabalu Main, Kinabalu East, Kinabalu Far East	Producing: Block B Maharajalela Jamalulalam ("MLJ") field
Licence start		26-Dec-2012	
Licence end	31-Dec-2040	25-Dec-2032	23 Nov 2029, with option to extend until 23 Nov 2039
Acquisition / award date	31-Mar-2018	24-Jan-2022	14-Oct-2024
Location	Offshore Sabah	Offshore Sabah (71 sq km)	Offshore Brunei
Water depth	18-60 m (59-197 ft)	56 m (184 ft)	< 100 m (< 328 ft)
Operatorship	Operated	Operated	Operated
Direct interest of Hibiscus	50%, via SEA Hibiscus Sdn Bhd #	60%, via Hibiscus Oil & Gas Malaysia Limited #, part of the Peninsula Hibiscus Sdn Bhd #	37.5%, via TotalEnergies EP (Brunei) B.V. #, wholly owned by Simpor Hibiscus Sdn Bhd #
Other interests	Petronas Carigali: 50%	Petronas Carigali: 40%	Shell: 35%; Brunei Energy: 27.5%
Asset type	Production	Production	Production (commenced 1999)
Facilities and infrastructure	21 platforms / structures, 146 wells, 1 Labuan Crude Oil Terminal (LCOT)	2 platforms, 36 wells	3 unmanned platforms (MLJ1, MLJ2, MLJ3); 22 exploration, appraisal and development wells drilled, 15 active wells
Development type	Fixed platforms with dry trees, inter-field pipelines and a trunk line to Labuan Crude Oil Terminal (LCOT)	Fixed platforms with oil pipeline and gas pipeline to Petronas Carigali-operated Semarang Platform; from there oil is piped to Labuan Crude Oil Terminal (LCOT) and gas is piped to Labuan Gas Terminal (LGAST)	Fixed platforms with gas and condensate pipelines to Brunei Onshore Processing Plant (OPP); gas sold to Brunei LNG Sdn Bhd (BLNG); condensate sent to Seria Crude Oil Terminal (SCOT) operated by Brunei Shell Petroleum
History		First oil: 1997	
Net oil reserves and resources (MMbbl)	2P reserves: 18.4; 2C resources: 8.9 *	2P reserves: 6.4 *	2P reserves: 3.4 **; 2C resources: 1.1 ***
Net gas reserves and resources (Bscf)	-	-	2P reserves: 109.8 **; 2C resources: 34.6 ***
* As at 1 Jul 2024			
** As at 1 Jan 2024 (2P condensate: 3.4 MMboe; 2P gas: 18.3 MMboe)			
*** As at 1 Jan 2023 (2C: 6.8 MMboe combined for both condensate and gas)			
# Wholly-owned subsidiaries of Hibiscus Petroleum Berhad			

SOURCES: CGSI RESEARCH, COMPANY REPORTS

PM3 CAA hub assets ➤

Figure 111: Hibiscus's oil and gas PSC assets: PM3 CAA hub

Jurisdiction	Malaysia-Vietnam Commercial Arrangement Area (CAA)	Vietnam	Malaysia	Malaysia
Licence name	PM3 CAA Area PSC	Block 46 Cai Nuoc PSC	PKNB Cluster PSC	PM327 PSC
	PM3 CAA Area PSC		Pertang, Kenarong, Noring and Bedong Discovered Resource Opportunity (DRO) PSC	
Fields	Producing: Bunga Orkid, Bunga Pakma, Bunga Raya, Bunga Seroja, Bunga Kekwa, Bunga Tulip Bunga Lavatera Bunga Aster Exploration: Greater Central Area, Greater Silver Area	Producing: Cai Nuoc (tie back to PM3 CAA PSC) Discovered: Hoa Mai	Discovered: Pertang, Kenarong, Noring, Bedong	Currently still in exploration stage
Licence start	16-Feb-1989	8-Aug-1990	1-Jul-2024	1-Feb-2023
Licence end	31-Dec-2027	31-Dec-2027	30-Jun-2048	31-Jan-2051
Acquisition / award date	24-Jan-2022	24-Jan-2022	26-Jul-2024	5-Jul-2024
Location	Offshore Malaysia and Vietnam (1,995 sq km)	Offshore Vietnam (82 sq km)	Offshore Pen. Malaysia's east coast	Offshore Pen. Malaysia's east coast (12,500 sq km)
Water depth	56 m (184 ft)	56 m (184 ft)	65-75 m (213-246 ft)	20-75m (66-246 ft)
Operatorship	Operated	Operated	Operated	Non-operated
Direct interest of Hibiscus	35%, via Hibiscus Oil & Gas Malaysia (PM3) Limited #, part of the Peninsula Hibiscus Sdn Bhd # group	70%, via Talisman Vietnam Limited #, part of the Peninsula Hibiscus Sdn Bhd # group	65%, via Hibiscus Oil & Gas Malaysia Limited #, part of the Peninsula Hibiscus Sdn Bhd # group	30%, via Straits Hibiscus Sdn Bhd #
Other interests	Petronas Carigali: 35% PetroVietnam: 30%	PetroVietnam: 30%	Petronas Carigali: 35%	Petronas Carigali: 60%; E&P Malaysia Venture: 10%
Asset type	Production	Production	Development	Exploration
Facilities and infrastructure	14 platforms / structures, 143 wells, 2 Floating Storage Offload (FSO) units	9 wells	To be developed via 3 platforms and 16 wells	To be confirmed
Development type	Fixed platforms with gas pipelines to Peninsular Malaysia and Vietnam, oil export via FSO Orkid and FSO PM3 CAA	Tie-back to PM3 CAA facilities	Gas produced at the PKNB Cluster to be tied-back to the PM3 CAA facilities for gas processing, before export via gas pipelines to Peninsula Malaysia and Vietnam	To be developed via tie-back to PM3 CAA facilities for gas processing First 4 years for exploration, next 4 years for development, final 20 years for production
History	First oil: Jul 1997 First gas: Oct 2003	First oil: 2003	Discovered by Murphy Oil in 2005; Petronas directly award Hibiscus the PKNB Cluster PSC in 2024 without open tender	PM327 PSC was awarded to Petronas Carigali and EPMV in 2023 in the Malaysia Bid Round 2022.
Notes	The East Bunga Kekwa field (in PM3 CAA) and the Cai Nuoc field (in Block 46) were unitised on 10 Feb 2020, with Hibiscus participation at 43.42%, Petronas Carigali at 26.58% and PetroVietnam at 30%.		Targeted to commence first gas production in 2028.	Exploration activities began in 2023, including acquisition of new 3D seismic, reprocessing of existing seismic data, and phased drilling of exploration wells.
Net oil reserves and resources (MMbbl)	2P reserves: 3.1 *	2P reserves: 0.2 *	-	-
Net gas reserves and resources (Bscf)	2P reserves: 49.2 *	-	2C reserves: 282	-
* As at 1 Jul 2024				
# Wholly-owned subsidiaries of Hibiscus Petroleum Berhad				

SOURCES: CGSI RESEARCH, COMPANY REPORTS

No longer producing: PM305 and PM314 ➤

Figure 112: Oilfields that are no longer producing: PM305 and PM314

Jurisdiction	Malaysia	
Licence name	PM305 PSC	PM314 PSC
Fields	The last producing Murai field terminated production when participation in the PM305 PSC ended on 17 Mar 2024	Participation in the PM314 PSC ended on 5 Sep 2020, with all abandonment obligations required to be carried out per the PSC terms completed
Licence start	27-Nov-2000	31-Mar-2004
Licence end	26-Nov-2029	30-Mar-2033
Acquisition / award date	24-Jan-2022	24-Jan-2022
Location	Offshore Peninsular Malaysia's east coast	
Water depth	73 m (239 ft)	73 m (239 ft)
Operatorship	Operated	
Direct interest of Hibiscus	60%, via Hibiscus Oil & Gas Malaysia Limited #, part of the Peninsula Hibiscus Sdn Bhd # group	60%, via Hibiscus Oil & Gas Malaysia Limited #, part of the Peninsula Hibiscus Sdn Bhd # group
Other interests	Petronas Carigali: 40%	Petronas Carigali: 40%
Asset type	Decommissioning	
Facilities and infrastructure	South Angsi A (SAA) platform, Angsi Southern Channel Unit (ASCU) platform, 10 wells (SAA), 6 wells (ACSU)	SAA platform, 3 wells (SAA)
Development type	Previously producing via Petronas Carigali-operated facilities and infrastructure at the nearby Angsi GPSC block, oil is exported to the Terengganu Crude Oil Terminal (TCOT)	Previously producing via South Angsi A platform
History	First oil: Mar 2004	
Notes	The PM305 and PM314 tracts were unitised effective 14 Aug 2005. The Murai field (PM305) was unitised with the proximate Angsi Southern Channel Unit (ASCU) field (on the GPSC block, operated by Petronas Carigali) effective 18 Mar 2004, with Hibiscus participation at 17.2% of the unitised fields.	
Net oil reserves and resources (MMbbl)	-	-
Net gas reserves and resources (Bscf)	-	-
# Wholly-owned subsidiaries of Hibiscus Petroleum Berhad		

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Anasuria Cluster ➤

Figure 113: Hibiscus's oil and gas concession assets: Anasuria Cluster

Jurisdiction	United Kingdom	United Kingdom	United Kingdom	United Kingdom	United Kingdom
Fiscal system	Concession	Concession	Concession	Concession	Concession
Licence name	Licence No P013 - Teal, Teal South and Guillemot A (Block 21/25a and Block 21/30a)	Licence No P185 - Cook (Block 21/20a)	Licence No P2535 - Teal West (Block 21/24d)	Licence No P2451 - Fyne (Block 21/28b)	Licence No P2532 - Cook West, Cook North, etc. (Block 21/19c and Block 21/20c)
Fields	Producing: Teal, Teal South, Guillemot A Discovered: Kite	Producing: Cook	Discovered: Teal West	Discovered: Fyne	Prospects: Cook West, Cook North, as potential extensions of the existing Cook field
Licence end	Life of field (no expiry)	Life of field (no expiry)	Life of field (no expiry) @	Life of field (no expiry)	Life of field (no expiry)
Acquisition / award date	10-Mar-2016	10-Mar-2016	1-Dec-2020	20-Nov-2023	1-Dec-2020
Location	Offshore UK Continental Shelf, UK Central North Sea, 175 km east of Aberdeen				
Water depth	94 m				
Operatorship	Jointly-operated	Non-operated	Operated	Operated	Non-operated
Direct interest of Hibiscus	50%, via Anasuria Operating Company Limited (AOCL); AOCL is jointly owned by Anasuria Hibiscus UK Limited # and Ping Petroleum UK PLC	19.325%, via Anasuria Hibiscus UK Limited #	100%, via Anasuria Hibiscus UK Limited # Hibiscus Energy UK Limited # is the operator	42.5%, via Anasuria Hibiscus UK Limited # AOCL will take over as operator upon first oil	19.325%, via Anasuria Hibiscus UK Limited #
Other interests	Ping Petroleum UK PLC: 50%	Ithaca Energy (UK) Limited (operator): 61.35%; Ping Petroleum: 19.325%	-	Ping Petroleum UK PLC: 42.5%; Rapid Oil: 15%	Ithaca Energy (UK) Limited (operator): 61.35%; Ping Petroleum: 19.325%
Asset type	Production	Production	Development	Development	Exploration
Facilities and infrastructure	13 subsea wells,		2 subsea wells (future)		-
Development type	Subsea tie-back to Anasuria FPSO	Subsea tie-back to Anasuria FPSO	-	Subsea tie-back to Anasuria FPSO	-
Notes			First oil planned for end-2025	First oil planned for 2027	
Net oil reserves and resources (MMbbl)	2P reserves: 15.9 *		2P reserves: 4.3 *	2C resources: 4 *	Subsurface studies yet to commence
Net gas reserves and resources (Bscf)	2P reserves: 5.4 *		-	-	Subsurface studies yet to commence

* As at 1 Jul 2024

Wholly-owned subsidiaries of Hibiscus Petroleum Berhad

@ The UK's North Sea Transition Authority (NSTA) on 12 Mar 2018 extended the licence for the Cook field into a 'life of field' licence. The licence is terminable only if there is a continuous minimum 12-month period in which the production has fallen below a minimum production level.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Greater Marigold Area Development (GMAD) ➤

Figure 114: Hibiscus's oil and gas concession assets: GMAD

Jurisdiction	United Kingdom	United Kingdom	United Kingdom	United Kingdom	United Kingdom
Fiscal system	Concession	Concession	Concession	Concession	Concession
Licence name	Licence No P198 - Marigold West (Block 15/13a) Unitised with Licence No P2158 - Marigold East (Block 15/18b)	Licence No P198 - Sunflower (Block 15/13b)	Licence No P2518 - Kildrummy southern part (Block 15/17a) and Kildrummy northern part (Block 15/12a)	Licence No P2608 - Crown (Block 15/18a and Block 15/19a)	Licence No P2635 - Cross (Block 15/18c) and Northwest of Marigold field (Block 15/13c)
Fields	Discovered: Marigold West, Marigold East	Discovered: Sunflower	Discovered: Kildrummy	Discovered: Crown	Prospect: Cross
Licence end	Life of field (no expiry)	Life of field (no expiry)	Life of field (no expiry)	Life of field (no expiry)	Life of field (no expiry)
Acquisition / award date	16-Oct-18	16-Oct-18	15-Jan-2021 (Block 15/17a) 30-Jan-2024 (Block 15/12a)	23-Feb-24	4-Jun-24
Location	Offshore UK Continental Shelf, UK Central North Sea, 250 km east of Aberdeen				
Water depth	140 m				
Operatorship	Operated	Operated	Operated	Operated	Operated
Direct interest of Hibiscus	61.25%, via Anasuria Hibiscus UK Limited # ****	87.5%, via Anasuria Hibiscus UK Limited #	100%, via Anasuria Hibiscus UK Limited #	100%, via Anasuria Hibiscus UK Limited #	100%, via Anasuria Hibiscus UK Limited #
Other interests	Ithaca Oil and Gas: 30%; Caldera Petroleum UK Ltd: 8.75%	Caldera Petroleum UK Ltd: 12.5%	-	-	-
Asset type	Development	Development	Development	Development	Exploration
Facilities and infrastructure	7 subsea wells at Marigold West; undisclosed number of subsea wells at Marigold East (future)	1 subsea well (future)	1 subsea well (future)		
Development type	Tieback to the Piper B platform, which is operated by Repsol Sinopec Resources UK Limited	Tieback to the Piper B platform	Tieback to the Piper B platform	Tieback to the Piper B platform	Tieback to the Piper B platform
History			Kildrummy northern part (Block 15/12a) was awarded in the first batch of the 33rd UK Offshore Licencing Round on 30 Oct 2023	Awarded in the first batch of the 33rd UK Offshore Licencing Round, announced on 30 Oct 2023	Awarded in the second batch of the 33rd UK Offshore Licencing Round, announced on 31 Jan 2024
Notes	First oil planned for 2028	First oil planned for 2028	No immediate plans to develop this asset	No immediate plans to develop this asset	No immediate plans to develop this asset
Net oil reserves and resources (MMbbl)	Marigold West 2C resources: 33 *	2C resources: 5.1 *	2C resources: 3.9 *	2C resources: 4.4 *	Subsurface studies yet to commence
Net gas reserves and resources (Bscf)	-	-	-	-	Subsurface studies yet to commence

* As at 1 Jul 2024

**** A Unitisation and Unit Operating Agreement (UUOA) was executed between Anasuria Hibiscus, Caldera Petroleum and Ithaca Energy. Under the UUOA, Anasuria Hibiscus's interest in the unitized Marigold unit is 61.25%. Hibiscus's interest in the individual Marigold West Field remains at 87.5%.

Wholly-owned subsidiaries of Hibiscus Petroleum Berhad

SOURCES: CGSI RESEARCH, COMPANY REPORTS

APPENDIX 4: CAPITAL ALLOCATION FRAMEWORK

How Hibiscus thinks about using its cash ►

Hibiscus disclosed its capital allocation framework during its Analyst Day event on 12 Sep 2024.

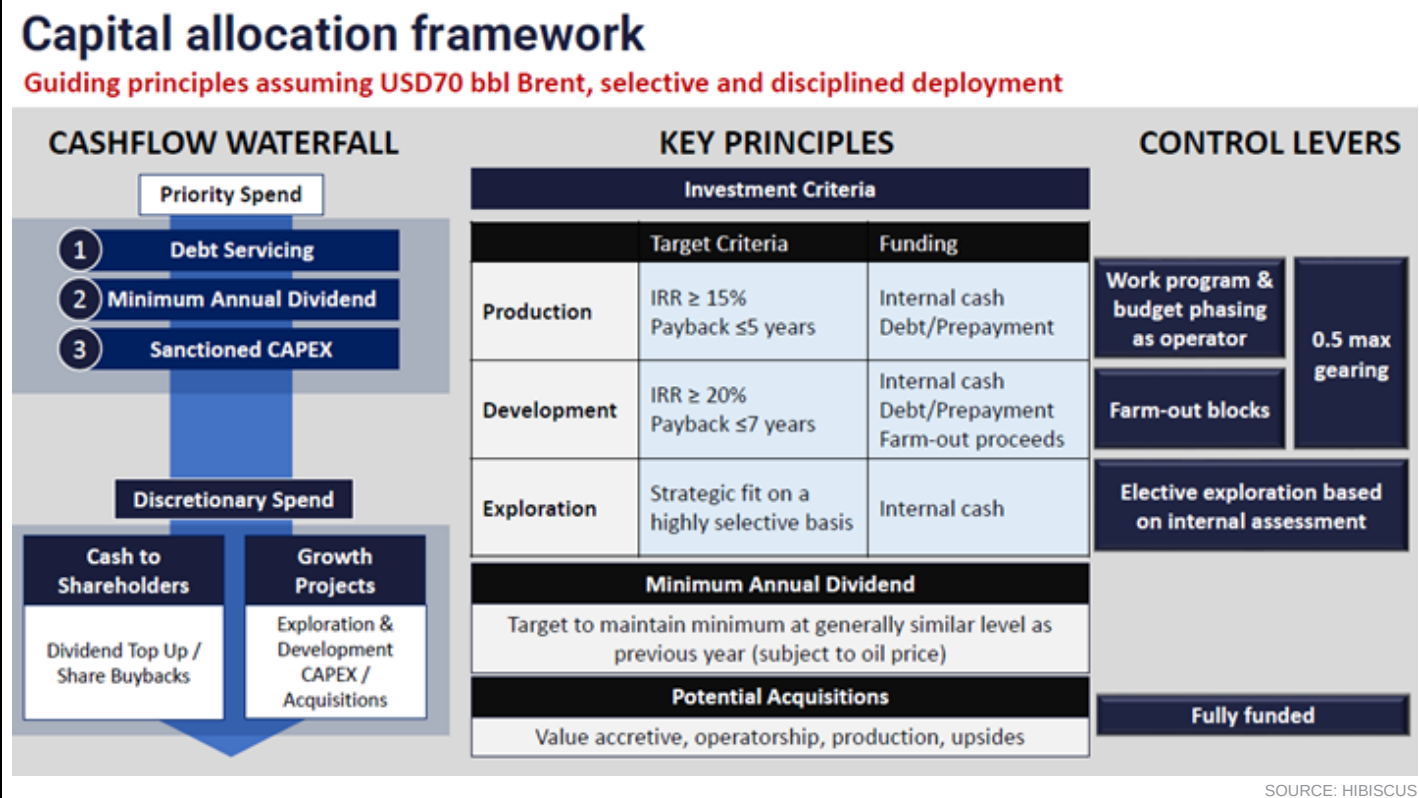
The key principles behind mature asset acquisitions or investments in production enhancement projects is that it must achieve an IRR of 15% or more over the life of the project, and have a payback of five years or less. These principles would apply to the recent Brunei MLJ acquisition, although we think that whether Hibiscus ultimately achieves this for MLJ is dependent on whether the current oil and gas price environment can sustain until the end of the concession, which can be stretched up to 2039F.

Development projects should have an IRR of 20% or more over the lift of the project, with a payback of seven years or less. These criteria would apply to the potential PKNB Cluster discovered resource opportunity development.

Hibiscus will undertake exploration projects on a strategic fit basis. The PM327 exploration block is such a project that Hibiscus has decided to undertake, because it is proximate to the existing PM3 CAA PSC and can potentially be developed via tie-back to existing production infrastructure at PM3 CAA.

In terms of the cashflow waterfall, investors will be delighted to note that Hibiscus is committed to a “minimum annual dividend” and that these dividends rank higher than “sanctioned capex”. Where possible, minimum annual dividends will be based on a targeted trajectory of rising absolute annual DPS, although this is ultimately subject to oil prices. Hibiscus is also willing, on a discretionary basis, to buy back its shares (as it had been doing since 26 Jul 2024) and to possibly top up dividends.

Figure 115: Hibiscus’s Capital Allocation Framework



APPENDIX 5: PRODUCTION SHARING CONTRACT

How Malaysian PSCs work in brief ►

Production sharing contracts (PSC) are one of the three main types of petroleum or gas fiscal regimes globally. PSCs are widely implemented in Malaysia, and the key features are as follows.

The PSCs set out the **term or duration** for which the PSC participants have the right to extract oil and gas resources from a specific production area or block. Each PSC has an exploration period, and/or a development period, to be followed by a production period. The PSC participants must fulfil certain minimum work and financial commitments in order to explore and develop the PSC area; these may include the commitment to drill a certain number of exploration wells.

The PSC participants have **defined equity stakes** in the block, also called working interests or participating interests. They share capex and opex based on their respective working interest.

One of the PSC participants will be nominated as the **operator** of the PSC, and a Joint Operating Agreement (JOA) is usually signed between the participants which enables the costs incurred by the PSC operator to be shared with the other PSC participants.

The PSC terms and conditions form the basis for calculating **how the production volume from oil and gas fields is to be shared** between Petronas and the PSC participants. These barrels of oil equivalent (boe) are shared in a way as to enable the PSC participants to recover their invested capex and their recurring opex over the duration of the PSC term. The share of production volume also includes an element of profit to the PSC participants. Unrecovered capex and opex in any particular quarter can be carried forward to future quarters to be recovered, as long as the PSC is still in force.

All **exploration and development capex** is cost recoverable under the PSC, if the exploration oil and gas block proceeds to production. Exploration wells drilled at existing producing blocks are also cost recoverable, even if those specific exploration wells do not turn out to be economic to develop; the exploration capex is simply recovered from the output of the existing producing wells. However, exploration capex for exploration blocks that do not ultimately proceed to production (due to uneconomic discoveries or dry holes) are not cost recoverable, and the PSC participants will bear those exploration costs at their own expense.

The PSCs also set out other financial obligations of the PSC participants, such as the requirement to pay **royalty** from production amounting to 10% of the value of the production (which is shared equally between the federal government and the respective state government on which the production asset is located); **research payment** obligations; **supplementary payment** obligations; **export duty** payments; and **abandonment cess** payments.

Separately, **petroleum income tax** is payable in Malaysia at a rate of **38%**, as set out in the Petroleum (Income Tax) Act 1967 (also known by its acronym PITA).

The majority of PSCs in Malaysia have **Petronas Carigali** as one of the PSC contractors, though not always as the operator of the PSC. Petronas Carigali is a wholly-owned subsidiary of Petronas, and their roles are different. Petronas's role is defined in the Petroleum Development Act of 1974, which states that all of the oil and gas resources in Malaysia belong to Petronas, who is also the regulator for the upstream industry through its Malaysia Petroleum Management (MPM) unit. Petronas Carigali, on the other hand, takes the role of a PSC participant, standing at the same level as other PSC participants.

Under the terms of the PSC, all the **assets** procured by the PSC participants for the purpose of extracting the hydrocarbon resources **belong to Petronas**, and must be handed back to Petronas at the end of the PSC term. However, the PSC participants have the right to use those assets within the duration of the PSC term.

The cost of the **abandonment of the production facilities** at a PSC block is to be covered by the regular payment of an abandonment cess by the PSC

participants to Petronas. In some cases, the abandonment cess payments also cover the decommissioning of the individual wells.

However, if the abandonment cess payments exclude coverage for wells decommissioning, then the PSC contractors are responsible for the cost of plugging and abandoning the wells when the wells are no longer economic to produce from, during the PSC term itself. Well abandonment costs that are scheduled to occur after the end of the PSC term are to be picked up by the future PSC participants.

