ERIA Research Project Report FY2024, No. 19

Global Strategies of International Oil Companies and Their Activities in Indonesia under Energy Transition

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Preface

After the 2021 United Nations Climate Change Conference (COP26), international oil and gas companies (IOCs) increased their investments in various renewable energies, such as solar photovoltaic (PV) systems and wind power, and decreased their investments in upstream oil and gas. However, the Russian invasion of Ukraine brought on a global price hike in the fossil fuel market due to a supply shortage of Russian oil and gas.

The Economic Research Institute for ASEAN and East Asia (ERIA) requested that INPEX Solutions prepare this report on IOC business strategies in Indonesia in light of these events. First, it reviews the global energy situation in terms of decarbonisation and energy supply security, especially oil and gas. Second, it looks at IOC activities around the globe, focussing on BP, Chevron, ConocoPhillips, INPEX, and Shell. Third, it examines the various IOC business strategies in Indonesia. Lastly, it notes how some IOCs are paying attention to both the internal rate of return as well as increasing carbon-neutral activities in their activities in Indonesia. Today, IOCs must invest in both renewable energy and upstream oil and gas activities to achieve carbon neutrality and energy supply security in parallel, so they are allocating money to more efficient business opportunities.

It is hoped that this report will be useful and effective for all companies that have been engaging in the oil and gas business in Indonesia.

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Executive Summary

Although the United Nations Climate Change Conference (COP26) in 2021 increased the momentum towards carbon neutrality in many countries, the Russian invasion of Ukraine in 2022 caused a global energy crisis. As a result, today, there is a need to strike a balance between decarbonisation and securing energy – including oil and gas – for the foreseeable future.

In light of the energy crisis that has occurred, some European international oil and gas companies (IOCs), such as BP, Eni, and Shell, have once again increased their oil and gas activities. In addition, some United States oil and gas companies, such as Chevron and ConocoPhillips, have been greatly expanding the scale of their production through mergers and acquisitions. Each company is also taking carbon neutrality into consideration.

Although some IOCs have increased their oil and gas activities, Chevron, ConocoPhillips, and Shell have withdrawn from the exploration and production (E&P) business in Indonesia to focus on the core areas of each company with an emphasis on profitability. It is unlikely that they will return to E&P activities in Indonesia. Yet Eni and INPEX are trying to develop new projects in Indonesia, and it is important to make it a win-win situation for them and the country.

Indonesia needs to develop new gas fields to meet the expected increase in domestic gas demand. Eni and INPEX have stated that a reasonable internal rate of return is a prerequisite for the development of new projects, so discussions with the government on economic conditions will be crucial. The development of regulations for the implementation of carbon capture and storage, including cross-border storage, is another key point.

Chapter 1

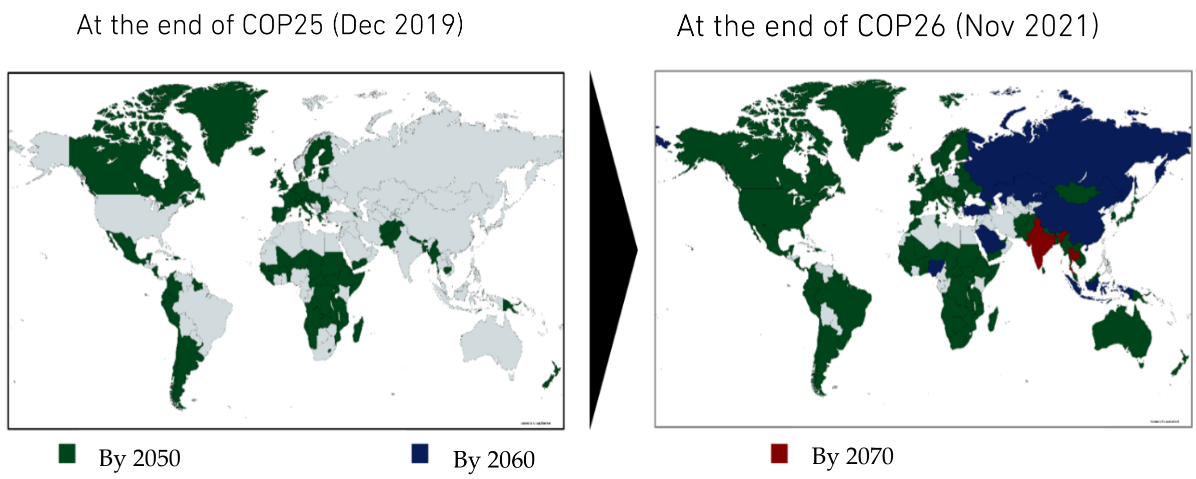
Current Global Energy Situation

In this section, the current global energy situation is described as background for this report. Although the 2021 United Nations Climate Change Conference (COP26) increased momentum towards carbon neutrality in many countries, the Russian invasion of Ukraine in 2022 caused a global energy crisis. As a result, a balance must now be struck between decarbonisation and securing energy, including oil and gas, for the foreseeable future.

1. COP26 and More Carbon-Neutral Declarations

From 31 October to 13 November 2021, the COP26 was held in Glasgow, United Kingdom (UK). During the COP25 in December 2019, 121 countries declared 2050 carbon-neutrality goals, most from the European Union (EU). Emissions of these countries accounted for 17.9% of the world's total emissions (METI, 2022). In the run-up to the COP26, momentum for generating more of these ambitious goals grew; China, the United States (US), and others announced carbon-neutrality targets. Japan made a declaration in October 2020, and Indonesia declared carbon neutrality by 2060 in July 2021. At the end of the COP26, more than 150 countries – including all G20 countries – set carbon-neutrality targets with annual time limits (Figure 1.1). The emissions of those countries accounted for 88.2% of the world's total emissions (METI, 2022).

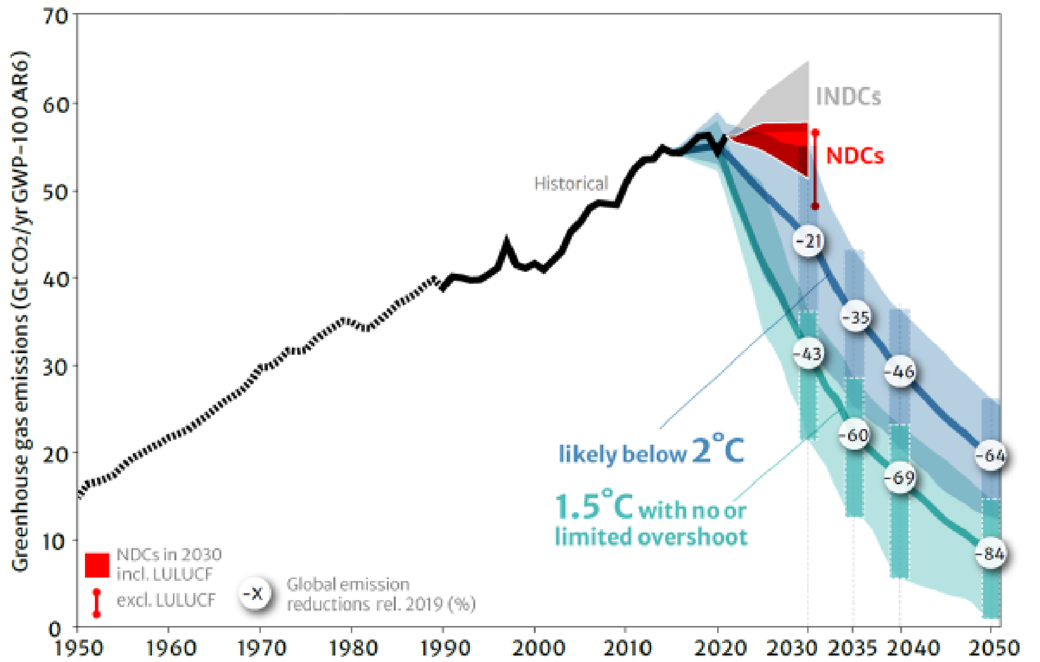
Figure 1.1. Countries and Regions Announcing Carbon Neutrality



COP = United Nations Climate Change Conference.
Note: English translation by INPEX Solutions.
Source: METI (2022).

Although a few countries declared themselves to be carbon neutral in preparation for the COP26, only about half actually raised their nationally determined contributions (NDCs).[1] Specifically, the EU, US, and Japan raised their 2030 emissions reduction targets, but China and many other large countries did not. As a result, according to an analysis by the United Nations Framework Convention on Climate Change (UNFCCC), projected emissions for 2030 based on NDCs are not in line with modelled global mitigation pathways consistent with the temperature goal of the Paris Agreement (Figure 1.2). The window is rapidly closing to implement existing commitments to limit global warming to 1.5°C above pre-industrial levels.

Figure 1.2. Emissions Based on Nationally Determined Contributions



		Reductions from 2019 emission levels (%)			
		2030	2035	2040	2050
Limit warming to1.5°C (>50%) with no or limited overshoot	GHG	43 [34-60]	60 [49-77]	69 [58-90]	84 [73-98]
	CO_2	48 [36-69]	65 [50-96]	80 [61-109]	99 [79-119]
Limit warming to 2°C (>67%)	GHG	21 [1-42]	35 [22-55]	46 [34-63]	64 [53-77]
	CO_2	22 [1-44]	37 [21-59]	51 [36-70]	73 [55-90]

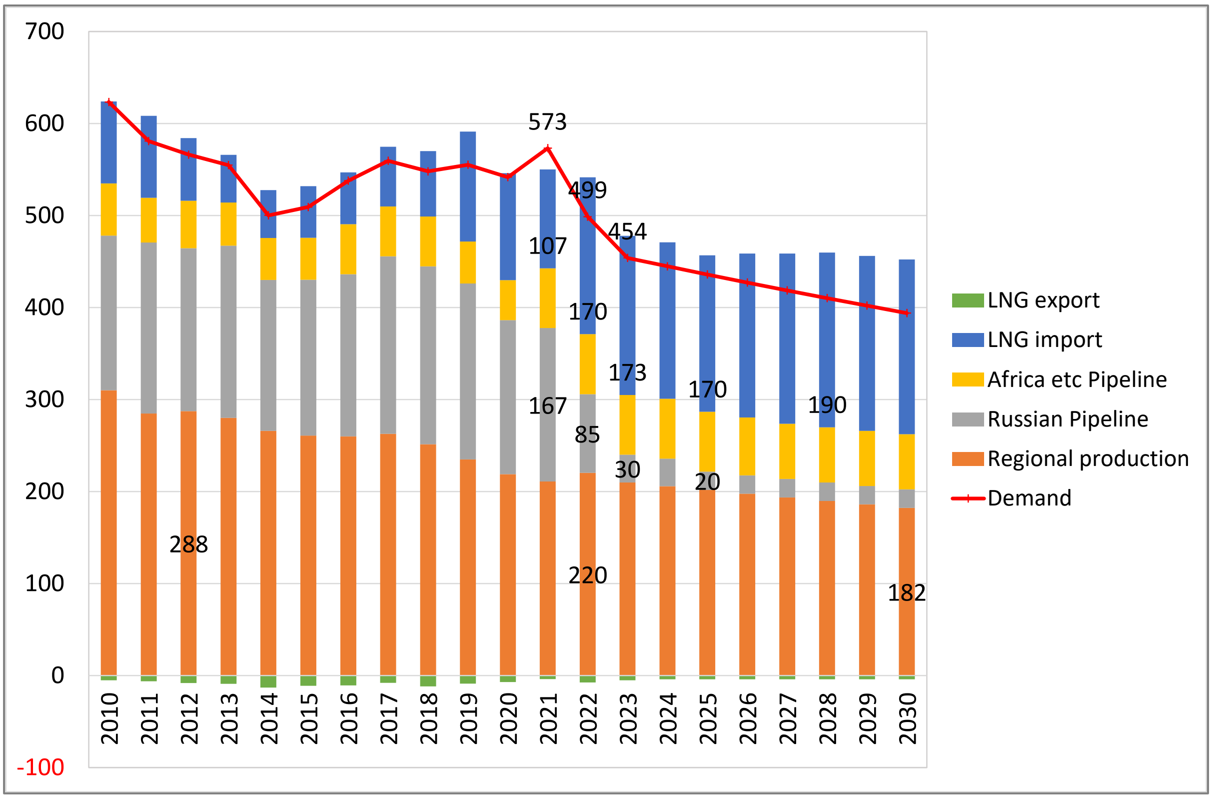
CO_2 = carbon dioxide; GHG = greenhouse gas; Gt = gigatonne; LULUCF = land use, land-use change, and forestry; NDC = nationally determined contribution.
Note: Historical emissions from 1950; projected emissions in 2030 based on NDCs; and emissions reductions required by the *Sixth Assessment Report of the Intergovernmental Panel on Climate Change*.
Source: UNFCCC (2023).

[1] Under the Paris Agreement – adopted in December 2015 and entered into force in November 2016 – all countries are obliged to submit and then to update their greenhouse gas (GHG) emissions reduction targets every 5 years as an NDC.

2. Russia's Invasion of Ukraine

Although the COP26 increased momentum towards carbon neutrality around the world, the Russian invasion of Ukraine in February 2022 triggered a global energy crisis – with Europe as its epicentre. Europe uses natural gas for power generation, heating, and industrial activities and had been dependent on pipeline imports from Russia for about 30% of its natural gas procurement. However, following the invasion, Europe announced a policy of reducing imports of Russian gas, known as REPowerEU. The plan includes diversification of natural gas procurement, expansion of renewable energy, and promotion of energy conservation. As a result, European imports of Russian gas are expected to decline from 167 billion cubic metres (bcm) in 2021 to 85 bcm in 2022 and to 30 bcm in 2023. European imports of liquefied natural gas (LNG) jumped from 107 bcm in 2021 to 170 bcm in 2022 (Figure 1.3).

Figure 1.3. Europe's Natural Gas Supply and Demand
(billion cubic metres)

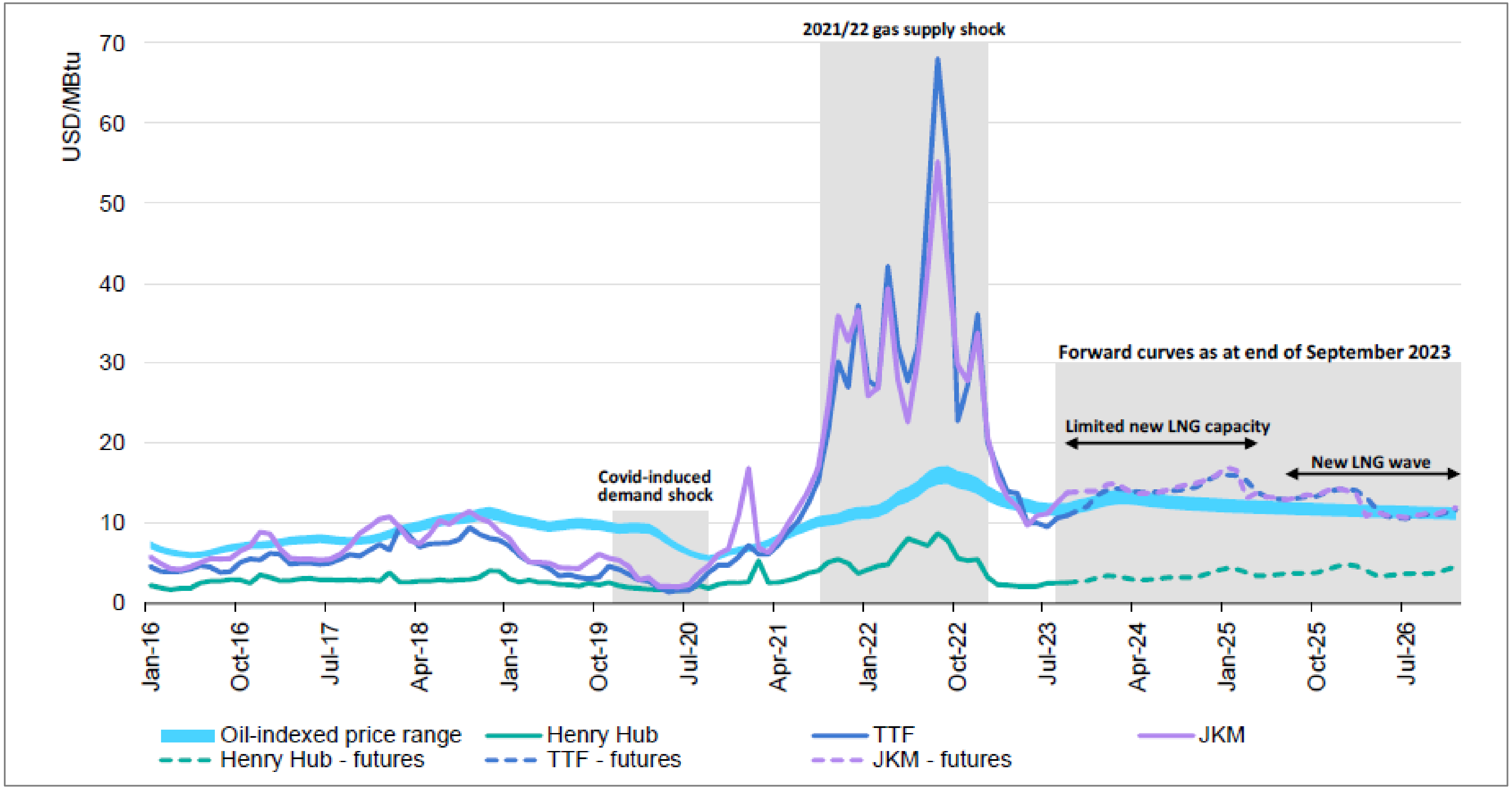


LNG = liquefied natural gas.
Source: INPEX Solutions based on Energy Institute (2023).

This surge in European LNG imports was mainly driven by procurement from the spot LNG market. The LNG market takes about 65% of its supply from medium- and long-term contracts and 35% from spot and short-term contracts. This spot supply flowed mainly to the Asian market until 2021, but in 2022, Europe bought the spot supply at high prices, making about half of the spot supply flow to the European market. This surge in spot gas prices, in turn, triggered a global energy crisis in 2022. The price spike led to production cuts in European industry, and European citizens suffered from high electricity and gas prices. Then, as Europe increased its LNG procurement, some Asian countries could not procure enough LNG and were forced to increase their coal consumption, making coal prices soar.

In 2023, gas spot prices – such as TTF and JKM – fell significantly from the sharp spike in 2022 (Figure 1.4). Europe weathered the 2022–2023 winter well, and Europe has also sufficient gas inventories ready for the 2023–2024 winter season. Nevertheless, the current spot price for gas remains at US$15 per million British thermal units (mmbtu) compared to under US$10/mmbtu before the start of this energy crisis. This is because Europe is still importing a high level of LNG, and several new LNG projects will not start production until around 2027.

Figure 1.4. Natural Gas Price Assumptions across Key Regions, 2016–2026



LNG = liquefied natural gas.

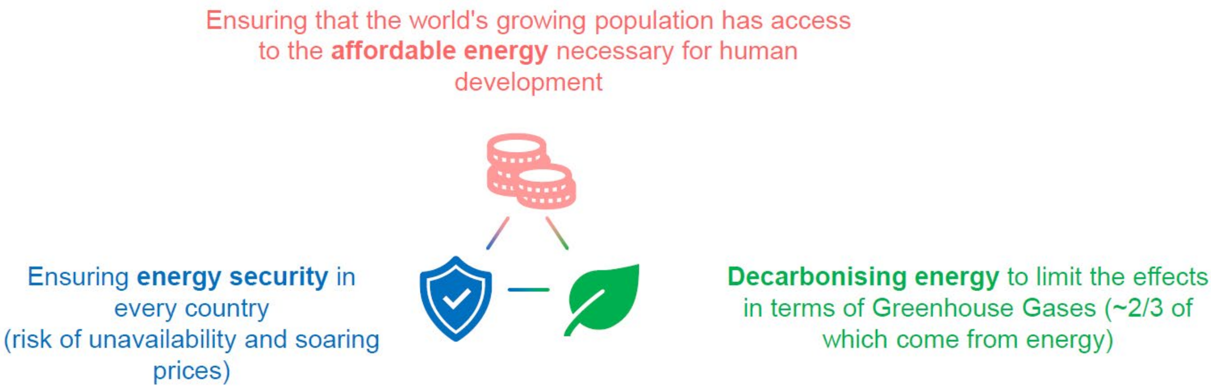
Note: Forward curves suggest that natural gas prices will remain above their historical averages in the medium term.

Source: IEA (2023).

3. Balance between Decarbonisation and Securing Energy

In the long run, the importance of decarbonisation around the globe is not likely to change. However, in light of the current energy crisis, some governments, corporate leaders, and industry experts are noting that a balance must be struck between decarbonisation and stable energy procurement, including oil and gas (Figure 1.5).

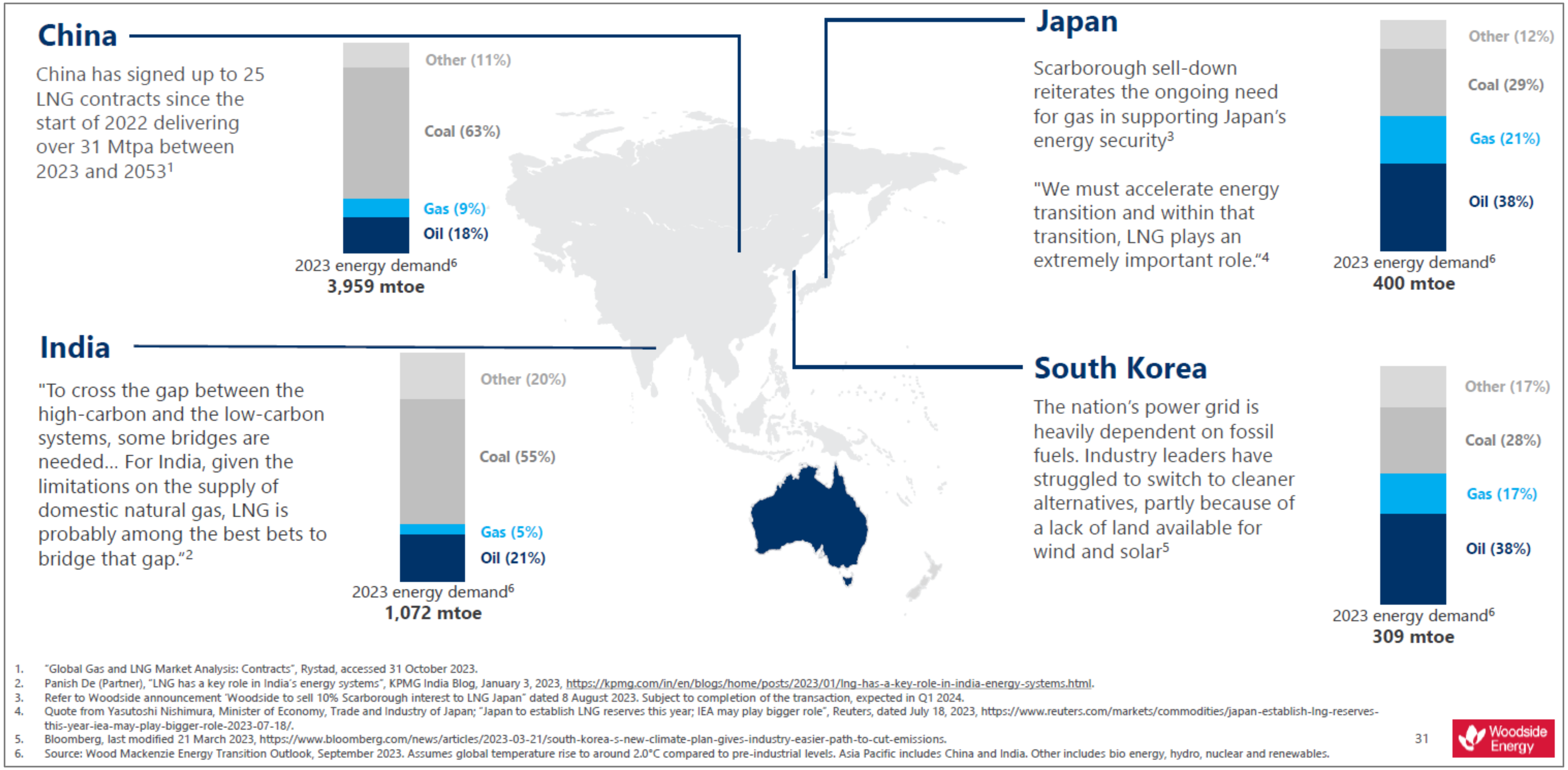
Figure 1.5. The Three Challenges of Energy Transition



Source: TotalEnergies (2023).

As for LNG – which sparked the energy crisis – China has signed long-term contracts for 31 million tonnes per annum (mtpa) from 2022 to ensure stable LNG procurement (Woodside Energy, 2023). Yasutoshi Nishimura, Minister of Economy, Trade and Industry of Japan, stated, 'We must accelerate energy transition, and within that transition, LNG plays an extremely important role' (Woodside Energy, 2023). Figure 1.6 summarises the different roles of LNG in various countries.

Figure 1.6. LNG Supporting Customer and Country Decarbonisation Goals



LNG = liquefied natural gas, mtpa = million tonnes per annum.

Source: Woodside Energy (2023).

Although the LNG industry has recently seen more spot transactions, suppliers originally built LNG facilities based on long-term contracts with customers. A stable energy supply can be ensured if consumers have long-term contracts based on realistic energy demand forecasts. However, if consumers always suppose that they can suddenly procure LNG from the spot market when needed due to uncertain energy demand forecasts,[2] the LNG market will tend to soar.

4. Net-Zero Emissions by 2060

The Government of Indonesia announced in 2021 – the year that the COP26 was held – a goal to achieve net-zero emissions by 2060. To do so, it noted the need for energy infrastructure, technology, and financing, emphasising the roles of the private sector as well as those of the government and financial institutions.

