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The Strategies of International Oil companies and its activities in Indonesia under Energy Transition

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The Strategies of International Oil companies and its activities in Indonesia under Energy Transition

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Executive Summary

Although the COP26 in 2021 increased the momentum toward carbon neutrality in many countries, the situation in Ukraine in 2022 caused an energy crisis. As a result, there is a need to strike a balance between decarbonization and securing energy, including oil and gas, for the foreseeable future.

Under these circumstances, in light of the energy crisis that has occurred, some European IOCs, such as BP, Shell and Eni, have once again somewhat increased their oil and gas activities. In addition, some U.S. oil and gas companies, such as Chevron and ConocoPhillips have been greatly expanding the scale of their production through M&A. It should be added, however, that each company is also taking carbon neutrality into consideration.

Although some IOCs have increased their oil and gas activities, among which Chevron, ConocoPhillips, and Shell have withdrawn from the E&P business in Indonesia. This is to focus more on the core areas of each company with an emphasis on profitability, and the author believes that it is unlikely that they will return to E&P activities in Indonesia again. On the other hand, Eni and INPEX are trying to develop new projects in Indonesia, and it's important to make it a win-win situation for them and the Indonesian government.

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 (Internal Rate of Return) is a prerequisite for the development of new projects, so discussions with the government on economic conditions will be a key point. Another key point is the development of regulations for the implementation of CCS, including cross-border storage.

Chapter 1

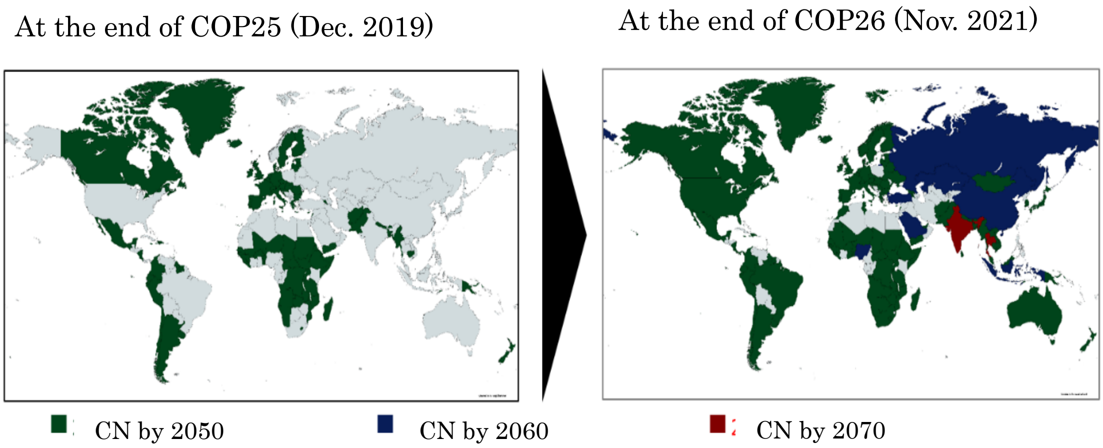
Global Energy Situation as background of this Study report

In Chapter 1, we examine the global energy situation as background for this report. Although the COP26 in 2021 increased the momentum toward carbon neutrality in many countries, the situation in Ukraine in 2022 caused an energy crisis. As a result, there is a need to strike a balance between decarbonization and securing energy, including oil and gas, for the foreseeable future.

1. COP26 and growing carbon neutral declaration

From October 31 to November 13, 2021, the 26th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change, commonly known as "COP," or "COP26," was held in Glasgow, the United Kingdom. One of the biggest topics of COP26 was the carbon neutrality declarations by countries around the world. At the time of COP25 in December 2019, 121 countries had declared 2050 carbon neutrality, most of them EU countries and the rest were small countries and the CO2 emissions of those countries accounted for 17.9% of the world's total CO2 emissions. Later, in the run-up to COP26, momentum for this ambitious goal grew, and China, the United States and other countries announced their carbon neutrality targets one after another. Japan also made a declaration in October 2020. Indonesia declared carbon neutrality by 2060 in July 2021. At the end of COP26, more than 150 countries, including all G20 countries, have set carbon neutrality targets with annual time limits. The CO2 emissions of those countries accounted for 88.2% of the world's total CO2 emissions.