At the end of field life, the facilities are handed back to Petronas and Petronas can decide if it will continue producing on its own accord (via Petronas Carigali), or request the existing PSC participants to continue producing (via an extension to the PSC tenure, upon which, the PSC terms and conditions may be renegotiated to improve the terms for the PSC participants).

If Petronas decides not to continue with production, Petronas will use the abandonment cess paid to-date by the PSC participants and decommission the facilities. If the facilities decommissioning is performed by Petronas after the end of the PSC tenure and if there is a cost overrun, Petronas is responsible for the excess abandonment cost. On the other hand, if the abandonment cost is less than the cumulative cess paid by the PSC participants, then Petronas is entitled to keep the difference.

However, if the PSC participants abandon the field prior to the end of the PSC tenure (perhaps due to faster-than-expected production decline), then the PSC participants are responsible for the performance of the abandonment works, and the PSC participants will be responsible for any cost differential between what has been paid as abandonment cess up to that point in time and the actual abandonment costs.

Please refer to Appendix 5 for details of Hibiscus's PSCs.

How production barrels are split up under the PSC ▶

In an illustrative Scenario 1 (not intended to reflect the reality of any particular PSCs that Hibiscus is a participant in), we assume that:

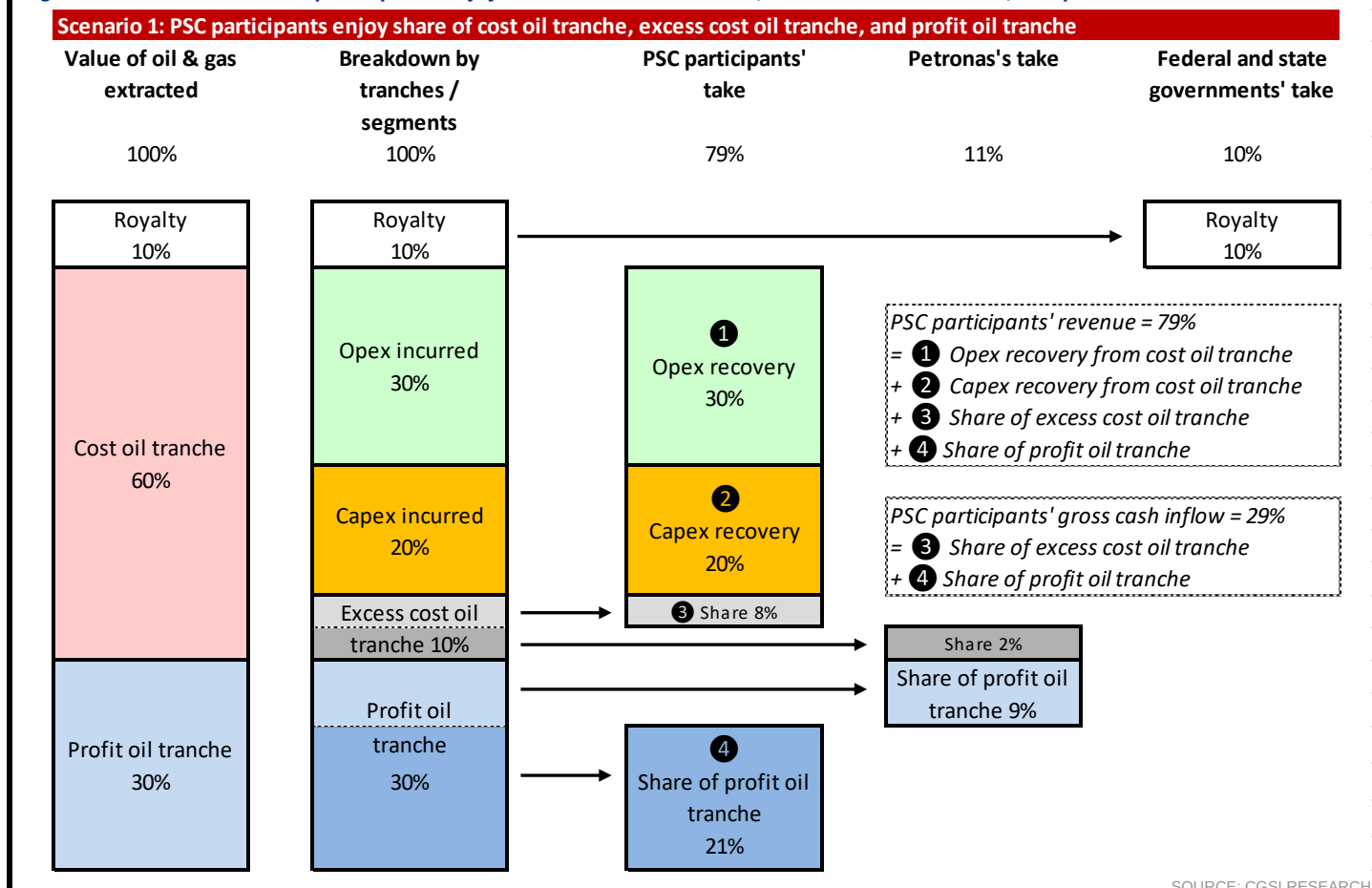
1. The PSC terms specify that value of the oil and gas extracted is broken up into three tranches, i.e. royalty 10%, cost oil tranche 60%, and profit oil tranche 30%.
2. The cost oil tranche is intended for PSC participants to recover their opex and capex incurred on a quarterly basis. If the cost oil tranche is worth more than the sum total of opex and capex incurred, the difference is classified as excess cost oil tranche.
3. The excess cost oil tranche and the profit oil tranche are shared between the PSC participants and Petronas based on pre-agreed percentages. In this illustration, we assume that the PSC participants are entitled to an 80% share of the excess cost oil tranche, and to 70% of the profit oil tranche. The rest belong to Petronas.

The net result is that the PSC participants' take will amount to 79% of the value of the hydrocarbons extracted for the quarter, and the PSC participants will be remunerated in kind by way of being allocated 79% of the barrels extracted.

Although the PSC participants have 100% participating interest in the PSC and bear all of the capex and opex spending, their **net entitlement to production** is only 79%. In other words, their net entitlement-to-gross production ratio is only 79%. This is due to the fixed 10% royalty, while in this example, the Petronas take is 11%, even though Petronas is not a PSC participant.

Separately, the PSC participants' gross cash inflow (before deductions for research payment, export duty, supplementary payment, PITA, and Sabah sales tax, if applicable) will amount to 29% of the value of the hydrocarbons produced.

Figure 116: Scenario 1: PSC participants enjoy share of cost oil tranche, excess cost oil tranche, and profit oil tranche



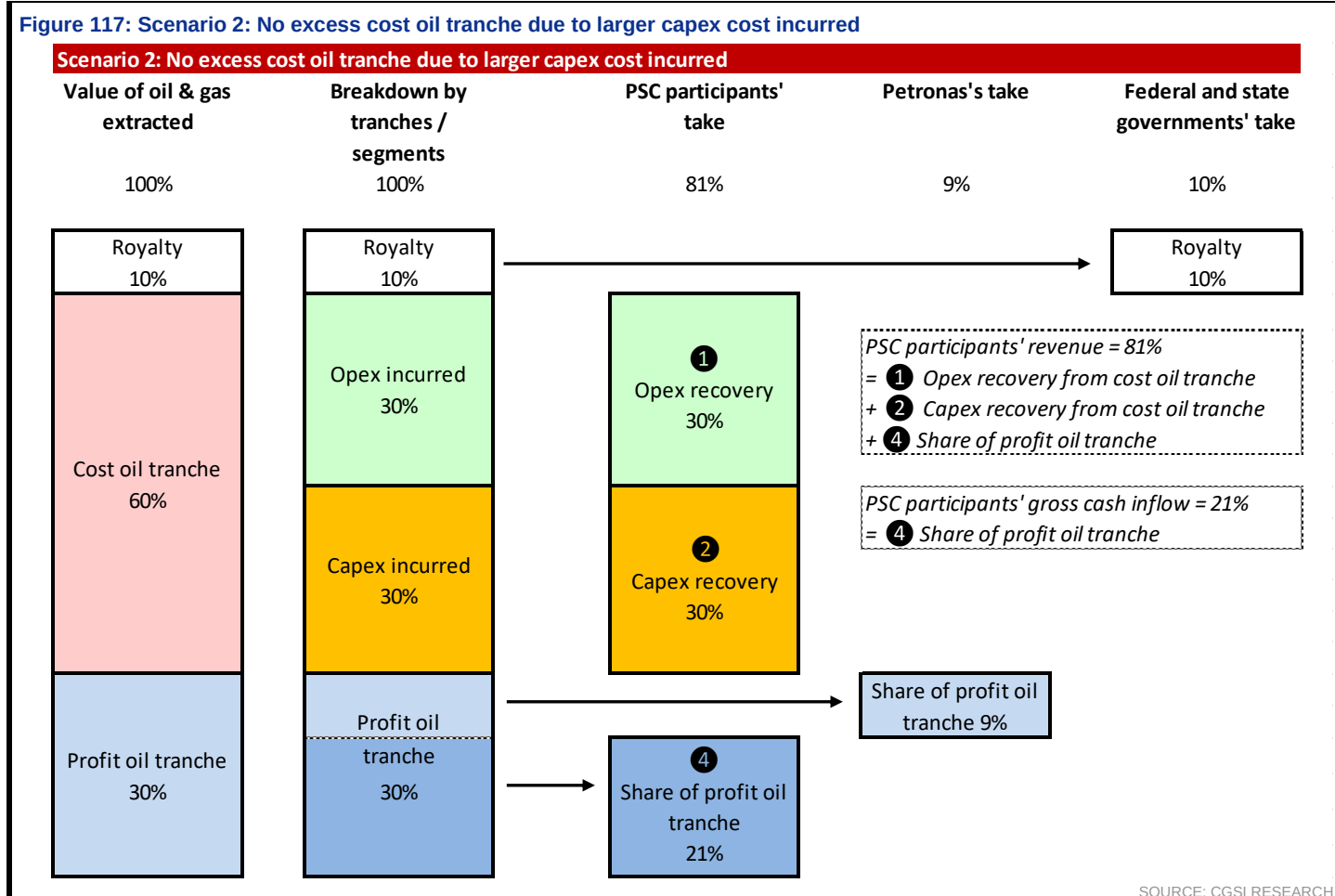
In Scenario 2, we assume that:

1. The breakdown between the tranches remain unchanged, i.e. royalty 10%, cost oil tranche 60%, and profit oil tranche 30%.
2. There is no excess cost oil tranche because the opex and capex spending exactly match the cost oil tranche.

The net result is that the PSC participants' take will amount to 81% of the value of the hydrocarbons extracted for the quarter. In this example, Petronas's take is 9%, reduced from the 11% in Scenario 1 due to the higher capex spending.

The PSC participants' gross cash inflow (before deductions for research payment, export duty, supplementary payment, and PITA) will amount to 21% of the value of the hydrocarbons produced, compared to 29% in the previous scenario, because the PSC participants do not have any share of excess cost oil tranche. This shows that all else being equal, PSC participants will enjoy higher gross cash inflows if it succeeds in keeping both opex and capex as low as possible.

Figure 117: Scenario 2: No excess cost oil tranche due to larger capex cost incurred

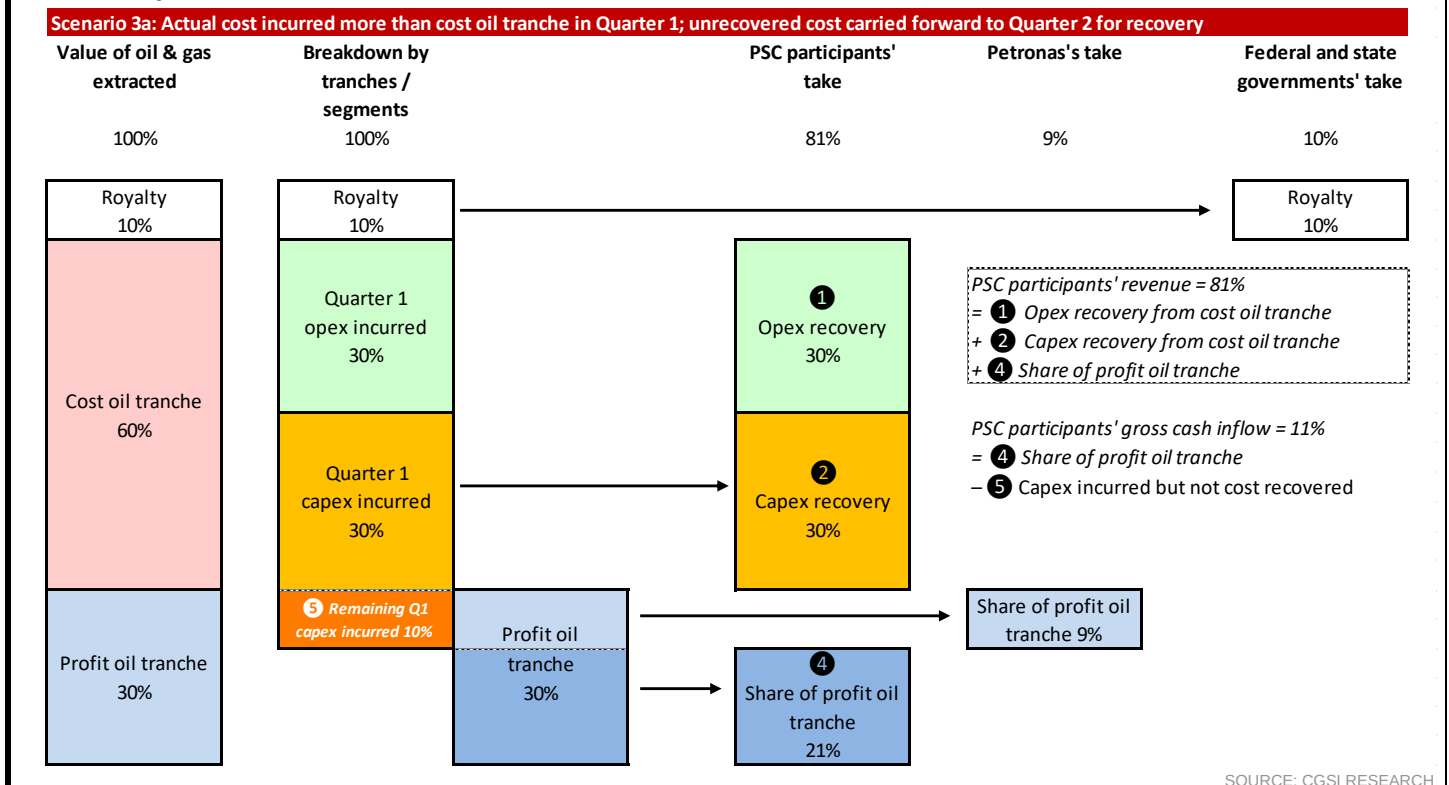


In Scenario 3a, the capex incurred is more than in Scenario 2. As a result, the actual combined opex and capex cost incurred in Quarter 1 exceeded the cost oil tranche by 10% pts.

Since the opex and capex recovery cannot exceed the cost oil tranche, the unrecovered capex will have to be carried forward to be recovered in the following Quarter 2.

The PSC participants' revenue in Quarter 1 is equivalent to 81% of the value/barrels of hydrocarbons extracted, which is the same as in Scenario 2, but the PSC participants' gross cash inflow declines to 11%, from 21% in Scenario 2, due to the extra capex incurred.

Figure 118: Scenario 3a: Actual cost incurred more than cost oil tranche in Quarter 1; unrecovered cost carried forward to Quarter 2 for recovery



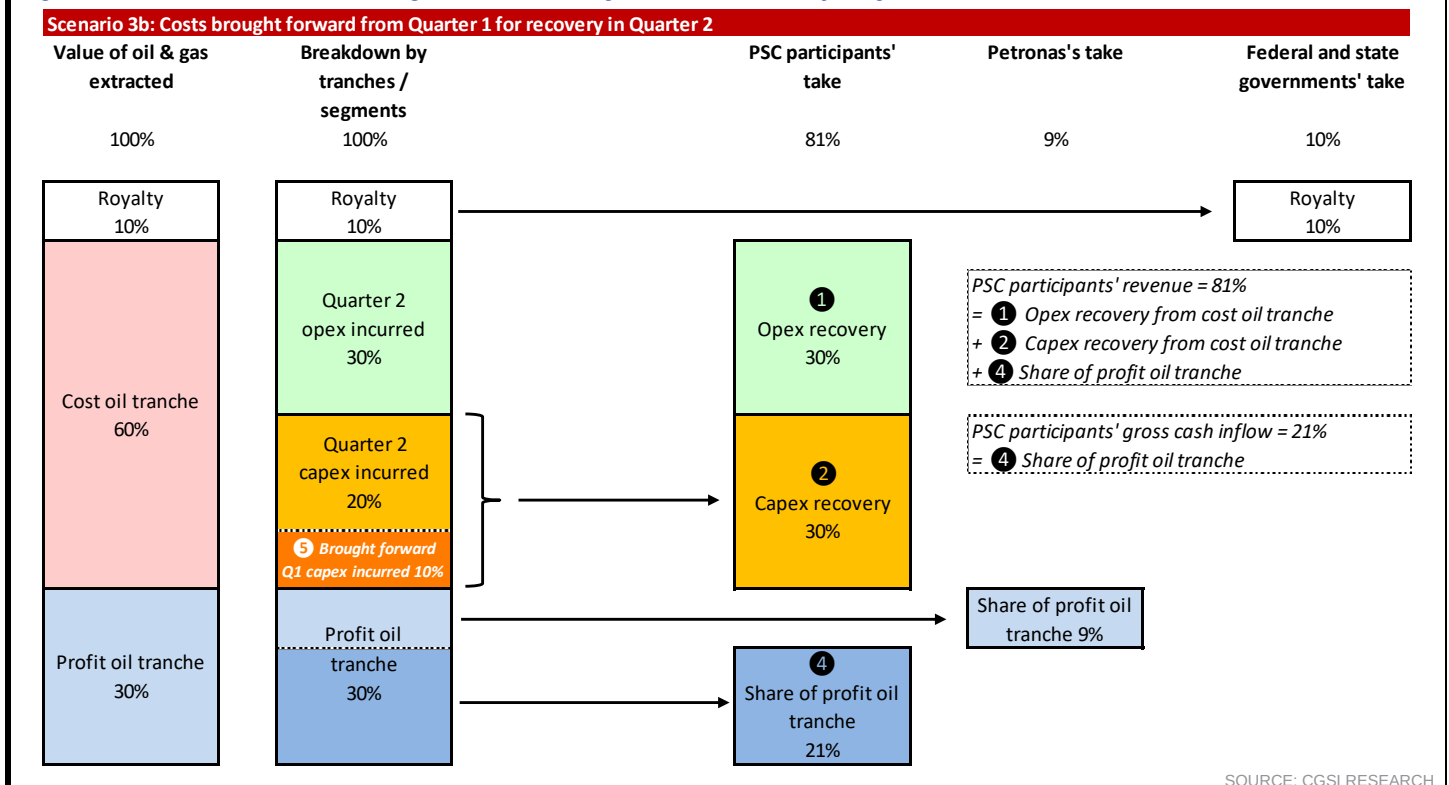
SOURCE: CGSI RESEARCH

Scenario 3b depicts the cost recovery in Quarter 2 of the portion of capex that was not cost recovered in Quarter 1 (Scenario 3a).

In this illustration, the brought forward unrecovered capex was fully recovered in Quarter 2, as the cost oil tranche in Quarter 2 was sufficient to facilitate its full recovery, together with the recovery of Quarter 2 opex and Quarter 2 capex.

There is no limit as to how many quarters ahead that the unrecovered opex and capex can be carried forward for future cost recovery, as long as the PSC tenure has not expired. Therefore, if the Quarter 2 cost oil tranche is still insufficient to fully recover all of the current opex and capex and the brought forward unrecovered capex from the Quarter 1, the PSC participants can make the cost recovery in future quarters.

Figure 119: Scenario 3b: Costs brought forward from Quarter 1 for recovery in Quarter 2



In Scenario 4, we describe a situation whereby:

1. The allocation of the cost oil and profit oil tranches changes, as set out under the terms of the PSC. In this illustration, the cost oil tranche narrows from 60% to 50% of the value of the hydrocarbons extracted, while the profit oil tranche widens from 30% to 40%.
2. In addition, the PSC participants' share of the excess cost oil tranche reduces from 80% to 70% (with the corresponding Petronas share rising from 20% to 30%).
3. Meanwhile, the PSC participants' share of the profit oil tranche declines from 70% to 60%, and Petronas's share rises from 30% to 40%.

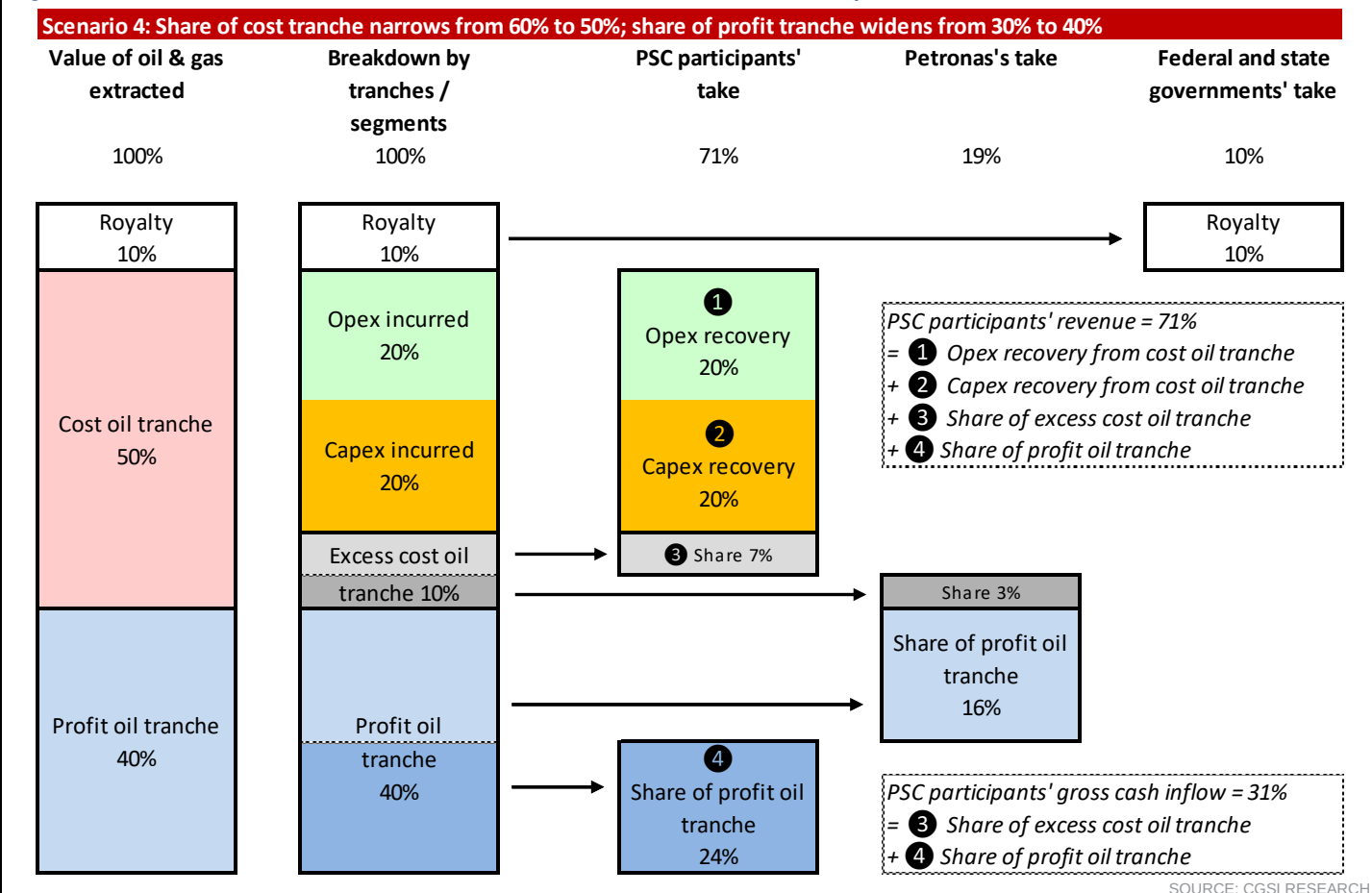
Under certain PSC terms, the allocation and sharing ratios described above changes depending on a specific calculation referred to as the 'R-over-C Index' or 'R/C Index', which we will explain later.