As outlined in IEA and MEMR (2022), between 2026 and 2030, Indonesia will add no capacity to coal-fired power plants, except to those which have reached financial closure or are under construction. The first stage of coal power plant retirement will begin in 2031. From 2036 to 2040, the second stage of coal power plant retirement will be conducted, with the last stage planned for 2051 to 2060.

Indonesia submitted its updated NDC in September 2022 (GOI, 2022). It has an unconditional emissions reduction target of 31.89% and a conditional target of 43.20% compared to the business-as-usual (BAU) scenario in 2030 (Figure 1.7). The country's 2030 emissions will total 2,869 million tonnes in the BAU scenario; 1,953 million tonnes in an unconditional scenario; and 1,632 million tonnes in a conditional scenario compared to 2010 emissions of 1,334 million tonnes.

[2] If nuclear power plants shut down unexpectedly, wind power does not generate as much electricity as expected due to weak winds, or new renewable energy generation does not proceed at a pace planned by a government, customers will have to rely on LNG.

Figure 1.7. Indonesia's Updated Nationally Determined Contribution, 2022

Sector	GHG Emission Level 2010* (MTon CO2-eq)	GHG Emission Level 2030 MTon CO_2-eq			GHG Emission Reduction MTon CO_2-eq		GHG Emission Reduction % of Total BaU		Annual Average Growth BAU (2010-2030)	Average Growth 2000-2012
		BaU	CM1	CM2	CM1	CM2	CM1	CM2		
1. Energy*	453.2	1,669	1,311	1,223	358	446	12.5%	15.5%	6.7%	4.50%
2. Waste	88	296	256	253	40	43.5	1.4%	1.5%	6.3%	4.00%
3. IPPU	36	69.6	63	61	7	9	0.2%	0.3%	3.4%	0.10%
4. Agriculture	110.5	119.66	110	108	10	12	0.3%	0.4%	0.4%	1.30%
5. Forestry and Other Land Uses (FOLU)**	647	714	214	-15	500	729	17.4%	25.4%	0.5%	2.70%
TOTAL	**1,334**	**2,869**	**1,953**	**1,632**	**915**	**1,240**	**31.89%**	**43.20%**	**3.9%**	**3.20%**

Notes: CM1= Counter Measure 1 (*unconditional mitigation scenario*)
CM2= Counter Measure 2 (*conditional mitigation scenario*)

*) Including fugitive.
**) Including emission from estate and timber plantations.

BAU = business as usual, CO_2eq = carbon dioxide equivalent, GHG = greenhouse gas, IPPU = industrial processes and product use, MT = metric tonne.
Source: Government of Indonesia (2022).

Indonesia hosted the G20 summit in November 2022. Thanks in part to the summit, the Government of Indonesia has deepened discussions regarding net-zero emissions, including through the Indonesia Just Energy Transition Partnership. This is a long-term energy transition partnership between Indonesia and various international partners, including those in the EU, Japan, and the US. It aims to mobilise US$20 billion in public and private financing to help it achieve its climate targets.

Chapter 2

Global Strategies of International Oil and Gas Companies

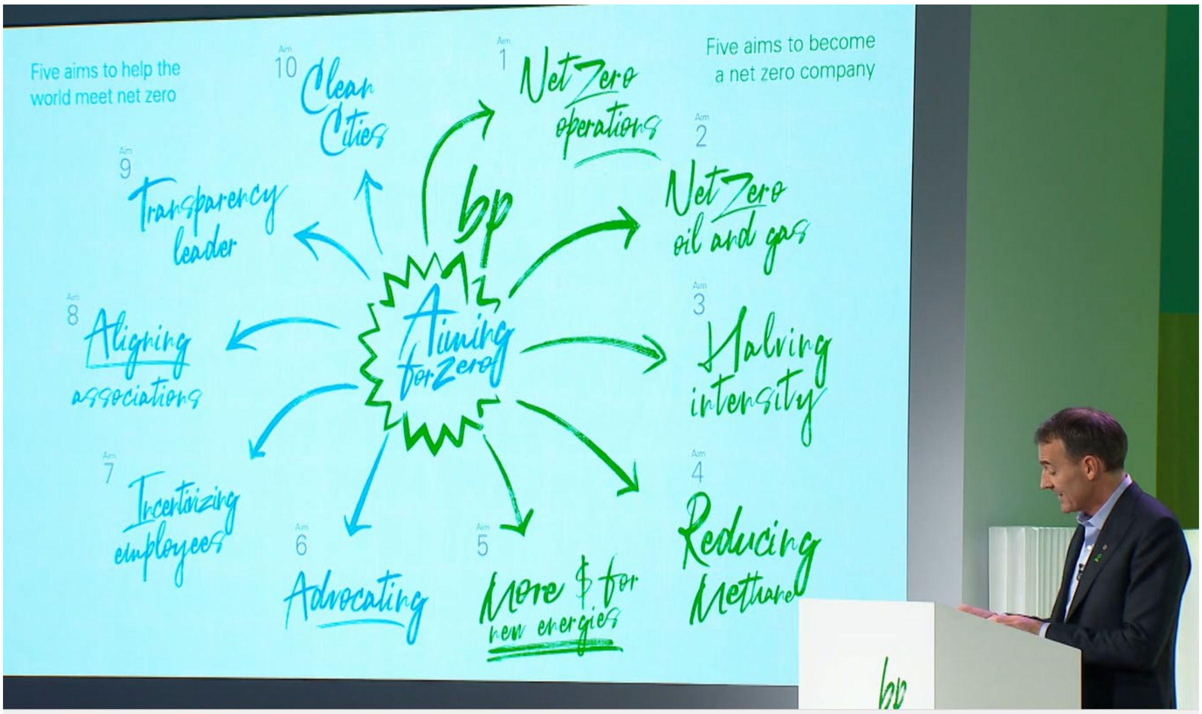
In this section, international oil and gas company (IOC) global strategies are examined in preparation for considering their activities in Indonesia. IOCs include BP, Shell, Eni, Chevron, ConocoPhillips, and INPEX. In light of the energy crisis, some European IOCs have increased their oil and gas activities, while some US IOCs have greatly expanded the scale of their production through mergers and acquisitions. It should be added, however, that each IOC is taking carbon neutrality into consideration.

1. BP's Global Strategy

BP is a British multi-national company engaged in oil and gas; refining; gas stations; and low-carbon energy such as solar power, wind power, and bioenergy. BP is one of the 'Oil and Gas Majors'; other majors include Chevron, ExxonMobil, Shell, and TotalEnergies.

BP announced a net-zero ambition by 2050 in 2020, and its content was the most proactive amongst the Majors on decarbonisation (Figure 2.1). Specifically, BP's oil and gas production would be reduced from 2.6 million barrels of oil equivalent per day (mmboe/d) in 2019 to 1.5 mmboe/d in 2030. At the time of the announcement, BP held shares in Rosneft – a Russian company – and BP's total production volume, including its stake in Rosneft, was 3.7 mmboe/d.

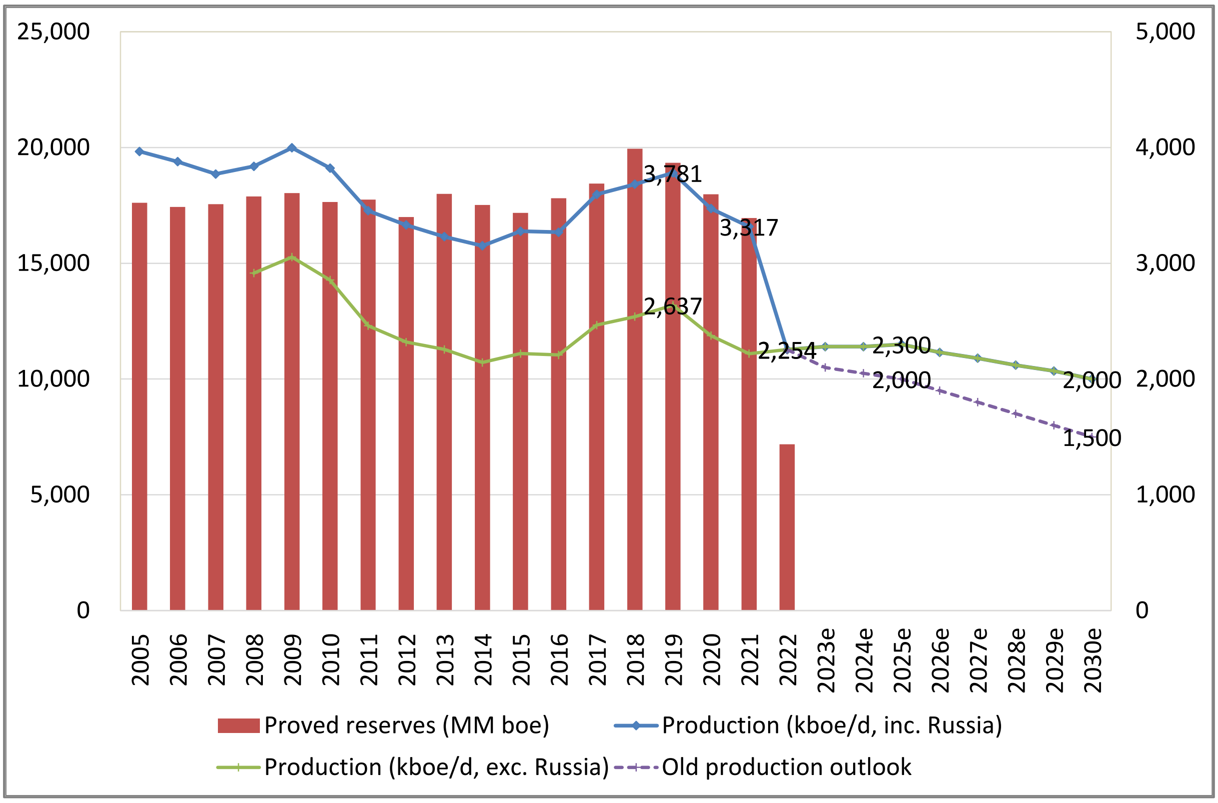
Figure 2.1. BP's Net-Zero Ambition by 2050



Source: BP, Archive of Results, Reports and Presentations, https://www.bp.com/en/global/corporate/investors/results-reporting-and-presentations/archive.html#tab_2020

In February 2023, however, BP revised its oil and gas production reduction target in light of the energy crisis. It increased its production target for 2030 from 1.5 mmboe/d to 2.0 mmboe/d. Following the Russian invasion of Ukraine in 2022, BP sold its Rosneft holdings, so BP's total production in 2022 fell to 2.2 mmboe/d, which it intends to reduce slightly to 2.0 mmboe/d in 2030 (Figure 2.2). This upwards revision of the production target came as a surprise, as BP has been the most proactive in decarbonising within the Majors.

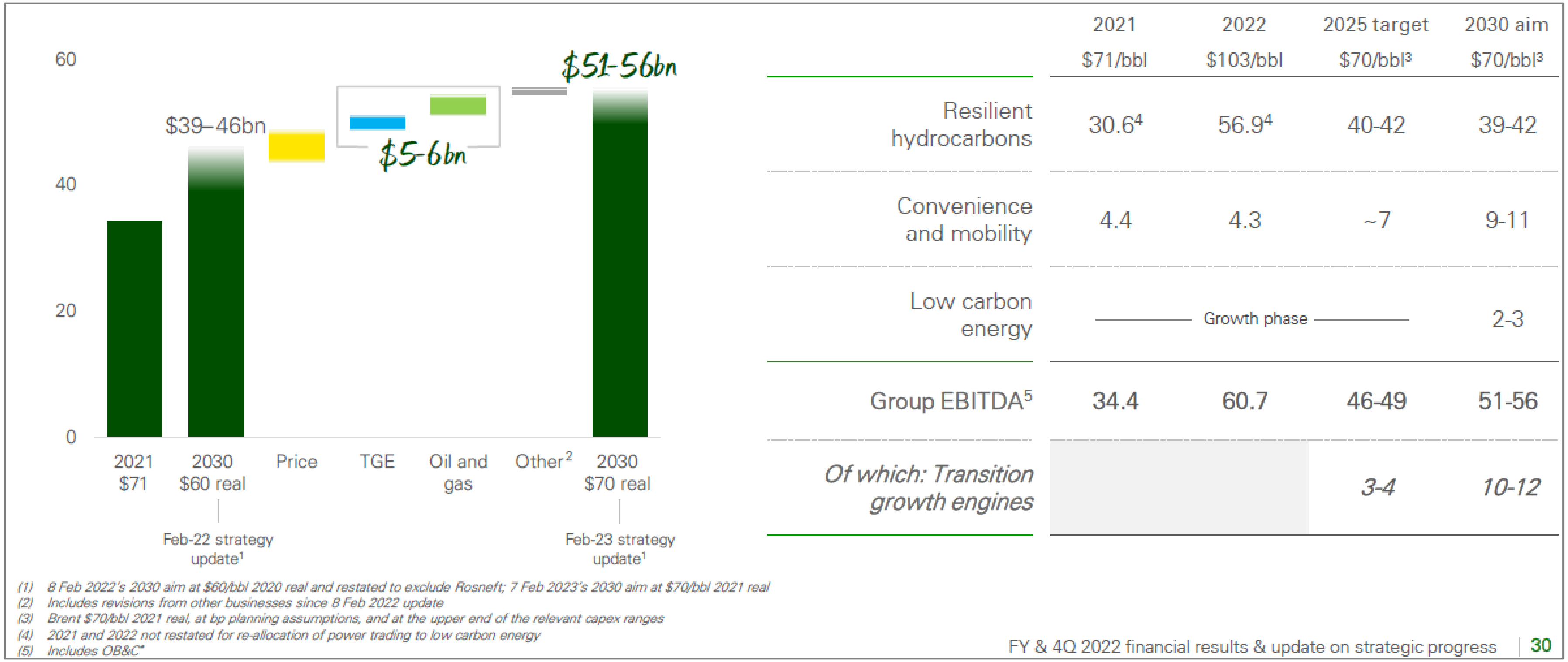
Figure 2.2. BP's Oil and Gas Production and Proved Reserves



boe = barrel of oil equivalent, e = estimate.
Note: Left axis = proved reserves, right axis = oil and gas production.
Source: INPEX Solutions.

This upwards revision of BP's oil and gas production target is not only due to the energy crisis but also to a business returns perspective. BP has been increasing the weight of investment in the low-carbon energy business, but returns are not currently expected. Earnings before interest, tax, depreciation, and amortisation (EBITDA) in 2030 are expected to be only US$2 billion–US$3 billion. Note that companywide EBITDA in 2030 is expected to be US$51 billion–US$56 billion, of which US$39 billion–US$42 billion is expected to come from oil and gas (Figure 2.3).

Figure 2.3. BP's EBITDA Outlook

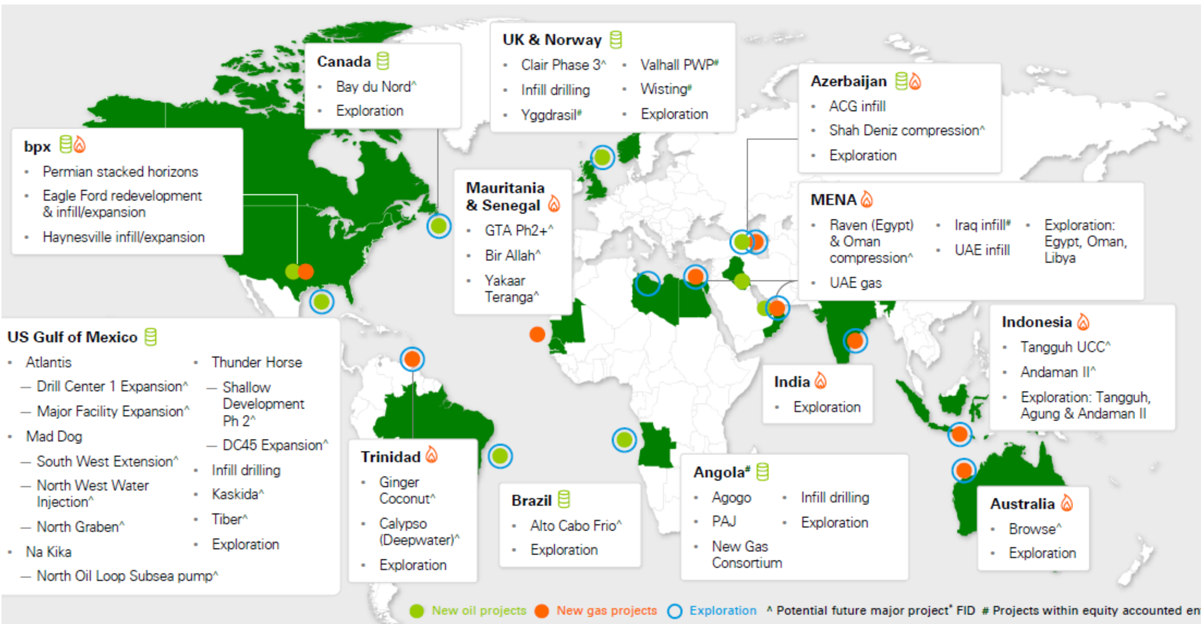


bbl = oilfield barrel, EBITDA = earnings before interest, taxes, depreciation, and amortisation.
Source: BP (2023c).

BP – as well as some other IOCs – is financing its investment in low-carbon energy from the earnings of its oil and gas business. If BP were to reduce its oil and gas production too quickly while the profitability of its low-carbon energy business remains low, it would be difficult to finance its investment in the low-carbon energy business.

BP has the following candidate projects to achieve production of 2.0 mmboe/d in 2030 compared to 2.2 mmboe/d in 2022 (Figure 2.4). The existing core areas of the US (i.e. shale oil and the Gulf of Mexico) and the Middle East and North Africa are the main areas with new projects, and existing assets and infrastructure will be used to promote new projects and exploration around them. BP expects US shale oil production to expand from about 120 thousand barrels of oil equivalent per day (kboe/d) in 2022 to about 240 kboe/d in 2030, while Gulf of Mexico production will expand from about 250 kboe/d in 2022 to about 350 kboe/d in 2030. In the Middle East (i.e. the United Arab Emirates [UAE] and Iraq). production is expected to expand from about 220 kboe/d in 2022 to about 320 kboe/d in 2030 (Figure 2.4).

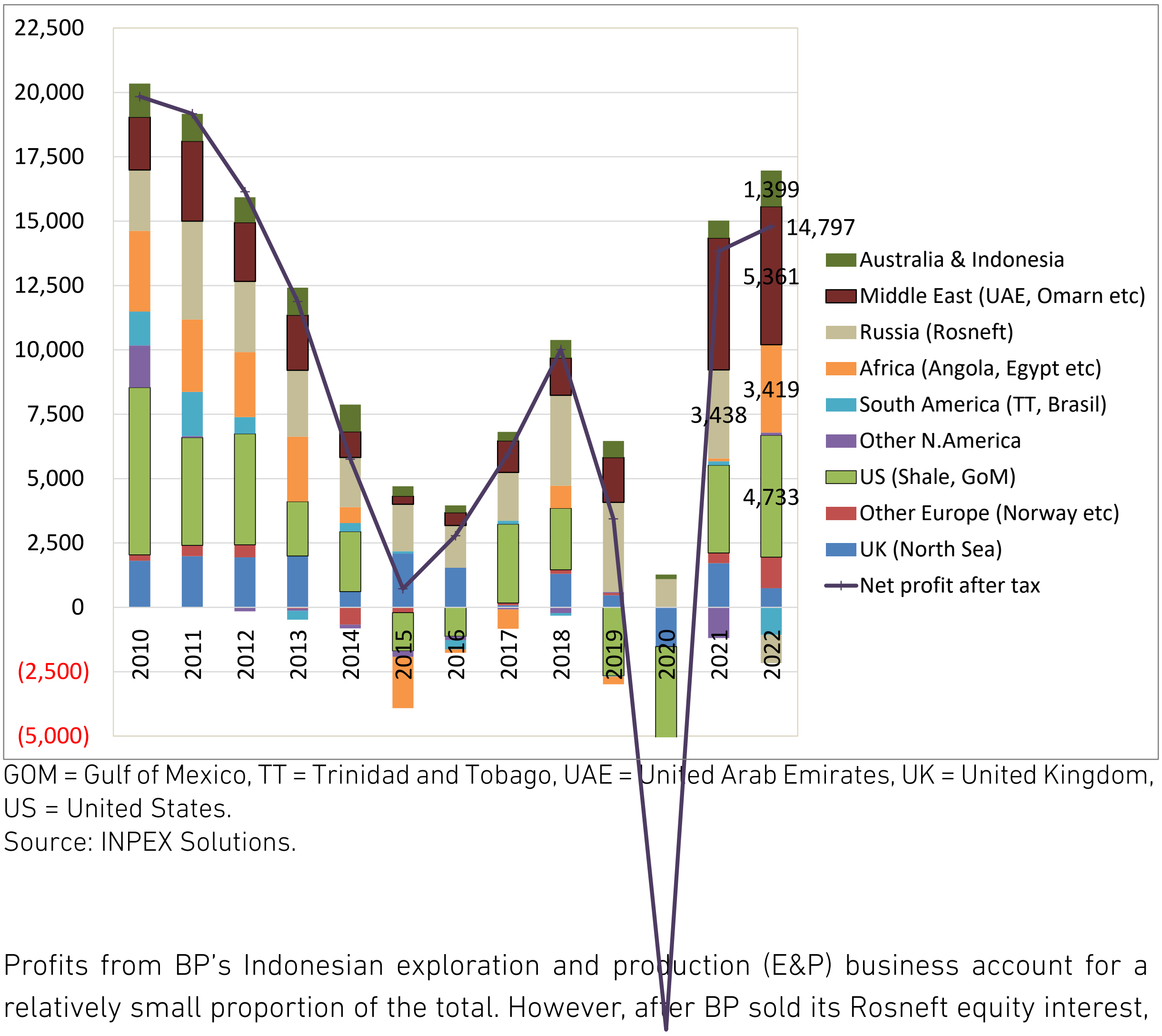
Figure 2.4. BP's New Oil and Gas Projects



MENA = Middle East and North Africa, UAE = United Arab Emirates, UK = United Kingdom, US = United States.
Source: BP (2023b).

BP earns about 80% of its net income from oil and gas operations and about 20% from downstream-related activities. Figure 2.5 shows the net income of the oil and gas business by region. Of its total net income of US$14.8 billion, the US (US$4.7 billion), the Middle East (US$5.4 billion), and Africa (US$3.4 billion) are the main sources, while those from Australia and Indonesia (US$1.4 billion) remain relatively low in 2022.

Figure 2.5. BP's Net Profit from Oil and Gas, 2010–2022
(US$ million)



GOM = Gulf of Mexico, TT = Trinidad and Tobago, UAE = United Arab Emirates, UK = United Kingdom, US = United States.
Source: INPEX Solutions.

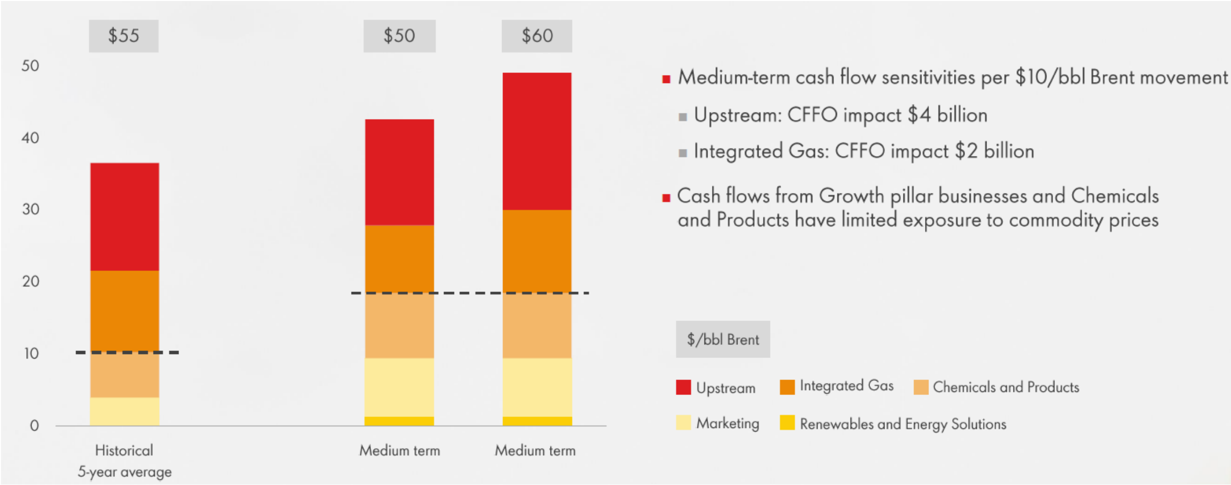
Profits from BP's Indonesian exploration and production (E&P) business account for a relatively small proportion of the total. However, after BP sold its Rosneft equity interest, BP lost its equity profits. These had contributed significantly to its overall profits, so BP would like to maintain its Indonesian E&P business as an important profit source. Moreover, from 2020 to 2022, BP focussed on shifting to renewable energy, so there are relatively few new projects in the oil and gas business pipeline. BP is thus aiming to promote new projects in Indonesia as well.

2. Shell's Global Strategy

Shell is also a British multi-national company engaged in oil and gas; refining; gas stations; and low-carbon energy such as solar power and wind power.

In 2021, Shell announced a plan to increase its investment ratio in renewable and energy solutions (i.e. hydrogen and carbon capture and storage [CCS]) and to decrease its investment ratio in upstream activities in light of the momentum of the energy transition in Europe and other regions. However, it noted that the midterm cash potential of renewables and energy solutions would be marginal (Figure 2.6). Indeed, the net income of renewables and energy solutions would be even smaller, since the net income will be cash minus depreciation and amortisation.