Figure 1.1. Countries and regions who announced Carbon Neutral (CN)



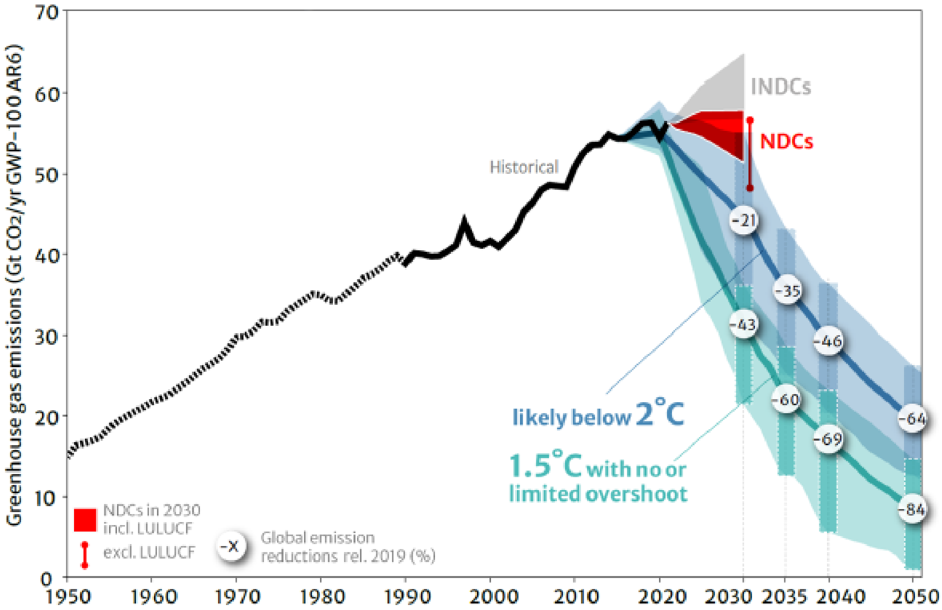
Source: METI, Japan (March 2022)
Notes: English Supplemental translation by INPEX Solutions
https://www.enecho.meti.go.jp/about/special/johoteikyo/cop26_02.html

Although many countries declared themselves carbon neutral in preparation for COP26, only about half of them actually raised their NDCs. NDC is an acronym for nationally determined contribution, and in the Paris Agreement (adopted in December 2015 and entered into force in November 2016), all countries are obliged to submit and update their greenhouse gas emission reduction targets every five years as a "nationally determined contribution (NDC)". At this time, many countries have submitted greenhouse gas emission reduction targets through 2030. However, only about half of the countries have actually raised their NDC. Specifically, the EU, the U.S., and Japan have raised their 2030 greenhouse gas emission reduction targets, but China and other countries have not.

As a result, according to an analysis by UNFCCC, United Nations Framework Convention on Climate Change, the projected greenhouse gas emissions for 2030 based on NDC are not in line with modelled global mitigation pathways consistent with the temperature goal of the Paris Agreement, and there is a rapidly narrowing window to raise ambition and implement existing commitments in order to limit warming to 1.5 °C above pre-industrial levels.

Figure 1.2. GHG emissions based on NDC

Historical emissions from 1950, projected emissions in 2030 based on nationally determined contributions, and emission reductions required by the Sixth Assessment Report of the Intergovernmental Panel on Climate Change



		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]