In this example, the excess cost oil tranche amounts to 10% of the value of hydrocarbons extracted, of which 7% is the PSC participants' take (70% of 10%) and 3% is Petronas's take (30% of 10%).

The profit oil tranche of 40% is shared in this way: 24% pts (60% of 40%) is the entitlement of the PSC participants, and 16% pts (40% of 40%) is Petronas's portion.

Overall, the PSC participants are entitled to 71% of the hydrocarbons produced; they are paid in barrels of oil or in cubic feet of gas which they then monetise by selling in the market. After paying for opex and capex costs incurred (total 40% of the hydrocarbons produced), the PSC participants have a gross cash inflow amounting to 31% of the hydrocarbons produced.

Figure 120: Scenario 4: Share of cost tranche narrows from 60% to 50%; share of profit tranche widens from 30% to 40%



To elaborate more on the situation we described in Scenario 4 above, we reproduce one possible example of PSC terms in Malaysia.

The allocation and sharing ratios depend on the R/C index, whereby:

$$R/C \text{ index} = \frac{\text{Total Cumulative PSC participants' Revenue (US\$)}}{\text{Total Cumulative PSC participants' Capex and Opex Costs (US\$)}}$$

The R/C index is a cumulative calculation, which takes into account the cumulative revenue of the PSC participants since the time production started in the numerator, and the cumulative capex and opex of the PSC participants since the PSC was awarded for the block in the denominator. The R/C index calculated up to the end of the previous quarter is the R/C index that will be used to determine the allocation and sharing ratios in the current quarter.

The R/C index is typically below zero in the early stages of production, because cumulative revenue is still less than the cumulative upfront opex and capex incurred to-date to bring the field into production. An R/C index of 1 suggests that the PSC participants have just fully recovered their cumulative capex and opex costs, but nothing more. As the field production matures, the R/C index rises above 1, and the PSC participants are finally making a positive return on their investment. Furthermore, a more mature production profile may also suggest less intensive capex spending.

The above are the reasons why the allocation to the cost oil tranche declines as the R/C index rises; see Figure 121, section (A). A lower allocation to the cost oil tranche correspondingly increases the allocation to the profit oil tranche, which results in an increased take for Petronas. This is because the PSC participants can in principle make a cost recovery claim against the entire cost oil tranche, but the profit oil tranche (and the excess cost oil tranche) must always be shared with Petronas.

Figure 121: Production Sharing Contract (PSC) terms in Malaysia (illustrative example only)

(A) Breakdown of Gross Revenue Tranches

	R/C Index	Royalty	Cost oil tranche	Profit oil tranche
Threshold 1	$0.0 \leq x < 1.0$	10%	70%	20%
Threshold 2	$1.0 \leq x < 1.4$	10%	60%	30%
Threshold 3	$1.4 \leq x < 2.0$	10%	50%	40%
Threshold 4	$2.0 \leq x < 2.5$	10%	30%	60%
Threshold 5	$2.5 \leq x < 3.0$	10%	30%	60%
Threshold 6	$x \geq 3.0$	10%	30%	60%

(B) Share of Excess Cost Oil tranche

	R/C Index	① BCP < THV		② BCP > THV	
		PSC participants' share	Petronas' share	PSC participants' share	Petronas' share
Threshold 1	$0.0 \leq x < 1.0$	0%	100%	0%	100%
Threshold 2	$1.0 \leq x < 1.4$	80%	20%	40%	60%
Threshold 3	$1.4 \leq x < 2.0$	70%	30%	40%	60%
Threshold 4	$2.0 \leq x < 2.5$	60%	40%	40%	60%
Threshold 5	$2.5 \leq x < 3.0$	50%	50%	40%	60%
Threshold 6	$x \geq 3.0$	40%	60%	20%	80%

Where BCP: Block Cumulative Production; THV: Threshold Volume

(C) Share of Profit Oil tranche

	R/C Index	① BCP < THV		② BCP > THV	
		PSC participants' share	Petronas' share	PSC participants' share	Petronas' share
Threshold 1	$0.0 \leq x < 1.0$	80%	20%	40%	60%
Threshold 2	$1.0 \leq x < 1.4$	70%	30%	30%	70%
Threshold 3	$1.4 \leq x < 2.0$	60%	40%	30%	70%
Threshold 4	$2.0 \leq x < 2.5$	50%	50%	30%	70%
Threshold 5	$2.5 \leq x < 3.0$	40%	60%	30%	70%
Threshold 6	$x \geq 3.0$	30%	70%	10%	90%

SOURCES: CGSI RESEARCH, COMPANY REPORTS

As shown in sections (B) and (C) in Figure 121, the PSC participants' share of the excess cost oil tranche and their share of the profit oil tranche also reduce as the R/C index climbs; the net result is larger Petronas takings and smaller overall takings for the PSC participants over time.

Another feature of some PSC agreements is the Block Cumulative Production (BCP) vs. Threshold Volume (THV) concept. THV is a hard number, say 30 MMbbl of oil or 750 Bcf of gas, just as an example. Once the block's cumulative production exceeds the THV, the sharing ratios change for the excess cost oil and profit oil tranches; they invariably change to the detriment of the PSC participants and to the benefit of Petronas.

For instance, assume that the R/C index is at 2.1, representing 'Threshold 4'. When BCP is below THV, the PSC contractors' share of the excess cost oil tranche will be 60% while their share of the profit oil tranche will be 50%; but these drops to just 40% and 30% respectively once BCP rises above THV.

According to Hibiscus, the **North Sabah PSC** terms incorporate the R/C index concept, but not the BCP vs. THV concept. On the other hand, both the **Kinabalu PSC** and **PM3 CAA PSC** do not contain the R/C index concept, but incorporate the BCP vs. THV concept. Hibiscus also pointed out that each PSC had different allocation and sharing percentages, and the numbers shown on Figure 121 are by no means representative of the commercial terms of Hibiscus's individual PSCs. Hibiscus is unable to disclose the specific commercial terms due to confidentiality reasons.

Constructing the P&L of PSC participants ►

The section above was a lengthy description of how PSC participants' revenue is derived and aggregated. To recap:

PSC participants' quarterly Revenue

- = Cost Oil recovered in the particular quarter
- + PSC participants' share of Excess Cost Oil tranche
- + PSC participants' share of the Profit Oil tranche

The PSC participants' revenue is split by reference to the participating interest of the individual participants. For instance, Hibiscus has a 50% participating interest in the North Sabah PSC; hence it will take a 50% share of the PSC participants' revenue for that PSC. The opex and capex incurred by the PSC participants is also split based on the participants' individual working interests.

PSC participants' Pretax Profit

- = PSC participants' Revenue
- Opex
- ❶ Research payment
- ❷ Export duty
- ❸ Sabah sales tax (applicable to North Sabah and Kinabalu only)
- Depreciation and amortisation
- ❹ Unwinding of provision for decommissioning
- ❺ Supplementary payment to Petronas

Where

- ① Research payment = 0.5% x PSC participants' Revenue
- ② Export duty = 10% x (PSC contractors' share of Excess Cost Oil + PSC's contractors' share of the Profit Oil)
- ③ Sabah sales tax = 5% x PSC participants' Revenue
- ④ The future stream of abandonment cess payments is booked into the balance sheet as a liability at its present value; this is the 'future valued' periodically, and the increase in the liability is booked into the P&L as an 'unwinding interest expense'.

- ⑤ The calculation for the supplementary payment is shown below.

Supplementary payment

= Specified percentage in the PSC agreement
x (1 – Export duty of 10%)
x (Realised selling price – Stipulated base price)
x Profit oil in terms of bbls

Where

Profit oil (in terms of bbls)
= [Production (bbls) – Royalty (bbls)] – Cost oil (bbls)
= [90% x Production (bbls)] – Cost oil (bbls)

And where

$$\text{Cost oil (in bbls)} = \frac{\text{Total Cost Oil (US\$)}}{\text{Weighted average selling price (US\$/bbl)}}$$

The supplementary payment to Petronas is effectively similar to a 'windfall tax'.

This means that once the realised selling price is more than the stipulated base price, supplementary payment must be made, based on the excess above the stipulated base price, multiplied by the percentage specified in the PSC agreement, multiplied by the profit oil in terms of bbls, but discounted by the export duty already paid.

Supplementary payments are only applicable to oil production and are paid by Hibiscus for its North Sabah PSC and Kinabalu PSC. The PM3 CAA PSC has not paid any supplementary payment in recent quarters because the stipulated base price is very high, while gas production is exempt from supplementary payments.

To derive the PSC participants' net profit, we first need to calculate the PITA.

PSC participants' Net Profit

= PSC participants' Pretax Profit

- ⑥ PITA

Where

⑥ PITA = 38% x ① PSC participants' Taxable Profit

① PSC participants' Taxable Profit

= PSC participants' Pretax Profit

+ Research payment (not tax deductible)

+ Export duty (not tax deductible)

+ ⑦ Unwinding cost of decommissioning provisions (not tax deductible)

+ Depreciation and amortisation

- ⑧ Capital Allowances

Where

⑦ The finance cost resulting from the periodic unwinding of decommissioning provisions is not tax deductible; only the actual decommissioning expenditures are tax deductible

⑧ Capital allowances:

- Only intangible capex is given 100% capital allowance deduction in Year 1
- Tangible capex capital allowance is based on specific rates over Year 1-10 (for example: Year 1: 22%; Year 2-10: 8%)

Note that the SbST and supplementary payments to Petronas are tax deductible under PITA.

APPENDIX 6: BRUNEI CONCESSION SYSTEM

The Brunei tax-royalty system in brief ►

The Brunei hydrocarbon fiscal system is a **concession system**, otherwise known as a tax-royalty fiscal system. In concession systems, the participants have been granted the licence by the Brunei regulators to explore, develop and produce hydrocarbons from a particular acreage over a specific period of time. All exploration and development capex are to be borne by the concession participants, which typically include private oil companies (POC) but also Brunei state-owned entities.

The concession participants in Brunei take **title** to all of the hydrocarbons produced, and pay royalties and taxes from the sale of the hydrocarbons. Hence, their **net entitlement-to-gross production** ratio is also 100%.

By comparison, under the Malaysian PSC system, the national oil company (NOC) Petronas has ownership of the hydrocarbons and the PSC participants are merely paid their share of the hydrocarbons to cover their capex and opex costs and a share of the profit. Although the Malaysian PSC participants have 100% participating interest in the PSC and bear all of the capex and opex spending, their net entitlement to production is always less than 100%, because the PSC mechanism always provides Petronas with a share of production (even though Petronas is not a PSC participant), and also because of the fixed 10% royalty.

In the Brunei fiscal system, the concession participants also **own all of the equipment and facilities** at the block, and continue to own them even after the tenure of the licence has come to an end; hence, the equipment and facilities can be sold for scrap and the sale proceeds can be kept by the concession participants. By comparison, all of the equipment and facilities at the Malaysian PSC blocks belong to Petronas, and the PSC participants merely have the right to use them during the PSC tenure; at the end of the PSC tenure, everything at the PSC must be handed back to Petronas and the PSC participants are not entitled to any compensation.

At the end of the field life, or at the end of the block licence tenure in Brunei, the concession participants will have the **obligation to decommission the facilities** and plug and abandon the wells. At the Malaysian PSCs, on the other hand, the entire PSC is simply handed back by the participants to Petronas, and Petronas will be responsible for the abandonment work, which it will fund using the cash it has received from regular contribution of abandonment cess by the participants over the course of the PSC tenure. No progressive abandonment cess payments are required under the Brunei fiscal terms, which means that the concession participants will have to fund the decommissioning work in a lump sum at the end of the licence tenure.

We are not aware of any domestic market obligations under the Malaysian PSC system. However, in Brunei, the concession participants may also need to comply with certain DMOs. Specifically for the Brunei MLJ licence, the **Domestic Gas Supply Obligation (DGSO)** is to allocate 10% of the gas produced to the domestic Brunei market at a price of US\$0.33/MMBtu. By comparison, the full, undiscounted wellhead gas price obtained by Brunei MLJ on the remaining 90% of the gas volumes was US\$5.19/MMBtu in 2023, in our estimate.

Constructing the P&L of Brunei concession participants ➤

The Brunei concession participants have the right to market and sell 100% of the production from the field.

Concession participants' Production Volume

- = Gas production (Mscf)
- + Crude oil production (bbls)
- + Condensate production (bbls)

Realised wellhead gas price (US\$/MMBtu)

- = ① Contracted wellhead gas price (US\$/MMBtu)
 - x 90% of volume produced
- + Domestic Gas Supply Obligation price of US\$0.33/MMBtu
 - x 10% of volume produced

Where

① The wellhead gas produced in Brunei is typically sold to Brunei LNG (BLNG) for liquefaction and sale as liquefied natural gas (LNG) to foreign customers.

Therefore, the wellhead gas price is contracted as a proportion of the average price that BLNG receives from its sale of LNG, typically c.45% of BLNG's average LNG selling price.

BLNG's LNG selling price is a weighted average of its selling price it receives from selling LNG in the Asian spot market and what it receives from selling LNG at long-term contract prices. We believe that BLNG's LNG selling price is heavily weighted towards long-term contract prices (at least two thirds of sales), and is less exposed to spot prices (at most one-third of sales), which would be typical of most LNG producers in Asia.

The Asian spot LNG price is represented by the Japan-Korea Marker (JKM) price, which is published by data provided S&P Global Platts.

The long-term contract LNG price is based on specific confidential agreements signed between BLNG and its customers, but may be pegged to the Japan Crude Cocktail (JCC) price. The JCC is a weighted average price of the mix of different crude oil slates that are imported into Japan.

In summary:

$$\begin{aligned}
 &\text{Wellhead gas price} = c.45\% \text{ of BLNG's average LNG selling price} \\
 &\text{BLNG's weighted average LNG selling price} \\
 &= (\text{Long-term contract LNG prices} \times \text{Weightage of at least two-thirds}) \\
 &+ (\text{Spot JKM prices} \times \text{Weightage of at most one-third})
 \end{aligned}$$

Concession participants' Revenue

- = Gas volume sold (Mscf)
 - x ② 1.125 (to convert Mscf volume to MMBtu volume)
 - x Realised wellhead gas price (US\$/MMBtu)
- + Crude oil volume sold (bbls)
 - x Realised oil price (US\$/bbl)
- + Condensate volume sold (bbls)
 - x Realised condensate price (US\$/bbl)

Where

② MMBtu = Mscf x 1.125 (for the Brunei MLJ gas)

Concession participants' Pretax Profit

- = Concession participants' Revenue
- ③ Royalty at 8% of revenue
- Opex
- Depreciation and amortisation
- ④ Unwinding of provision for decommissioning

Where

- ③ Royalties amounting to 8% of the royalties are paid in cash.
- ④ The future abandonment cost at the end of licence tenure is booked into the balance sheet as a liability at its present value; this is the 'future valued' periodically, and the increase in the liability is booked into the P&L as an 'unwinding interest expense'.

PSC participants' Net Profit

- = Concession participants' Pretax Profit
- ⑤ Petroleum income tax

Where

- ⑤ Petroleum Income Tax = 55% x ① Concession participants' Taxable Profit

① Concession participants' Taxable Profit

- = Concession participants' Pretax Profit
- + Depreciation and amortisation
- Capital Allowances

Hibiscus owns a 100% equity stake in TotalEnergies Brunei, which in turn, holds a 37.5% working interest in the Brunei MLJ field (Hibiscus completed the acquisition of TotalEnergies Brunei on 14 Oct 2024).

Production from the MLJ field is allocated to the concession participants based on their respective working interest. TotalEnergies Brunei will also share in the capex, opex, royalties and taxes based on its working interest of 37.5%.

Production entitlement of TotalEnergies Brunei

- = MLJ gas production
 - x 37.5% working interest
- + MLJ condensate production
 - x 37.5% working interest
- ...since no crude oil is produced from MLJ.

APPENDIX 7: UK CONCESSION SYSTEM

The UK fiscal system in brief ►

The UK hydrocarbon fiscal system is similar to the Brunei tax-royalty system, as both are concession system.

The concession participants in the UK have a licence to explore, develop and produce hydrocarbons from a particular acreage over a specific period of time. All exploration and development capex are to be borne by the concession participants.

The concession participants take title to all of the hydrocarbons produced and pay taxes from the sale of the hydrocarbons, but there are no royalty payments in the UK. Their net entitlement-to-gross production ratio is 100%.

There are no domestic market obligations for UK producers.

The concession participants also own all of the equipment and facilities at the licence area, and continue to own them even after the tenure of the licence has come to an end; hence, the equipment and facilities can be sold for scrap and the sale proceeds can be kept by the concession participants.

In the UK, exploration and development licences are granted with specific expiry dates which determines the time period provided for the licence holder to secure the Field Development Plan (FDP) approval and the production consent from the regulator, the North Sea Transition Authority (NSTA). This is intended to prevent licence holders from sitting on the licence indefinitely without developing it. However, once a licence area enters into production, the licence holders are permitted to continue production indefinitely, or until it is no longer economically feasible to extract the hydrocarbons.

At the end of the field life, or at the end of the block licence tenure in the UK, the concession participants will have the obligation to decommission the facilities and plug and abandon the wells. Concession participants are required to fund their decommissioning liabilities during the course of production, by periodically placing deposits into an escrow account, which is classified on the balance sheet as 'restricted cash'.

Decommissioning deposits into the escrow account are not given any tax benefits while production is ongoing, as the deposits do not enter into the tax calculations as deductions against taxable profit. However, after the decommissioning costs are actually incurred (at end of the field's production life), the UK government will return 40% of the actual decommissioning spending (after citing proof of spending) to the concession participants, being the tax benefit of the **Ring Fence Corporate Taxation (RFCT) of 30%** and **Supplementary Charge (SC) of 10%**. As a result, concession participants such as Hibiscus's 50% owned joint venture AOCL only deposits the net figure amounting to 60% of the forecast decommissioning costs into the escrow account, rather than the entire portion.

Taxation of UK hydrocarbons production is very heavy. Apart from the 30% RFCT and the 10% SC, the UK had also implemented the **Energy Profits Levy (EPL)**, which first took effect on 26 May 2022, but has since been raised twice.

First EPL regime – from 26 May 2022 to 31 Dec 2022

- Additional **25%** tax on UK oil and gas profits;
- Enhanced deduction such that 180% of certain categories of capex can be offset against taxable income;
- The UK government's intention at that time was not to extend the EPL regime beyond 31 Dec 2025F.

Second EPL regime – from 1 Jan 2023 to 31 Oct 2024

- Additional **35%** tax on UK oil and gas profits (from 25% previously);
- Enhanced tax deduction of certain categories of capex reduced to 129% (from 180% previously), although decarbonisation capex will still retain the 180% deduction;

- The UK government's intention at that time was to retain the EPL regime until 31 Mar 2028F.

Third and current EPL regime – from 1 Nov 2024 onwards

- Additional **38%** tax on UK oil and gas profits (from 35% previously);
- Enhanced tax deduction of certain categories of capex to be eliminated (from 129% previously); while enhanced deduction for decarbonisation capex is reduced to 166% (from 180% previously);
- The UK government's current intention is to retain the EPL regime until 31 Mar 2030F.

The net result is that UK oil and gas profits are now taxed at a rate of **78%**, comprising RFCT of 30%, SC of 10% and EPL of 38%.

The P&L of UK concession participants ➤

The UK concession participants have right to market and sell 100% of the production from the field.

Concession participants' Production Volume

- = Gas production (Mscf)
- + Crude oil production (bbls)
- + Condensate production (bbls)

Realised wellhead gas price (US\$/Mscf) – for the Anasuria Cluster

- = Gas volume produced from the Cook field (Mscf)
 - x ① 1.3 (to convert Mscf volume to MMBtu volume)
 - x 75% of the Heren National Balancing Point index (GBp/therm)
 - x 10 (to convert from GBp/therm to GBp/MMBtu)
 - ÷ 100 (to convert from GBp/MMBtu to GBP/MMBtu)
 - x US\$:GBP exchange rate (to convert from GBP/MMBtu to US\$/MMBtu)
- + Gas volume produced from the Guillemot A, Teal and Teal South fields (Mscf)
 - x ① 1.3 (to convert Mscf volume to MMBtu volume)
 - x 85% of the Heren Index (GBp/therm)
 - x 10 (to convert from GBp/therm to GBp/MMBtu)
 - ÷ 100 (to convert from GBp/MMBtu to GBP/MMBtu)
 - x US\$:GBP exchange rate (to convert from GBP/MMBtu to US\$/MMBtu)

Where

- ① MMBtu = Mscf x 1.3 (for the Anasuria Cluster gas)
- 1 GBP = 100 GBp (pence)
- 1 MMBtu = 10 therms

Concession participants' Revenue

- = Gas volume sold (Mscf)
 - x Realised wellhead gas price (US\$/Mscf)
- + Crude oil volume sold (bbls)
 - x Realised oil price (US\$/bbl)
- + Condensate volume sold (bbls)
 - x Realised condensate price (US\$/bbl)

Concession participants' Pretax Profit

- = Concession participants' Revenue
- Opex
- Depreciation and amortisation
- ② Unwinding of provision for decommissioning

Where

② The future abandonment cost at the end of licence tenure is booked into the balance sheet as a liability at its present value; this is the 'future valued' periodically, and the increase in the liability is booked into the P&L as an 'unwinding interest expense'.

PSC participants' Net Profit

- = Concession participants' Pretax Profit
- ③ Ring Fence Corporate Taxation (RFCT)
- ④ Supplementary Charge (SC)
- ⑤ Energy Profits Levy (EPL)

Where

- ③ RFCT = 30% x ① Concession participants' RFCT Income Tax Base
- ④ SC = 10% x ② Concession participants' SC Income Tax Base
- ⑤ EPL = 38% x ③ Concession participants' EPL Income Tax Base

① Concession participants' RFCT Income Tax Base

- = Concession participants' Pretax Profit
- + Depreciation and amortisation
- Base Capital Allowances (CA) amounting to 100% of capex

② Concession participants' SC Income Tax Base

- = Concession participants' Pretax Profit
- + Depreciation and amortisation
- Base CA amounting to 100% of capex
- Additional CA amounting to 62.5% of capex

③ Concession participants' EPL Income Tax Base

- = Concession participants' Pretax Profit
- + Depreciation and amortisation
- Base CA amounting to 100% of all capex
- Enhanced CA amounting to 66% of decarbonisation capex only

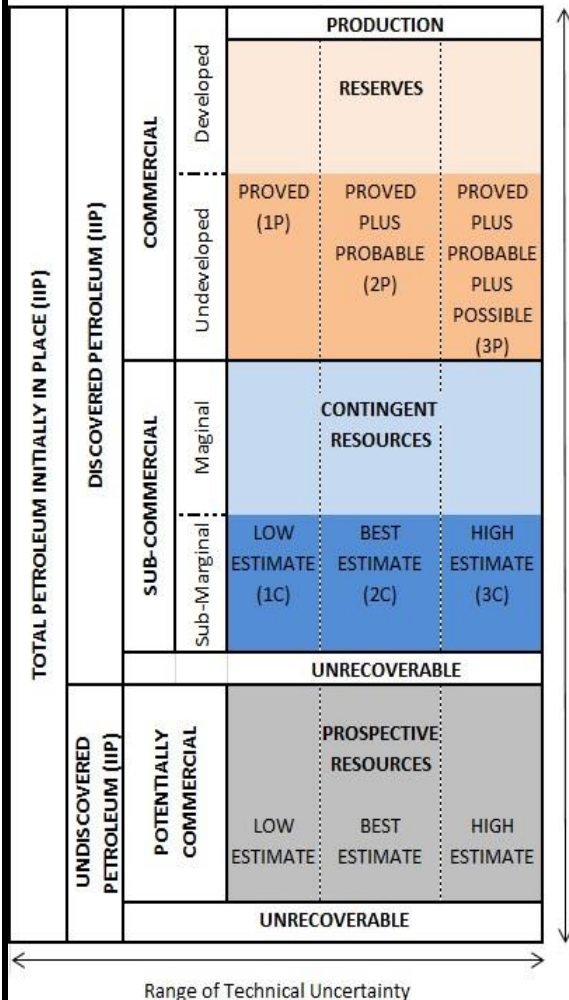
Note: The UK taxation regime permits a full current year CA claim on the entire value of the capex spent.