Figure 2.6. Shell's Cash Potential by Business Segment

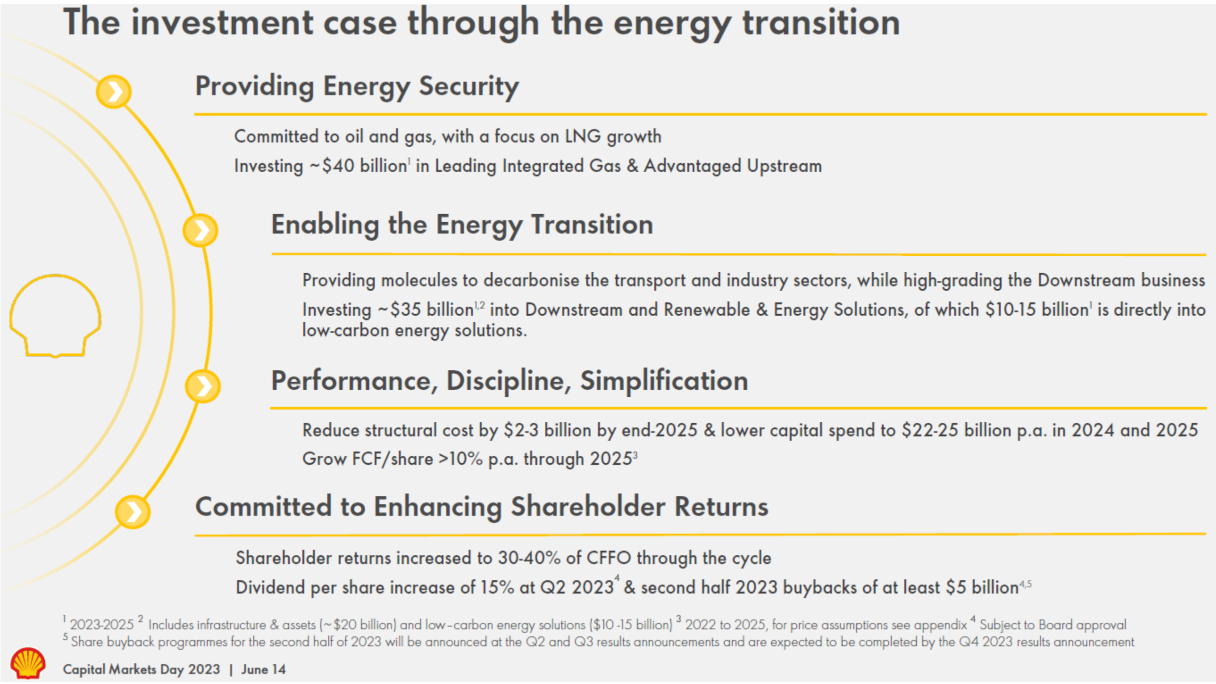


bbl = oilfield barrel, CFFO = cash flow from operations.
Source: Shell (2021).

At an investor relations meeting in February 2023, Shell's chief executive officer commented, 'In upstream, oil, and gas, we will continue to proudly deliver energy that the world needs. Regarding low-carbon business, we cannot justify going for a low return. If we cannot achieve double-digit returns in a business, we need to question very hard whether we should continue in that business. Absolutely, we want to continue to go for lower and lower and lower carbon, but it has to be profitable'.

Then, due to the global energy crisis, Shell revised its strategy slightly in June 2023, stating that it would commit to providing energy security for oil, gas, and LNG while continuing to take energy transition into consideration. Shell also stated that it would increase its investment discipline with a focus on performance results in the low-carbon business (Figure 2.7).

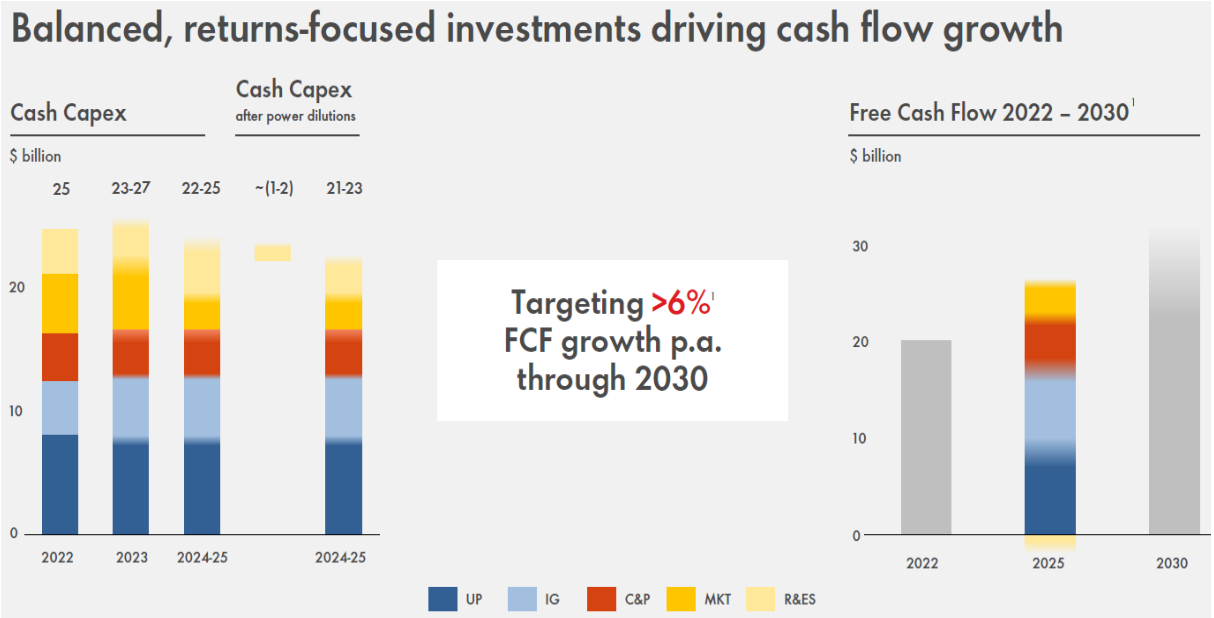
Figure 2.7. Shell's Current Overall Strategy



CFFO = cash flow from operations, LNG = liquefied natural gas.
Source: Shell (2023).

With this slight revision to its strategy, Shell said that its future investment plans will be balanced and focussed on returns. Specifically, investment in upstream and integrated gas in 2024–2025 will be flat in 2022–2023. In renewable and energy solutions, the company is considering a reduction in investment due to partial sale of its power business (Figure 2.8).

Figure 2.8. Shell's Capital Expenditures Plan



Capex = capital expenditures, FCF = free cash flow.
Source: Shell (2023).

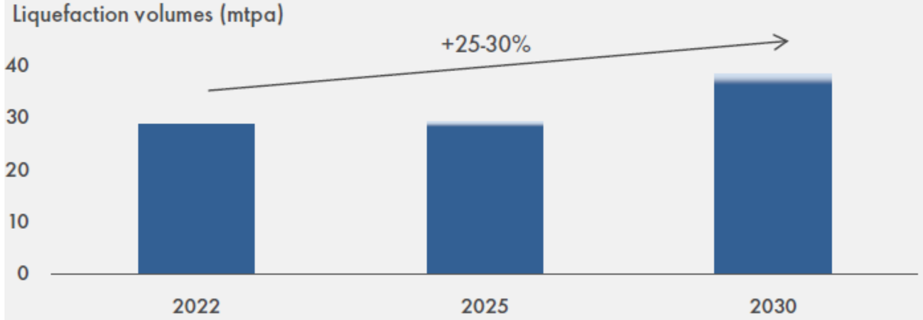
In its integrated gas and upstream businesses, Shell is somewhat more focussed on its LNG business. Equity volumes of LNG[3] will grow from about 30 mtpa in 2022 to about 38 mtpa in 2030 through selective investment, such as in LNG Canada Train 1-2, NLNG Train 7, Qatar North Field East, and South Expansion (Figure 2.9). The contracted volume of LNG[4] will grow from about 30 mtpa in 2022 to about 35 mtpa in 2030. Liquids, such as oil and natural gas production, is expected to remain flat at 1.4 mmboe/d through 2030.

Shell sold its interest in the Abadi LNG Project in 2023, removing Abadi LNG as a candidate for new LNG projects. It was explained that this decision is in line with Shell's focus on disciplined capital allocation.

[3] Shell invests its own money into the LNG projects.
[4] Shell agreed to purchase LNG from third parties.

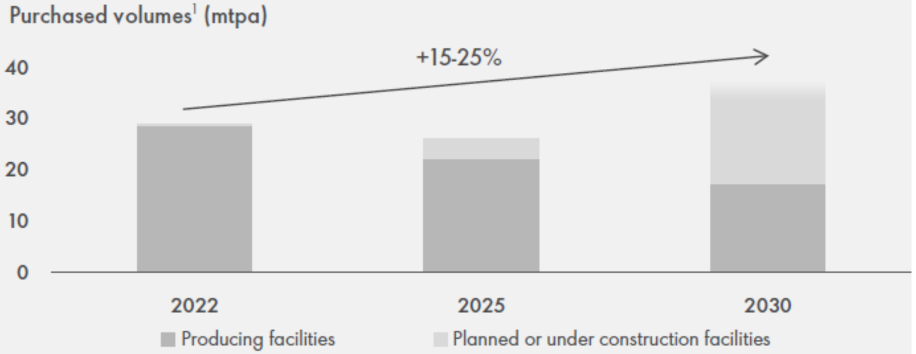
Figure 2.9. Shell's LNG Projects

Growing equity volumes through selective investment



Projects under construction	Country	Shell share %	LNG capacity 100%, mtpa
LNG Canada Train 1-2	Canada	40	14
NLNG Train 7	Nigeria	26	7.6
North Field East Expansion	Qatar	25	8
North Field South Expansion[2]	Qatar	9.4	16

Contracting for reliable and competitive offtake



3rd party offtake agreements	Country	Project status	LNG offtake mtpa
Venture Global – Calcasieu Pass	USA	Producing	2.0
Mozambique LNG	Mozambique	Under construction	2.0
Venture Global – Plaquemines LNG phase 1	USA	Under construction	1.9
Mexico Pacific – Train 1+2	Mexico	Pre-FID	2.6
Mexico Pacific – Train 3	Mexico	Pre-FID	1.1
Energy Transfer – Lake Charles	USA	Pre-FID	2.1
Next Decade – Rio Grande LNG	USA	Pre-FID	2.0

Volumes exclude spot purchases and Russia sourced volumes.
[1] Includes 3rd party purchases and purchases from JV's in addition to liquefaction volumes. Outlook for 2030 includes uncontracted volumes and volumes subject to project FID
[2] Subject to transaction completion

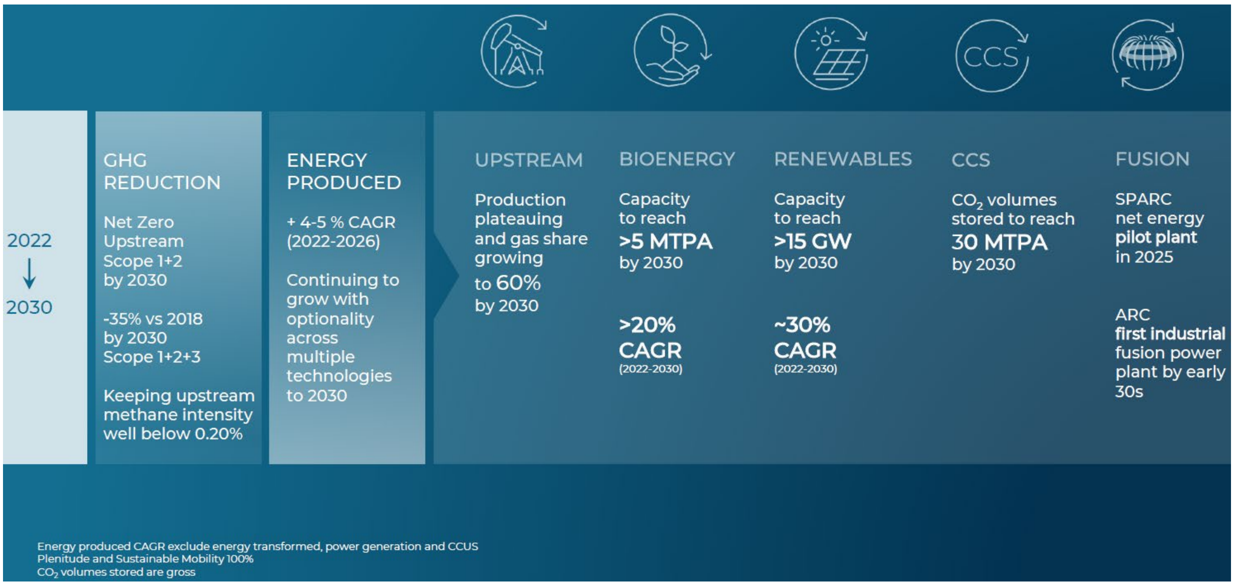
FID = final investment decision, LNG = liquefied natural gas, USA = United States.
Source: Shell (2023).

3. Eni's Global Strategy

Eni is an Italian multi-national company engaged in oil and gas; refining; gas stations; chemicals; and low-carbon energy such as solar power and wind power. Eni is not classified as a Major but has a production volume only slightly below that of the Majors.

Eni announced an ambitious and aggressive decarbonisation and energy transition strategy, *Net Zero GHG of Upstream Scope 1+2 by 2030*, by using CCS of 30 mtpa by 2030. Secondly, it is focussing on renewables, such as solar and wind power generation, with a capacity to reach more than 15 gigawatts by 2030. Eni is also working to achieve bioenergy capacity of more than 5 mtpa by 2030 (Figure 2.10).

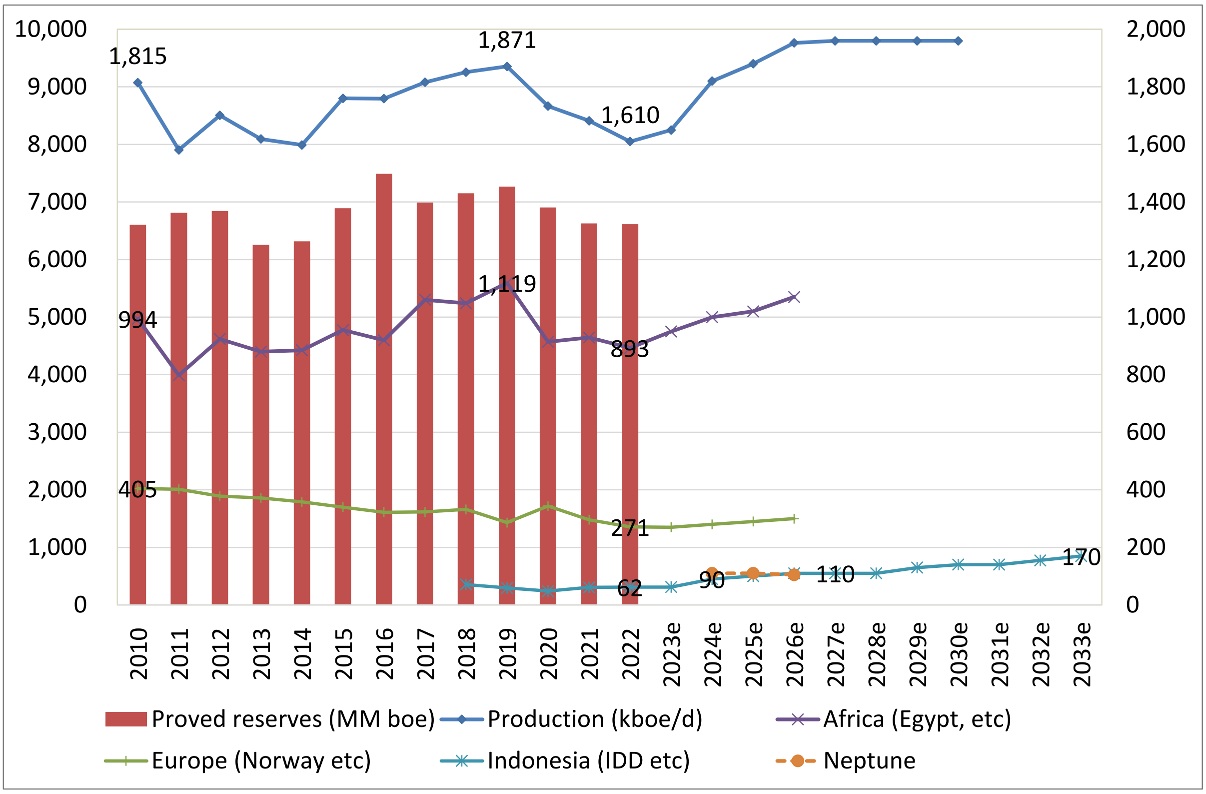
Figure 2.10. Eni's Outlook to 2030



CAGR = compound annual growth rate, CCS = carbon capture and storage, GHG = greenhouse gas, GW = gigawatt, MTPA = million tonnes per annum.
Source: Eni (2023/2)

Although it has pledged to expand its renewables and bioenergy businesses, in 2021 and 2022, about 95% of Eni's net income came from E&P and LNG. Thus, its E&P business, in combination with CCS and other measures, will be the main earnings driver until 2030. With respect to oil and gas production, Eni expects to expand production by 3%–4% per year in 2022–2026, plateau until 2030, and increase the gas share to 60% by 2030. The ambitious and aggressive decarbonisation and energy transition strategy announced does not mean that oil and gas production will be reduced in the foreseeable future (Figure 2.11).

Figure 2.11. Eni's Oil and Gas Production and Proved Reserves



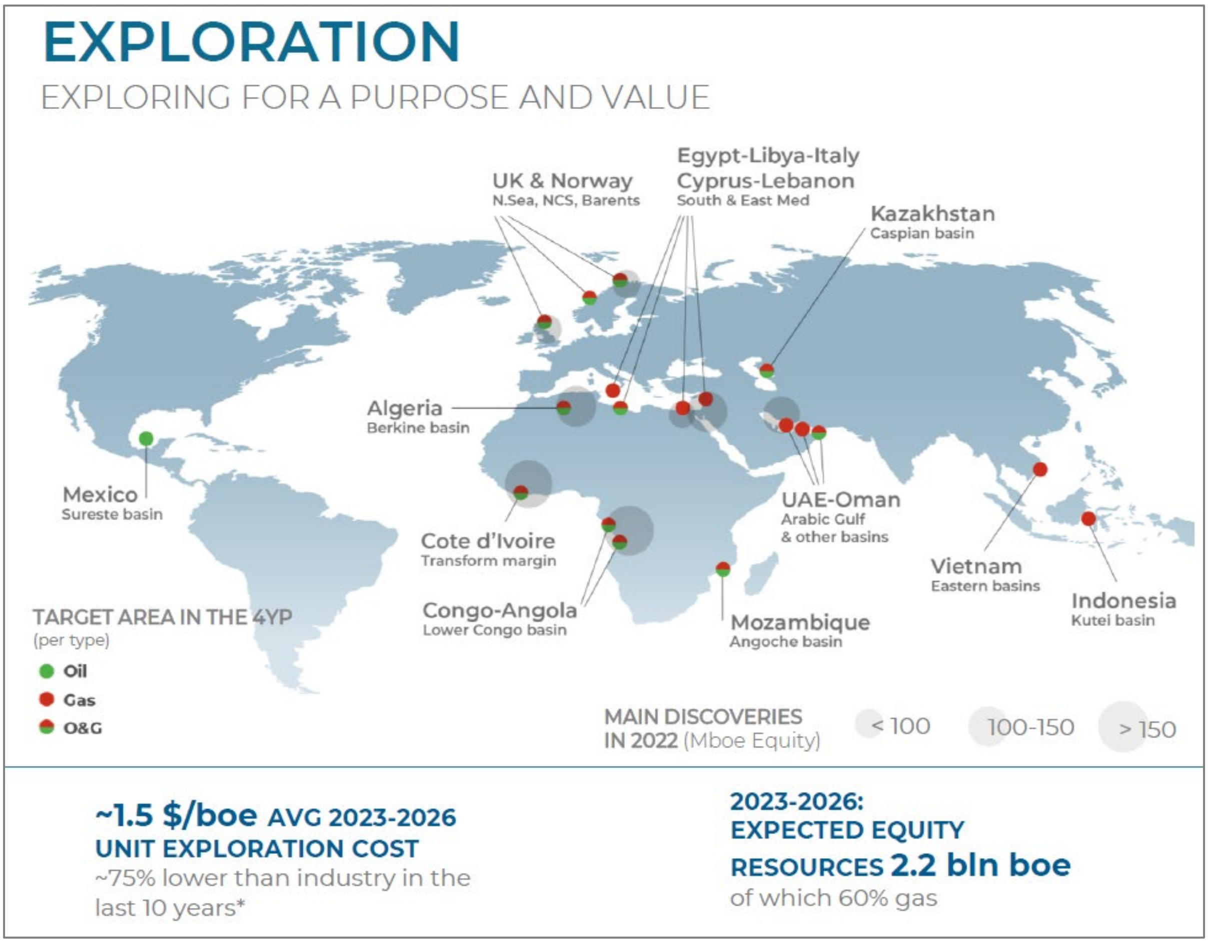
e = estimated, kboe = thousand barrels of oil equivalent, MMboe = million barrels of oil equivalent.
Note: left axis = proved resources, right axis = oil and gas production.
Source: INPEX Solutions.

Eni's strength is in oil and gas exploration – in particular African exploration, including the discovery of gas reserves in Mozambique in 2011 and the Zohr gas reserves in Egypt in 2015. Eni also discovered significant gas resources in Indonesia in 2023.

However, its production areas are too dispersed around the world. Eni's producing countries include Algeria, Angola, Congo, Egypt, Indonesia, Kazakhstan, Libya, Italy, Nigeria, Norway, UAE, US, and Venezuela (Figure 2.12). Areas where Eni conducts E&P are also very dispersed, probably because Eni is strong in exploration and has made many discoveries in exploration in new areas.

Eni merged its Angolan and Norwegian E&P operations with other companies that are operating E&P businesses in the same regions, making them equity method subsidiaries of Eni (Figure 2.21). The businesses in each area have been able to scale up and to operate independently.

Figure 2.12. Eni's Oil and Gas Business Areas



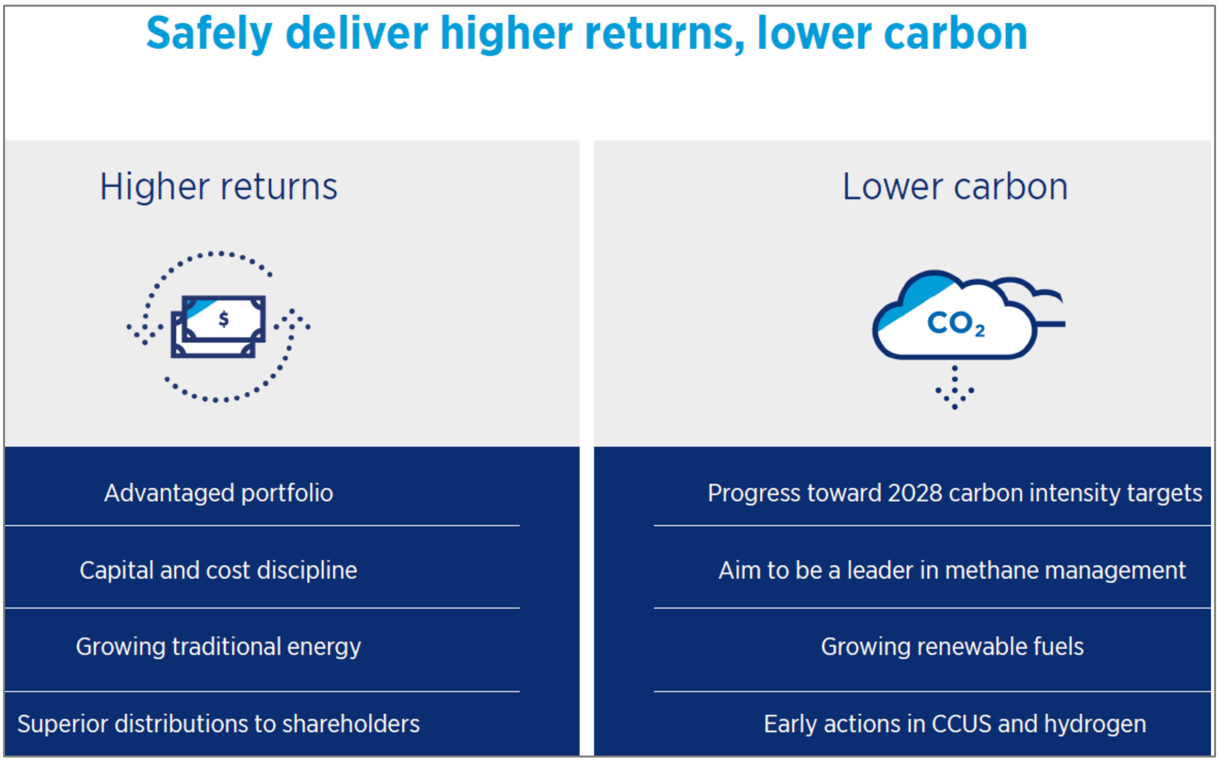
boe = barrel of oil equivalent, UAE = United Arab Emirates, UK = United Kingdom.
Source: Eni (2023c).

4. Chevron's Global Strategy

Chevron is an American multi-national company, engaged in oil and gas; refining; gas stations; and the upstream US shale oil business, including in the Permian Basin.

Chevron's global strategy focusses on higher returns and lower carbon (Figure 2.13). As for higher returns, Chevron is advancing its oil and gas business portfolio by selecting assets with high profitability and large reserves. As a result, the company will be able to provide greater returns to shareholders through dividends and other means. Regarding lower carbon, Chevron is reducing emissions intensity from upstream activities by reducing methane emissions. Chevron is involved in renewable fuels such as biofuels and is considering hydrogen and CCS. Chevron is not in the solar power nor wind power generation business.