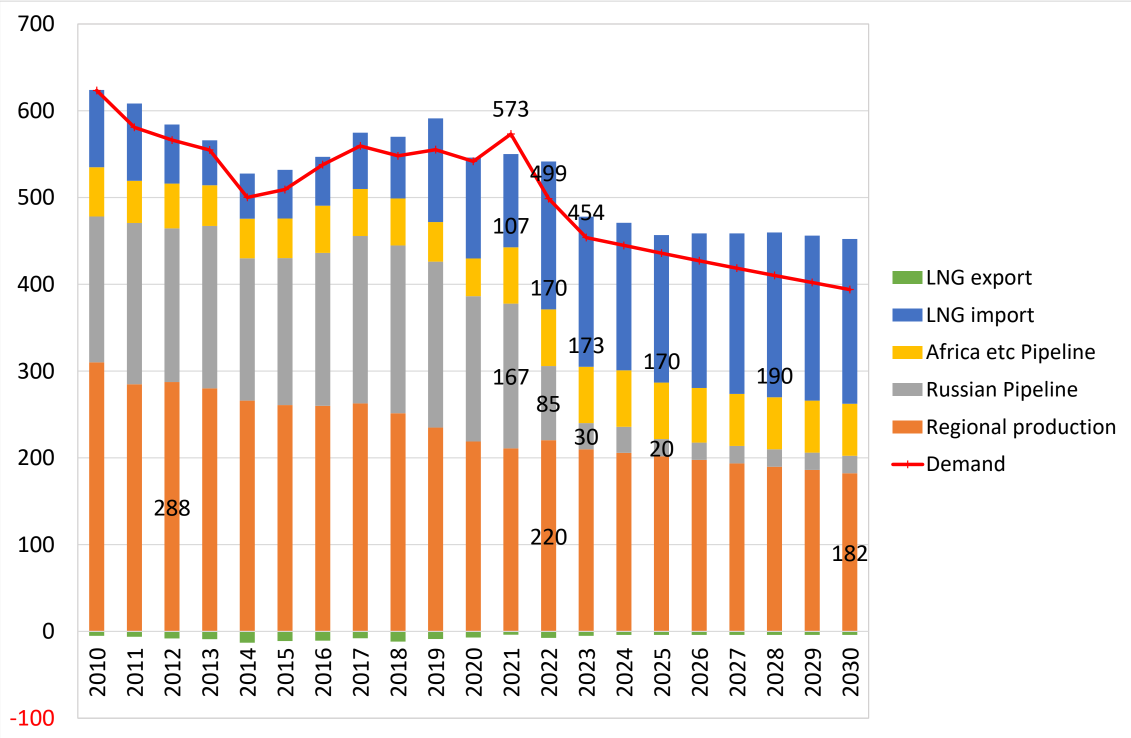
Sources: Upper panel: Historical data from the IPCC for 1950–1989 and from the 2022 NDC synthesis report for 1990–2020; 2030 projections from NDCs; and the reduction scenarios from the AR6 Synthesis Report (IPCC. 2023. *Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*. Core Writing Team, H Lee, and J Romero (eds.). Geneva: IPCC. Available at https://www.ipcc.ch/report/ar6/syr/). Lower panel: table SPM.5 in the AR6 Synthesis Report.
Abbreviation: LULUCF = land use, land-use change and forestry.

Source: UNFCCC (2023/9)
https://unfccc.int/documents/631600

2. Russian's invasion of Ukraine has caused Energy Crisis in 2022

Although the COP26 in 2021 had increased momentum toward carbon neutrality in countries around the world, Russia invaded Ukraine in February 2022, triggering a global energy crisis with Europe as its epicenter. Europe uses natural gas for power generation, heating, and industrial activities, and was dependent on pipeline imports from Russia for about 30% of its natural gas procurement. However, following Russia's invasion of Ukraine, Europe announced a policy of reducing imports of Russian gas ("REPowerEU Plan"). The contents of this REPowerEU Plan include diversification of natural gas procurement, expansion of the introduction of renewable energy, and promotion of energy conservation. As a result, European imports of Russian gas are expected to decline from 167 billion cubic meters (bcm) in 2021 to 85 bcm in 2022 and to 30 bcm in 2023. On the other hand, European imports of liquefied natural gas (LNG) jumped from 107 bcm in 2021 to 170 bcm in 2022.