Hibiscus owns a 50% equity stake in Anasuria Operating Company Limited (AOCL), which holds a 100% working interest in the Anasuria Cluster in the UK. Hence, Hibiscus has a 50% working interest in the production of the Anasuria Cluster, and will also share in the capex, opex, and taxes based on its working interest of 50%.

APPENDIX 8: RESERVES AND RESOURCES

How reserves and resources are described ➤

Figure 122: Classification and categorisation of reserves and resources



Total Hydrocarbons Initially In Place (IIP) can be broken down as discovered and undiscovered hydrocarbons.

Discovered hydrocarbons may be technically unrecoverable, until new technologies are developed. If the discovered hydrocarbons are technically recoverable, they may be classified either as:

- Reserves (commercially feasible to extract); or
- Contingent Resources (as they may be sub-commercial for now, among other reasons).

This is represented by the vertical axis, which describes the probability of commerciality.

The horizontal axis describes the technical probability of recoverability, of which there is always some uncertainty due to unforeseen variability in terms of how the reservoir behaves once production commences.

Discovered and Commercial Reserves can be:

- Proved (1P): 90% certainty that actual recovered volumes can exceed the 1P reserves estimate in terms of bbls (or boe)
- Proved and Probable (2P): 50% certainty
- Proved, Probable and Possible (3P): 10% certainty

2P and 3P reserves may be converted into 1P reserves over time as operating history reduces the uncertainty around recoverability.

Sub-commercial hydrocarbons are described as Contingent Resources. They can turn into Commercial Reserves if the economics of extraction improve, among other reasons.

Discovered but sub-commercial Contingent Resources can be categorised as follows:

- Low estimate (1C): 90% chance that actual volumes can exceed the 1C resources estimate in terms of bbls (or boe)
- Best estimate (2C): 50% chance
- High estimate (3C): 10% chance

Prospective Resources are undiscovered hydrocarbons that have a geological chance of discovery and have a chance for commercial development.

SOURCES: CGSI RESEARCH, EVALUATE ENERGY

Classification of resources by degree of commercial certainty ➤

In Figure 122, the classification of resources is represented by the vertical axis, which is the degree of commercial certainty.

Resources will be classified as Contingent Resources until they satisfy all of the criteria below, which will then enable the resources to be reclassified as Reserves:

- Evidence of a technically mature, feasible development plan;
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project;
- Evidence to support a reasonable time frame for development;
- A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria, based on estimated entitlement forecast quantities and associated cashflows;
- A reasonable expectation that there will be a market for forecast sales quantities, and that all produced streams (oil, gas, water, etc.) can be sold, stored, reinjected or otherwise appropriately disposed;

- Evidence that the necessary production and transportation facilities are available or can be made available; and
- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

Source: RPS Group, as contained in Hibiscus's shareholders' circulars

From the list above, it is clear that positive economics alone is insufficient for Contingent Resources to be reclassified as Reserves; the Final Investment Decision (FID) must be taken by the oil and gas companies in charge of the project, government approval must have been obtained, it must be reasonable to assume that project financing would be available, the production must have a viable means of transportation and a ready market, etc.

In Malaysia, any proposed development projects must secure approval from Petronas's Malaysia Petroleum Management (MPM) unit, which is the oil and gas regulator in Malaysia; without MPM approval, the estimated quantities will remain as Contingent Resources.

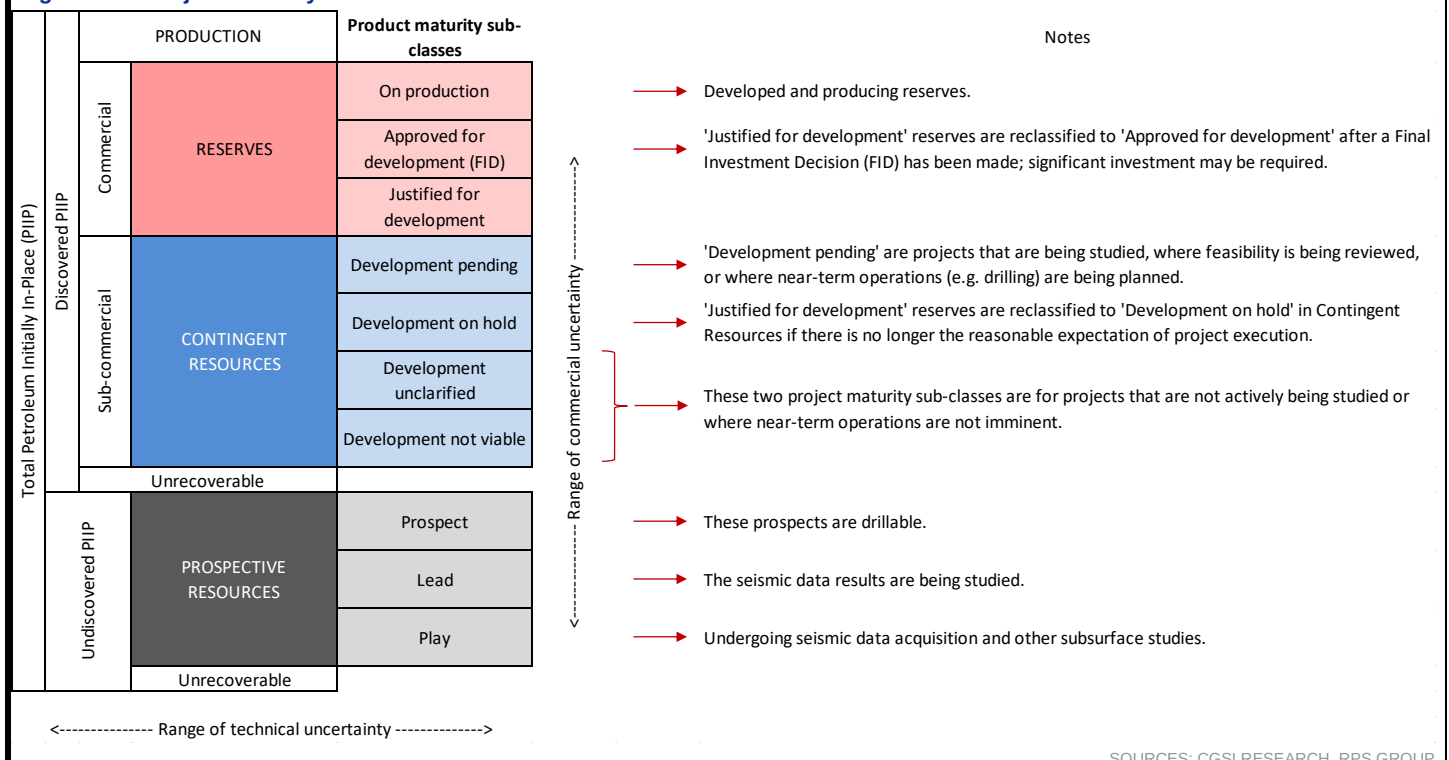
Discovered resources that are closer to existing production areas have a higher probability of achieving commerciality (e.g. via tie-back development concepts), hence the associated volumes are more likely to be Reserves rather than Contingent Resources.

Projects are the source of Reserves and Contingent Resources

The project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project, according to consultant RPS. Net recoverable resources refer to an entity's entitlement share of future production under the terms of the licence.

Each project has a specific maturity subclass (Figure 123). An accumulation of hydrocarbons is subject to separate and distinct projects that are at different stages of exploration or development. Therefore an accumulation may have recoverable quantities in several resources classes simultaneously.

Figure 123: Project maturity subclasses



For instance, four projects may be simultaneously ongoing for an accumulation of hydrocarbons.

- The first project may be in the 'development on hold' subclass;
- The second project may be in the 'development pending' subclass;
- The third project may be in the 'justified for development' subclass; while
- The fourth project may be in the 'approved for development' subclass.

In the case of this specific accumulation of hydrocarbons, the estimated recoverable quantities for the first and second projects will be classed as Contingent Resources, while the estimated recoverable quantities for third and fourth projects will attain Reserves classification.

Estimated recoverable quantities under the Reserves classification can be classified into two groups:

- Developed projects: Production is ongoing with minimal additional capex required; and
- Undeveloped projects: Projects have been sanctioned (FID) or justified for development, but the projects have not yet been executed and material future capex spending is required.

Meanwhile, Contingent Resources can be classified into two groups:

- Economically viable Contingent Resources: these are resources that meet the economic criteria for development (positive net cashflows), but remain Contingent because they do not meet all of the criteria for reclassification into Reserves, such as not having a ready market, or not yet securing regulatory approval to proceed.
- Economically not viable Contingent Resources: these are resources that do not meet the economic criteria for development (non-positive net cashflows).

Categorisation of resources ►

The categorisation of resources is represented by the horizontal axis (Figure 122). Estimates of recoverable and marketable quantities associated with each project or a group of projects is categorised to reflect uncertainty of recoverable volumes. This uncertainty reflects the reserve auditors' technical judgement as to the level of efficacy of the technology applied, and reflect certain commercial terms that may impact the quantities recovered.

The uncertainty in a project's recoverable Reserves is reflected by the 1P, 2P, and 3P categorisation.

- **Proved Reserves (1P)** means that there is **90% certainty** that actual recovered volumes can exceed the 1P reserves estimate in terms of bbls (or boe); this is the low estimate of reserves.
- **Proved and Probable Reserves (2P)** means that there is **50% certainty** of the actual volumes being above the estimate, but also 50% certainty that the actual volumes will be below that estimate. The 2P Reserves is accepted by reserve auditors as the best estimate of actual volumes.
- **Proved, Probable and Possible Reserves (3P)** means that there is only **10% certainty** that the actual volumes are above this estimate; this is the high estimate of reserves.

We highlight that 1P, 2P and 3P are cumulative reserve values. Hence, 2P reserves include 1P reserves, while 3P reserves include 1P and 2P reserves.

The associated incremental quantities are termed Proved (P1), Probable (P2), and Possible (P3):

- Proved (P1) reserves refer only to the 1P reserves.
- Probable Reserves (P2) = 2P reserves minus 1P reserves.
- Possible Reserves (P3) = 3P reserves minus 2P reserves.

Meanwhile, the uncertainty in a project's recoverable Contingent Resources is reflected by the 1C (90% certainty), 2C (50% certainty), and 3C (10% certainty) categorisation.

Therefore:

- $C1 = 1C$
- $C2 = 2C - 1C$
- $C3 = 3C - 2C$

APPENDIX 9: ENVIRONMENTAL ISSUES

How Hibiscus accounts for its GHG emissions ►

(A) Operational control emissions

Hibiscus accounts for its CO₂e emissions on the basis of **operational control**. This means that GHG emissions are included *in full* for all assets that are operationally controlled by Hibiscus. Hence:

- 100% of **North Sabah's** GHG emissions are included in Hibiscus's tally of its emissions, even though Hibiscus only has 50% working interest in the asset;
- 100% of **Kinabalu's** GHG emissions are included even though Hibiscus only has 60% working interest;
- 100% of **PM3 CAA's** GHG emissions are included even though Hibiscus only has 35% working interest;
- 100% of **Block 46 Cai Nuoc's** GHG emissions are included even though Hibiscus only has 70% participating interest (emissions from Block 46 Cai Nuoc are grouped together with PM3 CAA due to tie back to PM3 CAA facilities);
- 100% of GHG emissions from '**Licence No P013 - Teal, Teal South and Guillemot A**' in the UK North Sea and 100% of the Anasuria FPSO emissions are included even though Hibiscus only has 50% participating interest and the assets are jointly operated with Ping Petroleum; and
- 100% of the GHG emissions from the corporate headquarters in Kuala Lumpur.

GHG emissions from '**Licence No P185 – Cook**' in the UK North Sea are not included at the gross level since Hibiscus does not operate the field and only has 19.325% participating interest.

Separately, there are no further GHG emissions for **PM314** and **PM305** as production ceased Sep 2020 and Mar 2024, respectively.

In the future:

- 100% of GHG emissions from **Brunei's MLJ field** will be included in Hibiscus's tally of its emissions, as Hibiscus will be the operator of the field even though Hibiscus will only have 37.5% working interest;
- 100% of GHG emissions from **PKNB DRO PSC** will be included as Hibiscus will be the operator with 65% working interest;
- 100% of GHG emissions from '**Licence No P2535 - Teal West**' in the UK North Sea will be included, as Hibiscus will be the operator with 100% participating interest;
- 100% of GHG emissions from '**Licence No P2451 - Fyne**' in the UK North Sea will be included (assuming that this oilfield is developed), as Hibiscus will be the operator with 42.5% working interest;
- 100% of GHG emissions from the **Greater Marigold Area Development (GMAD)** will be included (assuming that these oilfields are developed), as Hibiscus will be the operator with 87.5% participating interests in Marigold West and Sunflower fields, and 100% equity stakes in the Kildrummy, Crown and Cross fields in the UK North Sea.

GHG emissions from '**Licence P2532 – Cook West and Cook North**' in the UK North Sea will not be included (even if these oilfields are developed in the future) since Hibiscus will not be operating the fields (Hibiscus has 19.325% working interest).

No GHG emissions from **PM327** will be included in the future (assuming that this block is developed), as Hibiscus will not be the operator (Hibiscus has 30% working interest).

(B) Working interest GHG emissions

Separately, Hibiscus also discloses its **net GHG emissions on a working interest basis**, which includes Hibiscus's equity share in the GHG emissions of each production asset that it has a working interest in, regardless of whether Hibiscus is the operator or not.

To derive working interest GHG emissions, Hibiscus's 19.325% share of the emissions of '**Licence P185 – Cook**' in the UK North Sea is included, in addition to 50% share of North Sabah's GHG emissions, 60% of Kinabalu's emissions, 35% of PM3 CAA's emissions, 50% share of Anasuria Cluster's emissions, etc. Also, 30% of the emissions from PM327 will be included in the future if the block is developed.

Figure 124: Operational control vs. working interest GHG emissions

Hibiscus's upstream E&P assets	Participating interest ❷	Operational control emissions included	Is Hibiscus the operator?
Assets in Southeast Asia			
North Sabah PSC	50%	100%	Yes
Kinabalu PSC	60%	100%	Yes
PM3 CAA	35%	100%	Yes
Block 46 Cai Nuoc PSC	70%	100%	Yes
Brunei MLJ	37.5%	100%	Yes
PKNB Cluster PSC	65%	100%	Yes
PM327 PSC	30%	None ❶	No
North Sea - Anasuria Cluster			
Licence No P013 - Teal, Teal South and Guillemot A	50%	100%	Yes
Licence No P185 – Cook	19.325%	None ❶	No
Licence No P2535 - Teal West	100%	100%	Yes
Licence No P2451 - Fyne	42.5%	100%	Yes, if development proceeds
Licence P2532 – Cook West and Cook North	19.325%	None ❶	No, even if development proceeds
North Sea - Greater Marigold Area Development (GMAD)			
Licence No P198 - Marigold West	87.5%	100%	Yes, if development proceeds
Licence No P198 - Sunflower	87.5%	100%	Yes, if development proceeds
Licence No P2518 - Kildrummy	100%	100%	Yes, if development proceeds
Licence No P2608 - Crown	100%	100%	Yes, if development proceeds
Licence No P2635 - Cross	100%	100%	Yes, if development proceeds
❶ Hibiscus is not/will not be the operator, hence GHG emissions not included on an operational control basis			
❷ GHG emissions on a working interest basis are included for all E&P assets based on the working interest percentage			

SOURCES: CGSI RESEARCH, COMPANY REPORTS

(C) Net GHG emissions

Hibiscus deducts the **UK allowances (UKA)** paid for and surrendered to the UK government from its gross GHG emissions to derive the **net GHG emissions**.

Net Scope 1 and 2 GHG emissions are derived after deducting **UK Allowances (UKA)** surrendered under the UK ETS.

For example, in FY24, Hibiscus was responsible for (a) 6,767,692 tCO₂e gross Scope 1 and 2 GHG emissions, but had paid for and surrendered (b) 64,497 UKAs in relation to emissions from the Anasuria Cluster; hence the net emissions were calculated as (a) – (b), or 6,703,195 tCO₂e.

AOCL, the operator of the Anasuria Cluster, was entitled under the UK ETS to (c) 27,997 free UKAs for each of CY23 and CY24. However, AOCL had emitted (d) 92,494 tCO₂ in FY24 (excluding emissions of CH₄, N₂O or HFC, which are not within the scope of the UK ETS), which was in excess of its entitlement of free allowances. Consequently, the number of UKAs that AOCL had to purchase from the UK government and surrender in FY24 was calculated as (d) – (c), or 64,497 UKAs.

Hibiscus is one of biggest emitters among listed O&G companies in Malaysia ➤

When we examine the Scope 1 and Scope 2 emissions of the listed O&G companies in Malaysia that are under our coverage, **Hibiscus stands out as one of the highest emitters of CO₂e** (see Appendix 11 for a description of GHG emissions categories).

As shown in Figure 125, in terms of Scope 1 emissions alone, **Hibiscus** was largest emitter among the listed companies with 6.8 MMtCO₂e of Scope 1 emissions (in FY6/24), followed by **Petronas Chemicals** in second place at 6 MMtCO₂e (FY12/23) and **MISC** in third place at 4.1 MMtCO₂e (FY12/23).

In the upstream exploration and production (E&P) category, **Petronas's** upstream operations in Malaysia and abroad produced 12.3 MMtCO₂e of Scope 1 emissions, c.80% higher than Hibiscus due its significantly larger scale of operations.

Dialog has equity interests in two offshore oilfields in Malaysia but the upstream E&P emissions from the Malaysian oilfields have not been included in its Scope 1 disclosure as Dialog argues that the oilfields are controlled by Petronas via its Malaysia Petroleum Management (MPM) unit. Dialog also operates one Thai onshore oilfield, but the emissions there have not been measured.

Figure 125: Malaysia Oil & Gas sector: CO₂e emissions

	O&G: Upstream E&P		O&G: Upstream Services					O&G: Midstream		O&G: Downstream		
	Hibiscus	Petronas (Upstream only)	Yinson	Bumi Armada	Velesto	Dayang	Wasco	Dialog	MISC	Petronas Chemicals	LC Titan	Petronas Dagangan
	FY Jun 2024	FY Dec 2023	FY Jan 2024	FY Dec 2023	FY Dec 2023	FY Dec 2023	FY Dec 2023	FY Jun 2024	FY Dec 2023	FY Dec 2023	FY Dec 2023	FY Dec 2023
Total CO₂e emissions (tonnes)	6,819,693	12,420,000	2,048,433	986,860	64,013	2,110	29,512	19,580	7,118,519	7,430,000	390,158	50,326,100
Scope 1	6,765,417	12,253,289	43,487	1,850	63,469	958	15,452	8,722	4,106,235	5,960,000	?	53,600
Scope 2	2,275	166,711	312	400	477	1,153	14,060	10,858	39,851	1,470,000	390,158	72,500
Scope 3	52,001		2,004,635	984,610	67			2,972,433				50,200,000
Cat 1: Purchased goods and services								757,671				9,400,000
Cat 3: Fuel and energy-related activities								1,132,578				
Cat 4: Upstream transport and distribution	52,001											
Cat 6: Business travel			3,716	960	67			12,280				
Cat 7: Employee commuting			796	1,340				7,116				
Cat 8: Upstream leased assets								40,438				
Cat 11: Use of sold products			1,809									40,800,000
Cat 13: Downstream leased assets			1,998,315	982,310				999,402				
Cat 15: Investments								22,948				

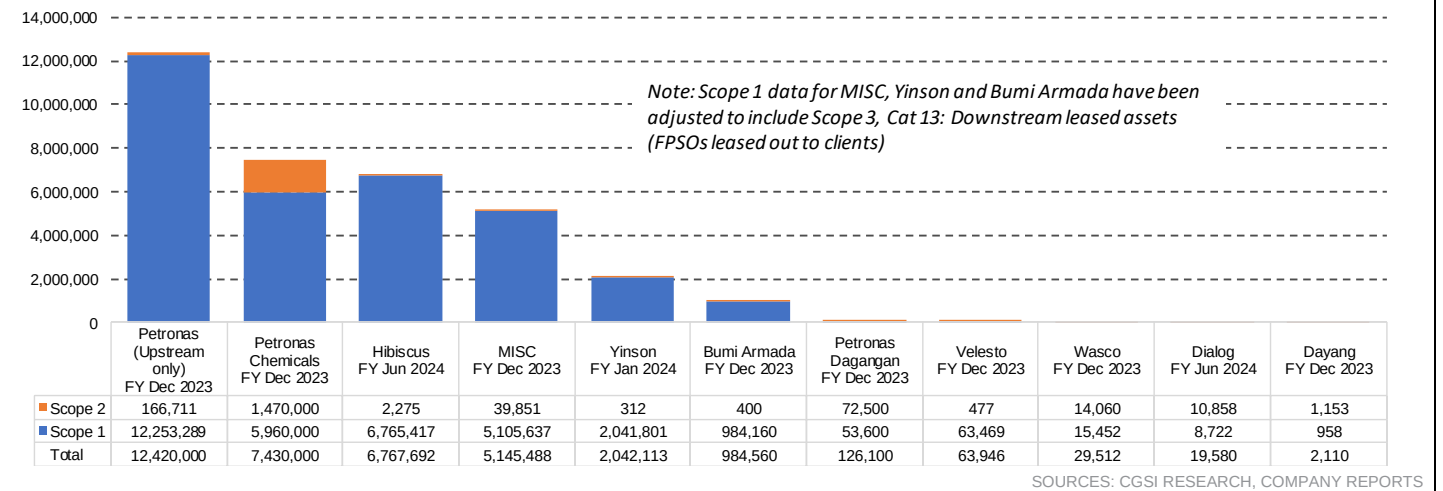
Note: Yinson, Bumi Armada and MISC operate FPSO vessels on behalf of their customers, and the emissions from those FPSOs belong to their customers which operate the oil and gas fields on which those FPSOs are deployed. This is the reason why those FPSO emissions are classified by Yinson, Bumi Armada and MISC as Scope 3 emissions under 'Category 13: Downstream Leased Assets', rather than as Scope 1 emissions.

SOURCES: CGSI RESEARCH, COMPANY REPORTS

For upstream services companies that operate FPSOs like **Yinson**, **Bumi Armada** and **MISC**, the FPSO emissions are not included as Scope 1 emissions; rather they are included as Scope 3 emissions under Category 13: Downstream leased assets. This is because the oil companies that lease those FPSOs control the operations of those FPSOs; hence the FPSOs' emissions are Scope 1 to those oil companies.

However, in Figure 126, we have reclassified those Category 13 emissions as Scope 1 in order to better visualise emissions from those FPSO operators. For the purposes of measuring emissions intensity per million ringgit of revenue (Figure 127), we have also made the same reclassification, as the FPSO leasing revenues are included as part of the revenues of Yinson, Bumi Armada and MISC.

Figure 126: Malaysia Oil & Gas sector: Scope 1 and Scope 2 CO₂e emissions (tCO₂e)



From the perspective of emissions intensity, calculated as Scope 1 and 2 CO₂e emissions per million ringgit of revenue, Hibiscus is the most significant emitter, significantly higher than the upstream division of Petronas as a direct comparable, and also significantly higher than the other downstream, midstream, and upstream oil and gas service providers in Malaysia (Figures 127-128).