Figure 2.13. Chevron's Overall Strategy



CCUS = carbon capture, use, and storage.
Source: Chevron, Events and Presentations, https://www.chevron.com/investors/events-presentations

Chevron is active in mergers and acquisitions of oil and gas companies. In May 2023, it announced its acquisition of PDC Energy in an all-stock transaction in exchange for Chevron's issuance of new shares, valued at US$6.3 billion. Through this acquisition, Chevron could increase the production volume of the Denver Julesburg (DJ) Basin, a major US shale oil-producing region, from 150 kboe/d to 350 kboe/d, growing to 400 kboe/d in 2027.

In October 2023, Chevron announced plans to acquire Hess Corporation in an all-stock transaction valued at US$53 billion (Figure 2.14). The main purpose may be to acquire world-class assets in Guyana. Chevron already has an exploration bloc in Suriname; through this deal, Chevron could further strengthen its ties in the Guyana–Suriname area.

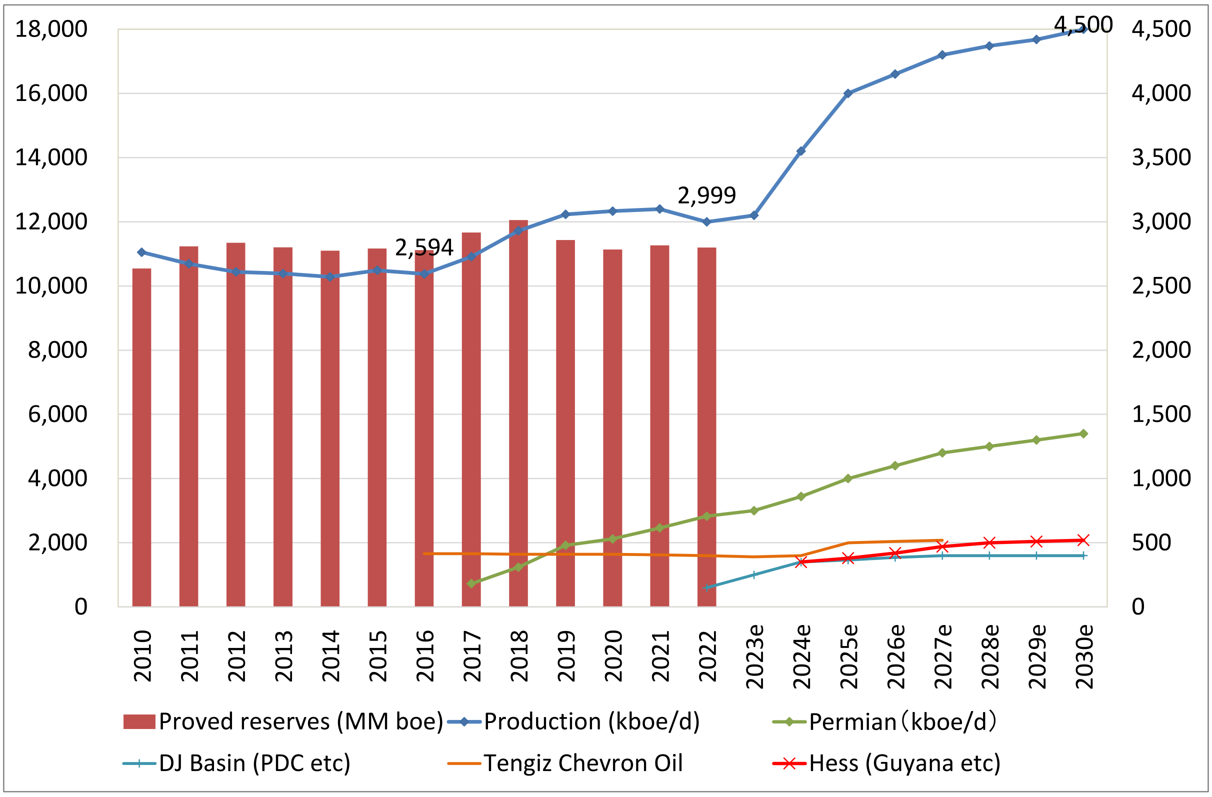
Figure 2.14. Chevron's Merger and Acquisition with Hess Corporation

DJ = Denver Julesburg, TCO = Tengizchevroil.
Source: Chevron, Events and Presentations, https://www.chevron.com/investors/events-presentations

These two mergers and acquisitions, in addition to the original Permian Basin production growth forecast, are expected to increase Chevron's production from 3.0 mmboe/d in 2022 to 4.5 mmboe/d in 2030. Chevron's production has hovered between 2.5 mmboe/d and 3.0 mmboe/d for the past 20 years, so this production expansion outlook is a significant change (Figure 2.15).

Chevron has large core areas of 500 kboe/d to 1,500 kboe/d each, including the Permian and DJ basins, Tengizchevroil in Kazakhstan, and Guyana, which it will acquire through the Hess Corporation acquisition. Indeed, Chevron is selecting promising core areas.

Figure 2.15. Chevron's Oil and Gas Production and Proved Reserves



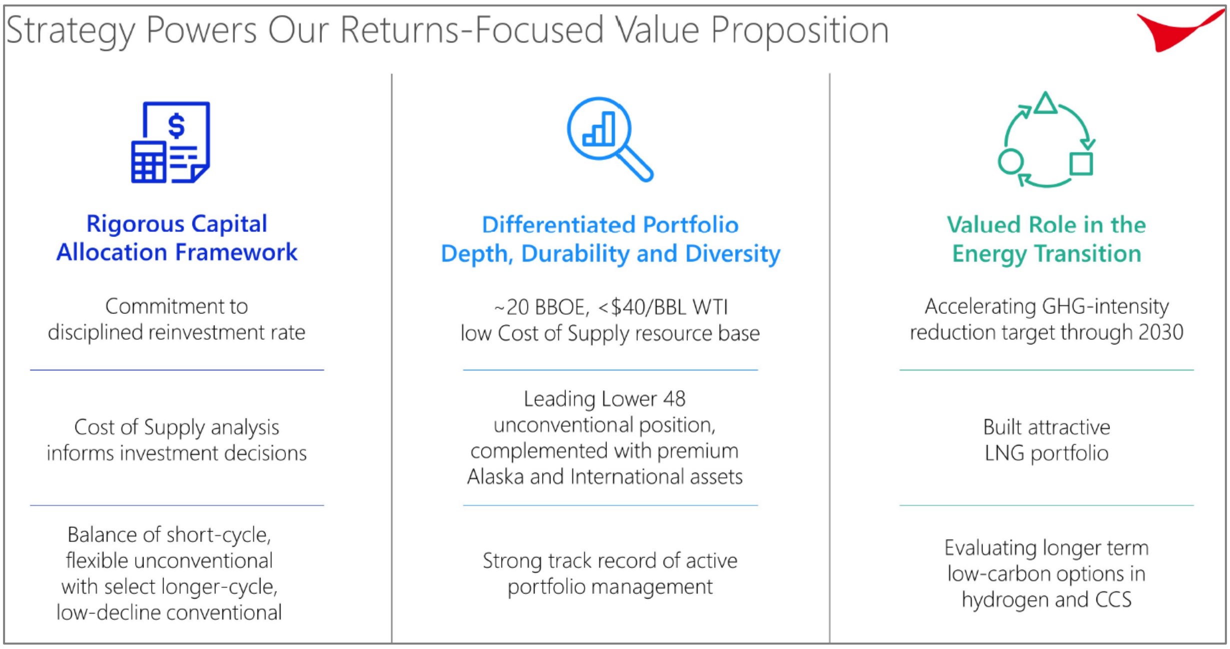
Note: left axis = proved resources, right axis = oil and gas production.
boe = barrel of oil equivalent, e = estimated.
Source: INPEX Solutions.

5. ConocoPhillips's Global Strategy

ConocoPhillips is an American multi-national corporation engaged in oil and gas E&P. ConocoPhillips is not a Major but has a production volume only slightly below that of the Majors. ConocoPhillips is not currently in the oil refining nor gas station business, as it has sold those businesses. Recently, ConocoPhillips has been focussing on the US shale oil business, mainly in the Permian Basin.

The mandate of ConocoPhillips is to raise competitive returns by striving to supply energy in line with an actual energy transition, while maintaining net-zero ambitions (Figure 2.16). ConocoPhillips is focussed on returns and a commitment to disciplined investment based on the cost–supply analysis of each asset. As a result, ConocoPhillips has a strong track record of active oil and gas portfolio management.

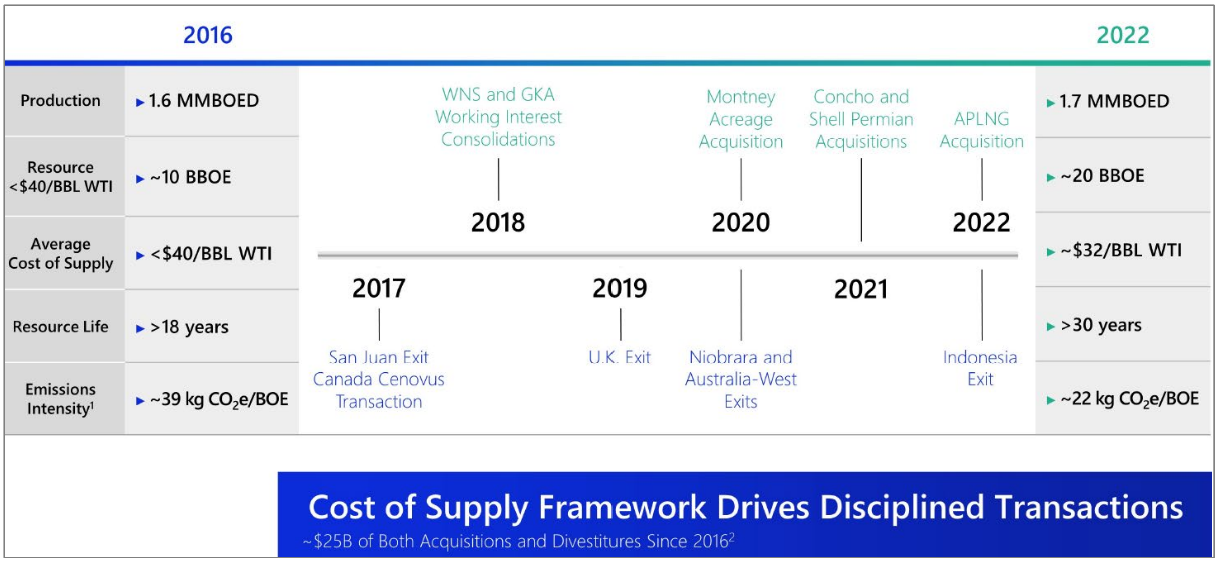
Figure 2.16. Overall Strategy of ConocoPhillips



bbl = oilfield barrel, boe = barrel of oil equivalent, CCS = carbon capture and storage, GHG = greenhouse gas, LNG = liquefied natural gas.
Source: Conoco, Upcoming and Past Investor Presentations, https://www.conocophillips.com/investor-relations/investor-presentations/

Regarding portfolio management, ConocoPhillips divested from and exited the UK upstream business in 2019 and Australia-West assets in 2020. ConocoPhillips acquired Concho, a US shale oil company operating mainly in the Permian Basin, as well as Shell's Permian Basin assets in 2021. Through these transactions, ConocoPhillips is shifting its focus to the core area of US shale oil. In 2022, it divested its interest of Corridor production sharing contract (PSC), an Indonesian gas asset, and increased its interest in Australia Pacific LNG (Figure 2.17).

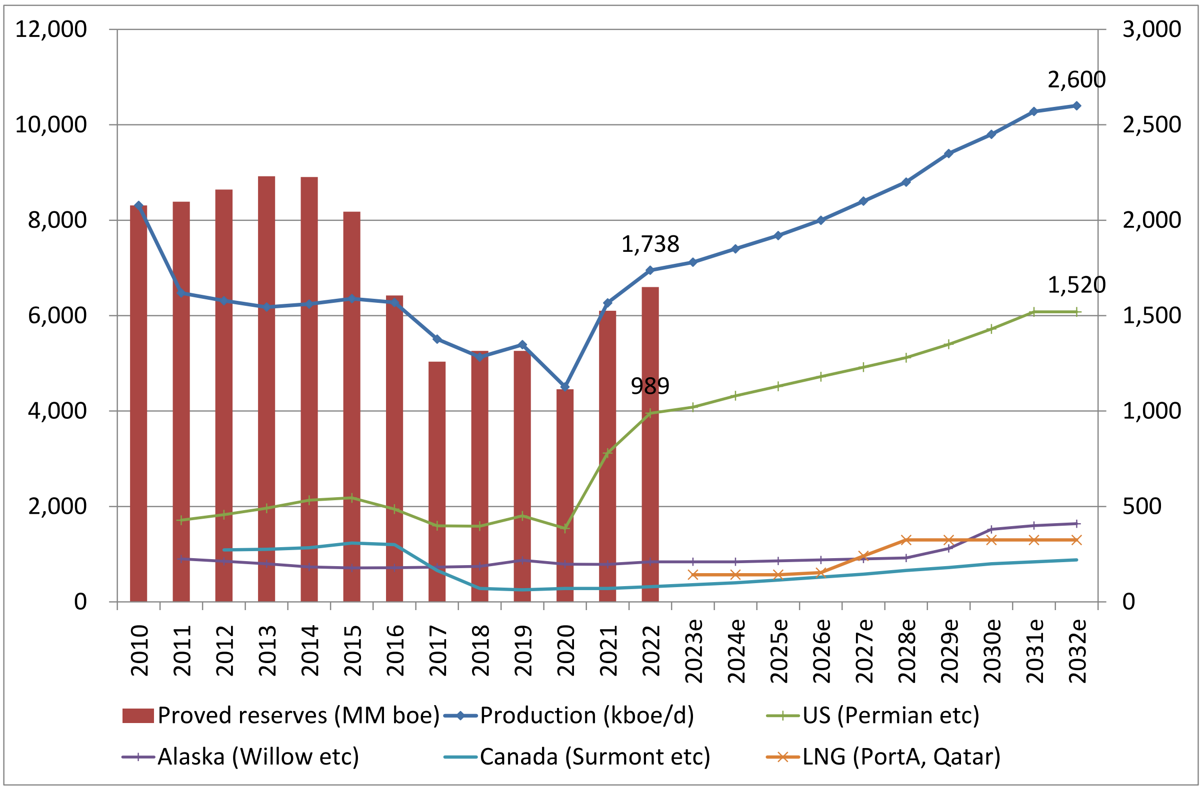
Figure 2.17. ConocoPhillips's Active Portfolio Management of Oil and Gas



BBOE = billion barrels of oil equivalent, bbl = oilfield barrel, CO2 = carbon dioxide, UK = United Kingdom.
Source: Conoco, Upcoming and Past Investor Presentations, https://www.conocophillips.com/investor-relations/investor-presentations/

Overall, ConocoPhillips's upstream portfolio focusses on shale oil – such as in the Permian Basin, Alaska (Willow project), and Canada (Surmont oil sands and Montney shale) – and LNG (Australia Pacific LNG, Port Arthur LNG, and Qatar LNG) (Figure 2.18). ConocoPhillips plans to increase oil and gas production volume from 1.7 mmboe/d in 2022 to 2.6 mmboe/d in 2032 – significant growth. Since ConocoPhillips is concentrating on these core areas, it is unlikely to return to the Indonesian E&P business once it has withdrawn.

Figure 2.18. ConocoPhillips's Oil and Gas Production and Proved Reserves



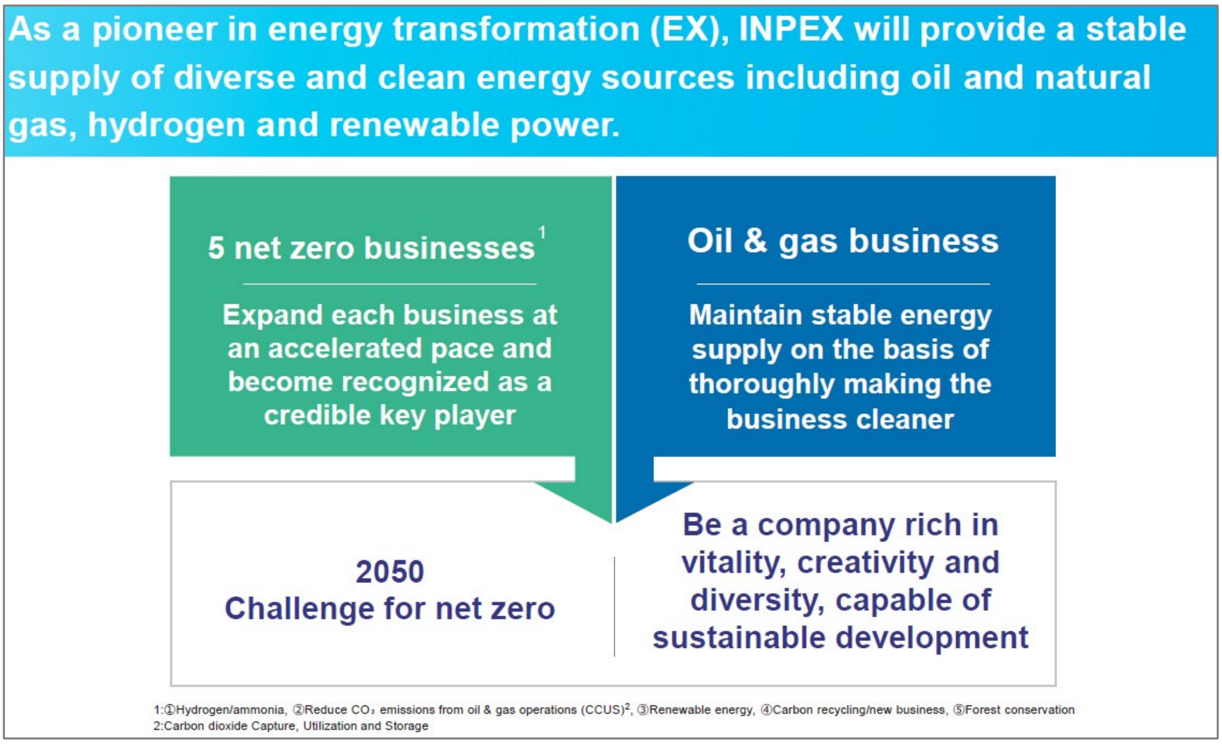
Note: left axis = proved resources, right axis = oil and gas production.
boe = barrel of oil equivalent, e = estimated.
Source: INPEX Solutions.

6. INPEX's Global Strategy

INPEX is a Japanese multi-national corporation engaged in oil and gas E&P; marketing; and net-zero businesses, such as geothermal, solar, and wind power. INPEX is not a Major, and its oil and gas production is less than that of ConocoPhillips and Eni.

In February 2022, INPEX announced *INPEX Vision @2022*, which includes a long-term strategy and medium-term business plan. Through a basic management policy aiming towards a net-zero carbon society by 2050, INPEX will provide a stable supply of oil and gas as well as five net-zero businesses (Figure 2.19).

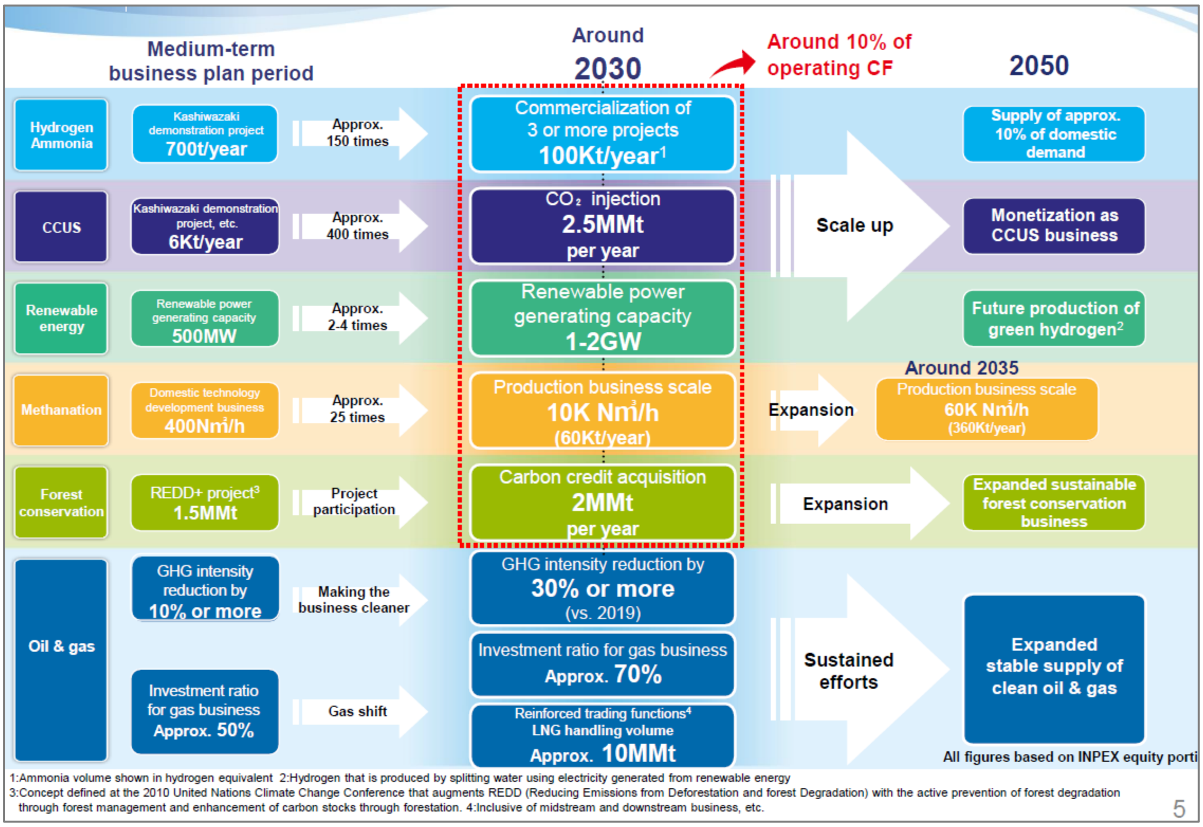
Figure 2.19. INPEX's Basic Management Policy towards a Net-Zero Carbon Society by 2050



Source: INPEX (2022).

For the five net-zero businesses, INPEX is engaging in hydrogen and ammonia; carbon capture, use, and storage (CCUS); renewable energy; methanation; and forest conservation, targeting around 10% of operating cash flow in 2030 (Figure 2.20). In terms of actual business activities, a demonstrative production facility in Niigata, Japan has been constructed, and overseas feasibility studies are being conducted for hydrogen and ammonia. For CCUS, it is targeting implementation at Ichthys LNG in Australia, and two Japanese CCS project ideas have passed a screening process of the Japan Organization for Metals and Energy Security (JOGMEC). For renewable energy, INPEX has acquired some stakes of geothermal power projects in Indonesia as well as some shares in various European wind farm projects.

Figure 2.20. INPEX's Vision



CCUS = carbon capture, use, and storage; CF = cash flow; GW = gigawatt; MW = megawatt; t = tonne.

Source: INPEX (2022).

In its oil and gas business as well as its five net-zero businesses, INPEX is focussing on five core business areas – Abu Dhabi, Australia, Europe, Japan, and South-east Asia (including Indonesia). It is seeking to improve efficiency by centralising business assets in these areas (Figure 2.21).

Australia – especially the Ichthys LNG project – is the biggest source of the company's net income. INPEX has accelerated involvement and development at nearby exploration sites, discovered assets, and is working to ensure long-term production volume maintenance. It also implemented appraisal well drilling and evaluation work for Ichthys CCS.

In Abu Dhabi, INPEX and its partners are trying to increase production capacity across all producing assets, including the Abu Dhabi Onshore Concession (to 2.00 mmboe/d), Upper Zakum (to 1.00 mmboe/d), Lower Zakum (to 0.45 mmboe/d) and Satah and Umm Al Dalkh (to 0.045 mmboe/d). INPEX is pursuing clean ammonia and hydrogen business opportunities as well.

In South-east Asia, INPEX is aiming to reach a final investment decision on the Abadi LNG project in the second half of the 2020s. In Japan, INPEX owns the Minami-Nagaoka Gas Field as well as the Naoetsu LNG Receiving Terminal and related natural gas trunk pipeline network. It is using these facilities as sites for demonstration tests of methanation, CCUS, and other technologies.

Finally, in Europe, INPEX acquired stakes in a Norwegian producing asset in 2021, is promoting the development of discovered but undeveloped oil and gas fields in the vicinity and will pursue exploration opportunities.

Figure 2.21. INPEX's Core Business Areas

CCUS = carbon capture, use, and storage.
Source: INPEX (2022).

7. Summary of International Oil and Gas Companies' Global Strategies

From this section, two points emerge. First, in light of the energy crisis, European IOCs have raised their oil and gas production targets, while US IOCs have engaged in mergers and acquisitions and raised their future production targets significantly. However, even in this context, the companies are taking into account net-zero ambitions, and CCS will be important.

Second, although the companies have raised their production targets, they are focussing on specific core areas and adhering to investment discipline.

Table 2.1. International Oil and Gas Companies' Global Strategies

Company	Global Strategy
BP	Revise oil and gas production target in light of the energy crisis Begin new oil and gas projects
Shell	Continue to deliver oil and gas as needed Selectively invest in LNG Canada and Qatar LNG expansion Sell interest in the Abadi LNG project in Indonesia
Eni	Grow oil and gas production 3%–4% per year from 2022 to 2026 Target net-zero emissions of upstream scope 1+2 by 2030 Emphasise CCS and nature-based solutions
Chevron	Focus on significant oil and gas production growth through Permian and mergers and acquisitions Focus on core areas
ConocoPhillips	Grow oil and gas production by Permian Focus on core areas
INPEX	Focus on 5 net-zero businesses, including CCUS and hydrogen Focus on core areas such as South-east Asia, including Indonesia

Source: INPEX Solutions.