Fig.1.3. Europe Natural Gas Supply & Demand (bcm)

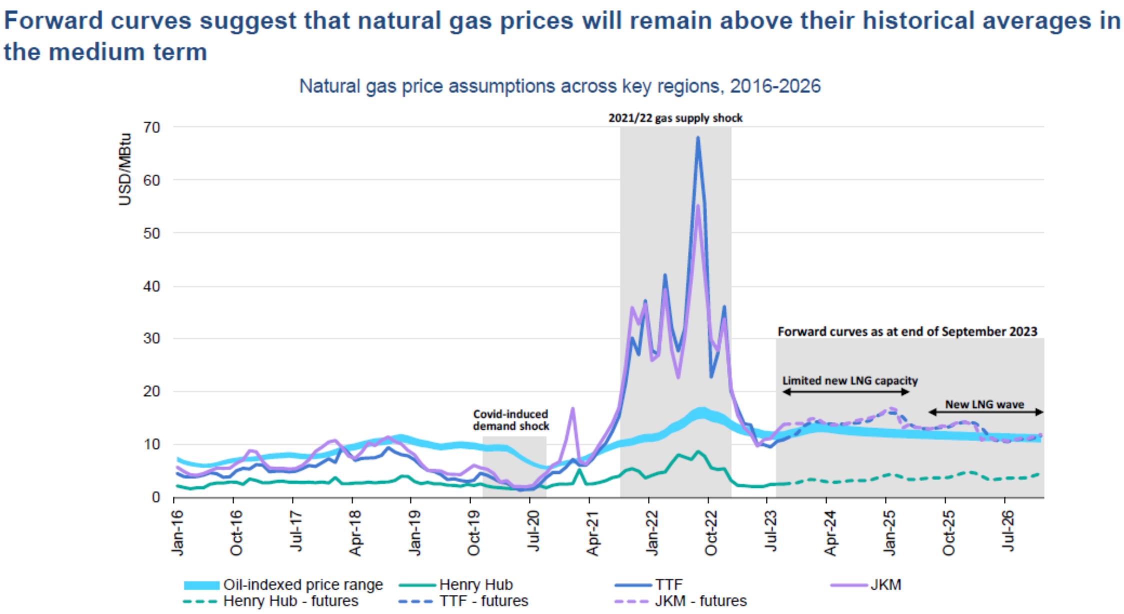


Source: INPEX Solutions, Actual data is based on Statistical Review of World Energy 2023 (2023/6)

This surge in European LNG imports was mainly driven by procurement from the spot LNG market. The LNG market consists of about 65% of 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 spot supply at high prices, and a little less than half of the spot supply flowed to the European market. This surge in spot gas prices triggered the global energy crisis in 2022. The gas price spike led to production cuts in European industry, and European citizens suffered from high electricity and gas prices. As Europe increased its LNG procurement, some Asian countries could not procure enough LNG and were forced to increase their coal consumption. Coal prices also soared.

In 2023, gas spot prices, such as TTF and JKM, are down significantly from the sharp spike in 2022. This is due to the fact that Europe has weathered the winter season, which is the demand season for gas in Europe, and that Europe has sufficient gas inventories ready for the 2023-2024 winter season. Nevertheless, the current spot price for gas is still $15/mmbtu (million British thermal units), compared to a price range of just under $10/mmbtu before the start of this energy crisis. This is because Europe is still importing a high level of LNG, and because several new LNG projects are being built after the energy crisis, but they will not start production until around 2027.