Figure 127: Emissions intensity (tonnes of Scope 1 and 2 CO₂e emissions per million revenue)

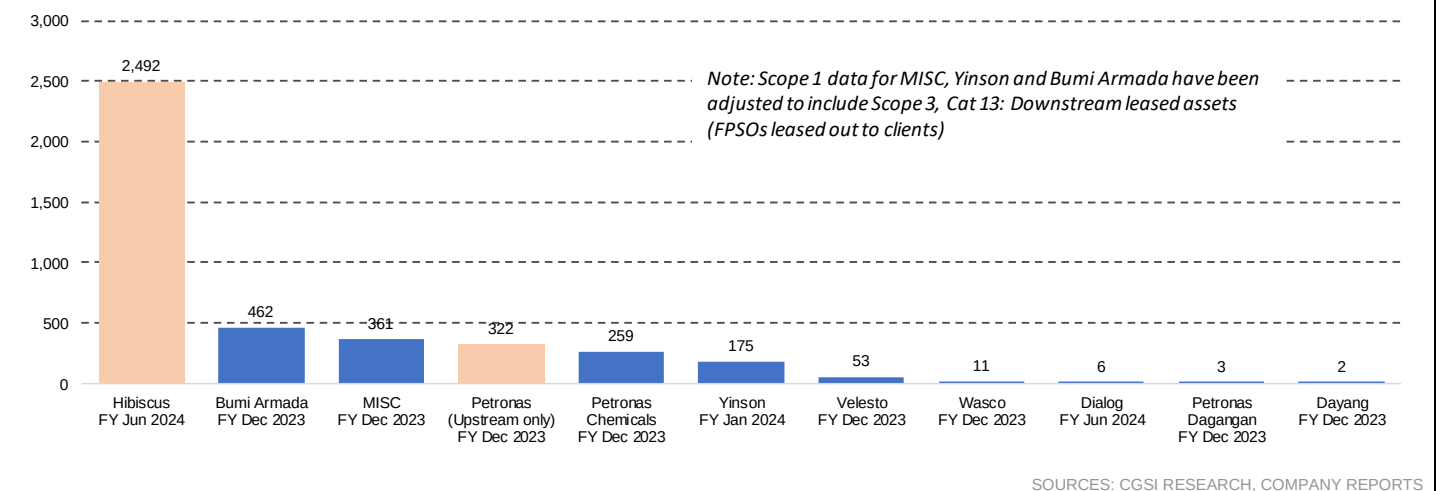
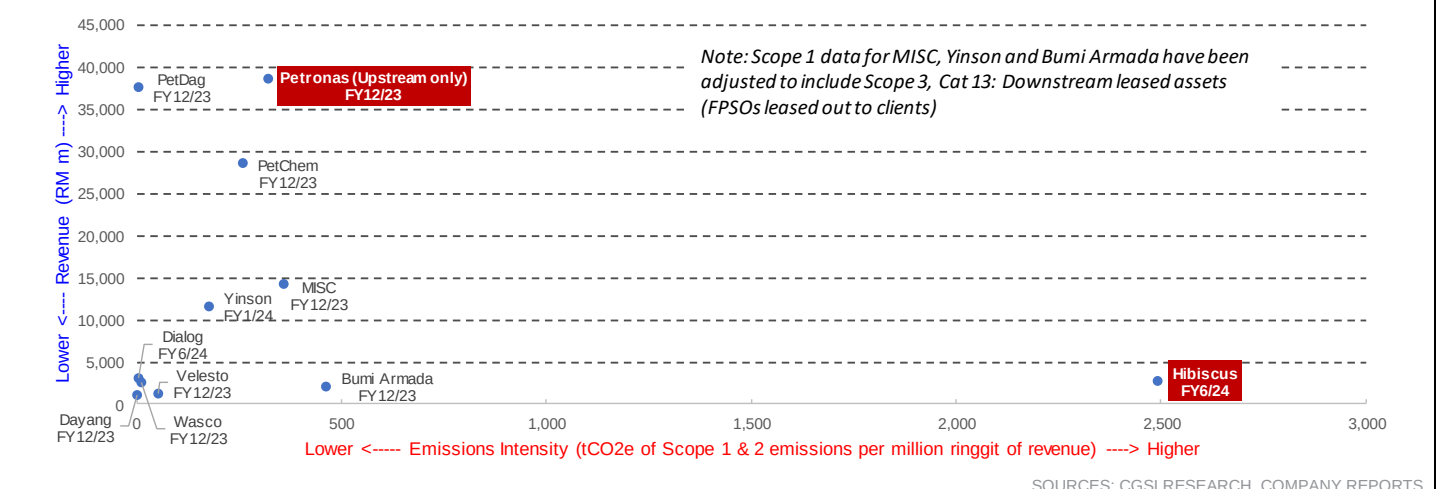


Figure 128: Emissions intensity (tCO₂e of Scope 1 & 2 emissions per million ringgit of revenue) vs. revenue (RM m)



Sources of Hibiscus's GHG emissions ►

A detailed breakdown and tabulation of Hibiscus's Scope 1, 2 and 3 GHG emissions can be found in Appendix 10.

Scope 1 emissions ►

Hibiscus's Scope 1 GHG emissions arise mainly from three key sources:

- From the **venting of CO₂ and methane by the AGRU**. The sales gas cannot have more than 8% of CO₂ content based on buyer specifications, but the wellhead gas extracted at PM3 CAA has CO₂ content of 40-44%. The captured CO₂ is then vented from the acid gas removal unit (AGRU). The AGRU also cannot capture all of the methane because it is a physical separation process; hence some residual methane is also vented out together with the CO₂.
- From the **energy consumed by the equipment** on the oil and gas fields, e.g. the AGRU, gas compressors, diesel-powered generators, etc. Gas compressors compress gas from the natural pressure of 2,500 kPa to 14,000 kPa to send the gas via pipeline to be processed (e.g. at Kinabalu, and at Brunei MLJ), or to facilitate gas lift operations or to inject into the subsea reservoir to increase oil production rates (e.g. at North Sabah).
- From the **flare stack**, where associated gas needs to be burned off for safety and process reasons. Sometimes, the gas compressor may be offline, but the production of oil is continuing; hence the associated gas that is produced with the oil has to be flared.

Scope 2 emissions ►

Scope 2 emissions arise only in relation to purchased electricity for Hibiscus's offices. There are no Scope 2 GHG emissions at offshore operations; all GHG emissions at offshore operations are Scope 1 emissions. Hibiscus's Scope 2 emissions are inconsequential at only 0.034% of its total Scope 1 and 2 GHG emissions.

Scope 3 emissions ►

Hibiscus disclosed its Scope 3 emissions data for FY22, FY23 and FY24 in relation to its **North Sabah** asset under '**Category 4: Upstream Transportation and Distribution**'. According to Hibiscus, this relates to the emissions from the diesel consumption of third-party OSV vessels used in its North Sabah offshore operations, such as accommodation work barges (AWB), workboats, and anchor handling towing supply (AHTS) vessels.

Category 4 emissions data is also available for Anasuria Cluster, Kinabalu and PM3 CAA, but have not been disclosed as Hibiscus is debating internally if the CO₂e emissions from OSV fuel consumption is to be classified as Scope 3 or Scope 1, since Hibiscus actually pays for the fuel used by the OSVs. We would argue that those emissions from OSVs' fuel consumption are by their very nature Scope 3 emissions; if Hibiscus did not pay for the OSVs' fuel consumption, the OSVs' daily charter rates would simply be adjusted higher, hence we view this as a financial arrangement borne out of conventional practice.

Hibiscus did not include any Scope 3 emissions from 'Category 9: Downstream transportation and distribution', because its oil production is sold to its sales agents and offtakers such as Trafigura (for North Sabah), BP (for Anasuria Cluster) and PETCO (for Kinabalu and PM3 CAA), and from FY25F onwards, TotalEnergies (for Brunei MLJ). The offtakers are the ones responsible to arrange for downstream transportation, and those emissions rightly belongs to them.

Hibiscus did not include any Scope 3 emissions from 'Category 10: Processing of Sold Products', and 'Category 11: Use of Sold Products'. The challenge of

reporting Category 10 is Hibiscus's lack of information in terms of which refinery is processing the oil, given that different refineries have different emissions factors. As noted earlier, Hibiscus does not sell the crude oil directly to the refineries, but rather through its sales agents and offtakers. Meanwhile, downstream distributors such as oil distributors like Petronas Dagangan will report Category 11 emissions as their Scope 3 emissions, so we think that Hibiscus should not report it to avoid double counting.

Further analysis of Hibiscus's Scope 1 emissions ➤

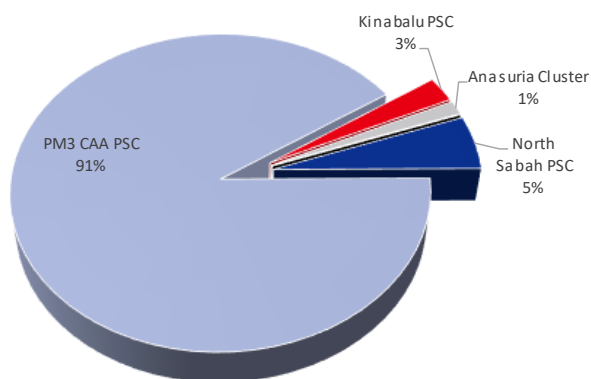
The **PM3 CAA** asset singlehandedly contributed **91%** of Hibiscus's Scope 1 and 2 emissions in FY24 (Figure 129). PM3 CAA's primary production is that of natural gas, but the natural gas extracted at the wellhead from PM3 CAA is acidic in nature and has a very high CO₂ content of 40-44%. This exceeds the gas purchasers' specification that the sale gas does not contain more than 8% CO₂ content (because too much CO₂ content reduces the heating value of the gas).

As a result of the high CO₂ content in the PM3 CAA wellhead gas, the AGRU is required to separate the CH₄ from the CO₂ and reduce the content of CO₂ in the sale gas to not more than 8%. The CO₂ captured by the AGRU is then vented into the atmosphere. Some methane gas is also inadvertently vented into the atmosphere, as the AGRU involves a physical separation process which is imperfect and hence cannot capture all of the methane gas. Both the vented CO₂ and the vented CH₄ gases are GHGs, and such venting from PM3 CAA's **AGRU** contributed **71%** of Hibiscus's Scope 1 and 2 emissions in FY24 (Figure 130).

Combustion contributed a further **20%** of Hibiscus's emissions last financial year, of which 80% was combustion originating from PM3 CAA. This is largely due to the energy requirements of the AGRU, which is powered by the combustion of natural gas from PM3 CAA. In short, the processing requirements of the sour gas (high CO₂ content) found in PM3 CAA is the main source of Hibiscus's GHG emissions.

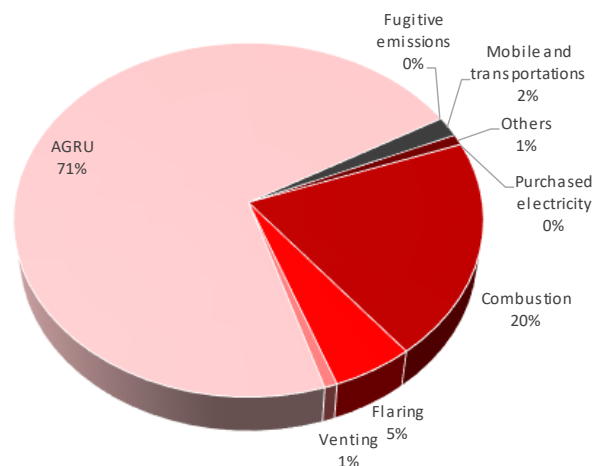
Flaring contributed **5%** of Hibiscus's GHG emissions in FY24, of which North Sabah contributed 47%, Kinabalu 26%, and PM3 CAA 22%, and the residual 5% contributed by Anasuria Cluster. The associated gas produced at North Sabah is not sold, but rather reinjected into the reservoirs in order to enhance oil production; however, unplanned outages at the gas compressors at North Sabah may have resulted small amounts of flaring. At Kinabalu, the gas compressors that send the associated gas to another platform do not have sufficient capacity to manage the volumes of gas being produced, also resulting in small amounts flaring; the Kinabalu gas compressors are currently being upgraded to reduce incidences of flaring.

Figure 129: Breakdown of Hibiscus's gross Scope 1 and 2 GHG emissions by asset (FY24)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 130: Breakdown of Hibiscus's gross Scope 1 and 2 GHG emissions by source (FY24)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

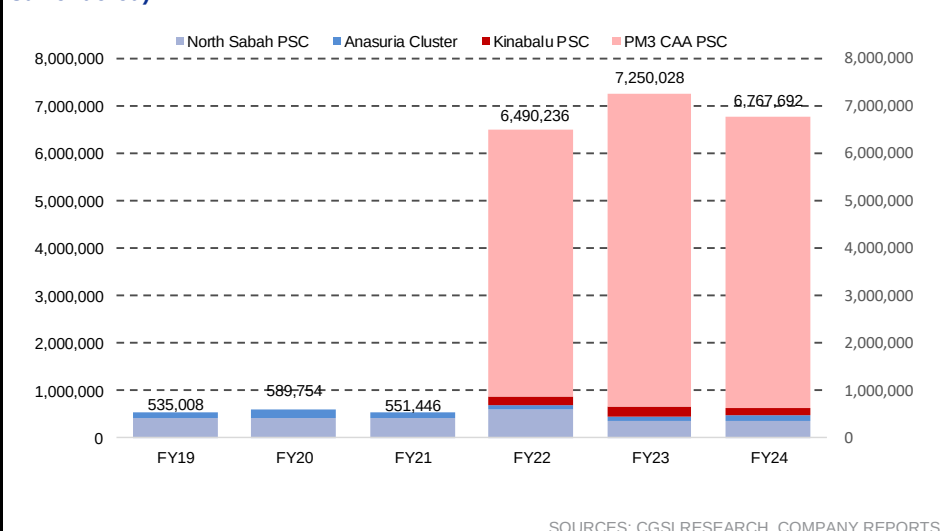
Movement in Hibiscus's GHG emissions ►

Hibiscus's gross GHG emissions spiked in FY22 after it had completed the acquisition of the assets sold by Repsol, of which the most consequential were Kinabalu and PM3 CAA. Although the acquisition was finalised only on 24 Jan 2022, Hibiscus had – for disclosure purposes – incorporated the emissions of Kinabalu and PM3 CAA for the whole of FY22 (Figure 131).

In FY23, gross GHG emissions rose 11.7% yoy (with the emissions for the acquired Repsol assets included for a full year in FY22), which was in excess of the 7.6% yoy increase in production; this resulted in a 3.8% yoy increase in emissions intensity to 231.70 tCO₂e/kboe. The main cause of this was the yoy increase in PM3 CAA's absolute GHG emissions in FY23 despite a yoy decline in production rate, which could have been due to various operating issues.

In FY24, there was more favourable news in terms of emissions performance, because gross GHG emissions fell 6.7% yoy despite gross production rising 3.9% yoy, resulting in a substantial 10.2% yoy decline in emissions intensity to 208.07 tCO₂/kboe. This was again due almost entirely to the improvement in PM3 CAA's emissions performance; even though its production rose yoy in FY24, it managed to deliver a yoy drop in absolute emissions due to the implementation of the Membrane Phase 1 project in Apr 2022 (late-FY23) and the progressive implementation of the Membrane Phase 2 project from Dec 2023 onwards (mid-FY24).

Figure 131: Hibiscus's gross Scope 1 and 2 GHG emissions by asset (tCO₂e) - actual historical emissions (prior to deducting emissions at Anasuria Cluster relating to UKA surrendered)



Targets and pathways to reduction of Hibiscus's GHG emissions ►

Hibiscus has already made some notable achievements since its wholly-owned subsidiary Peninsula Hibiscus completed the acquisition of Repsol's assets:

- Up to FY24, net GHG emissions based on operational control has declined **20.4%** to 6.7 MMtCO₂e from 8.42 MMtCO₂e in the FY20 baseline (Figure 132); while
- The net GHG emissions intensity has declined **6.9%** to 208.07 tCO₂e/kboe of production vs. the FY20 baseline of 223.44tCO₂e/kboe (Figure 133).

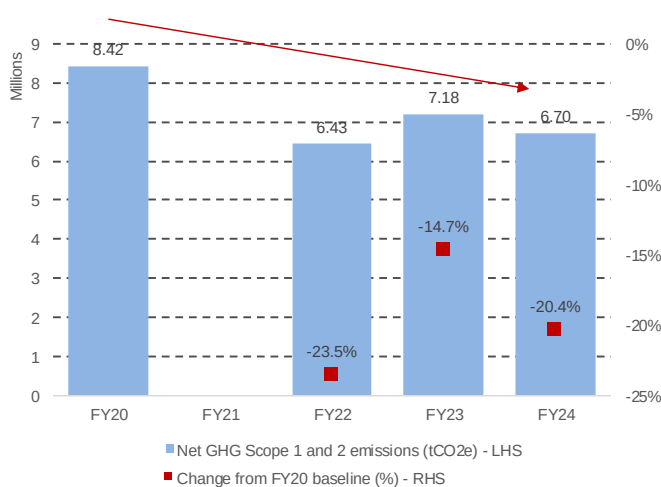
In both cases, we highlight that the FY20 emissions baseline has been retrospectively adjusted upwards as if the acquisition of the Repsol assets had taken place at the beginning of FY20, even though the acquisition was actually completed only on 24 Jan 2022. This rebasing is permitted by globally-accepted

GHG accounting methodology upon mergers and acquisitions. In the future, Hibiscus will retrospectively lift the FY20 absolute GHG emissions baseline again, in order to incorporate the Brunei MLJ acquisition that was completed on 14 Oct 2024, although we expect the inclusion of Brunei MLJ to reduce the Hibiscus group's average emissions intensity metric due to the low-CO₂ content of the gas produced at Brunei MLJ.

The 20.4% decline in the absolute emissions relative to the FY20 baseline was the combined effect of the:

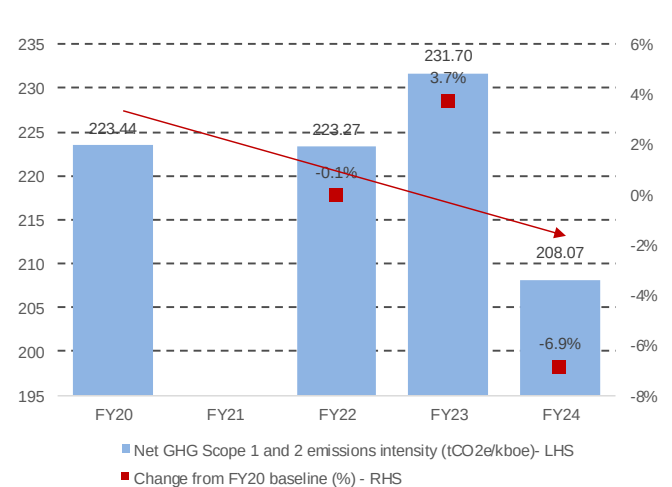
- 14.5% decline in the production between the FY20 baseline and FY24; and
- 6.9% decline in the emissions intensity due to various emissions-reduction projects, such as the progressive installation of advanced membrane units at PM3 CAA's AGRU between Apr 2022 and 3QCY24 (Figure 134).

Figure 132: Net GHG emissions (operational control) vs. FY20 baseline (tCO₂e)



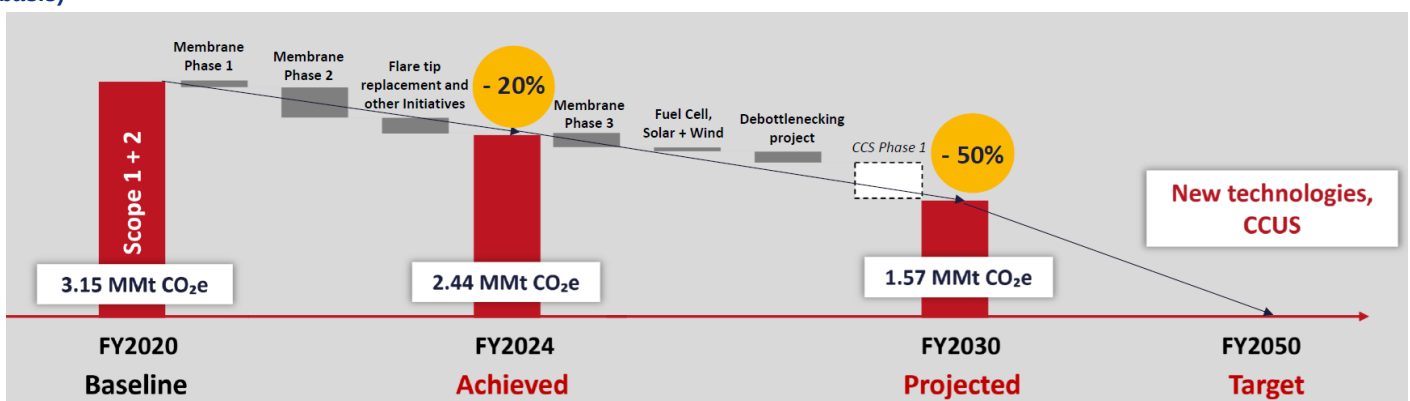
SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 133: Net GHG emissions intensity (operational control) vs. FY20 baseline (tCO₂e/kboe)



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 134: Pathways to 50% GHG emissions reduction by FY30F (vs. FY20 baseline) and net zero by FY50F (working interest basis)



NOTE: This chart shows Hibiscus's equity share (working interest) in GHG emissions. On an operational control basis, the FY20 baseline was 8.42 MMtCO₂e, while the FY24 emissions was 6.70 MMtCO₂e.

SOURCE: HIBISCUS

Moving forward, Hibiscus has two goals (Figure 134):

- The **interim FY30F goal is to reduce absolute emissions by 50%** relative to the FY20 baseline;
- The ultimate goal is to achieve its **Net Zero 2050 target**, in terms of absolute emissions (net zero for Scope 1 and 2 emissions only; no consideration for Scope 3 emissions).

Hibiscus sets its GHG targets in terms of absolute GHG emissions, rather than in terms of emissions intensity. This is understandable, because emissions intensity typically increases as production volume decreases as the oil and gas fields progressively deplete.

However, the downside of setting absolute GHG emissions targets is that ongoing natural declines in production volume will also result in lower GHG emissions, of which credit should not be attributed to Hibiscus, in our view.

While Hibiscus has disclosed its target to reduce absolute GHG emissions (working interest basis) by **36%** from FY24's 2.44 MMtCO₂e to **FY30F's 1.57 MMtCO₂e**, Hibiscus did not disclose what level of absolute production it hopes to achieve in FY30F. This makes it difficult to analyse how much of the absolute GHG emissions decline targeted for FY30F can be attributed to natural production decline between now and then, and how much can be attributed to specific technical and project-based efforts at reducing emissions.

What we do know is that Hibiscus's FY30F absolute GHG emissions target is based on the following assumptions for production levels:

- The extension of the PM3 CAA PSC licence from its current expiry of 31 Dec 2027F, by at least 10 years or even up to 20 years, that will add to future production;
- The continued development of new fields that will also contribute to increased production. Hibiscus plans to start production at Teal West in the UK by end-CY25F and at the PKNB Cluster by CY28F, while the PM327 block will be explored with a view to future development;
- However, the above additions to production may be more than offset by natural production decline in the existing fields, in our view.

As a result, we believe that Hibiscus's absolute emissions target of 1.57 MMtCO₂e by FY30F can be partly attributed to overall production decline, and partly to four potential future projects that are intended by Hibiscus to reduce the emissions intensity of its hydrocarbons production.

Having said this, we are confident that Hibiscus is committed to executing most of the proposed projects between FY25F and FY30F.

Figure 135: Pathway to GHG emissions reduction (operational control basis, and working interest basis) - from information supplied by Hibiscus

	a	b	c = a x b	d	e = a / d	Notes
	Hibiscus's net emission (operational control) tCO ₂ e	Working interest %	Hibiscus's share of net emissions (working interest) tCO ₂ e	Gross production (operational control) kboe	Emissions intensity tCO ₂ e/kboe	
FY20 emissions baseline (Scope 1 and 2)	8,416,395		3,150,000	37,667	223.44	
<u>Projects:</u>						
- Membrane Phase 1	-228,571	35%	-80,000			Project executed at PM3 CAA
- Membrane Phase 2	-1,428,571	35%	-500,000			Project executed at PM3 CAA
- Flare tip replacement and other initiatives	-56,057	0%	-126,777			The replacement of more reliable flare tips in North Sabah in 4Q23 has helped to reduce venting at the facilities, per Annual Report 2024
FY24 emissions level (Scope 1 and 2)	6,703,195		2,443,223	32,216	208.07	
<i>Change from the FY20 baseline</i>	<i>-20.4%</i>		<i>-22.4%</i>	<i>-14.5%</i>	<i>-6.9%</i>	
<u>Projects:</u>						
- Membrane Phase 3	-457,143	35%	-160,000			Project to be executed at PM3 CAA
- Fuel cell, solar and wind	-120,000	50%	-60,000			Assumed projects executed at North Sabah; fuel cell, solar and wind projects has the potential to reduce emissions between 30 tCO ₂ e and 90 tCO ₂ e p.a.
- Kinabalu gas compressor debottlenecking project	-166,667	60%	-100,000			Project currently being executed at Kinabalu
- CCS Phase 1	-1,571,429	35%	-550,000			Project to be executed at PM3 CAA
FY30F emissions level (Scope 1 and 2)	4,387,957		1,573,223			
<i>Change from the FY20 baseline</i>	<i>-47.9%</i>		<i>-50.1%</i>			
CGSI comment: Production decline between FY20 and FY24 also likely contributed to absolute emissions reduction of c.20%, but this was not specifically quantified by Hibiscus. Hibiscus attributed the entire absolute emissions decline to specific projects, which is likely overstating the impact of the projects, in our view. Similarly, the targeted reduction in absolute emissions further to FY30F was also entirely attributed to specific projects, and Hibiscus did not disclose how future changes in production (whether upwards or downwards) will affect absolute emission levels before taking into account the impact of any emissions-reduction projects.						