Chapter 3

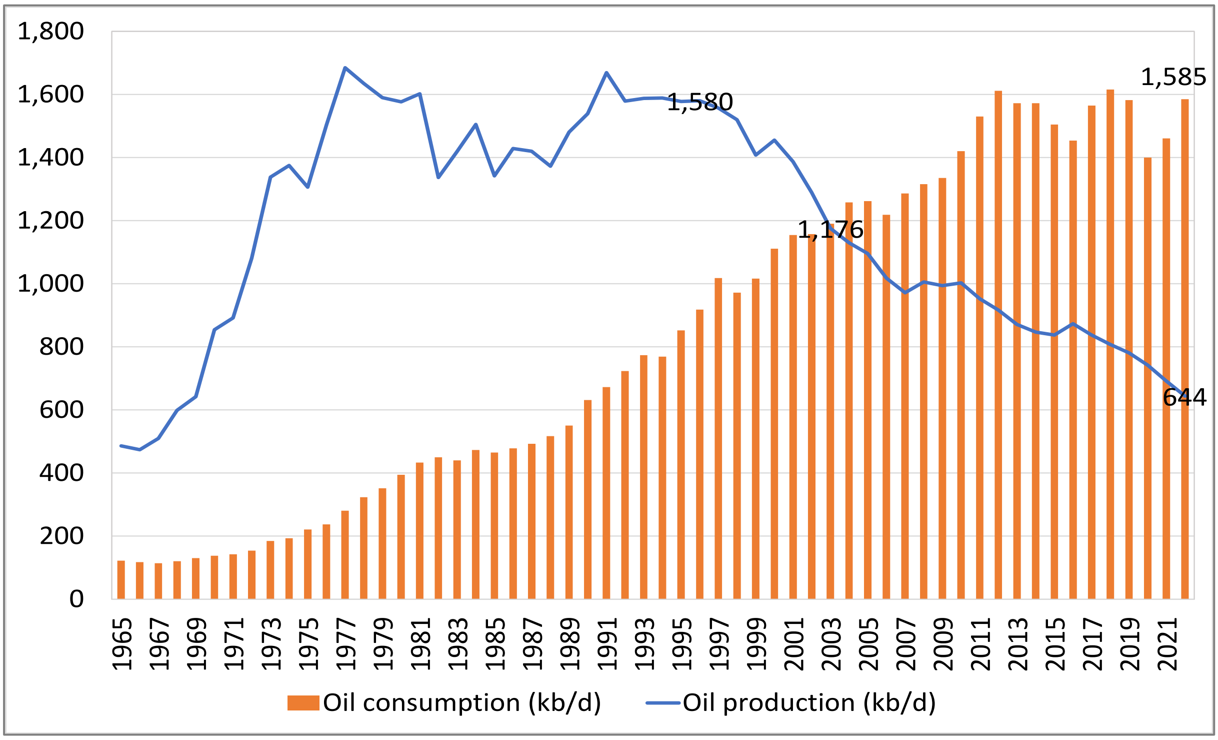
International Oil and Gas Companies' Business Activities in Indonesia

In this section, IOC oil and gas business activities in Indonesia are examined, as Indonesia is a major oil and gas producing country in the Association of Southeast Asian Nations (ASEAN) region. Although many IOCs have increased their oil and gas activities due to the global energy crisis, Chevron, ConocoPhillips, and Shell have withdrawn from the E&P business in Indonesia to focus on their core areas for profitability, which do not include Indonesia. It is unlikely that they will return to E&P activities in Indonesia again. However, Eni and INPEX are trying to develop new projects in Indonesia, and it is important to make these situations win–win for them and the country.

1. Trends in Indonesia's Oil and Gas Production

Indonesia's oil production remained at a high level – 1,400 kboe/d to 1,600 kboe/d from the 1970s to the 1990s – but production has declined since around 2000, contracting to 644 kboe/d in 2022. This is due to falling production at several major mature oil fields, such as Rokan, as well as a lack of large new oil fields being discovered. Indonesia's oil consumption also continued to increase from the 1970s to around 2010; by 2004, consumption exceeded production, making Indonesia a net importer of oil. As a result, Indonesia withdrew from the Organization of Petroleum Exporting Countries (OPEC) in 2008. Consumption in 2022 was 1,585 kboe/d (Figure 3.1).

Figure 3.1. Indonesia's Oil Production and Consumption
(kboe/d)



kboe/d = thousands of barrels of oil equivalent per day.
Source: INPEX Solutions based on Energy Institute (2023).

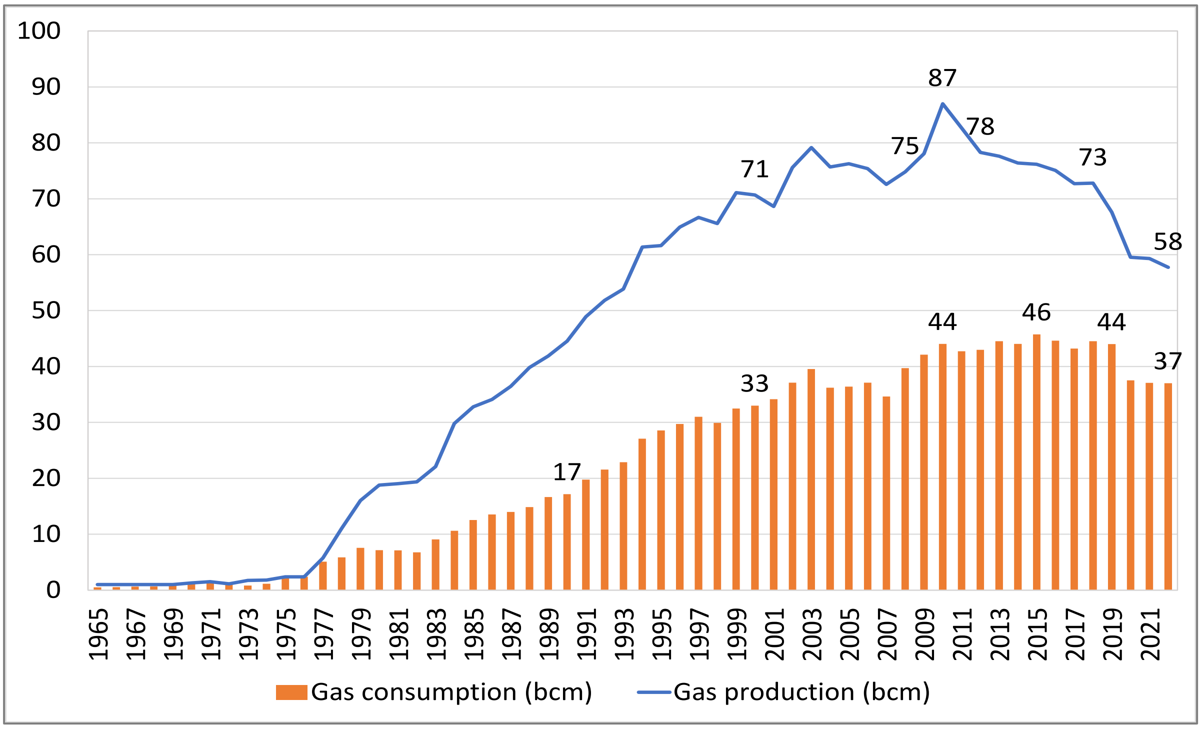
The Government of Indonesia has set a target to achieve oil production of 1 mboe/d by 2030. To achieve this target, it needs to increase oil production 1.55 times in 8 years from 644 kboe/d in 2022.

After increasing from the 1980s to the 1990s, Indonesia's gas production remained at a high level, 70–80 bcm/year from 2000 to 2018. One of the projects that contributed to this was the Tangguh LNG Train 1-2, which started production in 2009 and continues to produce about 12 bcm/year. Additionally, Tangguh LNG Train 3 started operations in October 2023.

However, after 2019, Indonesia's gas production declined, falling to 58 bcm in 2022. A reason for this decline was falling production at Mahakam, which had been a large gas production field. In addition, other small gas fields' production in Indonesia fell.

Gas consumption in Indonesia grew in the 1990s and 2000s, remained flat in the 2010s, and declined after 2020 to 37 bcm in 2022 (Figure 3.2). This slowdown in gas consumption occurred due to declining domestic gas production as well as the impact of the COVID-19 pandemic. At present, Indonesia's domestic gas production exceeds its consumption. However, Indonesia has contracts to export LNG, so a decline in domestic production has led to a curtailment of domestic consumption. Indonesia can import LNG but would like to use domestic gas first. In turn, there has been an increase in the consumption of domestically produced coal.

Figure 3.2. Indonesia's Gas Production and Consumption
(bcm)



bcm = billion cubic metres.
Source: INPEX Solutions based on Energy Institute (2023).

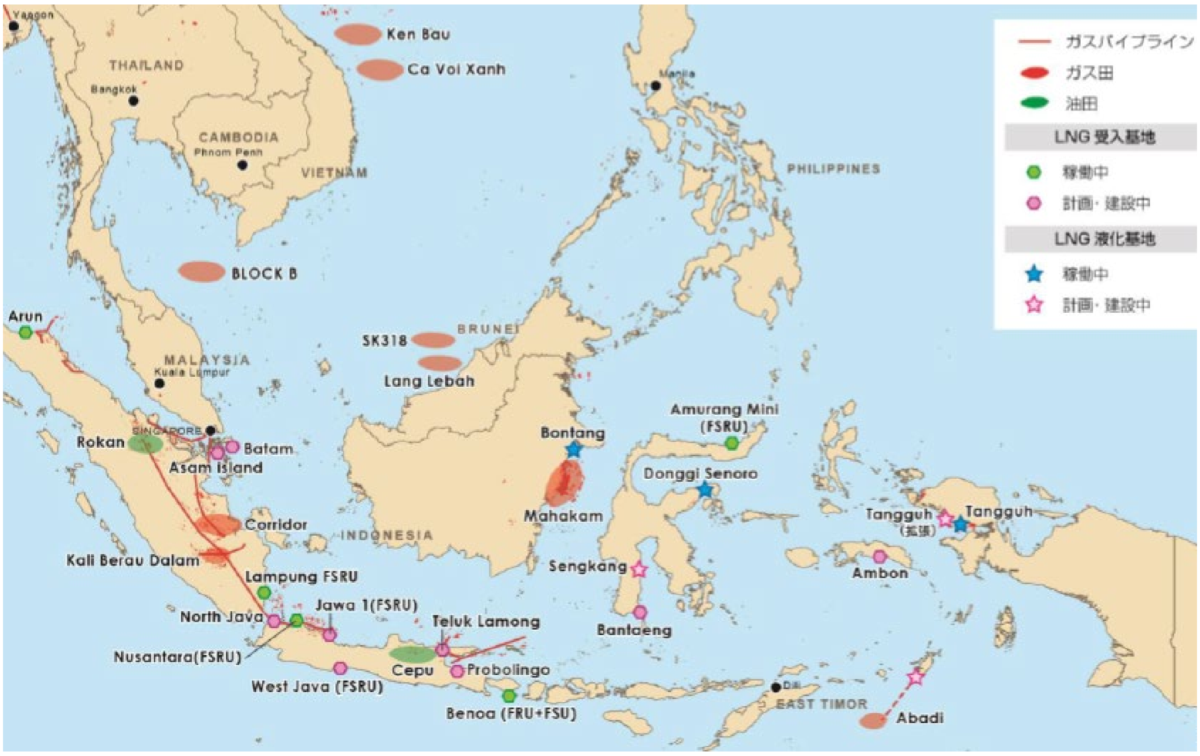
The government has set a target to achieve natural gas production of 12 billion cubic feet per day (bcf/d) – which is equivalent to about 123 bcm – by 2030. To achieve this target, it needs to increase natural gas production 2.11 times in 8 years from 58 bcm in 2022.

2. Major Oil and Gas Assets in Indonesia

Indonesia's major oil fields are Rokan on Sumatra and Cepu on Java, which together account for about half of Indonesia's total domestic oil production of 644 kboe/d. Rokan was a huge oil field from the 1960s to the 1990s, but production has declined since 2000 and is likely to drop further in the future. Chevron has operated Rokan for many years, but in August 2021, Pertamina – an Indonesian state-owned oil and gas company – became the operator. Cepu is newer than Rokan, and its production ramped up in the 2010s and will remain at a high production level for a few more years; after this, production is likely to decline. Cepu is operated by ExxonMobil with a 45% stake, and its partner is Pertamina with a 45% stake.

Indonesia's major gas fields and LNG facilities are Corridor, Donggi Senoro LNG, Mahakam, and Tangguh LNG, which together account for about half of Indonesia's total domestic gas production of 58 bcm (Figure 3.3). Tangguh LNG Train 1–3 (19 bcm annually) and Donggi Senoro LNG (3 bcm annually) are expected to continue high levels of gas/LNG supply for the foreseeable future. Corridor and Mahakam, however, are likely to continue their production decline into the 2020s. Thus, the development of new gas projects in Indonesia is crucial; major discovered – but undeveloped – gas fields include and Abadi LNG, Indonesia Deepwater Development (IDD), and Geng North (Figure 3.4).

Figure 3.3. Map of Major Oil and Gas Fields in Indonesia



LNG = liquefied natural gas.
Note: Gas pipeline (red line), gas field (red circle), oil field (green circle), LNG receiving terminal in operation (green hexagon), planned LNG receiving terminal (pink hexagon), LNG liquefaction terminal in operation (blue star), planned LNG liquefaction terminal (pink star).
Source: JOGMEC (2022).

Figure 3.4. Explanation of Oil and Gas Fields in Indonesia

Type	Field Name	Description	Operator
Oil	Rokan	Large oil field 1960s–1990s but has declined since 2000s	Chevron –> Pertamina (2021)
	Cepu	Production ramped up in 2010s	ExxonMobil
Gas LNG	Tangguh LNG Train 1–3	About 19 bcm annually	BP
	Corridor	Likely to continue production decline	ConocoPhillips –> Medco Energi (2022)
	Mahakam (Bontang LNG)	Likely to continue production decline	Total and INPEX –> Pertamina (2018)
	Donggi Senoro LNG	About 3 bcm annually	Mitsubishi
New Gas LNG	IDD	Before final investment decision	Chevron –> Eni (2023)
	AbadiLNG	Revised development plan approved in 2023	INPEX
	Geng North	Discovered in 2023	Eni

bcm = billion cubic metres, LNG = liquefied natural gas.
Source: INPEX Solutions.

3. Exiting Indonesia's Exploration and Production Business

Some IOCs have exited Indonesian E&P business (Figure 3.5).

Figure 3.5. Indonesia's Exploration and Production Business

Chevron	Rokan could not extend	IDD divest	Exit
TotalEnergies	Mahakam could not extend		almost Exit
ConocoPhillips		Corridor divest	Exit
Shell		Abadi divest	Exit
ExxonMobil	Cepu		Continuing
BP	Tangguh LNG		Continuing
Repsol	Corridor		Continuing
Eni		IDD Geng North	New project
INPEX	Mahakam could not extend	Abadi	New project

IDD = Indonesia Deepwater Development, LNG = liquefied natural gas.
Source: INPEX Solutions.

Chevron could not extend Rokan's production license, so Indonesia's Pertamina took over Rokan's operations in 2021. Chevron had operated Rokan for many years, and when the field contract expired in 2021, Chevron applied to the Government of Indonesia for an extension. The government rejected Chevron's application and selected Pertamina as the future operator. The government stated that Pertamina offered better economic terms than Chevron. Chevron also sold its interest in IDD to Eni in 2023; Chevron may no longer consider Indonesia a core area due to its failure to renew the Rokan contract. As a result, Chevron has entirely withdrawn from the Indonesian E&P business.

Similarly, TotalEnergies was unable to renew its interest in Mahakam with the government in 2017; Pertamina took it over. Although TotalEnergies has a minority interest in Sebuku now, it has almost entirely exited the Indonesian E&P business due to its experience with Mahakam.

ConocoPhillips sold its interest in Corridor to Medco Energi in 2021, exiting the E&P business in Indonesia as well. At about the same time, ConocoPhillips increased its equity interest in Australia Pacific LNG in Australia. ConocoPhillips may have sold Corridor because Corridor is soon expected to experience a production decline; ConocoPhillips may have thus simply chosen to invest in Australia Pacific LNG over Corridor.

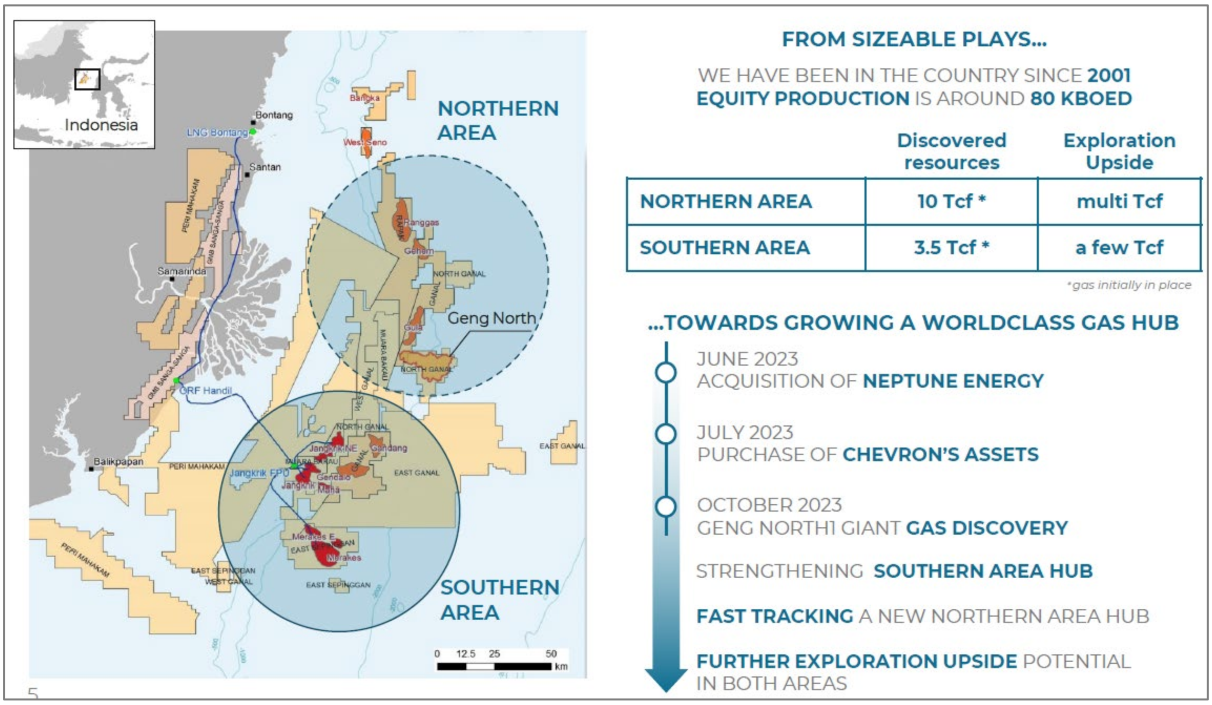
Shell sold its interest in Abadi to Petronas and Pertamina in 2023, exiting the E&P business in Indonesia. It explained that this decision is in line with Shell's focus on disciplined capital allocation. Shell purchased Abadi's interest from INPEX in 2011 but has not made a final investment decision yet.

In total, Chevron, TotalEnergies, ConocoPhillips, and Shell – the Majors – have withdrawn from the E&P business in Indonesia. ExxonMobil, BP, and Repsol are continuing their existing E&P projects in Indonesia, and Eni and INPEX are about to start new E&P projects.

4. Eni's Expansion in Indonesia

Eni has been involved in the E&P business in Indonesia since 2001 and expanded its E&P business there in 2023. Specifically, in June, Eni announced the acquisition of Neptune Energy, which has several interests in Indonesia; in July, Eni acquired Chevron's interests of IDD; and in October, Eni discovered a huge gas resource through exploration in Geng North. All three of these actions are in Indonesia's Kutai Basin and will thus allow the company to strengthen its focus there. As a result, Eni has 10 trillion cubic feet (Tcf) of discovered gas resources in the northern Kutai Basin and 3.5 Tcf in the southern portion (Figure 3.6).

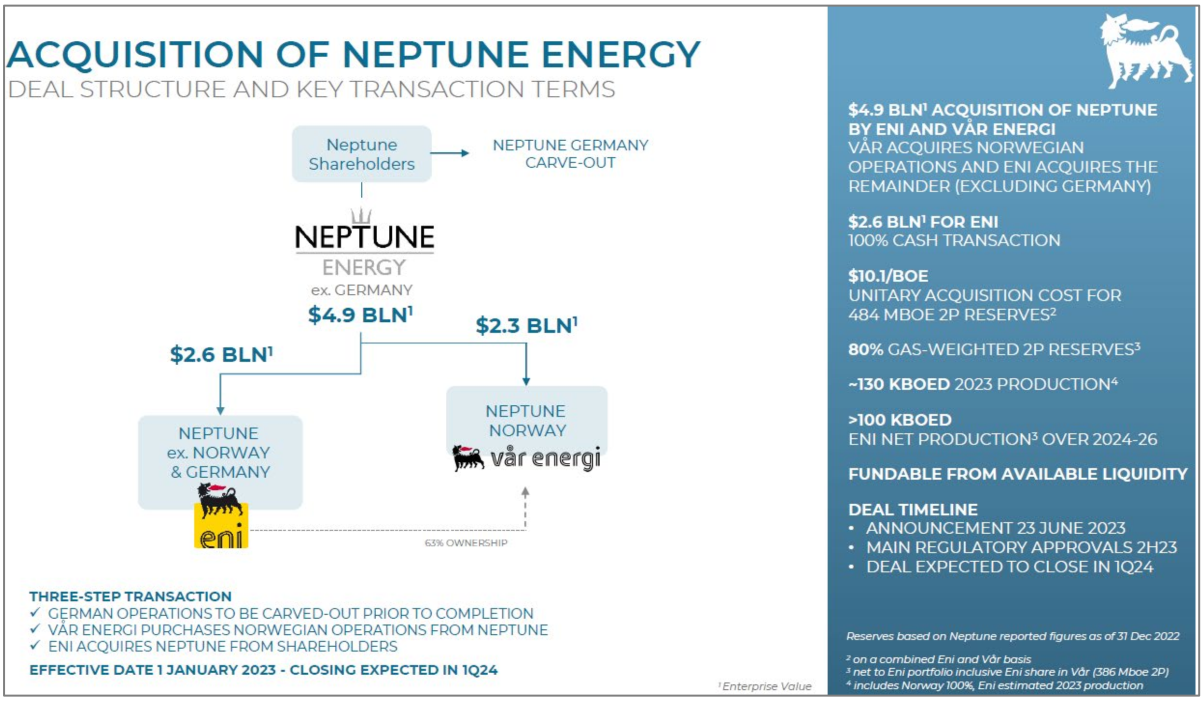
Figure 3.6. Eni's Exploration and Production Expansion in Indonesia



kboe = thousands of barrels of oil equivalent, Tcf = trillion cubic feet.
Source: Eni (2023b).

Eni acquired Neptune Energy – excluding its German and Norwegian operations – for an enterprise value of US$2.6 billion. Neptune Energy's Norwegian operations were acquired by Eni's 63%-owned Norwegian subsidiary, Vår Energi, for US$2.3 billion.[5] Eni's production in 2022 was 1,610 kboe/d, which will increase by just over 100 kboe/d with the acquisition of Neptune Energy (Figure 3.7).

Figure 3.7. Eni's Acquisition of Neptune Energy

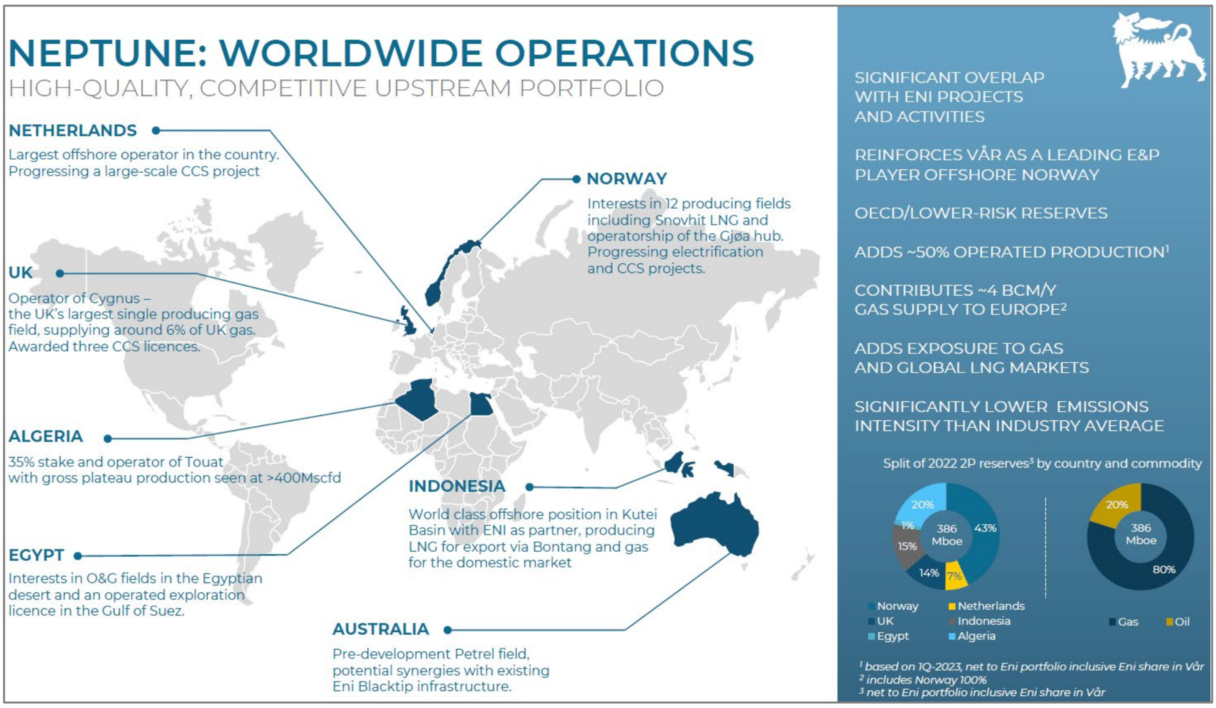


boe = barrel of oil equivalent, kboed = thousand barrels of oil per day.
Source: Eni (2023a).