Fig.1.4. Natural gas price assumptions across key regions



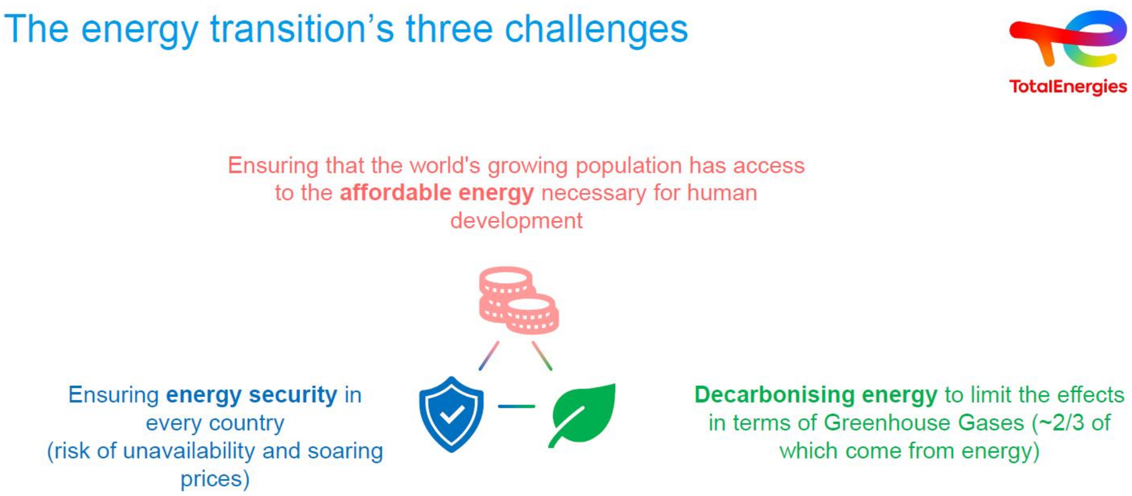
Source: IEA (2023/10)

https://www.iea.org/reports/medium-term-gas-report-2023

3, Need to strike a balance between decarbonization and securing energy, including oil and gas

In the long run, the importance of decarbonization is not likely to change. However, in light of the current energy crisis, some countries, corporate leaders and Industry experts are beginning to say that there is a need to strike a balance between decarbonization and stable energy procurement, including oil and gas.

Fig.1.5. The energy transition's three challenges

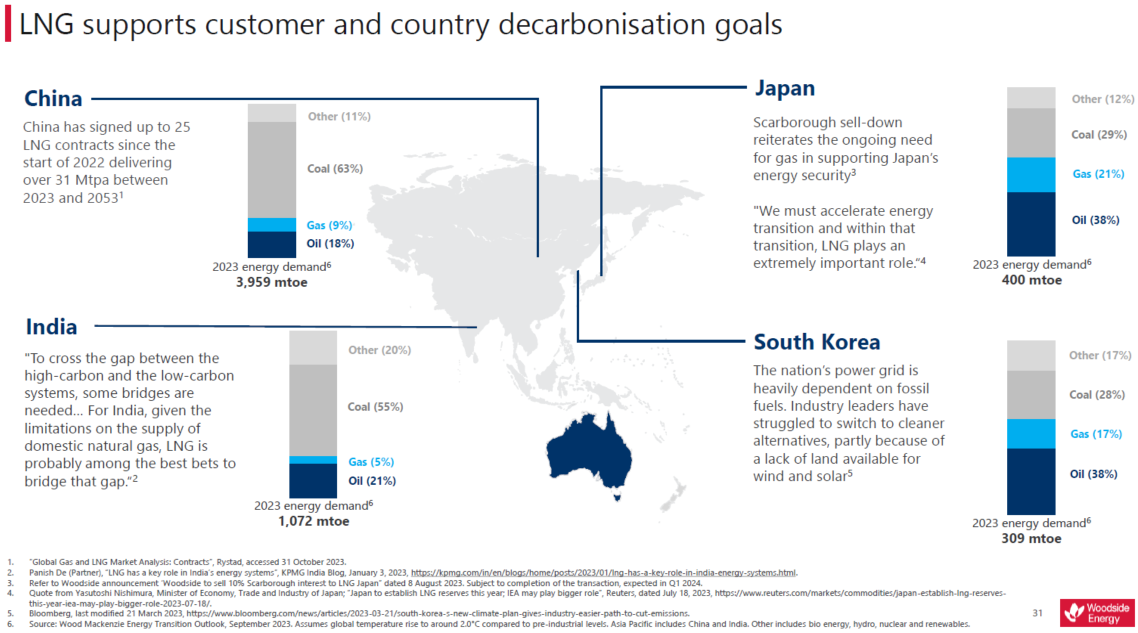


Source: TotalEnergies (2023/11)
https://totalenergies.com/sites/g/files/nytnzq121/files/documents/2023-11/TotalEnergies_Energy_Outlook_2023_EN.pdf

As for LNG, which triggered the energy crisis, China has signed long-term contracts for 31 mtpa from 2022 onward to ensure stable LNG procurement. In Japan, Mr. Yasutoshi Nishimura, Minister of Economy, Trade and Industry of Japan, said "We must accelerate energy transition and within that transition, LNG plays an extremely important role".