SOURCES: CGSI RESEARCH, COMPANY REPORTS

The membrane projects (Phase 1, 2 and 3) at PM3 CAA >

The AGRU is a complex set of equipment, and is intended to first dehumidify the natural gas, then remove the mercury and H₂S, and then send the gas through the membrane structures to physically separate the CH₄ from the high concentration of CO₂ contained in the gas. The CO₂ is vented into the atmosphere and the CH₄ is monetised as sales gas.

Over time, the existing membranes have aged and have become less efficient in separation, meaning that a greater volume of CH₄ is not properly separated and is flared before being vented into the atmosphere together with the removed CO₂. This causes economic loss to Hibiscus as it could not sell the CH₄ as sales gas, and also results in the undesired flaring and venting.

The purpose of the advanced membrane projects, Phase 1, 2 and 3, is intended to improve the effectiveness of the CH₄-CO₂ separation process and to reduce the flaring of CH₄. This entails the replacement of the old membranes with new and better ones that have improved technologies for better gas separation.

The **Membrane Phase 1** trial was very limited in nature, and executed in Apr 2022 as a test to see how much CH₄ can be captured and flaring/venting reduced. The Phase 1 trial managed to achieve GHG reduction of **80,000 tCO₂e p.a.** at the working interest level, according to Hibiscus. By capturing the methane via these membrane projects, the CH₄ will not need to be flared, which then reduces the GHG emissions.

After the Membrane Phase 1 trial was completed, Hibiscus moved on to a more extensive Membrane Phase 2 which began in Dec 2023 and is targeted for completion by end-CY24F. According to Hibiscus's Annual Report 2024, **Membrane Phase 2** can facilitate emissions reduction of **200,000 to 500,000 tCO₂e p.a.** at the working interest level.

In the future, Hibiscus is considering the **Membrane Phase 3** project. However, while the Phase 1 and 2 projects have been very effective in capturing the methane gas molecules (as they were implemented in the secondary skids that do most of the work of recovering CH₄ from the raw gas), Hibiscus assesses the Phase 3 project as potentially being less effective in capturing CH₄ for technical reasons (as it will be implemented in the primary skids). If Hibiscus decides to proceed with the Membrane Phase 3 project, we expect GHG emissions reduction of **160,000 tCO₂e p.a.** at a working interest level, or 457,143 tCO₂e p.a. at the operational control level after grossing up by Hibiscus's 35% participating interest in PM3 CAA.

The capex cost from the membrane projects is cost recoverable from Petronas, and the PSC partners will also contribute their share of the capex (Hibiscus only bears the capex up to its 35% participating interest). The other PSC partners in PM3 CAA are Petronas Carigali and PetroVietnam Exploration Production Corporation (PVEP).

Kinabalu gas compressor debottlenecking project >

Hibiscus has been undertaking an upgrade and debottlenecking of the gas compressor at the Kinabalu PSC since Mar 2022 and this project is slated to finish in FY25F (the current financial year). The project involves improving the efficiency of the low-pressure and high-pressure compressors at the Kinabalu Complex to increase the amount of produced gas that can be transported to the Semarang platform, thereby reducing the need for flaring.

At the Kinabalu PSC, Hibiscus is only entitled to the oil production from the two platforms that it operates, with all rights to the associated gas is relinquished to Petronas (associated gas is the gas that is produced together with the oil). Separately, Petronas Carigali also produces non-associated gas from a third platform at the Kinabalu Complex that does not involve Hibiscus. The associated and non-associated gas produced at Kinabalu are sent to the nearby Semarang platform that is operated by Petronas Carigali.

According to Hibiscus, the limitations of the current gas compressors at the Kinabalu Complex result in a small amount of produced gas that cannot be

transported to the platform and is instead flared, resulting in higher GHG emissions. Hence, the project to upgrade the capacity of the Kinabalu gas compressor will help:

- To reduce flaring;
- To increase the volume of gas that can be compressed and sent to Semarang to be monetised; and at the same time
- To increase the volume of oil that can be produced due to reduced backpressure to the well at the processing facilities.

According to Hibiscus, the upgrading of the Kinabalu gas compressor can reduce GHG emissions by **100,000 tCO₂e p.a.** at a working interest level, or 166,667 tCO₂e p.a. at the operational control level after grossing up by Hibiscus's 60% participating interest in the Kinabalu PSC.

Carbon capture and storage (CCS) project at PM3 CAA ➤

In our view, it will be highly desirable for CCS to be implemented at the PM3 CAA Complex, given the significant emissions from that complex.

While the PM3 CAA PSC is expiring on 31 Dec 2027F, we are reasonably confident that the PSC will be extended by some 10 years at the minimum, or potentially up to 20 years to 31 Dec 2047F, based on feedback from Hibiscus. Due to ESG considerations, we believe that all the PSC partners are likely to be onboard to undertake a **CCS Phase 1** project if and when the PSC is extended.

Hibiscus commenced the first part of its CCS study on reservoir candidates screening, storage capacity and flow assurance study in May 2023, and this has since been completed. The second part of the CCS study on its economic feasibility and overall concept is ongoing and will be completed by end-2024F, according to Hibiscus.

The CCS Phase 1 project is likely to be operational in the **2028-2029F timeframe**, according to Hibiscus. The CO₂ itself is captured by the AGRU, which separates the CO₂ from the CH₄ sales gas. However, instead of venting the captured CO₂ into the atmosphere, the CCS Phase 1 project will reinject the CO₂ into depleted PM3 CAA gas reservoirs for geological storage.

Hibiscus estimates that CCS Phase 1 can reinject between **500,000 and 800,000 tCO₂ p.a.** into depleted gas wells at the working interest level, or between 1.4 MMtCO₂e and 2.3 MMtCO₂ p.a. at the operational control level after grossing up by Hibiscus's 35% participating interest in the PM3 CAA PSC.

The AGRU vented 4.8 MMtCO₂e into atmosphere in FY24 on an operational control basis; this suggests that the CCS Phase 1 project could have prevented **between 29% and 48%** of the CO₂ emissions from the AGRU if it had been implemented at the start of FY24.

Given the high cost of the potential CCS solution at PM3 CAA, it is imperative for the project to be **cost recoverable** under the terms of the PSC extension that is to be effective from 1 Jan 2028F; this has not yet been confirmed. In any case, Hibiscus, Petronas Carigali and PetroVietnam will all have to fork out their portion of the capex cost in proportion to their working interest in PM3 CAA, if the CCS Phase 1 project goes ahead. Hibiscus has not yet provided guidance on the potential capex cost of the CCS Phase 1 solution, and neither has it officially selected its technology partners.

CCS Phase 2 (post-FY30F) may involve a larger volume of CO₂ removal of between 1 MMtCO₂e to 3 MMtCO₂e p.a. at the working interest level, and will be executed in conjunction with the start-up of the operations at the PKNB Cluster and PM327 fields, which will be developed in the future via tie-back to the PM3 CAA facilities, according to Hibiscus.

Fuel cell, solar and wind initiatives ➤

Hibiscus expects additional renewable energy (RE) initiatives to reduce emissions by between **30 tCO₂e and 90 tCO₂e p.a.** in the period between FY25F and FY30F, which is very minor.

Up to FY24, Hibiscus has installed some RE sources to power its offshore platforms and facilities. At North Sabah, Hibiscus has 21 platforms across four fields; solar photovoltaic (PV) installations have been placed at eight platforms across four fields, while wind turbines have been installed at two platforms across two fields. Hibiscus also plans to install more offshore hybrid solar PV and wind turbine systems in several platforms in 2025. Hibiscus is also exploring the feasibility of using fuel cells.

It will be difficult for Hibiscus to use RE to a greater extent, mainly due to space limitations at the platforms, and the intermittency of RE which then results in an immaterial contribution to the platforms' overall power needs. Wind turbines are generally not very useful in Malaysia as the country is located in a low-wind speed region. Hence, RE installations are typically placed on satellite platforms (rather than at main platforms) where energy consumption is less, with the RE paired with small battery systems to be used primarily as backup power especially during the monsoon season when it may be harder for OSVs to deliver diesel supplies over to the offshore platforms for genset usage.

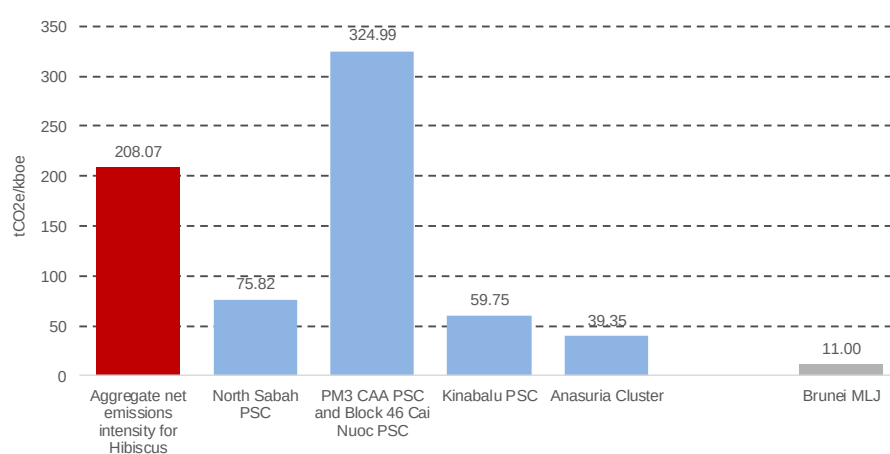
Brunei MLJ asset to reduce Hibiscus's weighted average emissions intensity ➤

Hibiscus completed the acquisition of TotalEnergies EP (Brunei) BV on 14 Oct 2024, and this gives Hibiscus a 37.5% equity stake in the Brunei Block B MLJ field. The emissions of the Brunei MLJ field will only be incorporated into Hibiscus's disclosures from FY25F onwards and we currently do not have any official GHG emissions disclosures from the field.

However, Hibiscus did disclose that Brunei MLJ is producing gas and condensate at a low GHG emissions intensity of 11 tCO₂/kboe, which compares very favourably with Hibiscus's existing portfolio (Figure 136). This is because of the

- high proportion of gas in the output of Brunei MLJ; and because
- the Brunei MLJ gas is sweet with low CO₂ content.

Figure 136: Net emissions intensity for Hibiscus's assets in FY24 (tCO₂e/kboe) – Brunei MLJ data is for CY23



SOURCES: CGSI RESEARCH, COMPANY REPORTS

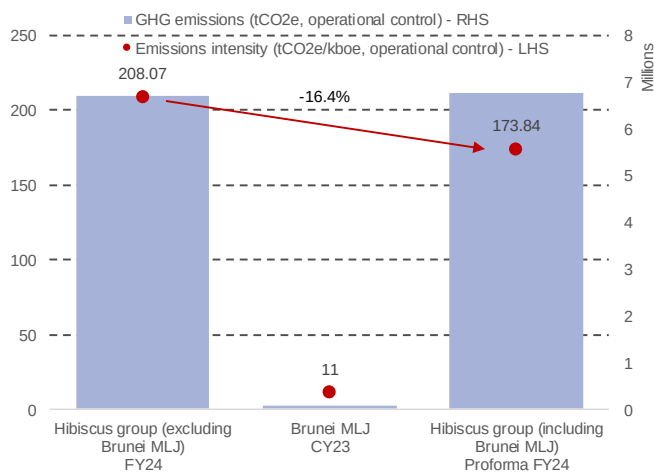
Brunei MLJ has a lower emissions intensity than the rest of Hibiscus's assets because in 2023, gas comprised 87% of Brunei MLJ's production on a boe basis, and gas production typically releases less GHG emissions than oil production. In Hibiscus's portfolio, North Sabah, Kinabalu and Anasuria Cluster are principally oil production assets. While PM3 CAA is principally a gas production asset, with gas comprising 62% of its boe production, oil production is still a sizable portion of its production.

In a report published in May 2023, the International Energy Agency (IEA) noted that in 2022, global upstream oil production had an emissions intensity of 62 tCO₂e/kboe, whereas global upstream gas production had an emissions intensity of 43 tCO₂e/kboe (excluding emissions from midstream transportation and downstream processing). Oil production may release more emissions because as a liquid, it may require more energy to pump out of the subsurface. In addition, a part of the associated gas from the oilfield may be flared if it cannot be economically monetised, and a part of the associated gas may also be reinjected into the oil reservoir to enhance rates of recovery, which also consumes energy.

Another reason for the low emissions intensity of the Brunei MLJ asset, is because its gas has CO₂ content of less than 10%, in our estimate. By comparison, PM3 CAA gas has a high CO₂ content of 40-44% which is separated at the AGRU and then vented into the atmosphere, while some CH₄ is also inadvertently vented with the CO₂ due to the imperfect physical separation process.

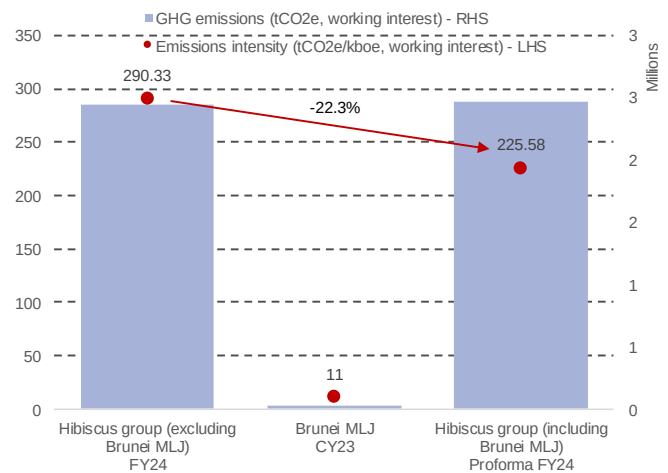
Hibiscus also claimed that Brunei MLJ outperforms the global average emissions intensity of 18 tCO₂/kboe. We expect the inclusion of Brunei MLJ to help Hibiscus reduce the overall emissions intensity of its oil and gas production portfolio.

Figure 137: Operational control net emissions intensity to drop post-acquisition of Brunei MLJ



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 138: Working interest net emissions intensity to drop post-acquisition of Brunei MLJ



SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 139: Impact on emissions intensity of the Brunei MLJ acquisition

		Operational control basis	Working interest basis	Notes
Brunei MLJ				
Brunei MLJ production (kboe, CY23)	a	6,771	2,539	As disclosed in the Brunei MLJ acquisition shareholder circular
Brunei MLJ emissions intensity (tCO ₂ e/kboe, CY23)	b	11	11	As unofficially disclosed by Hibiscus
Brunei MLJ GHG emissions (tCO ₂ e, CY23)	c = a x b	74,485	27,932	
Hibiscus group (excluding Brunei MLJ)				
Hibiscus group production (kboe, FY24)	d	32,216	8,415	Working interest production estimated by CGSI
Hibiscus group emissions intensity (tCO ₂ e/kboe, FY24)	e = f / d	208.07	290.33	Working interest emissions intensity is higher than operational control emissions intensity because Hibiscus includes the GHG emissions from various assets based on its respective equity shares. However, Hibiscus's net entitlement of production for its PSC assets (North Sabah, Kinabalu and PM3 CAA) is always lower than its respective equity shares, due to the structure of the PSC terms and conditions.
Hibiscus group Scope 1 and 2 GHG emissions (tCO ₂ e, FY24)	f	6,703,195	2,443,223	These Hibiscus emissions are net of UKAs surrendered under the UK ETA
Hibiscus group (including Brunei MLJ)				
Total enlarged production (kboe)	g = a + d	38,987	10,955	
Enlarged group emissions intensity (tCO ₂ e/kboe)	h = i / g	173.84	225.58	
Total enlarged emissions (tCO ₂ e)	i = c + f	6,777,680	2,471,155	
Decline in emissions intensity (%)	j = (h/e) - 1	-16.4%	-22.3%	Emissions intensity declines 16% under operational control and 22% under working interest basis

SOURCES: CGSI RESEARCH, COMPANY REPORTS

New solar farm in Brunei to reduce OPP emissions ➤

To reduce the Brunei MLJ emissions intensity further, TotalEnergies had approved the new solar farm project beside the Onshore Processing Plant (OPP) prior to the sale of the asset to Hibiscus. According to Hibiscus, it is eager to implement the project, over a period of three years between 2025 and 2027F, with the solar energy to be used to power part of the OPP's energy requirements, specifically the low-pressure compressor (LPC) that will be installed in 2HCY25F.

Over an area of 22.41 acres, a solar farm can be set up with a capacity of c.13 MW, and produce c.18,000 MWh of electricity p.a. once fully built (13 MW x 24 hours x 365 days x 15.8% solar capacity factor). According to Hibiscus, the solar farm can avoid emissions of **c.11,500 tCO₂e p.a.** (based on a carbon avoidance ratio of 0.639 tCO₂e/MWh), which would represent c.15% of Brunei MLJ's operational control emissions of 74,485 tCO₂e in 2023. In reality, the potential emissions offset should be less than 15% because the LPC is a new piece of equipment that we expect will increase the OPP's power requirements once it becomes operational in the future.

The UK EMISSIONS TRADING SCHEME (ETS) ➤

The UK ETS replaced the UK's participation in the European Union Emissions Trading Scheme (EU ETS) on 1 Jan 2021. The UK ETS plays an important role in the UK's ambition to be Net Zero by 2050. The UK sets its carbon budget based on its climate goals, and allocates free carbon allowances to various companies based on their relative size and activity levels.

AOCL, the operator of the Anasuria Cluster, is subject to the rules of the UK ETS. This means that AOCL needs to surrender one UK Allowance (UKA) for every one tCO₂ that it emits in excess of its permitted free allowances for each calendar year period. AOCL does not need to surrender UKAs for its non-CO₂ GHG emissions like N₂O.

AOCL can purchase the UKAs from the UK government's auctions or from the secondary market, and AOCL can warehouse the UKAs as 'Intangible Assets' on its balance sheet.

AOCL will report its emissions to the regulator on a calendar year basis and surrender UKAs in Apr of every year with respect to emissions above its free allowances.

The Anasuria facilities have been allocated 27,997 free UKA p.a. from 2021 to 2025F. Given that AOCL emitted 94,885 tCO₂ in FY23 and 92,494 tCO₂ in FY24 (CO₂ emissions only, excluding emissions of CH₄, N₂O and HFCs), which were above the allocation of free allowances, AOCL was obligated to purchase and surrender 66,887 UKAs in FY23 and 64,497 UKAs in FY24, at an average price of GBP63.21 and GBP66.62, respectively (Figure 140).

Figure 140: AOCL: Number of UKAs surrendered and average price paid

		FY23	FY24
Carbon emissions (tCO ₂)		94,884	92,494
Deduct: Free allowances (tCO ₂)		-27,997	-27,997
Number of UKAs that need to be surrendered (tCO₂)	<i>a</i>	66,887	64,497
Cost incurred (RM m)	<i>b</i>	25.0	25.4
Average RM:GBP1	<i>c</i>	5.9126	5.9116
Average price of UKAs paid (GBP/tCO₂)	<i>d = (b/c) / a</i>	63.21	66.62

SOURCES: CGSI RESEARCH, COMPANY REPORTS

The price paid by AOCL in FY23 looks reasonable relative to the average auction price of GBP70 for the UKAs in that time period. Unfortunately, AOCL had probably warehoused too many surplus UKAs prior to FY24, and AOCL's average UKA cost of GBP66.62 in FY24 was much higher than the average auction price of GBP39 in that financial year. This was because UKA prices corrected significantly from 2023 onwards and currently remains below GBP40 (Figure 141).

Figure 141: UK Allowance (UKA) auction prices (GBP/tCO₂)



UKA prices had corrected significantly because of the following reasons:

- When the UK ETS took the place of the European Union Emissions Trading Scheme (EU ETS) in 2021, British power plants had to sell their inventory of European Union Allowances (EUA) and purchase UKAs in their place, as only UKAs can be surrendered under the UK ETS. This exchange process was largely completed by mid-2022.
- A downturn in UK industrial activity followed the Russian invasion of Ukraine from Feb 2022, due to the spike in energy prices, resulting in lower emissions.
- The UK government oversupplied the UK ETS market between 2021 and 2023 with too many UKAs that went unused. In Jul 2023, the UK government decided to release an additional 53.5m UKAs between 2024F and 2027F, from the reserve pots of UKA inventory that were unused between 2021 and 2023. This shocked the market and caused UKA prices to fall further. The extra auction of UKAs was intended to raise funds to support the UK government's move to build new green infrastructure as part of the mission to deliver clean power by 2030F, according to a UK government website.

However, moving forward, UKA prices could stabilise or even increase.

- The allocation of free allowances have been determined by the UK government until 2025F only; we expect this annual free allocation to gradually decline from 2026F onwards, especially in light of the already-reduced carbon intensity of UK industry.
- In Oct 2023, the UK government announced that the number of UKAs available for auction in 2024F will be 69m (-12% vs. 2023's 79m), and that the UK government will reduce the UKAs available for auction to fall to c.44m by 2027F (-44% vs. 2023). The UK government recognised that the carbon price is currently too low and considerably fewer carbon allowances needed to be released.

We expect AOCL to buy more UKAs in the future, once the Teal West production begins from late-2025F and the oil is fed into the Anasuria FPSO for processing. We expect Teal West to contribute to extra production to the Anasuria Cluster, and AOCL's allocation of free allowances should also fall in 2026F. However, given the much lower level of UKA prices currently, AOCL may still be able to keep a lid on its UKA purchase costs.

Separately, two separate legal entities in the UK – Anasuria Hibiscus UK Limited and Hibiscus Energy UK Limited – hold Hibiscus's development assets in the UK, in particular the Greater Marigold Area Development (GMAD), which comprise of several potential developments. These legal entities may be entitled to their separate quota of free allowances if the GMAD fields commence production in the

future, and have factored-in the costs of complying with the UK ETS costs as part of their economic evaluation for those development projects.

In FY23, Hibiscus used an internal carbon price assumption of US\$104/tonne to estimate the future UKA costs for when the development assets have progressed into production phase. However, Hibiscus lowered down the internal carbon price to US\$84.50/tonne in FY24, in view of the decline in UKA prices.