Neptune Energy's assets include Norway (43% of total reserves), Algeria (20%), Indonesia (15%), UK (14%), and the Netherlands (7%). Most overlap with Eni's existing operating regions, so this acquisition will strengthen each business area. About 80% of the reserves are gas and 20% are oil, which fits Eni's policy of increasing the gas ratio (Figure 3.8).

[5] Thus, Eni also indirectly owns Neptune Energy's Norwegian assets. Note that Eni had merged its Norwegian operations with Point Resources AS, which is primarily Norway-focussed, to form Vår Energi in 2018.

Figure 3.8. Neptune Energy's Oil and Gas Assets



CCS = carbon capture and storage, E&P = exploration and production, LNG = liquefied natural gas, Mboe = million barrels of oil equivalent, Mscfd = thousand standard cubic feet per day, OECD = Organisation for Economic Co-operation and Development, O&G = oil and gas, UK = United Kingdom.
Source: Eni (2023a)

In Indonesia, Eni owns 55.00% of Muara Bakau, 50.22% of North Ganal, 40.00% of West Ganal, 70.00% of East Ganal, and 65.00% of East Sepinggan. With the acquisition of Neptune Energy, Eni will acquire 33.33% of Muara Bakau, 38.04% of North Ganal, 30.00% of West Ganal, 30.00% of East Ganal, and 20.00% of East Sepinggan. Total production volume was 22.7 kboe/d in the first quarter of 2023 (Figure 3.9).

Figure 3.9. Acquisition of Neptune Energy Strengthens Eni's Indonesia Operations

kboed = thousands of barrels of oil equivalent per day, LNG = liquefied natural gas.
Source: Eni (2023a).

Eni also announced the acquisition of Chevron's interests in Ganal PSC (62%), Rapak (62%), and Makassar Straits (72%) in the Kutai Basin, offshore of East Kalimantan. Eni already had a 20% interest in Ganal and Rapak. These are the part of the IDD project, with estimated reserves of approximately 2 Tcf (Figure 3.10). Eni will increase its interests in each of the blocks and take on operatorship through this acquisition.

The IDD project has yet to undergo a final investment decision. Therefore, Eni expects that this acquisition will allow it to fast track the development of the IDD project, leveraging synergies with Eni-operated Jangkrik infrastructure and the existing Bontang LNG facility.

Figure 3.10. Eni's Acquisition of Chevron's Assets in Indonesia
(%)

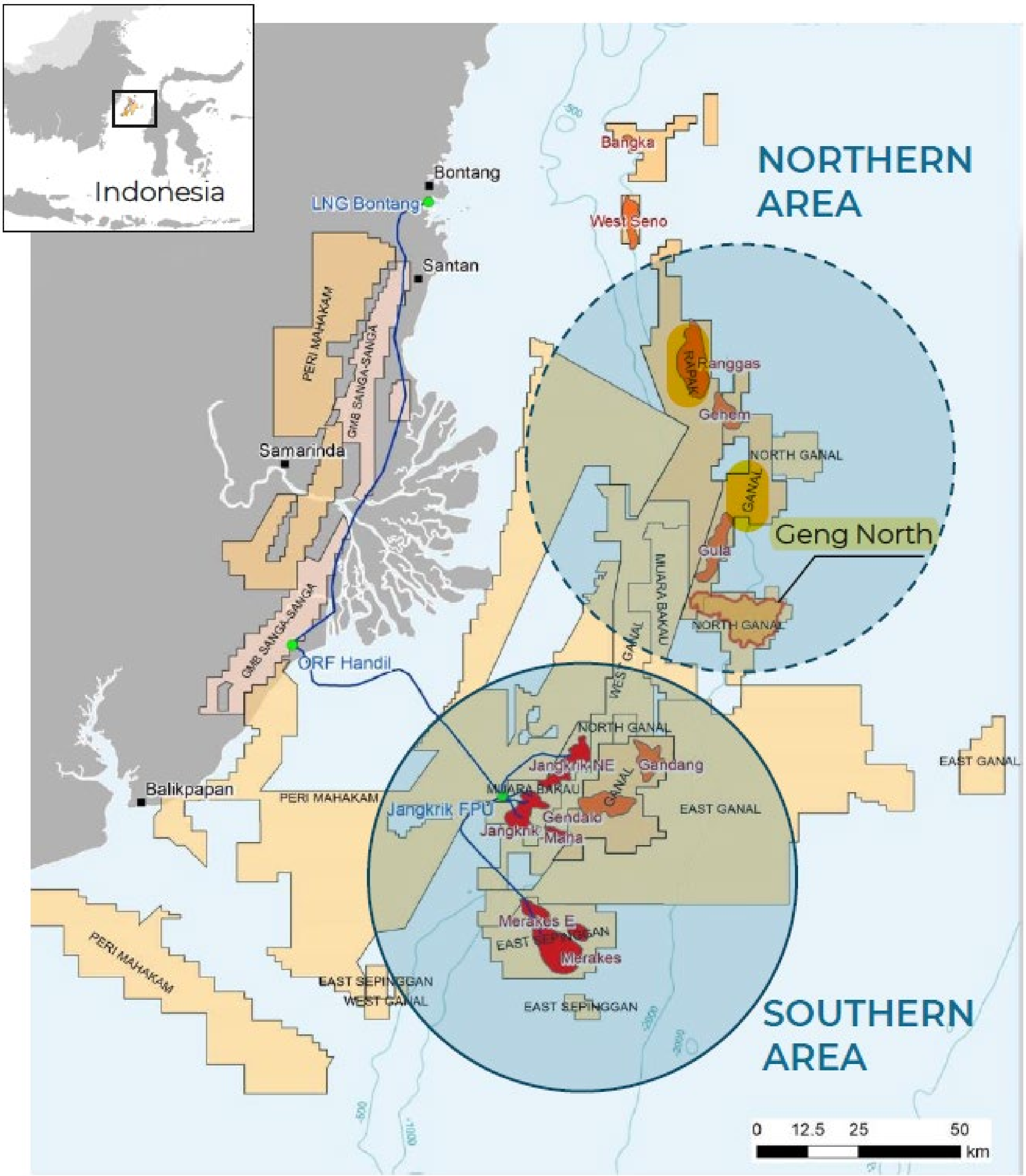
Company	Ganal	Rapak	Makassar Straits
Chevron	62	62	72
Eni	20	20	0
Eni + Chevron	82	82	72

Notes:
1. These are part of the Indonesia Deepwater Development project.
2. Has estimated natural gas reserves of about 2 trillion cubic feet.

Source: INPEX Solutions.

Finally, Eni announced significant gas discovery in the Geng North-1 exploration well. Preliminary estimates indicate a volume of 5 Tcf of gas. Thanks to its significant size, the discovery has the potential to contribute to the creation of a new production hub to be connected to the Bontang LNG facility (Figure 3.11). The Geng North discovery is located next to the IDD areas, Ganal and Rapak, so significant synergies between the two areas could be expected in terms of gas development options.

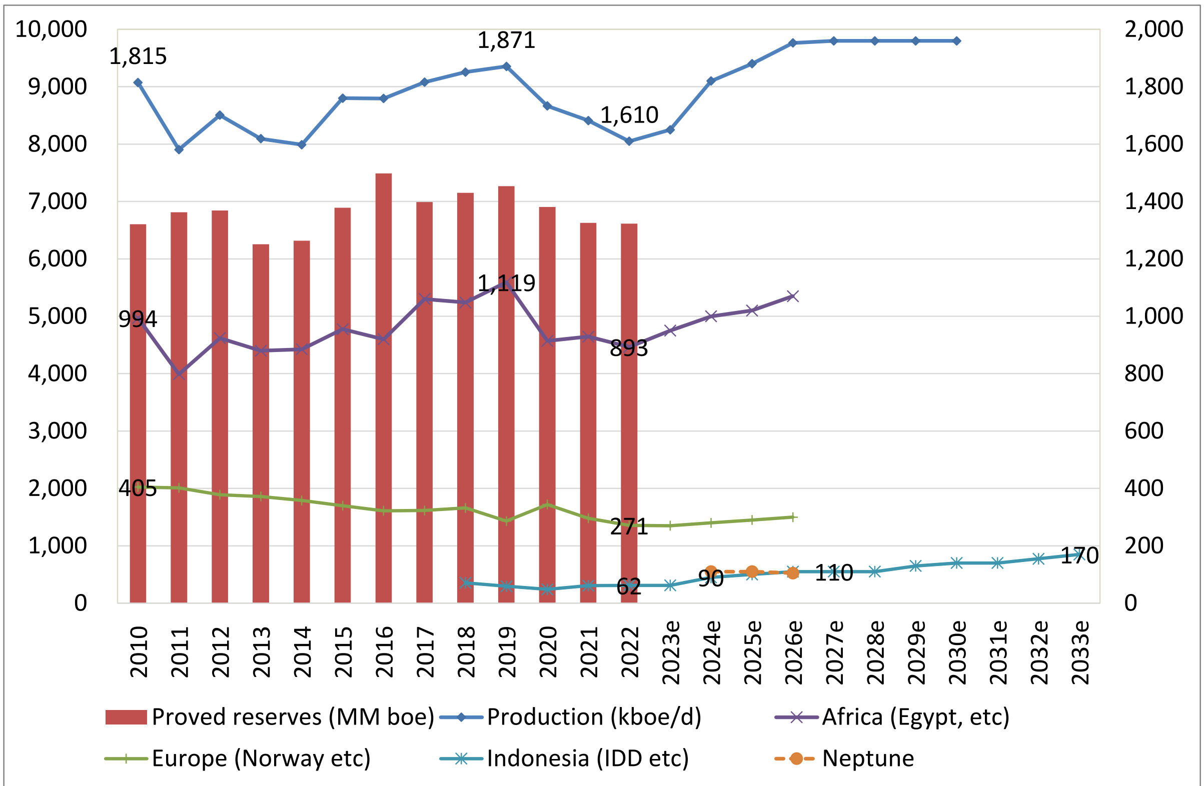
Figure 3.11. Eni's Oil and Gas Fields and Infrastructure in Indonesia



Source: Eni (2023a).

Eni's oil and gas production in 2022 was 1,610 kboe/d, of which Indonesia produced 62 kboe/d, or 4% of the total. By acquiring Neptune's Indonesian interests, it could go up to about 90 kboe/d. Eni is progressing its new projects, such as Merakes East (15 kboe/d, Eni share 65%, start in 2025) and Maha (34 kboe/d, Eni share 60%, start in 2026), so its Indonesian production could go increase to about 110 kboe/d. The expansion of Eni's production in Indonesia after that time depends on IDD and Geng North, but it could expand to about 170 kboe/d. Thus, Indonesia's production could expand to about 9% of Eni's production around 2033 (Figure 3.12).

Figure 3.12. Eni's Oil and Gas Production and Proved Reserves, Estimated to 2033

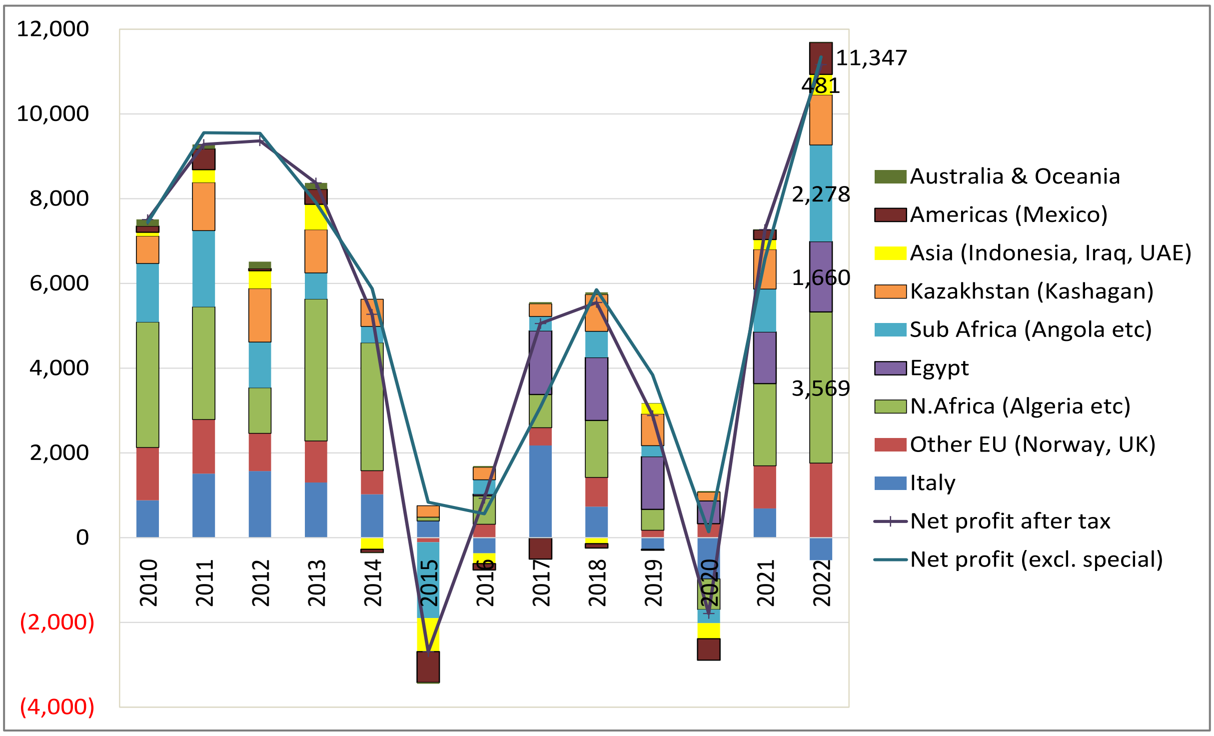


Note: Left axis = proved reserves, right axis = oil and gas production.
e = estimated, IDD = Indonesia Deepwater Development, kboe = thousand barrels of oil equivalent, MMboe = million barrels of oil equivalent.
Source: INPEX Solutions.

In 2022, Eni's North Africa operations – consisting of Algeria and Libya – earned US$3.6 billion, Egypt earned US$1.7 billion, and Sub-Saharan Africa – comprising Angola, Congo, Mozambique, and Nigeria – earned US$2.3 billion. Together, these regions accounted for 66% of Eni's total net income of US$11.3 billion, indicating that Africa is Eni's core area.

Eni's Asian operations – consisting of Indonesia, Iraq, and the UAE – earned US$481 million in 2022, accounting for only 4% of total net income. Note that Asia produced 174 kboe/d, or 11% of total production. Since Indonesia's net income and production are a small percentage of the total, it is not likely that Indonesia is a core area for Eni. However, if the next gas resource is developed with reasonable profitability, Indonesia will become an important area for Eni.

Figure 3.13. Eni's Oil and Gas Net Profit by Region
(US$ million)



EU = European Union, UAE = United Arab Emirates, UK = United Kingdom.
Source: INPEX Solutions.

5. INPEX and the Abadi LNG Project

Abadi LNG is a project that has taken time to commercialise because a final investment decision has not yet been made, although gas resources were discovered through exploration in 2000. INPEX acquired a 100% interest in the Masela block in November 1998 through an open bid. It subsequently conducted exploration activities as the operator, discovering the Abadi gas field through the first exploratory well drilled in 2000. Following exploration, evaluation activities, and development studies, INPEX conducted pre-front-end engineering design (FEED)[6] work from March to October 2018 based on an onshore LNG development scheme envisioning LNG production capacity of 9.5 mtpa. INPEX submitted a revised plan of development in June 2019 to the government and received

[6] FEED work is done prior to engineering, procurement, and construction (EPC) work. It involves field studies and budgeting, including technical issue identification and cost outlines, upon which bidding for EPC work is based. The oil and gas E&P business involves the participation of several contractors, such as drilling contractors and geophysical exploration subcontractors. Of these, an EPC contractor oversees EPC work.

approval in July 2019. With the revised development plan, Indonesia also approved an extension of the term of the Masela PSC until 2055.

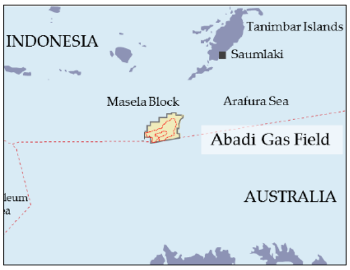
Detailed survey work of the planned construction site for the LNG plant and its surrounding areas had been underway until it was suspended due to the COVID-19 pandemic. Subsequently, considering the need to contribute to a net-zero carbon society and to make the project cleaner and more competitive amidst energy transition, INPEX has been consulting on a revised development plan that introduces CCS. It submitted that plan in April 2023, which was approved in December 2023. Through this development plan, INPEX aims to provide a stable supply of clean energy on a large scale, with 9.5 mtpa of LNG and 150 million cubic feet per day of pipeline gas.

Indonesia's Pertamina and Malaysia's Petronas are the new partners in this Abadi LNG project. Pertamina and Petronas purchased the shares of Abadi LNG from Shell when it sold its stake in the project. Pertamina has a very strong presence and experience in oil and gas development in Indonesia, and Petronas has experience in LNG operations in Malaysia and globally. Indonesia and Malaysia will have strong demand for LNG in the future, and Abadi LNG can contribute to their stable supplies.

Project economics is an important factor, and INPEX aims to achieve an internal rate of return (IRR) in the mid-10% range. INPEX is in discussions with the government on project economics (Figure 3.14).

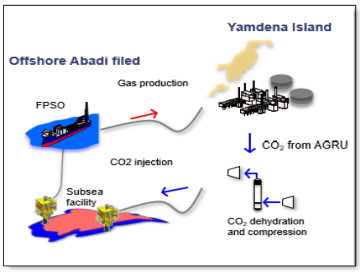
Figure 3.14. Abadi LNG Project Outline

- **Competitive and clean project** through **comprehensive cost optimization and CCS**
- Investability to be maintained/increased through FEED period



Project Economics

Aim to achieve an IRR in the mid 10% range



Stable supply of clean LNG

LNG: 9.5 MTPA
Pipeline gas: 150 mmscfd

New partners

Contribution to energy security in Asia with national E&P companies (Pertamina and Petronas)

AGRU = acid gas removal unit; CCS = carbon capture and storage; E&P = exploration and production; FEED = front-end engineering design; FPSO = floating production, storage, and offloading facility; IRR = internal rate of return; LNG = liquefied natural gas; MTPA = metric tonnes per annum; mmscfd = million standard cubic feet per day.
Source: INPEX (2023).

Abadi LNG's development concept consists of sub-sea, umbilical, riser, and flowline (SURF); a floating production, storage, and offloading facility (FPSO); gas export pipeline (GEP); onshore LNG plant (OLNGP); and CCS as follows:

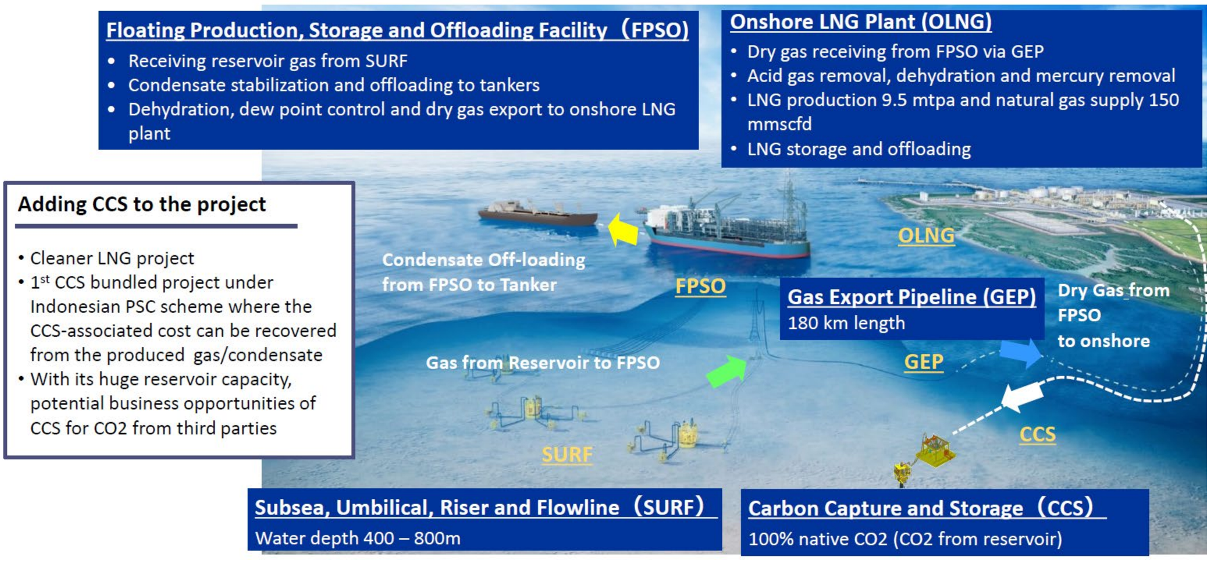
(i) The SURF transports gas from a sub-sea reservoir to the FPSO.

(ii) The FPSO receives the reservoir gas from the SURF and dehydrates, controls the dew point, and then exports the dry gas to the OLNGP by the GEP. The reservoir contains gas and condensate, so this condensate is stabilised in the FPSO and then offloaded to tankers.

(iii) The OLNGP receives dry gas from the FPSO via the GEP and then removes acid gas and dehydrates and removes mercury. This gas is converted into LNG, stored, and offloaded.

(iv) CCS is added to the project to offset the 100% native carbon dioxide from the reservoir (Figure 3.15).

Figure 3.15. Abadi LNG Project Development Concept



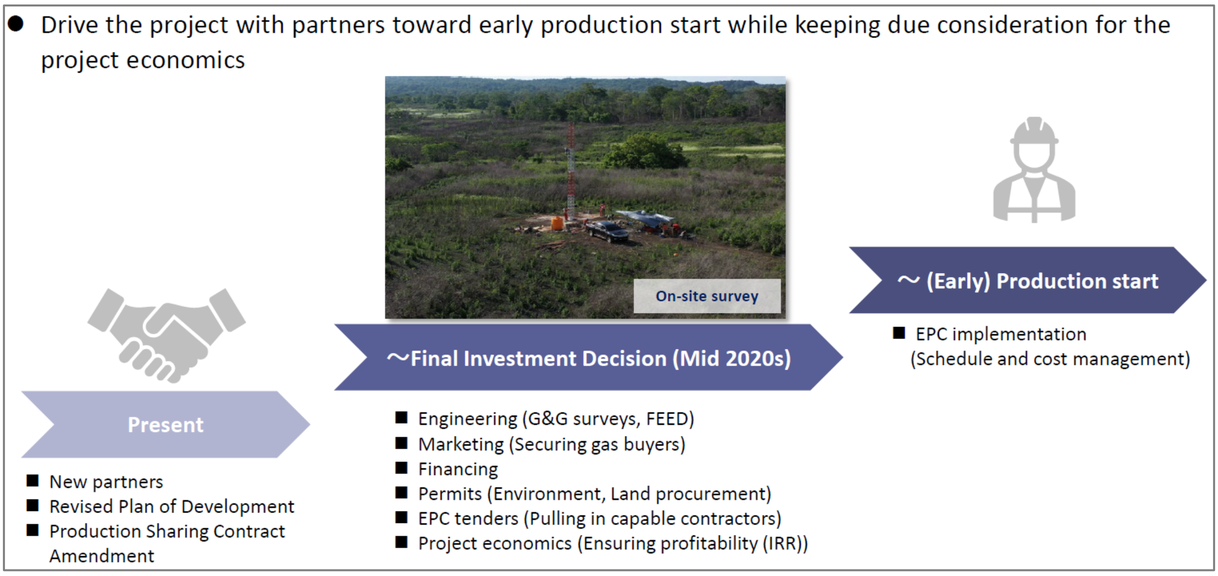
CCS = carbon capture and storage, km = kilometre, LNG = liquefied natural gas, m = metre, mtpa = metric tonnes per annum; mmscfd = million standard cubic feet per day, PSC = production sharing contract.
Source: INPEX (2023).

Abadi will be the first CCS-bundled project under an Indonesian PSC[7] where the CCS-associated costs can be recovered from the produced gas and condensate. Additionally, with its huge reservoir capacity, INPEX is considering potential business opportunities of CCS for carbon dioxide from third parties.

[7] A PSC scheme is a type of upstream oil and natural gas development contract between oil-producing countries and E&P companies.

As a way forwards, INPEX will work on FEED; LNG marketing to secure gas buyers; and secure financing of the project's Capex and engineering, procurement, and construction (EPC) tenders. Based on these tasks, INPEX is hoping to make a final investment decision in the latter half of the 2020s and to commence production in the early 2030s (Figure 3.16).