APPENDIX 10: DETAILED GHG EMISSIONS DISCLOSURES BY HIBISCUS

Group ►

Figure 142: Hibiscus Petroleum Bhd group GHG emissions

	FY19	FY20	FY21	FY22	FY23	FY24	Notes
	tCO2e	tCO2e	tCO2e	tCO2e	tCO2e	tCO2e	
Scope 1 emissions by source							
Combustion	226,330	280,499	269,272	1,250,651	1,373,605	1,344,398	
Flaring	209,535	233,482	241,510	460,183	374,478	345,963	
Venting	94,047	70,993	36,037	183,644	55,897	54,784	
AGRU	0	0	0	4,514,050	5,266,850	4,831,194	
Fugitive emissions	3,039	2,898	2,960	2,206	2,148	1,411	
Mobile and transportations	374	235	65	76,706	111,129	123,841	
Others	0	0	0	0	63,817	63,826	
Total Scope 1 emissions	533,325	588,107	549,844	6,487,440	7,247,924	6,765,417	
Breakdown by type of gas (by tonnes of respective gases)							
Carbon dioxide (CO2)	473,956	489,389	490,990	4,118,196	4,801,883	4,528,233	
Methane (CH4)	2,423	4,640	2,694	94,017	96,942	88,544	
Nitrous oxide (N2O)	17	17	16	63	72	79	
Hydrofluorocarbons (HFC)	0.00	0.00	0.01	0.02	0.00	0.00	
Breakdown by type of gas (by tCO2e)							
Carbon dioxide (CO2)	473,956	489,389	490,990	4,118,196	4,801,883	4,528,233	derived using GWP of 1
Methane (CH4)	60,575	116,000	67,350	2,350,425	2,423,550	2,213,600	derived using GWP of 25
Nitrous oxide (N2O)	5,021	5,066	4,768	18,774	21,456	23,542	derived using GWP of 298
Differential / rounding	-6,227	-22,348	-13,264	45	1,035	42	
Scope 2 emissions by source							
Purchased electricity	1,683	1,647	1,602	2,796	2,104	2,275	
Total GHG Scope 1 and 2 emissions	535,008	589,754	551,446	6,490,236	7,250,028	6,767,692	
North Sabah PSC	400,793	430,834	425,227	587,841	361,504	368,834	
PM3 CAA PSC	0	0	0	5,630,270	6,604,192	6,128,611	PM3 CAA and Kinabalu emissions for FY22 included in full, even though Hibiscus only acquired the assets on 24 Jan 2022
Kinabalu PSC	0	0	0	184,850	185,437	173,610	
Anasuria Cluster	134,140	158,840	126,183	87,221	98,843	96,582	
Rounding	75	80	36	54	52	55	
Less: UK ETS payment	-87,419	-110,611	-86,233	-55,695	-66,888	-64,497	For FY24, AOCL's CO2 emissions were 92,494 tCO2 (excluding emissions of CH4, N2O or HFC). Minus free allowances of 27,997 tCO2 will result in the difference of 64,497 tCO2 in UKA that needs to be surrendered. Note that AOCL does not need to surrender UKAs for non-CO2 GHG emissions.
Net GHG Scope 1 and 2 emissions - Operational control	447,589	479,143	465,213	6,434,541	7,183,140	6,703,195	
Net GHG Scope 1 and 2 emissions - Operational control (FY20 baseline)		8,416,395		6,434,541	7,183,140	6,703,195	
Change from FY20 baseline (%)				-23.5%	-14.7%	-20.4%	
Net GHG Scope 1 and 2 emissions - Working interest	214,413	229,886	224,598	2,384,883	2,613,068	2,443,223	
North Sabah PSC (50% working interest)	200,397	215,417	212,614	293,921	180,752	184,417	Multiplied by working interest
PM3 CAA PSC (35%)				1,970,595	2,311,467	2,145,014	Multiplied by working interest
Kinabalu PSC (60%)				110,910	111,262	104,166	Multiplied by working interest
Anasuria Cluster (50%)	67,070	79,420	63,092	43,611	49,422	48,291	Multiplied by working interest
...offset by UK ETS payment (50%)	-43,710	-55,306	-43,117	-27,848	-33,444	-32,249	Multiplied by working interest
Differential / rounding	-9,344	-9,646	-7,991	-6,305	-6,391	-6,416	The reconciliation difference is because Hibiscus's participating interest in Cook is only 19.325%.
Scope 3 emissions							
Category 4: Upstream transportation and distribution				26,272	50,092	52,001	Arising from marine OSVs employed by Hibiscus's North Sabah operations
Category 6: Business travel				0	0	0	
Total Scope 3 emissions				26,272	50,092	52,001	

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 143: Hibiscus's net emissions intensity (tCO₂e/kboe)

	FY19	FY20	FY21	FY22	FY23	FY24
Aggregate net emissions intensity (tCO₂e/kboe)						
Actual	48.50	57.08	48.33	223.27	231.70	208.07
FY20 baseline retrospectively adjusted up for the Peninsula Hibiscus acquisition in Jan 2022		223.44		223.27	231.70	208.07
Change from FY20 baseline (%)				-0.1%	3.7%	-6.9%
Aggregate net emissions intensity (tCO₂e/kboe) - breakdown by asset						
North Sabah PSC	76.02	69.80	66.89	109.14	67.95	75.82
PM3 CAA PSC and Block 46 Cai Nuoc PSC				359.56	382.36	324.99
Kinabalu PSC				53.88	73.20	59.75
Anasuria Cluster				36.54	36.07	39.35

SOURCES: CGSI RESEARCH, COMPANY REPORTS

GHG emissions by production asset ►

Figure 144: North Sabah PSC GHG emissions

	FY19	FY20	FY21	FY22	FY23	FY24
	tCO ₂ e	tCO ₂ e	tCO ₂ e	tCO ₂ e	tCO ₂ e	tCO ₂ e
Scope 1 emissions by source						
Combustion	147,701	203,053	192,283	214,643	166,828	148,137
Flaring	154,242	152,274	192,507	185,369	135,412	163,013
Venting	93,833	70,807	35,866	183,498	55,746	54,643
Fugitive emissions	3,036	2,898	2,941	2,162	2,064	1,359
Mobile and transportations	374	235	65	47	33	32
Total Scope 1 emissions	399,186	429,267	423,662	585,719	360,083	367,184
Breakdown by type of gas (by tonnes of respective gases)						
Carbon dioxide (CO ₂)	347,455	340,493	371,813	373,522	283,415	288,845
Methane (CH ₄)	2,207	4,340	2,501	8,371	2,982	3,063
Nitrous oxide (N ₂ O)	8.85	8.33	9.19	9.57	3.93	5.92
Breakdown by type of gas (by tCO₂e)						
Carbon dioxide (CO ₂)	347,455	340,493	371,813	373,522	283,415	288,845
Methane (CH ₄)	55,175	108,500	62,525	209,275	74,550	76,575
Nitrous oxide (N ₂ O)	2,637	2,482	2,739	2,852	1,171	1,764
Hydrofluorocarbons (HFC)	-6,081	-22,208	-13,415	70	947	0
Scope 2 emissions by source						
Purchased electricity	1,608	1,567	1,564	2,122	1,421	1,650
Total GHG Scope 1 and 2 emissions	400,794	430,834	425,226	587,841	361,504	368,834
Scope 3 emissions						
Category 4: Upstream transportation and distribution				26,272	50,092	52,001
Category 6: Business travel				n.a.	n.a.	n.a.
Total Scope 3 emissions				26,272	50,092	52,001
Average gross oil eqvt production (kboe)	5,272	6,172	6,357	5,386	5,320	4,865
Aggregate net emissions intensity (tCO ₂ e/kboe)	76.02	69.80	66.89	109.14	67.95	75.82

SOURCES: CGSI RESEARCH, COMPANY REPORTS

Figure 145: PM3 CAA PSC GHG emissions

	FY22	FY23	FY24
	tCO ₂ e	tCO ₂ e	tCO ₂ e
Scope 1 emissions by source			
Combustion	933,158	1,081,811	1,071,897
Flaring	114,103	102,627	75,154
AGRU	4,514,050	5,266,850	4,831,194
Fugitive emissions	41	83	52
Mobile and transportations	68,472	89,683	87,236
Others	0	62,680	62,682
Total Scope 1 emissions	5,629,824	6,603,734	6,128,215
Breakdown by type of gas (by tonnes of respective gases)			
Carbon dioxide (CO ₂)	3,478,205	4,242,806	3,979,486
Methane (CH ₄)	85,575	93,834	85,345
Nitrous oxide (N ₂ O)	41.00	51.00	51.00
Breakdown by type of gas (by tCO₂e)			
Carbon dioxide (CO ₂)	3,478,205	4,242,806	3,979,486
Methane (CH ₄)	2,139,375	2,345,850	2,133,625
Nitrous oxide (N ₂ O)	12,218	15,198	15,198
Hydrofluorocarbons (HFC)	26	-120	-94
Scope 2 emissions by source			
Purchased electricity	447	458	396
Total GHG Scope 1 and 2 emissions	5,630,271	6,604,192	6,128,611
Scope 3 emissions			
Category 4: Upstream transportation and distribution	n.a.	n.a.	n.a.
Category 6: Business travel	n.a.	n.a.	n.a.
Average gross oil eqvt production (kboe) - inclusive of Block 46 Cai Nuoc PSC	7,829	17,272	18,858
Aggregate net emissions intensity (tCO ₂ e/kboe)	359.56	382.36	324.99

SOURCES: CGSI RESEARCH, COMPANY REPORTS

NOTE: PM3 CAA emissions for FY22 included in full, even though Hibiscus only acquired the asset on 24 Jan 2022

Figure 146: Kinabalu PSC GHG emissions

	FY22	FY23	FY24
	tCO2e	tCO2e	tCO2e
Scope 1 emissions by source			
Combustion	26,646	39,483	44,951
Flaring	149,843	123,230	90,767
Venting	0	0	0
Fugitive emissions	1.21	1.03	0.35
Mobile and transportations	8,187	21,412	36,574
Others	0	1,137	1,144
Total Scope 1 emissions	184,677	185,263	173,436
Breakdown by type of gas (by tonnes of respective gases)			
Carbon dioxide (CO2)	182,777	180,777	167,408
Methane (CH4)	5	51	52
Nitrous oxide (N2O)	6.00	11.00	16.00
Breakdown by type of gas (by tCO2e)			
Carbon dioxide (CO2)	182,777	180,777	167,408
Methane (CH4)	125	1,275	1,300
Nitrous oxide (N2O)	1,788	3,278	4,768
Rounding	-13	-67	-40
Scope 2 emissions by source			
Purchased electricity	173	174	174
Total GHG Scope 1 and 2 emissions	184,850	185,437	173,610
Scope 3 emissions			
Category 4: Upstream transportation and distribution	n.a.	n.a.	n.a.
Category 6: Business travel	n.a.	n.a.	n.a.
Average gross oil eqvt production (kboe)	1,715	2,533	2,905
Aggregate net emissions intensity (tCO2e/kboe)	53.88	73.20	59.75

SOURCES: CGSI RESEARCH, COMPANY REPORTS

NOTE: Kinabalu emissions for FY22 included in full, even though Hibiscus only acquired the asset on 24 Jan 2022

Figure 147: Anasuria Cluster GHG emissions

	FY19	FY20	FY21	FY22	FY23	FY24
	tCO2e	tCO2e	tCO2e	tCO2e	tCO2e	tCO2e
Scope 1 emissions by source						
Combustion	78,629	77,446	76,990	76,205	85,484	79,413
Flaring	55,292	81,208	49,003	10,869	13,208	17,028
Venting	215	186	171	145	151	140
Fugitive emissions	4	0	19	2	0	0
Total Scope 1 emissions	134,140	158,840	126,183	87,221	98,843	96,581
Breakdown by type of gas (by tonnes of respective gases)						
Carbon dioxide (CO2)	126,501	148,896	119,176	83,692	94,884	92,494
Methane (CH4)	216	300	193	66	75	84
Nitrous oxide (N2O)	8	8	7	6	7	7
Hydrofluorocarbons (HFC)	0.002	0.000	0.008	0.023	0.000	0.000
Breakdown by type of gas (by tCO2e)						
Carbon dioxide (CO2)	126,501	148,896	119,176	83,692	94,884	92,494
Methane (CH4)	5,400	7,500	4,825	1,650	1,875	2,100
Nitrous oxide (N2O)	2,384	2,384	2,086	1,788	2,086	2,086
Hydrofluorocarbons (HFC)	2	0	8	23	0	0
Rounding	-147	60	88	68	-2	-99
Scope 2 emissions by source						
Purchased electricity	0	0	0	0	0	0
Total GHG Scope 1 and 2 emissions	134,140	158,840	126,183	87,221	98,843	96,581
Scope 3 emissions						
Category 4: Upstream transportation and distribution				n.a.	n.a.	n.a.
Category 6: Business travel				0	0	0
Average gross oil eqvt production (kboe)				1,194	2,741	2,454
Aggregate net emissions intensity (tCO2e/kboe)				73.08	36.07	39.35

SOURCES: CGSI RESEARCH, COMPANY REPORTS

APPENDIX 11: GHG EMISSIONS CATEGORIES

What are Scope 1, Scope 2 and Scope 3 GHG emissions? ➤

GHG emissions can be classified into three different categories for the purposes of reporting them.

Scope 1 emissions refer to direct emissions from the operations of companies' owned and controlled facilities, as well as the companies' fleet of vehicles. For instance, an electricity generation company's Scope 1 emissions would include the GHG emissions from the combustion of coal, oil and natural gas for the purposes of power generation. It would also include the vehicular emissions from its own lorries and trucks that transport the thermal coal from the nearby port to its coal-fired power plant.

Scope 2 emissions refer to indirect emissions from electricity, heating, steam and cooling purchased or acquired for the polluting entity's operational use. For example, a manufacturing plant may purchase electricity from a third-party power plant to operate its machinery and to power its corporate offices. The GHG emissions arising from the production of that purchased electricity are counted as the manufacturing plant's Scope 2 emissions, and these overlap with the power plant's Scope 1 emissions. However, if the manufacturing plant owns and operates its in-house power plants, then the emissions from those power plants are the manufacturing company's Scope 1 emissions.

Scope 3 emissions are also indirect emissions, are very broad and encompass a whole range of emissions from sources that are not owned or controlled by the reporting entity, but which form part of the polluter's upstream and downstream value chains.

Upstream Scope 3 emissions are classified into eight categories:

- **Category 1: Purchased goods and services** – emissions from the production of goods and services that are purchased by the reporting entity for use as its raw materials or to facilitate its normal business operations;
- **Category 2: Capital goods** – emissions from the production of capital goods, such as production machineries, that are purchased by the reporting entity;
- **Category 3: Fuel and energy-related activities** – emissions arising from the production of fuel and energy that are purchased by the reporting entity (note that the combustion of coal, oil or natural gas within the polluter's facility is counted as its Scope 1 emissions);
- **Category 4: Upstream transportation and distribution** – emissions generated by third-party suppliers' vehicles that deliver purchased goods to the polluter's facility;
- **Category 5: Waste generated in operations** – emissions from the decomposition or incineration of the polluter's waste products generated from its production facilities or business operations;
- **Category 6: Business travel** – emissions from vehicles, ships or aircraft used by employees on their business travels;
- **Category 7: Employee commuting** – emissions from vehicles used by employees to travel to work daily; and
- **Category 8: Upstream leased assets** – emissions from the assets that are legally owned by third parties, but which are leased by the reporting entity which is also the lessee. In a situation where the lessor controls the asset and enjoys the primary risks and rewards from the ownership of the asset, and also operationally controls the asset, the direct emissions from the asset would be the lessor's Scope 1 emissions. If the reporting entity is the lessee, then it would be counted as its Scope 3 emissions. For example, in a case where a reporting entity leases a single floor of a skyscraper to house its office, and does not enjoy the primary risk and rewards of the building's ownership, the Scope 1 and Scope 2 emissions from that single floor would be counted as the lessee's Scope 3 emissions.

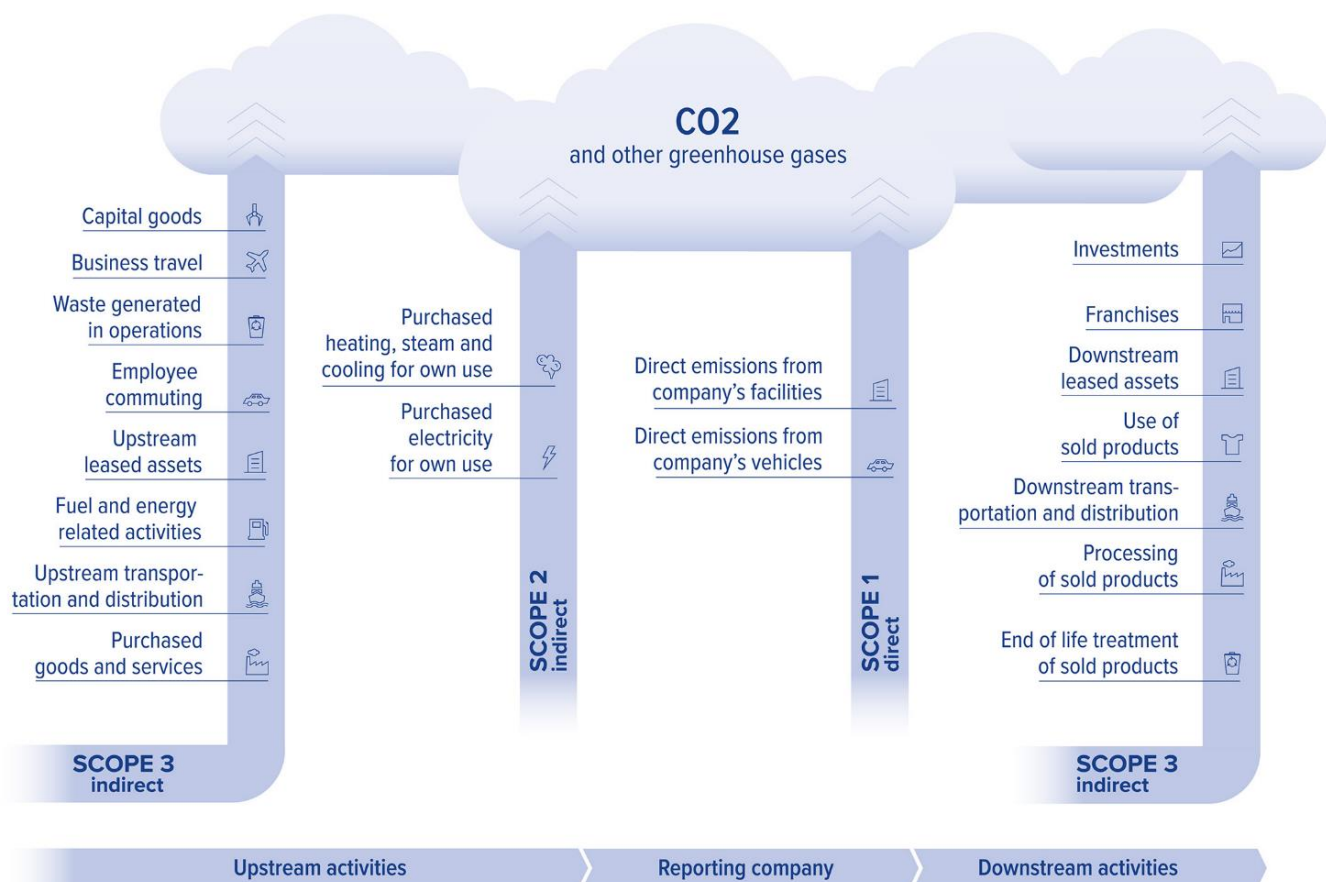
Downstream Scope 3 emissions are classified into seven categories:

- **Category 9: Downstream transportation and distribution** – emissions generated by third-party vehicles contracted by the reporting entity to deliver sold goods to customers;
- **Category 10: Processing of sold products** – emissions from the intermediate processing of sold products prior to sale to end-customers;
- **Category 11: Use of sold products** – emissions arising from the use of sold products by end-customers, for instance, emissions from the combustion of gasoline by car users are Scope 3 emissions for the fuel retailer;
- **Category 12: End-of-life treatment of sold products** – emissions from the recycling, disposal, or incineration of sold products;
- **Category 13: Downstream leased assets** – emissions from the assets that are legally owned by the reporting entity and which are leased to third-party lessees; these third-party lessees ultimately control how those assets will be used or deployed and enjoy the economic rewards and risks from using those assets for their intended purposes. The direct emissions from those assets would be the lessee's Scope 1 emissions, but the lessor's and reporting entity's Scope 3 emissions. The lessee's Scope 2 emissions arising from the use of the assets subject to the lease would also be counted as part of the lessor's and reporting entity's Scope 3 emissions.

For instance, the reporting entity may own a floating production storage and offload (FPSO) ship for long-term lease to an upstream oil company; the upstream oil company accounts for the FPSO ship's direct emissions as its Scope 1 emissions because it directs the operations of the FPSO ship, enjoys the economic benefits from leasing the ship (i.e. it will ultimately receive the proceeds from selling the oil that is produced from the FPSO ship), and also accepts the risks from leasing the ship (i.e. it is committed to continue paying for the lease of the ship even though there is the risk that oil prices may decline sharply in the future). The FPSO-owning reporting entity would treat the FPSO ship's direct emissions as its Scope 3 emissions, not its Scope 1 emissions.

- **Category 14: Franchises** – franchisors should account for the Scope 1 and Scope 2 emissions that occur from the operation of franchises as part of their Scope 3 emissions; and
- **Category 15: Investments** – investors who do not have operational control over investee companies should treat the latter's Scope 1 and Scope 2 emissions as part of its Scope 3 emissions.

Figure 148: Sources of Scope 1, Scope 2 and Scope 3 GHG emissions



SOURCE: GHG PROTOCOL

Operational control accounting vs. equity share accounting for Scope 3 emissions ►

Operational control accounting

Underlying our GHG accounting discussion above is the assumption that the reporting entity counts as its Scope 1 and Scope 2 emissions, the Scope 1 and Scope 2 emissions of the assets where it has operational control.

However, if the reporting entity does not have operational control, then the Scope 1 and Scope 2 emissions of the assets will be included in the reporting entity's Scope 3 emissions.

For 'Category 8: Upstream Leased Assets', the reporting entity (lessee) does not have control over the emissions of the leased asset, hence, the Scope 1 and Scope 2 emissions of the asset will be the reporting entity's Scope 3 emissions. In the case of 'Category 13: Downstream Leased Assets', the reporting entity (lessor) does not operationally control the leased asset, hence, the Scope 1 and Scope 2 emissions of the asset will be the reporting entity's Scope 3 emissions.

Applying operational control accounting to non-wholly-owned assets

For non-wholly-owned assets, the application of operational control GHG accounting can be tricky. As an example of Scope 3 emissions accounting for 'Category 13: Downstream Leased Assets', we bring up the case of Yinson Holdings (YNS MK, SP: RM2.30, Add, TP: RM3.23), a Malaysian FPSO lessor. During FY1/21, Yinson wholly-owned some of its FPSO ships, owned 76% of one FPSO, and owned 49% of two FPSOs; these refer to FPSOs that were operated during the financial year and excluded FPSOs that were still in construction stage. All (i.e. 100%) of the Scope 1 and Scope 2 emissions of each of its FPSOs were

included in Yinson's Scope 3 emissions, even though Yinson did not wholly-own all of its FPSOs. Hence, all of the Scope 1 and Scope 2 emissions from the 76%-owned FPSO, and all of the Scope 1 and Scope 2 emissions from the two 49%-owned FPSOs, were counted into, and reported as part of, Yinson's Scope 3 emissions.

However, the treatment for non-wholly-owned assets under 'Category 15: Investments' may be different. Based on GHG Protocol's technical guidance notes, if Company A (the reporting entity) invests in 49% of Company B's voting shares, but does not have operational control over Company B, then Company A should include 49% of Company B's Scope 1 and Scope 2 emissions as part of Company A's Scope 3 emissions.

Equity share accounting

As an alternative, reporting entities have the option of using equity share accounting for reporting Scope 3 GHG emissions. In Yinson's case, this would mean including only 49% of the Scope 1 and Scope 2 emissions from its two 49%-owned FPSOs into its Scope 3 emissions. This was, in fact, the methodology adopted by Yinson in FY1/21, before it switched over to the operational control accounting methodology in FY1/22.

Who is responsible to abate which type of emissions? ➤

Polluting entities are solely responsible for abating or mitigating the Scope 1 emissions, which are directly linked to the operations of the polluter in question. As the technical solutions to abate Scope 1 emissions may not be immediately available, or remain prohibitively expensive, polluters may voluntarily choose to offset those Scope 1 emissions via the use of carbon credits in Voluntary Carbon Markets (VCM).

Polluters should also endeavour to reduce their Scope 2 emissions, by say, switching over to cleaner sources of electricity, such as buying power from gas-fired power plants or RE plants, rather than from coal- or oil-fired power plants, or by working together with the national power generation company to increase the proportion of RE in the generation mix.

In the case of Scope 3 emissions, however, the primary responsibility for abatement lies with the other parties that account for those Scope 3 emissions as their Scope 1 or Scope 2 emissions. In the case of FPSO lessors, the responsibility for abating or reducing FPSO emissions lies with lessees, i.e. the oil and gas companies that lease and control the operations of those FPSOs. The lessees should pay for the cost of abatement. However, FPSO lessors can play their part by encouraging the lessees to abate and by proposing potential technical solutions for that purpose.