Figure 3.16. Abadi LNG's Way Forwards

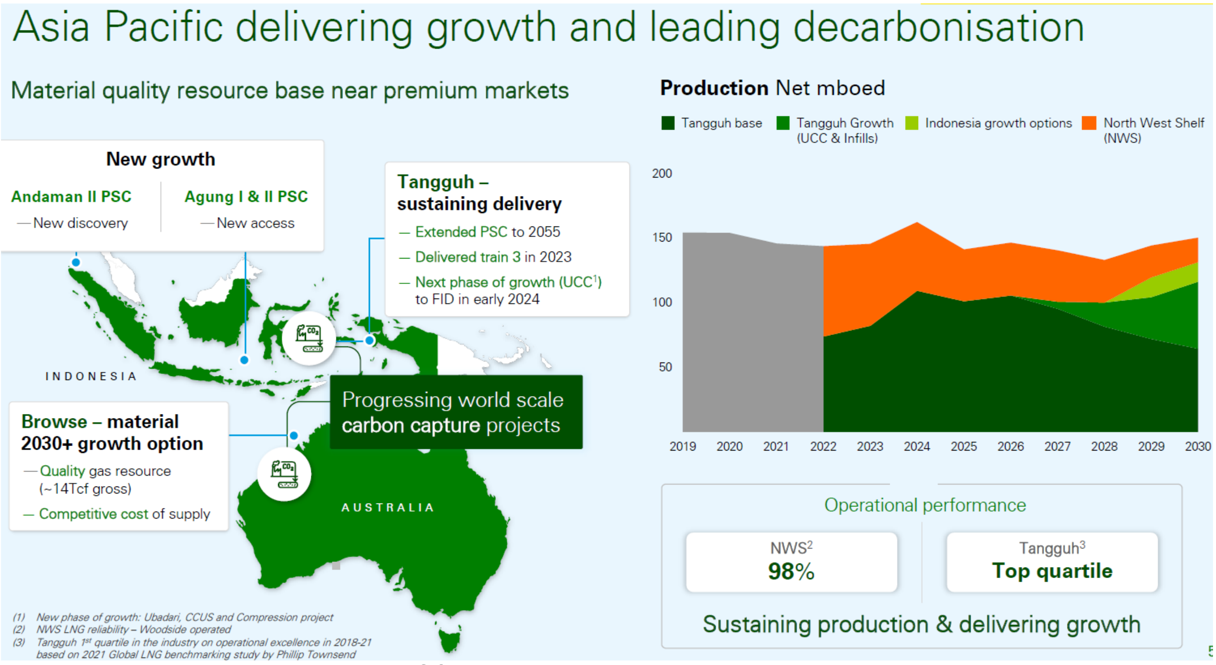


EPC = engineering, procurement, and construction; FEED = front-end engineering design; G&G = geological and geophysical; IRR = internal rate of return, LNG = liquefied natural gas.
Source: INPEX (2023).

6. BP and Tangguh LNG

Tangguh LNG, of which BP is the operator, is one of the most important assets in Indonesia. At Tangguh LNG, Expansion Project Train 3 shipped its first LNG cargo in October 2023 and will be fully operational in 2024 (Figure 3.17). Since production at the base is expected to decline from around 2027, BP plans to maintain Tangguh LNG production through infills; Ubadari; CCUS; and compression projects.

Figure 3.17. BP Plans to Sustain Tangguh LNG



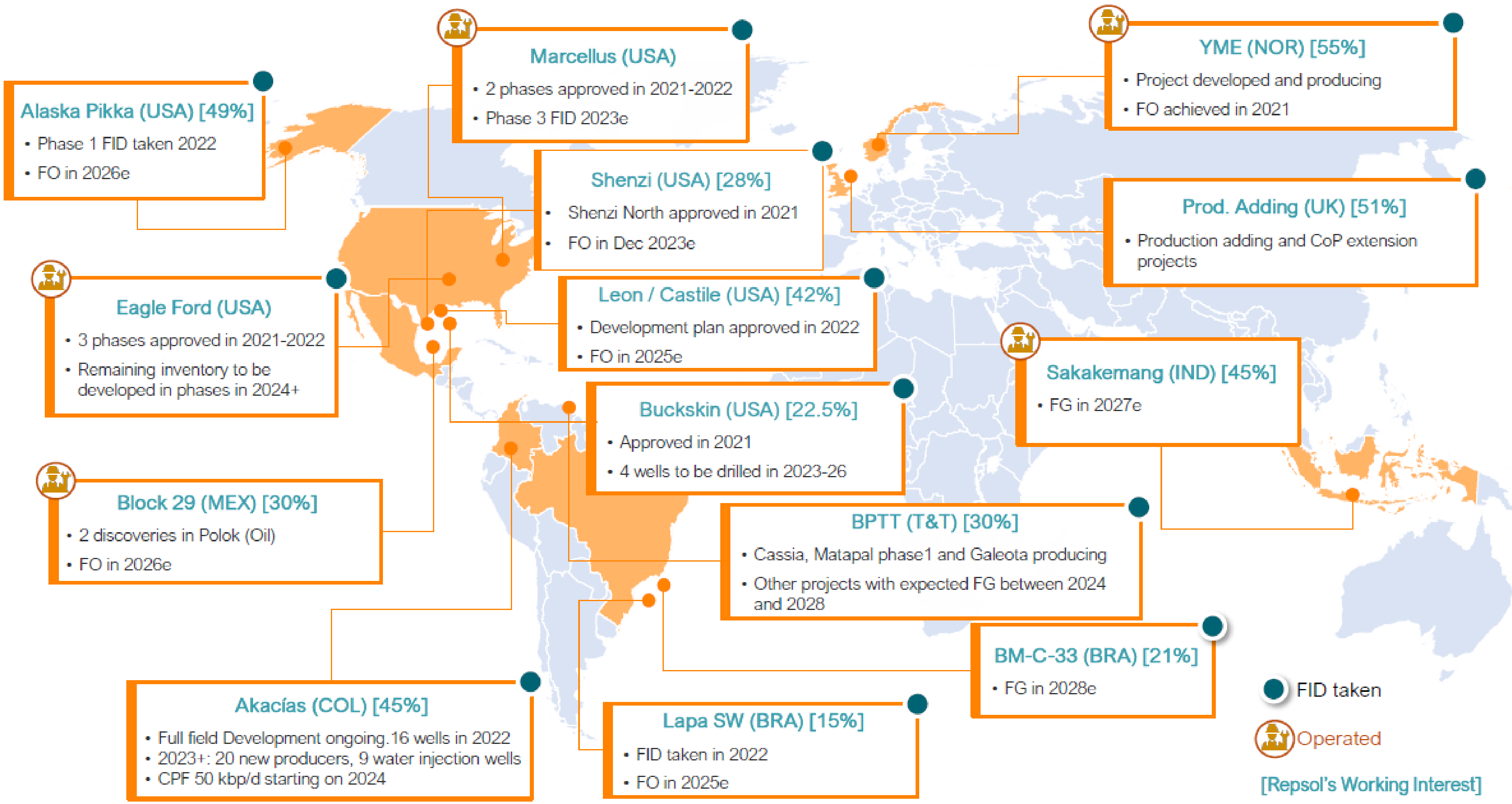
FID = final investment decision, PSC = production sharing contract, Tcf = trillion cubic feet.
Source: BP (2023b).

7. Repsol and the Sakakemang Project

Repsol discovered gas resources in Sakakemang in South Sumatra in 2019. Although the gas reserves are smaller than originally thought and the carbon dioxide content is higher, Repsol is aiming for a final investment decision in 2024 for the project with CCS, and with Firstgas in 2027. The gross Capex of this project is about US$0.5 billion; Repsol holds 45% of this project, so Repsol's net Capex would be about US$0.2 billion.

In its investor relations material, Repsol explained that its core areas include the US (i.e. Alaska Pikka, Eagle Ford, Gulf of Mexico, Marcellus), Brazil, Libya, Norway, and the UK. Repsol's 'other areas' include Algeria, Bolivia, Canada, Colombia, Indonesia, Peru, Trinidad and Tobago, and Venezuela. Although Indonesia is classified as an 'other area', Sakakemang is one of the few projects where Repsol is the operator (Figure 3.18).

Figure 3.18. Repsol's New Oil and Gas Projects



FID = final investment decision.
Source: Repsol, Investor Updates, https://www.repsol.com/en/shareholders-and-investors/repsol-as-an-investment/presentations/index.cshtml

8. Mubadala Energy's Discovery

Mubadala Energy, an international energy company headquartered in Abu Dhabi, discovered gas with the potential of 6 Tcf in the southern Andaman Sea, about 100 kilometres offshore from North Sumatra. Mubadala Energy is the operator of the South Andaman Gross Split PSC with an 80% working interest. This is the second consecutive successful well for Mubadala Energy in the Andaman area, after the success of Timpan-1 in Andaman-II (Figure 3.19).

Figure 3.19. Mubadala Energy's Discovery

Source: Sulistiyaningsih (2023).

With Mubadala Energy's gas discovery in South Andaman and Eni's gas discovery in Geng North, Indonesia held some of the top gas resource discoveries in the world in 2023.

9. Summary of International Oil and Gas Companies' Business Activities in Indonesia

Chevron, ConocoPhillips, and Shell have withdrawn from the oil and gas business in Indonesia to focus on their core areas, which do not include Indonesia. It is unlikely that they will return to oil and gas business in Indonesia. However, Eni and INPEX are trying to develop new projects in Indonesia, and BP is trying to maintain Tangguh LNG through new associated projects. It is crucial to make these win–win situations for IOCs and Indonesia.

Chapter 4

Key Factors for Win-Win Situations between the Government of Indonesia and International Oil and Gas Companies

Indonesia needs to develop new gas fields to meet the expected increase in domestic gas demand. Eni and INPEX have stated that a reasonable IRR is a prerequisite for the development of new projects, so discussions with the government on economic conditions are key. Another crucial point is the development of regulations for the implementation of CCS, including cross-border storage.

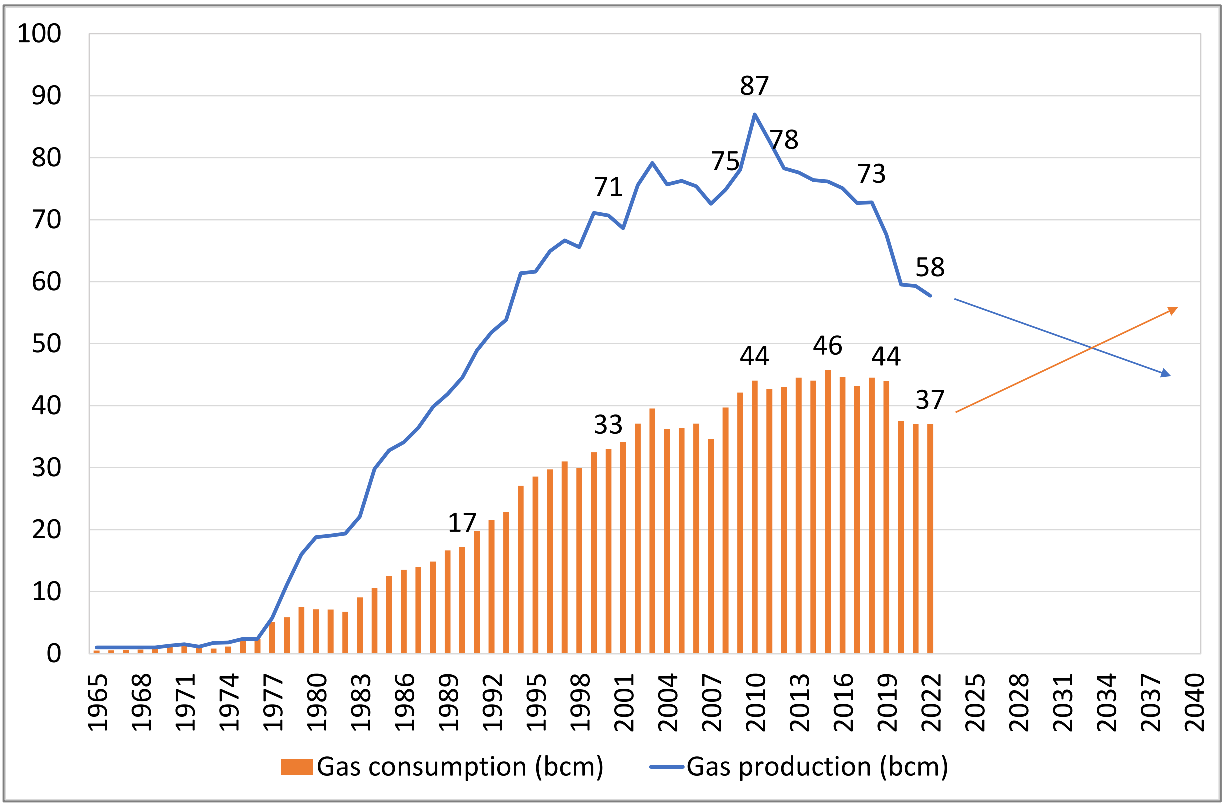
1. Indonesia Needs More Domestic Gas Production

Indonesia needs more domestic gas production to meet domestic gas demand, which is expected to grow in the late 2020s to 2030s. Indonesia's gas demand was sluggish from 2020 to 2022, not only because of the COVID-19 pandemic but also because of a decline in domestic gas production. If domestic gas production stabilises or increases, potential gas demand may strengthen. Although Indonesia also has great potential for solar power generation, gas power generation is needed to back up the fluctuations in solar power generation during cloudy days and at night. Yet the difficulty of building new coal-fired power plants due to climate-change issues will also affect the need for gas-fired power generation.

If several large new projects around domestic gas production are not developed, Indonesia's domestic gas production may decline in the future due to falling production rates from existing gas fields. If this happens, Indonesia's domestic gas demand will exceed domestic gas production, and Indonesia will need to import LNG (Figure 4.1).

Figure 4.1. Indonesia's Gas Production and Consumption Outlook

(bcm)



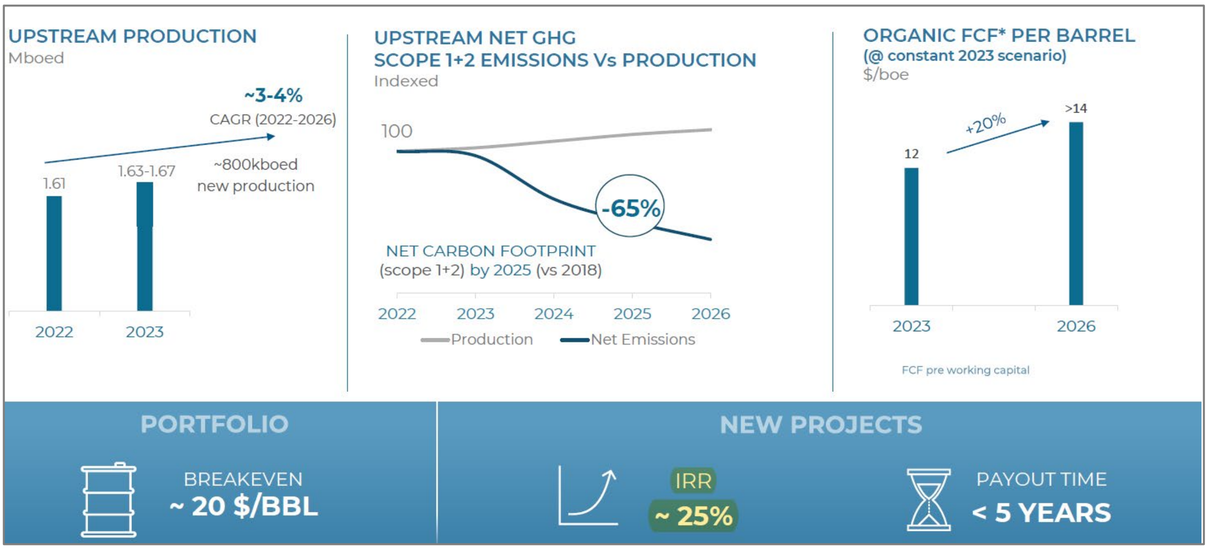
bcm = billion cubic metres.
Source: INPEX Solutions.

2. Need for IRR Improvement of New Projects

INPEX is aiming for an IRR in the mid-10% range if Abadi LNG is developed. The target IRR for the E&P business is typically just over 20% because of the various risks involved, such as exploration and oil price fluctuations. However, the IRR for LNG projects is typically lower than that for that for E&P because LNG projects require investment in the development of gas resources as well as in facilities to liquefy the gas. Therefore, a target IRR of 15% is not too high – but not easy to achieve.

Eni explained that its target IRR for new E&P projects from 2023 to 2026 is just under 25% (Figure 4.2). This does not yet include IDD or Geng North, which are major projects in Indonesia, but does include other new projects in Indonesia – Merakes East (15 kboe/d by 65%) and Maha (34 kboe/d by 40%). IDD and Geng North will use the existing Bontang LNG terminal and will not require investment in LNG liquefaction facilities, so their IRRs will be higher than that of Abadi LNG, which requires investment in LNG liquefaction facilities. Nevertheless, with Eni targeting an IRR of just under 25% for new E&P development, it is unlikely that Eni will decide on new development in Indonesia without reasonably high IRRs.

Figure 4.2. Eni's Upstream Outlook

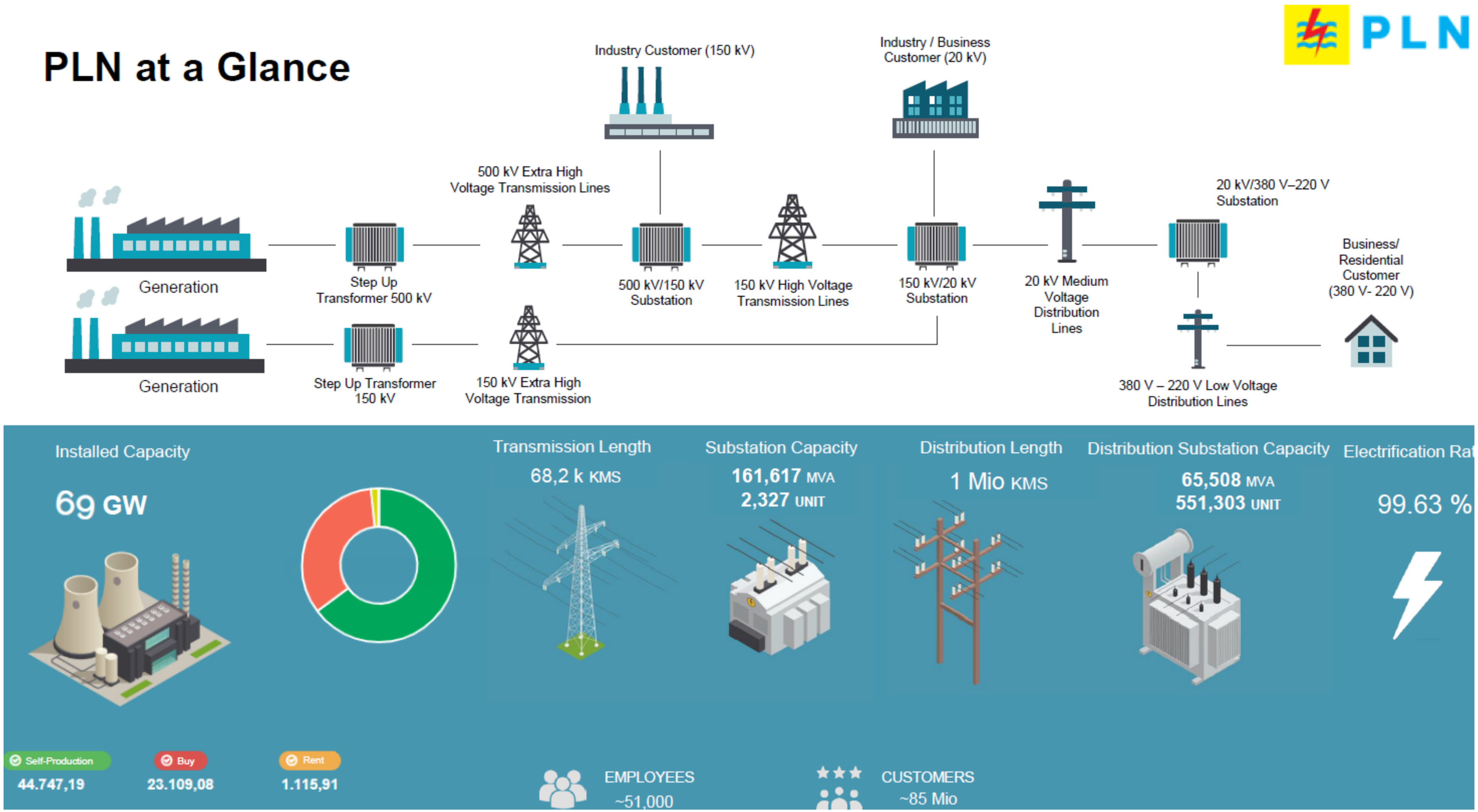


boe = barrels of oil equivalent, CAGR = compound annual growth rate, FCF = free cash flow, GHG = greenhouse gas, IRR = internal rate of return.
Source: Eni (2023c).

3. Indonesian Electric Power Market Situation

In the Indonesian electricity market, PLN – an electricity corporation wholly owned by the government – has a near monopoly in the power supply business. In the power generation sector, PLN is responsible for 60%, with independent power producers (IPPs) accounting for the remaining 40%, probably to reduce PLN's investment burden. PLN also has a near monopoly in the transmission and distribution of electricity, probably so it can control the electricity market. Therefore, PLN is the sole buyer (i.e. off-taker) of electricity generated by IPPs (Figure 4.3).

Figure 4.3. PLN at a Glance



GW = gigawatt, km = kilometres, kV = kilovolt, MVA = megavolt amp, V = volt.
Source: PLN (2023).

Indonesia's electricity market and tariffs are regulated through various laws. PLN conducts public service obligations to produce and to deliver electricity to end-users, whereby electricity tariffs are determined by the government. Specifically, PLN operates power generation, transmission, and distribution businesses under the supervision of the Ministry of Energy and Mineral Resources, based on the State Enterprise Law No. 19/2003 and Electricity Law No. 30/2009. PLN's annual budget, long-term investment plan, and financing plan must be approved by the Ministry of State-Owned Enterprises, and its auditors and directors are appointed by the ministry. Domestic electricity tariffs are subject to government approval and are currently kept below PLN's production costs. The State Enterprises Law No. 19/2003 stipulates that the government is obliged to make up the difference, and a subsidy equal to the difference plus a certain margin is provided from the annual state budget (Figure 4.4).

Figure 4.4. Regulated Electricity Laws and Tariffs in Indonesia

PLN conducts public service obligations by law to produce and deliver electricity to end users whereby electricity tariff are determined by the Government

Key Regulations Governing PLN

Law No. 19/2003	Indonesian State-Owned Enterprises	• Regulating the nature, purpose, activities and limitations on Indonesian state-owned enterprises • Highlighting public service obligation (PSO) role as one of Indonesian state-owned enterprises' economic purposes to strive in increasing Indonesian citizens' welfare.
Law No. 30/2009	The Electricity Law	• Electricity business is controlled by the state through PLN, and PLN is the last resort electricity provider, in that if PLN is not supplying a particular area and there are no regional-owned companies, private enterprises or cooperatives that elect to supply electricity in that area, the Government is obligated to instruct SOE's (which include PLN) to supply electricity to that area.
Presidential Regulation No. 4/2016, as amended by No. 14/2017	Acceleration of Electricity Infrastructure Development	• Increase the pace of development of electric infrastructure through 35,000 MW for power generation and 46,000 km transmission lines in to fulfill Indonesia's demand for electricity and stimulate economic growth.
Ministry of Energy and Mineral Resources Decree No. 39K/20/MEM/2019	2019–2028 National Master Plan	• 10-year nationwide plan for electricity generation, transmission & distribution plans. • Highlight investment strategies to achieve required capacities, fuel mix, and electrification ratio.
Ministry of Energy and Mineral Resources Regulation No. 28/2016, as amended by 3/2020	The Electricity Tariff	• Tariff is regulated for various end users at different VA. Residential with 900 VA will be subsidized. • Variables for tariff adjustment (reviewed quarterly): FX rate, ICP (State Budget assumption), and inflation.
Ministry of Finance Regulation No. 44/PMK.02/2017 as lastly amended by No. 174/PMK.02/2019	Electricity Subsidy Mechanism	• PLN is eligible to claim subsidy for generated electricity at a 7% PSO margin. • Annual subsidy amount will be based on budgeted subsidy amount of that fiscal year's State Budget.
Ministry of Finance Regulation No. 227/PMK/2019	Compensation Mechanism	• PLN is eligible to claim compensation to the government for financially unprofitable assignments, based on the audit result from the state auditor.

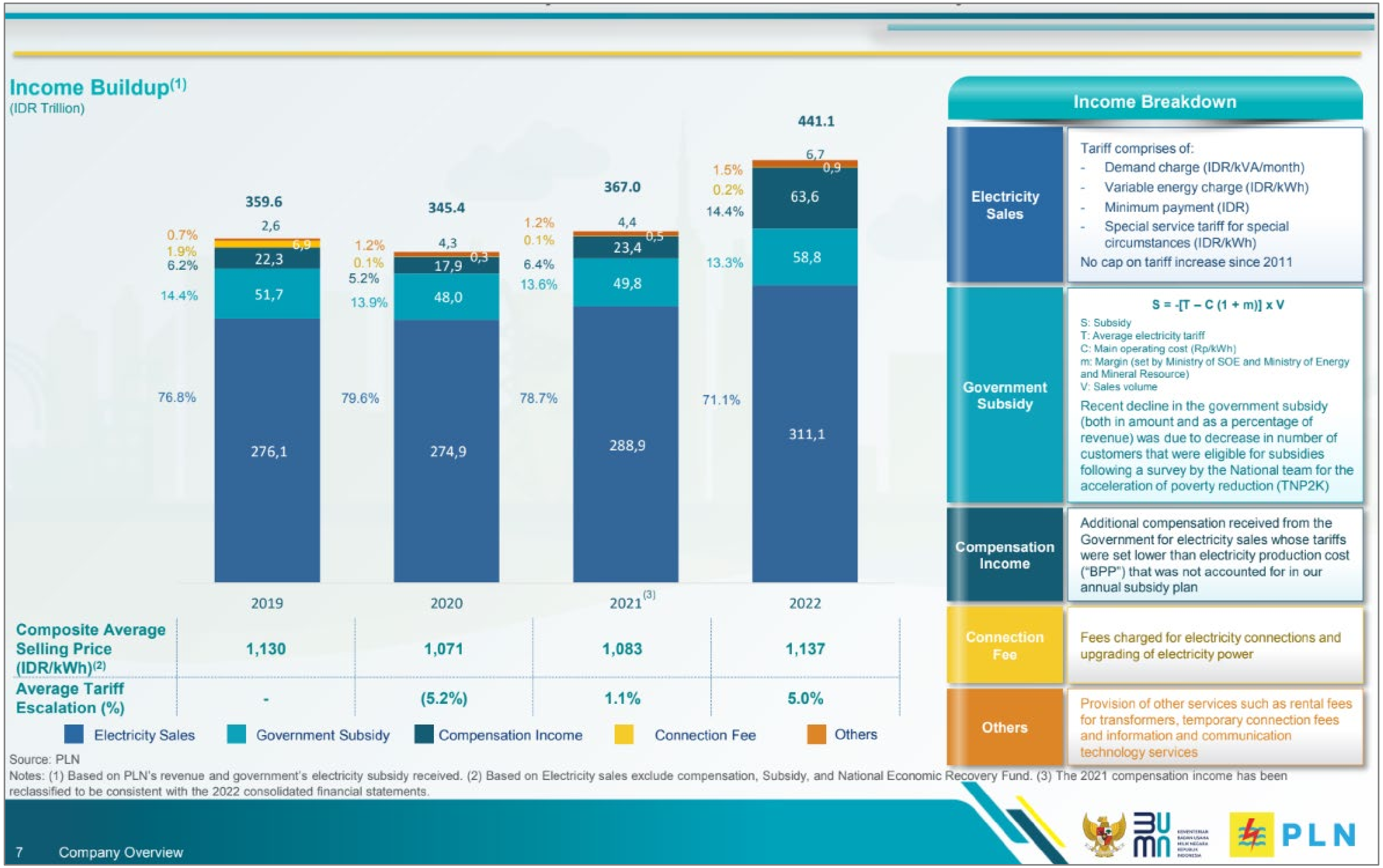
Electricity Tariff Types

Demand Charge	Rates vary depending on capacity of electricity connection. Applicable to small customers with capacity of 450 VA or 900 VA for whom PLN receives subsidy
Monthly Minimum Payment	Charged for each customer apart from customers with a capacity of 450 VA or 900 VA
Variable Energy Charge	Charge fixed rates based on customer categories, increased for peak usage between 6.00 – 10.00 pm for large scale industrial, business and public customers, but not for residential customers
Special Service Tariff	Charged for special circumstances and in particular, for business and industrial customers who require special services

ICP = installation control point, km = kilometre, MV = megavolt, SOE = state-owned enterprise, VA = volt-ampere
Source: PLN (2020).

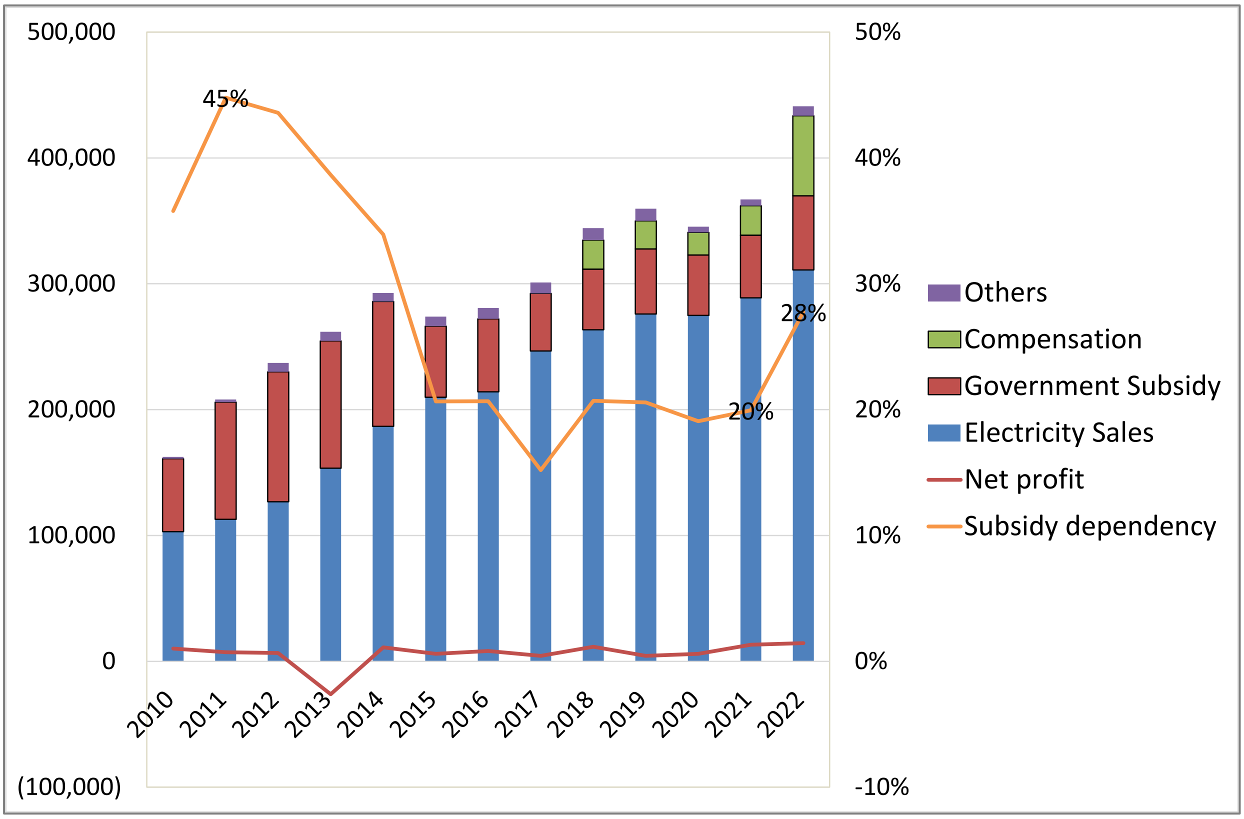
PLN's sales mainly consist of electricity sales, government subsidies, and government compensation income (Figure 4.5). The dependence of government subsidies and government compensation income on total sales fell from 45% in 2011 to 20% in 2015 and remained at almost 20% until 2021, rising to 28% in 2022. The global energy crisis caused fuel prices – including coal – to soar, which cannot be fully passed on to electricity prices and has thus ed to increased reliance on government subsidies and compensation income.

Figure 4.5. PLN Income Model



kWh = kilowatt-hour, kVA = kilovolt-ampere, SOE = state-owned enterprise.
Source: PLN (2023).

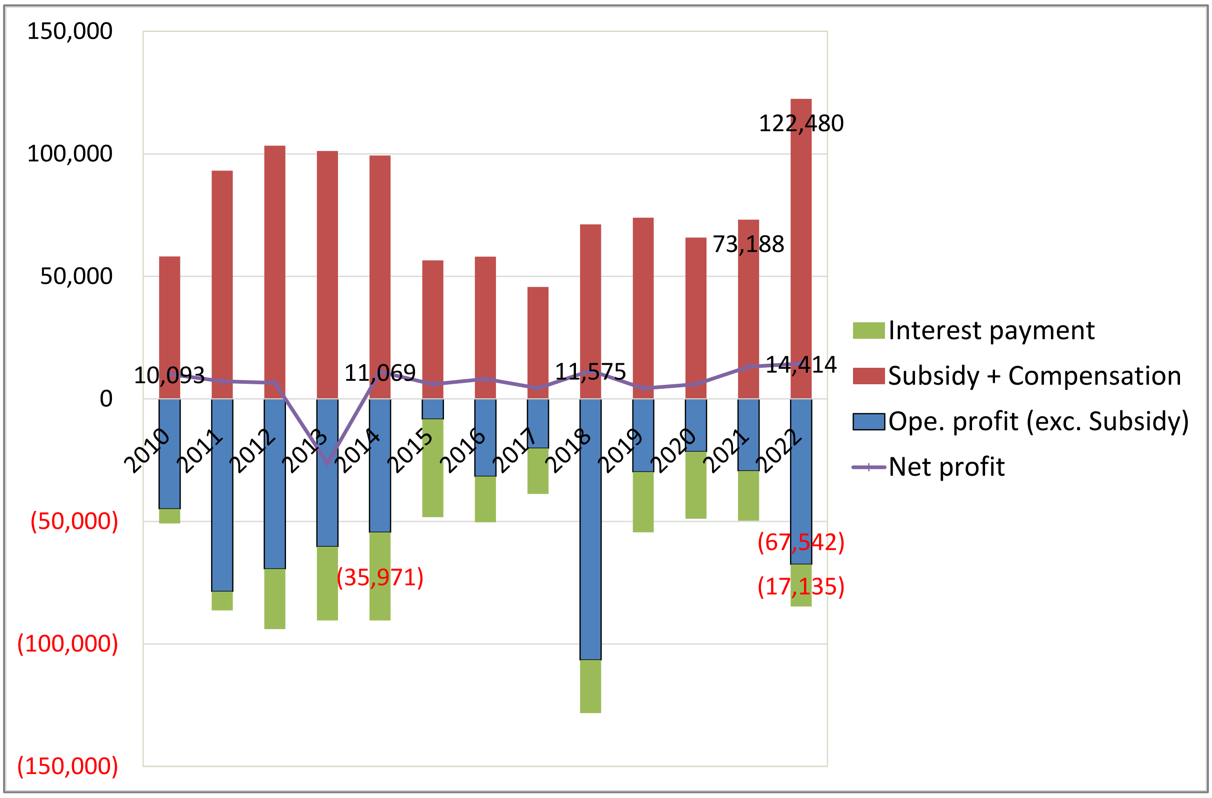
Figure 4.6. Breakdown of PLN Sales
(IDR billion)



Note: Subsidy dependency % = (government subsidies + compensation) divided by total sales.
Source: INPEX Solutions.

In 2022, PLN had a net income of IDR14 billion, which was due to government subsidies and government compensation income of IDR122 billion, while operating income excluding government subsidies and government compensation income was a loss of IDR6.7 billion (Figure 4.6). Looking at the trend of operating income excluding government subsidies and guarantees, the company has been in the red all this time. This is because the government has set the retail electricity sales price at a lower price than the cost of electricity generation, which is unavoidable (Figure 4.7).

Figure 4.7. Breakdown of PLN Net Profits



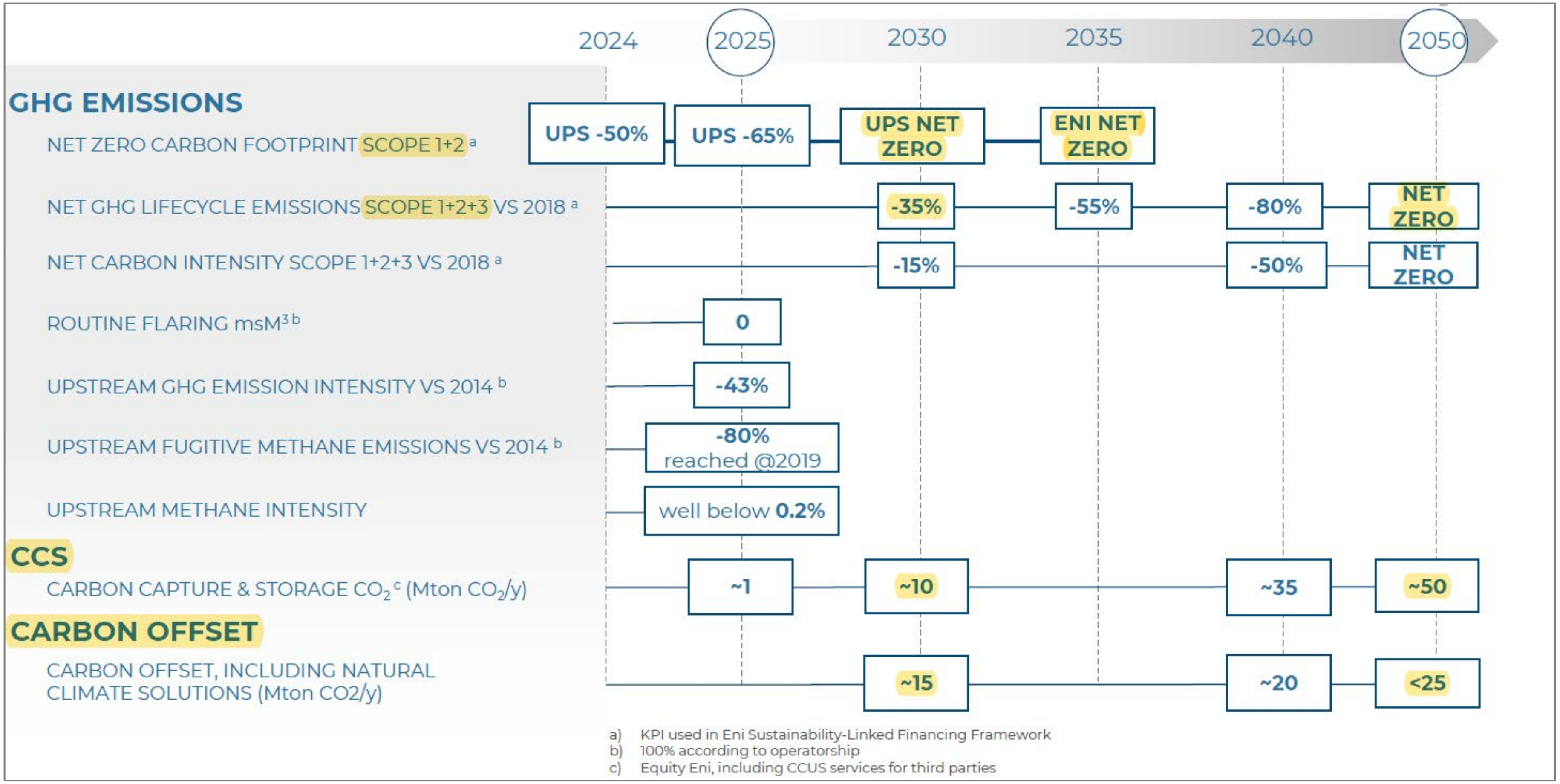
Source: INPEX Solutions.

However, if the electricity mix shifts from coal-fired power generation to solar and gas-fired power generation in the medium to long term, the price of electricity may rise. In addition, the selling price of natural gas for electricity needs to be high enough to allow for the development of new gas field projects in Indonesia. Since the government cannot continue to increase subsidies, it will be necessary to raise electricity prices appropriately while considering economic conditions and other factors.

4. Importance of Carbon Capture and Storage

CCS is important for the government and IOCs with E&P operations in Indonesia to develop clean energy. As mentioned in the previous section, INPEX plans to attach CCS to Abadi LNG when it develops the project. Eni is targeting net-zero scope 1 and 2 emissions from its upstream business by 2030 (Figure 4.8). To achieve this goal, Eni intends to establish CCS with a storage capacity of 10 million tonnes per year by 2030, and to provide 15 million tonnes per year of carbon offsets through natural climate solutions (Figure 4.8).

Figure 4.8. Eni's Decarbonisation Targets



CCS = carbon capture and storage, CO2 = carbon dioxide, GHG = greenhouse gas.
Source: Eni (2023).

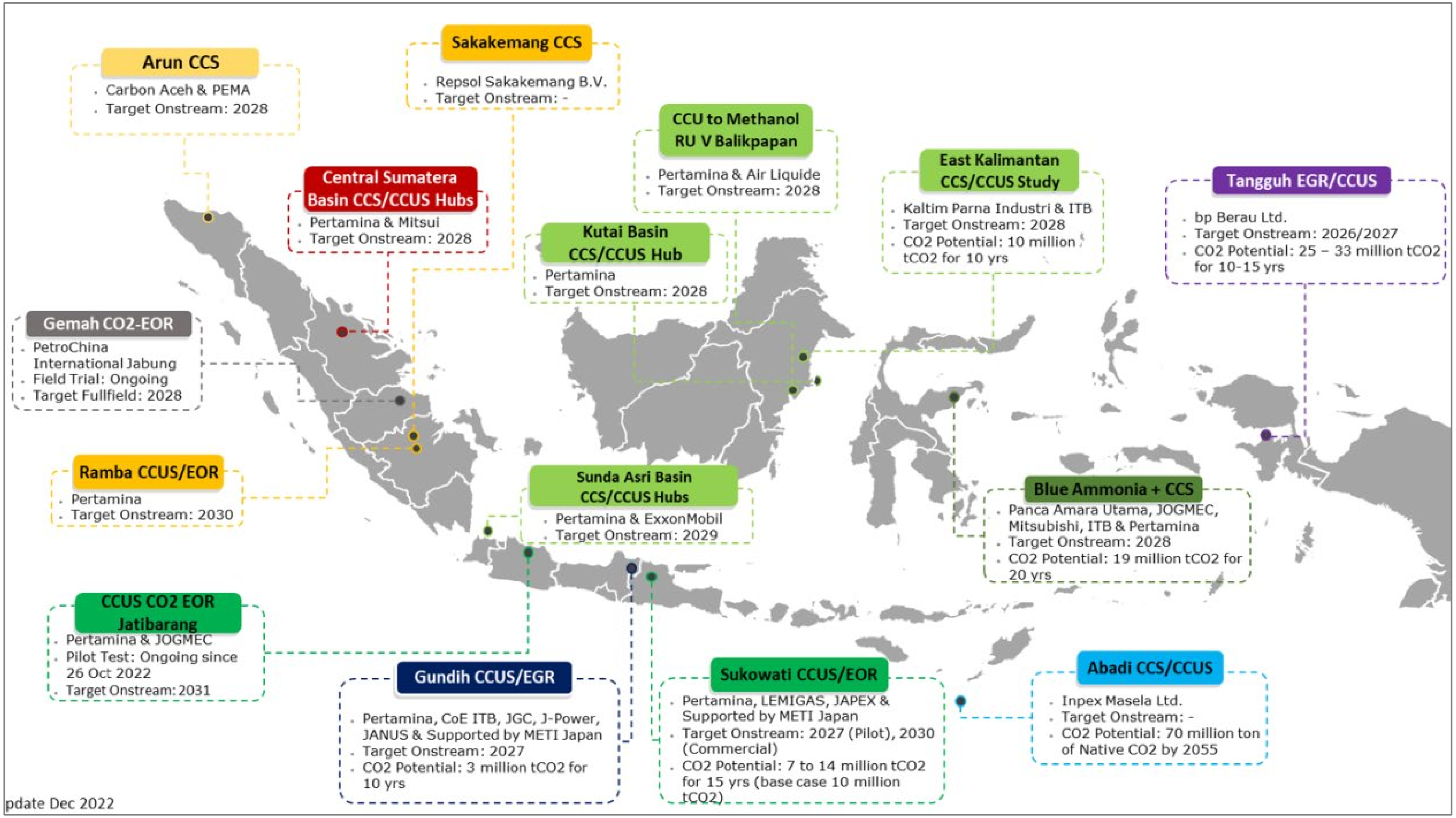
According to the Asia CCUS Network, 15 CCS/CCUS projects are in the pipeline in Indonesia as of the end of December 2022 (Figures 4.9 and 4.10). The most advanced are Tangguh and Abadi. With these CCS/CCUS projects in the pipeline, the total potential implementation of CCS and CCUS in 2030 and up to 2035 is targeted to be 25 million–70 million tonnes.

The Tangguh project is enhanced gas recovery (EGR) through CCUS operated by BP. Tangguh EGR/CCUS is integrated with Ubadari gas field development, and this integrated project will extend the gas feed to Tangguh Train 3 while the EGR/CCUS will reduce the Tangguh LNG carbon footprint via carbon dioxide sequestration. This integrated project is estimated to be an investment of about US$2.6 billion and was approved by the government in 2021. Currently, BP is conducting FEED, targeting coming onstream in 2026/2027.

In November 2023, ExxonMobil and Pertamina agreed to continue their collaboration for a CCS hub evaluation in the Sunda–Asri Basin. This CCS hub is expected to offer significant geological storage, capturing and injecting carbon dioxide from domestic and regional industries. Its storage capacity is expected to up to 3 gigatonnes in the saline aquifer, and its investment value exceeds US$2 billion.

As mentioned previously, Eni is planning to develop a new project in the Kutai Basin, but it is unknown whether CCS is attached. Petronas is also considering a CCS/CCUS hub in the Kutai Basin, and Eni may be able to collaborate with this CCS project.

Figure 4.9. CCS/CCUS Project Pipeline in Indonesia



CCS = carbon capture and storage; CCUS = carbon capture, use, and storage; EGR = enhanced gas recovery; EOR = enhanced oil recovery, tCO2 = tonne of carbon dioxide.

Source: Asia CCUS Network (2022).

Table 4.1. Details of the CCS/CCUS Project Pipeline in Indonesia

No.	Project	Expected Carbon Storage	Expected Onstream
1	CCS Arun, Carbon Aceh, and PEMA	Huge, under detailed assessment	2028
2	Gemah CO2 EOR (CCUS), Petrochina International Jabung	Significant, under detailed assessment	2028
3	Ramba OC2 EOR (CCUS)	Significant, under detailed assessment	2030
4	Central Sumatra Basin CCS/CCUS, Pertamina and Mitsui	Huge, under detailed assessment	2028
5	Sakakemang CCS, Repsol Sakakamang	2 million tonnes per year and 30 million tonnes in total	2028
6	Jatibarang CO2 EOR (CCUS), Pertamina and JOGMEC	146,000 tonnes per year	2031
7	Gundih CO2 EGR (CCUS), Pertamina, J-Power, Janus, COE CCS	3 million tonnes for 10 years	2027
8	Sukowati CO2 EOR (CCUS), Pertamina, LEMIGAS, JAPEX	7 million–14 million tonnes for 15 years	2027 pilot 2030 commercial
9	Sunda Asri Basin, Pertamina and ExxonMobil	6–10 gigatonnes in saline aquifer	2029
10	Kutai Basin CCS/CCUS Hub, Pertamina	Huge, under detailed assessment	2028
11	CCUS to methanol, Pertamina Refinery Balikpapan, Pertamina and Air Liquide	Significant, under detailed assessment	2028
12	East Kalimantan CCS/CCUS, Kaltim Parna Industri	10 million tonnes for 10 years	2028
13	Blue Ammonia CCS, Panca Amara Utama, JOGMEC, Mitsubishi, Pertamina	19 million tonnes for 20 years	2028
14	Tangguh CO2 EGR (CCUS), BP Tangguh	25 million–33 million tonnes for 10–15 years	2026/2027
15	Abadi CCS/CCUS, INPEX Masela	70 million tonnes by 2055	2029

CCS = carbon capture and storage; CCUS = carbon capture, use, and storage; CO2 = carbon dioxide; EGR = enhanced gas recovery; EOR = enhanced oil recovery; JOGMEC = Japan Organization for Metals and Energy Security.
Source: Sidemen (2023).

There are several challenges to implementing CCS. The first is commercial. Who will pay for the cost of CCS? When E&P companies implement CCS to develop new oil and gas fields, will they have to pay the full development costs of CCS? Can they pass these costs on to the sales price or through other means? Will the implementation of CCS by E&P companies in developing new oil and gas fields cause the price of natural gas to rise so that the utility companies will have to pay the cost? Will regulations allow electric utilities to pass on the increased costs of CCS to the price of electricity? Will the government continue to cover the cost of CCS through subsidies or tax credits? Will the end-user ultimately pay for CCS?

Currently, the answers are unclear. CCS implementation is still in the early stages in many countries. Japan is trying to implement CCS first with government subsidies, the US is promoting CCS with government tax credits, and Europe is implementing CCS with government subsidies and some cost-sharing by E&P companies. The initial stage of CCS implementation can be promoted with government subsidies, but it will be necessary for the populations to have a common understanding that the cost of CCS will ultimately be borne by the end-user.

As previously explained, Abasi's CCS-associated costs can be recovered from the produced gas and condensate under the Indonesian PCS. This means that CCS-associated costs could reduce the project IRR if the E&P company is unable to pass on the CCS costs to the end-users.

The second challenge relates to regulations, laws, and rules. Is the implementation of CCS mandatory? Presently, it appears that the implementation of CCS by E&P companies for new oil and gas field development is not mandatory in most countries. However, many E&P companies are considering the implementation of CCS or carbon offset through nature-based solutions when developing new oil and gas fields. E&P companies are also in discussions with governments to ensure that the contribution of CCS implementation is properly recognised in legal terms.

One of the points that the companies are discussing with governments is whether CCS operators must monitor and ensure that carbon is sequestered in the ground forever. If there is a legal responsibility to guarantee that carbon is sequestered forever, it will be difficult for operators to implement CCS. Therefore, in Japan and other countries, a system in which the responsibility is transferred to the government after a certain period of monitoring by the operator is being considered.

In Indonesia, Malaysia, and other countries, CCS as a service business is being considered, in which E&P companies store their own carbon through CCS as well as that emitted by industrial sectors. When carbon from industries outside of Indonesia is captured and stored at CCS reservoirs in Indonesia, it is necessary to establish laws in each country so that this cross-border carbon is legally recognised as a contribution to emissions reduction without double-counting. Indonesia is preparing a presidential regulation to allow this cross-border CCS, which will be welcomed by CCS operators.

The third challenge is technical, which includes how to reduce costs, how to improve accuracy in estimating underground carbon storage capacity, and how to prepare pipelines and carriers for carbon transport. Since E&P companies have experience in implementing CCS/CCUS through enhanced oil recovery in oil and gas fields, the technical challenges in implementing CCS on a large scale mentioned earlier will be eventually solved.

Table 4.2. Challenges of Carbon Capture and Storage

Challenges	Details
Commercial	E&P companies pay? Power companies pay? Government pays? Full subsidy? Full tax reduction? End-users pay?
Regulation	Is CCS mandatory or voluntary? Who is responsible for ensuring carbon is stored? Forever? How to deal with cross-border carbon? Double-counting?
Technical	Cost down Accuracy of carbon storage capacity estimation Infrastructure: carbon pipeline, maritime transport

CCS = carbon capture and storage.
Source: INPEX Solutions.

5. Summary of Win-Win Situations between the Government and International Oil and Gas Companies

Indonesia needs to develop new gas fields to meet the expected increase in domestic gas demand, and Eni and INPEX have stated that a reasonable IRR is a prerequisite for the development of new projects. Discussions with the government on economic conditions will be a key point. Another point is the development of regulations for the implementation of CCS, including cross-border carbon storage.

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