Global Warming Potential (GWP) of different gases ➤

GWP is a measure to standardise the measurement of different GHGs in terms of how they contribute to global warming by comparison with CO₂, taking into account the effects of time. CO₂ will always have a GWP of 1 because that is the benchmark against which all other GHGs are compared against. CH₄ is a much more potent GHG than CO₂, with a GWP of 81 over a 20-year time horizon, declining to 28 over a 100-year horizon, and to 8 over a 500-year horizon. Although CH₄ will remain in the atmosphere for just 12 years after its initial release into the air, its greenhouse effects last much longer than that, because after 10 years, most of the emitted methane will have reacted with ozone to form CO₂ and water. This CO₂ will continue to warm the environment for hundreds of years after that.

The concept of **carbon dioxide equivalent (CO₂e)** follows from the GWP metrics. One tonne of CH₄ is equivalent to 81 tonnes of CO₂ on a 20-year horizon basis,

and is equivalent to 28 tonnes of CO₂ on a 100-year basis. The 100-year time horizon is used as the standard measure when computing CO₂e for the purpose of declaring CH₄ emissions. Hence, one tonne of CH₄ is said to be equivalent to 28 tonnes of CO₂e. However, using a 100-year horizon underestimates the near- and medium-term warming impact of CH₄ emissions, which is almost three times more potent over a 20-year period.

Figure 149: Greenhouse gases (GHG) and their Global Warming Potential (GWP)

No	Type of GHG	Lifetime (years)	GWP for a given time horizon		
			20-year	100-year	500-year
1	Carbon dioxide (CO ₂)	Note ^a	1	1	1
2	Methane (CH ₄)	12	81	28	8
3	Nitrous oxide (N ₂ O)	109	273	273	130
4	Sulphur hexafluoride (SF ₆)	3,200	18,300	25,200	34,100
5	Nitrogen trifluoride (NF ₃)	569	13,400	17,400	18,200

Note a Between 65% and 80% of CO₂ released into the air dissolves into the ocean over a period of 20–200 years. The rest is removed by slower processes that take up to several hundreds of thousands of years. (Source: Guardian)

SOURCE: IPCC SIXTH ASSESSMENT REPORT

The GWP values are issued by the Intergovernmental Panel on Climate Change (IPCC), which is a United Nations (UN) body. Figure 149 above sets out the values determined at the IPCC's Sixth Assessment Report (AR6), which was initially released in 2021 and finalised in 2023. Figure 150 below shows how the GWP values have evolved over time, with the Fourth Assessment Report (AR4) published in full in 2007.

We highlight that Hibiscus uses the GWP values in the Fourth Assessment Report (AR4), as these are also the values used by Petronas.

Figure 150: Global Warming Potential of various GHGs relative to CO₂

IPCC Global Warming Potential (GWP) values relative to CO₂

Common chemical name or industrial designation	Chemical formula	GWP values for 100-year time horizon		
		Fourth Assessment Report (AR4)	Fifth Assessment Report (AR5)	Sixth Assessment Report (AR6)
Major Greenhouse Gases				
Carbon dioxide	CO ₂	1	1	1
Methane – non-fossil	CH ₄	25	28	27.0
Methane – fossil	CH ₄	N/A	30	29.8
Nitrous oxide	N ₂ O	298	265	273
Nitrogen trifluoride	NF ₃	17,200	16,100	17,400
Sulfur hexafluoride	SF ₆	22,800	23,500	24,300

SOURCE: GHG PROTOCOL

APPENDIX 11: MENTIONED COMPANIES

Figure 151: Not rated and not listed companies mentioned in this report

No	Companies mentioned	Bloomberg code	Share price	CGSI Research	
				Recom.	Target price
1	3D Energi	TDO AU	A\$1.40	Not rated	N.A.
2	Anasuria Hibiscus UK Limited	Not listed	N.A.	N.A.	N.A.
3	Anasuria Operating Company Limited	Not listed	N.A.	N.A.	N.A.
4	Apache Corp	APA US	US\$25.18	Not rated	N.A.
5	Baker Hughes	BKR US	US\$105.00	Not rated	N.A.
6	Bass Oil	BAS AU	A\$6.95	Not rated	N.A.
7	BP plc	BP/ LN	GBp406	Not rated	N.A.
8	Brava Energia	BRAV3 BZ	BRL17.27	Not rated	N.A.
9	Brunei Energy	Not listed	N.A.	N.A.	N.A.
10	Brunei LNG	Not listed	N.A.	N.A.	N.A.
11	Brunei Shell Petroleum	Not listed	N.A.	N.A.	N.A.
12	BW Offshore	BWO NO	NOK31.50	Not rated	N.A.
13	Caldera Petroleum	Not listed	N.A.	N.A.	N.A.
14	Capricorn Energy	CNE LN	GBp214	Not rated	N.A.
15	Carnarvon Hibiscus	Not listed	N.A.	N.A.	N.A.
16	Chevron	CVX US	US\$150.92	Not rated	N.A.
17	ConocoPhillips	COP US	US\$105.00	Not rated	N.A.
18	Dagang NeXchange Berhad	DNEX MK	RM6.95	Not rated	N.A.
19	E&P Malaysia Venture	Not listed	N.A.	N.A.	N.A.
20	Eni S.p.A.	ENI IM	€14.28	Not rated	N.A.
21	EnQuest	ENQ LN	GBp406	Not rated	N.A.
22	Equinor	EQNR NO	NOK269.20	Not rated	N.A.
23	Esso	Not listed	N.A.	N.A.	N.A.
24	ExxonMobil	XOM US	US\$120.70	Not rated	N.A.
25	Fortuna International Petroleum Corporation	Not listed	N.A.	N.A.	N.A.
26	Gazprom	GAZP RM	RUB120.70	Not rated	N.A.
27	Genel Energy	GENL LN	GBp77	Not rated	N.A.
28	Hibiscus Oil & Gas Malaysia (PM3) Limited	Not listed	N.A.	N.A.	N.A.
29	Hibiscus Oil & Gas Malaysia Limited	Not listed	N.A.	N.A.	N.A.
30	HiRex Petroleum	Not listed	N.A.	N.A.	N.A.
31	Ithaca Energy	ITH LN	GBp105	Not rated	N.A.
32	Karoon Energy	KAR AU	A\$1.40	Not rated	N.A.
33	Liberty Energy	LBRT US	US\$105.00	Not rated	N.A.
34	Lime Petroleum	Not listed	N.A.	N.A.	N.A.
35	Malaysia Marine and Heavy Engineering	MMHE MK	RM6.95	Not rated	N.A.
36	Masirah Oil	Not listed	N.A.	N.A.	N.A.
37	Mitsubishi Corporation	8058 JP	JPY3,240	Not rated	N.A.

SOURCES: CGSI RESEARCH, BLOOMBERG; NOTE: SHARE PRICE AS AT 27 NOV 2024

Figure 152: Not rated and not listed companies mentioned in this report

No	Companies mentioned	Bloomberg code	Share price	CGSI Research	
				Recom.	Target price
38	Modec	6269 JP	JPY3,240	Not rated	N.A.
39	Murphy Oil	MUR US	US\$105.00	Not rated	N.A.
40	NEO Energy (ZPL)	Not listed	N.A.	N.A.	N.A.
41	NTPC	NTPC IN	INR415.75	Not rated	N.A.
42	OKEA	OKEA NO	NOK22.48	Not rated	N.A.
43	OMV	OMV AG	€14.28	Not rated	N.A.
44	Ophir Energy	Not listed	N.A.	N.A.	N.A.
45	Pan Orient Energy Corp	Not listed	N.A.	N.A.	N.A.
46	Peninsula Hibiscus	Not listed	N.A.	N.A.	N.A.
47	Petrobras	PBR US	US\$13.88	Not rated	N.A.
48	Petrolia Nasional (Petronas)	Not listed	N.A.	N.A.	N.A.
49	Petronas Carigali	Not listed	N.A.	N.A.	N.A.
50	Petronas Trading Corporation (PETCO)	Not listed	N.A.	N.A.	N.A.
51	PetroVietnam	PVS VN	VND34,000	Not rated	N.A.
52	PetroVietnam Exploration Production Corp	Not listed	N.A.	N.A.	N.A.
53	Ping Petroleum	Not listed	N.A.	N.A.	N.A.
54	Rapid Oil	Not listed	N.A.	N.A.	N.A.
55	Repsol	REP SM	€11.72	Not rated	N.A.
56	Repsol Sinopec	Not listed	N.A.	N.A.	N.A.
57	Rex International	REXI SP	\$0.11	Not rated	N.A.
58	Samsung Heavy Industries	010140 KS	Won11,900	Not rated	N.A.
59	Santos	STO AU	A\$6.64	Not rated	N.A.
60	Sapura Energy	SAPE MK	RM0.03	Not rated	N.A.
61	SEA Hibiscus	Not listed	N.A.	N.A.	N.A.
62	Serica Energy	SQZ LN	GBp130	Not rated	N.A.
63	Shell	SHEL LN	GBp2,540	Not rated	N.A.
64	Shell Deepwater Borneo	Not listed	N.A.	N.A.	N.A.
65	Simpor Hibiscus	Not listed	N.A.	N.A.	N.A.
66	Sinopec	600028 CH	Rmb6.38	Not rated	N.A.
67	Swift Exploration	Not listed	N.A.	N.A.	N.A.
68	Talisman Vietnam Limited	Not listed	N.A.	N.A.	N.A.
69	TotalEnergies	TTE FP	€54.07	Not rated	N.A.
70	Trafigura	Not listed	N.A.	N.A.	N.A.
71	United Oil & Gas	UOG LN	GBp0.195	Not rated	N.A.
72	Uzma Berhad	UZMA MK	RM0.80	Not rated	N.A.
73	Valeura Energy	VLE CN	C\$5.19	Not rated	N.A.
74	Woodside Petroleum	WDS AU	A\$24.37	Not rated	N.A.

SOURCES: CGSI RESEARCH, BLOOMBERG; NOTE: SHARE PRICE AS AT 27 NOV 2024

ESG in a nutshell



LSEG ESG Scores

B-	A+	B-	C	B-	B+
ESG Grade	ESG Controversies Grade	ESG Combined Grade	ESG Environment Pillar Grade	ESG Social Pillar Grade	ESG Governance Pillar Grade

Among the listed oil and gas companies in Malaysia, Hibiscus stands out as one of the highest emitters of carbon dioxide equivalent (CO₂e). From the perspective of emissions intensity, calculated as Scope 1 and 2 CO₂e emissions per million ringgit of revenue, Hibiscus is the most significant emitter, significantly higher than the upstream division of Petronas as a direct comparable, and also significantly higher than the other downstream, midstream, and upstream oil and gas service providers in Malaysia. Nevertheless, Hibiscus has a long-term Net Zero 2050 target and has a medium-term target to reduce its absolute CO₂e emissions by 50% by FY30F, relative to the FY20 baseline.

Keep your eye on

More than 90% of Hibiscus's GHG emissions in FY24 came from the PM3 CAA PSC, where the acid gas removal unit (AGRU) strips out the CO₂ from the natural gas and vents it to the atmosphere; some methane gas is also inadvertently vented. The AGRU is also energy intensive, requiring the combustion of natural gas to power the equipment. Consequently, Hibiscus disclosed a significant jump in GHG emissions after it acquired the PM3 CAA asset from Repsol in FY22.

Implications

From the high emissions base in FY22, Hibiscus has had some success in mitigation. Net GHG emissions fell 21% yoy in FY24 to 5.7 tonnes of CO₂e (tCO₂e) yoy, which represented a 20.4% drop from the FY20 baseline. Net GHG emissions intensity fell 10% yoy in FY24 to 208.07 tCO₂e/kboe, and was 6.9% lower compared to the FY20 baseline. Hibiscus managed a decline in GHG emissions in FY24 because it had executed the Membrane Phase 1 project in Apr 2022 and has been executing the Membrane Phase 2 project since Dec 2023 (up to late-2024F).

ESG highlights

The Membrane Phase 1 trial was very limited in nature, and executed in Apr 2022 as a test to see how much CH₄ can be captured and flaring/venting reduced. The Phase 1 trial managed to achieve GHG reduction of 80,000 tCO₂e p.a. at the working interest level.

After the Membrane Phase 1 trial was completed, Hibiscus moved on to a more extensive Membrane Phase 2 which began in Dec 2023 and is targeted for completion by end-CY24F. Membrane Phase 2 can facilitate emissions reduction of 200,000 to 500,000 tCO₂e p.a. at the working interest level.

Implications

In the future, Hibiscus is considering the Membrane Phase 3 project. Hibiscus assesses the Phase 3 project as potentially being less effective in capturing CH₄ for technical reasons, but if Hibiscus decides to proceed with the Membrane Phase 3 project, we expect GHG emissions reduction of 160,000 tCO₂e p.a. at a working interest level. Hibiscus has also been undertaking an upgrade and debottlenecking of the gas compressor at the Kinabalu PSC since Mar 2022 and this project is slated to finish in FY25F. The project will reducing the need for flaring and can reduce GHG emissions by 100,000 tCO₂e p.a. at a working interest level.

Trends

Given the voluminous CO₂ emissions at the PM3 CAA complex, Hibiscus plans to undertake a carbon capture and storage (CCS) project once it secures an extension of the PSC beyond the current 31 Dec 2027F expiration. The CCS Phase 1 project is likely to be operational in the 2028-2029F timeframe, whereby the CO₂ captured by the AGRU will be reinjected into the depleted gas reservoirs for geological storage.

Hibiscus estimates that CCS Phase 1 can reinject between 500,000 and 800,000 tCO₂ p.a. into depleted gas wells at the working interest level. This suggests that the CCS Phase 1 project could have prevented between 29% and 48% of the CO₂ emissions from the AGRU if it had been implemented at the start of FY24.

Implications

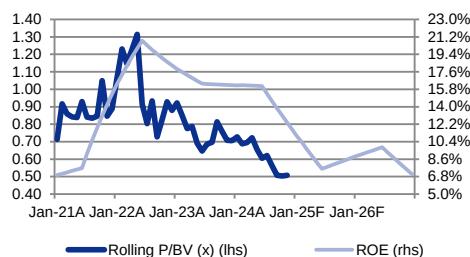
CCS Phase 2 (post-FY30F) may involve a larger volume of CO₂ removal of between 1 MMtCO₂e to 3 MMtCO₂e p.a. at the working interest level, and will be executed in conjunction with the start-up of the operations at the PKNB Cluster and PM327 fields, which will be developed in the future via tie-back to the PM3 CAA facilities.

Separately, Hibiscus disclosed that Brunei MLJ is producing gas and condensate at a low GHG emissions intensity of 11 tCO₂/kboe, which compares very favourably with Hibiscus's existing portfolio at 208.07 tCO₂e/kboe in FY24. If Brunei had been included into Hibiscus at the start of FY24, we estimate that Hibiscus's GHG emissions intensity would have been 16% lower at 173.84 tCO₂e/kboe.

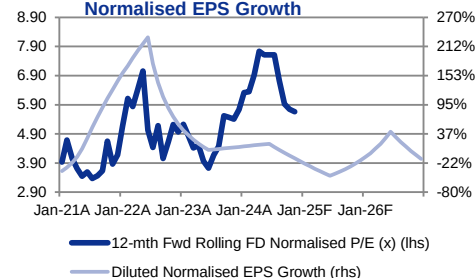
SOURCES: CGSI RESEARCH, LSEG, COMPANY REPORTS

BY THE NUMBERS

P/BV vs ROE



12-mth Fwd FD Normalised P/E vs FD Normalised EPS Growth



We expect FY25F core net profit to decline yoy due to lower average oil prices, lower average sales volume, and the weaker US\$, despite the inclusion of Block B MLJ from 14 Oct 2024.

We expect FY26F core net profit to rise yoy as North Sabah production could pick-up from late-CY24F due to the SF30 Water Flood Phase 2 project, while the Teal West field may start producing from late-CY25F.

Profit & Loss

(RMm)	Jun-23A	Jun-24A	Jun-25F	Jun-26F	Jun-27F
Total Net Revenues	2,345	2,716	2,440	3,063	2,719
Gross Profit	1,527	1,767	1,384	1,818	1,523
Operating EBITDA	1,253	1,273	1,153	1,523	1,273
Depreciation And Amortisation	-480	-476	-557	-798	-857
Operating EBIT	773	797	595	725	416
Financial Income/(Expense)	-62	-58	-99	-129	-96
Pretax Income/(Loss) from Assoc.	1	-1	0	0	0
Non-Operating Income/(Expense)	0	0	0	0	0
Profit Before Tax (pre-EI)	712	738	496	596	319
Exceptional Items	0	0	0	0	0
Pre-tax Profit	712	738	496	596	319
Taxation	-312	-271	-256	-264	-158
Exceptional Income - post-tax					
Profit After Tax	401	467	241	331	161
Minority Interests	0	0	0	0	0
Preferred Dividends					
FX Gain/(Loss) - post tax					
Other Adjustments - post-tax					
Preference Dividends (Australia)					
Net Profit	401	467	241	331	161
Recurring Net Profit	401	467	241	331	161
Fully Diluted Recurring Net Profit	401	467	241	331	161
Normalised Net Profit	401	467	241	331	161
Fully Diluted Normalised Profit	401	467	241	331	161

Cash Flow

(RMm)	Jun-23A	Jun-24A	Jun-25F	Jun-26F	Jun-27F
EBITDA	1,253	1,273	1,153	1,523	1,273
Cash Flow from Invt. & Assoc.					
Change In Working Capital	-297	-181	459	82	-184
(Incr)/Decr in Total Provisions	0	0	-61	-61	-61
Other Non-Cash (Income)/Expense	558	672	656	927	953
Other Operating Cashflow	-552	-585	-611	-847	-900
Net Interest (Paid)/Received	-59	-46	-99	-129	-96
Tax Paid	-177	-154	-247	-295	-205
Cashflow From Operations	727	979	1,250	1,199	779
Capex	-516	-743	-1,217	-630	-94
Disposals Of FAs/subsidiaries	0	0	0	0	0
Acq. Of Subsidiaries/Investments	0	-231	-633	-5	-7
Other Investing Cashflow	18	61	25	17	27
Cash Flow From Investing	-498	-914	-1,825	-618	-74
Debt Raised/(repaid)	179	-261	274	-278	-235
Proceeds From Issue Of Shares	0	0	0	0	0
Shares Repurchased	0	-16	-63	0	0
Dividends Paid	-55	-67	-46	-46	-47
Preferred Dividends					
Other Financing Cashflow	-9	-40	-68	-87	-66
Cash Flow From Financing	114	-385	96	-411	-348
Total Cash Generated	343	-320	-479	170	357
Free Cashflow To Equity	408	-196	-301	303	470
Free Cashflow To Firm	306	172	-451	728	828

Hibiscus has guided for heavy capex spending in FY25F, but we think that some of the spending may spill over into FY26F due to typical delays in project implementation.

We have included the Brunei MLJ acquisition cost of US\$195.8m into our model (FY24: US\$49m and FY25F: US\$146.8m), as well as the US\$100m prepayment facility taken to fund the acquisition.

SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

BY THE NUMBERS... cont'd

We have incorporated the US\$100m prepayment facility taken by Hibiscus to fund the acquisition of Brunei MLJ in FY25F.

We have assumed a further RM500m in additional bank borrowings in FY25F to fund Hibiscus's capex spending.

Balance Sheet

(RMm)	Jun-23A	Jun-24A	Jun-25F	Jun-26F	Jun-27F
Total Cash And Equivalents	960	688	209	379	737
Total Debtors	411	549	493	619	549
Inventories	199	193	215	254	244
Total Other Current Assets	521	905	1,001	914	861
Total Current Assets	2,091	2,335	1,919	2,166	2,390
Fixed Assets	2,183	2,334	3,421	3,317	2,844
Total Investments	5	4	4	4	4
Intangible Assets	1,452	1,432	2,099	2,035	1,745
Total Other Non-Current Assets	468	499	499	491	475
Total Non-current Assets	4,108	4,269	6,023	5,847	5,068
Short-term Debt	0	0	0	0	0
Current Portion of Long-Term Debt	215	214	338	290	295
Total Creditors	902	982	1,523	1,618	1,238
Other Current Liabilities	287	383	395	397	397
Total Current Liabilities	1,403	1,579	2,256	2,305	1,930
Total Long-term Debt	648	535	708	490	259
Hybrid Debt - Debt Component					
Total Other Non-Current Liabilities	1,458	1,390	1,746	1,701	1,639
Total Non-current Liabilities	2,106	1,925	2,454	2,191	1,898
Total Provisions	0	0	0	0	0
Total Liabilities	3,509	3,504	4,710	4,496	3,827
Shareholders' Equity	2,690	3,100	3,232	3,517	3,631
Minority Interests	0	0	0	0	0
Total Equity	2,690	3,100	3,232	3,517	3,631

Key Ratios

	Jun-23A	Jun-24A	Jun-25F	Jun-26F	Jun-27F
Revenue Growth	38.2%	15.8%	(10.1%)	25.5%	(11.2%)
Operating EBITDA Growth	54.4%	1.6%	(9.5%)	32.1%	(16.4%)
Operating EBITDA Margin	53.5%	46.9%	47.2%	49.7%	46.8%
Net Cash Per Share (RM)	0.12	-0.08	-1.09	-0.52	0.24
BVPS (RM)	3.34	3.85	4.21	4.58	4.73
Gross Interest Cover	10.01	7.46	4.80	4.95	3.37
Effective Tax Rate	43.8%	36.7%	51.5%	44.3%	49.6%
Net Dividend Payout Ratio	12.6%	14.6%	25.5%	18.5%	28.7%
Accounts Receivables Days	63.52	64.68	77.88	66.23	78.38
Inventory Days	80.93	75.60	70.63	68.74	75.92
Accounts Payables Days	10.44	12.47	9.63	9.38	10.35
ROIC (%)	13.9%	12.2%	8.1%	7.7%	4.6%
ROCE (%)	25.0%	22.8%	15.3%	17.3%	10.4%
Return On Average Assets	7.50%	7.86%	4.15%	5.16%	2.85%

We expect Hibiscus's net oil equivalent production rate to grow in FY25-26F from North Sabah and Teal West projects, as well as the inclusion of Block B MLJ from 14 Oct 2024.

Key Drivers

	Jun-23A	Jun-24A	Jun-25F	Jun-26F	Jun-27F
Net oil equivalent production rate (boepd)	19,499.0	20,845.0	27,682.3	31,919.1	30,224.0
Total oil and gas sold (MMboe)	7.1	7.9	9.0	12.1	11.0
Realised oil and gas price (US\$/boe)	72.2	73.0	59.3	60.2	57.0
2P oil and gas reserves (MMboe)	67.0	57.4	77.5	65.9	54.9

SOURCES: CGSI RESEARCH ESTIMATES, COMPANY REPORTS

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South Korea	CGS International Securities Hong Kong Limited, Korea Branch	Financial Services Commission and Financial Supervisory Service
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Score Range:	90 - 100	80 – 89	70 - 79	Below 70	No Survey Result
Description:	Excellent	Very Good	Good	N/A	N/A

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Distribution of stock ratings and investment banking clients for quarter ended on 30 September 2024

588 companies under coverage for quarter ended on 30 September 2024

	Rating Distribution (%)	Investment Banking clients (%)
Add	67.0%	0.5%
Hold	23.5%	0.9%
Reduce	9.5%	0.2%

Spitzer Chart for stock being researched (2 year data)

Hibiscus Petroleum Bhd (HIBI MK)

— Price Close



Recommendation Framework

Stock Ratings

Definition:

Add The stock's total return is expected to exceed 10% over the next 12 months.

Hold The stock's total return is expected to be between 0% and positive 10% over the next 12 months.

Reduce The stock's total return is expected to fall below 0% or more over the next 12 months.

The total expected return of a stock is defined as the sum of the: (i) percentage difference between the target price and the current price and (ii) the forward net dividend yields of the stock. Stock price targets have an investment horizon of 12 months.

Sector Ratings

Definition:

Overweight An Overweight rating means stocks in the sector have, on a market cap-weighted basis, a positive absolute recommendation.

Neutral A Neutral rating means stocks in the sector have, on a market cap-weighted basis, a neutral absolute recommendation.

Underweight An Underweight rating means stocks in the sector have, on a market cap-weighted basis, a negative absolute recommendation.

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