Although the LNG industry has recently seen an increase in the proportion of spot transactions, suppliers have originally built new LNG facilities based on long-term contracts with customers. Stable energy supply can be ensured as long as consumers have long-term contracts based on realistic energy demand forecasts. However, if consumers take the stance that they can simply procure LNG from the spot market when they need it, based on uncertain energy demand forecasts, the LNG market will tend to soar. In the event that 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 the pace planned by the government, the reality is that customers will have to rely on LNG.

Fig.1.6. LNG supports customer and country decarbonization goals



Source: Woodside (2023/11)

https://www.woodside.com/docs/default-source/asx-announcements/2023-asx/investor-briefing-day-2023.pdf?sfvrsn=a282d577_3

4, Indonesia government set the targets for Net Zero Emission by 2060 or sooner.

The Indonesian government also announced in 2021, the year COP26 was held, its goal of achieving Net Zero Emission by 2060 or sooner. The Indonesian government said, "The transition to net zero emission requires energy infrastructure, technology, and financing". Speaking of financing, the Indonesian government emphasized the role of the private sector as well as the government and the financial institutions.

As the Roadmap to 2060, the Indonesian government explained that between 2026 and 2030, there will be no additional capacity from coal-fired power plants, except from those which have reached financial close or under construction. Indonesia will start the first stage of coal power plant retirement in 2031. In the period 2036-2040, the second stage of coal power plant retirement will be conducted. Finally, from 2051 to 2060, the last stage of coal power plant retirement will be performed.

The Indonesian government submitted its updated NDC (Nationally Determined Contribution) in September 2022. NDC is a climate action plan and target to cut greenhouse gas emission and each country to the Paris Agreement is required to submit NDC to United Nations. The updated Indonesian NDC has an unconditional emissions reduction target of 31.89 % and a conditional target of 43.20 % as compared to Business-as-Usual (BaU) scenario in 2030, as shown in the Figure below. This “conditional” means that additional mitigation measures will be taken. Indonesian government explained that its 2030 emission will be 2,869 million ton in BaU and 1,953 million ton in unconditional scenario and 1,632 million ton in conditional scenario compared to 2010 emission of 1,334 million ton.

The Indonesia government hosted G20 Bali summit in November 2022. Through the G20 Bali summit, the Indonesian government has deepened discussions toward net zero emission, including the Indonesia "Just Energy Transition Partnership", JETP. JETP is the long-term energy transition partnership between Indonesia and International partners group, such as US, Japan, EU etc, that aims to mobilize $20 billion in public and private financing to help Indonesia achieve its climate targets.

The author believes that the Indonesian government has made progress in discussions on Net Zero Emission through COP26, updated NDC and the G20 Bali Summit, while taking into consideration the stable supply of energy in light of the recent energy crisis.

Fig.1.7. Indonesia government submitted its updated NDC in 2022.

Table 1. Projected BAU and emission reduction from each sector category

Sector	GHG Emission Level 2010* (MTon CO2-eq)	GHG Emission Level 2030			GHG Emission Reduction				Annual Average Growth BAU (2010-2030)	Average Growth 2000-2012
		MTon CO_2-eq			MTon CO_2-eq		% of Total BaU			
		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.

Source: UNFCCC (2022/9)

https://unfccc.int/sites/default/files/NDC/2022-09/23.09.2022_Enhanced%20NDC%20Indonesia.pdf

Chapter 2

Global Strategy of International Oil Companies after this Energy Crisis

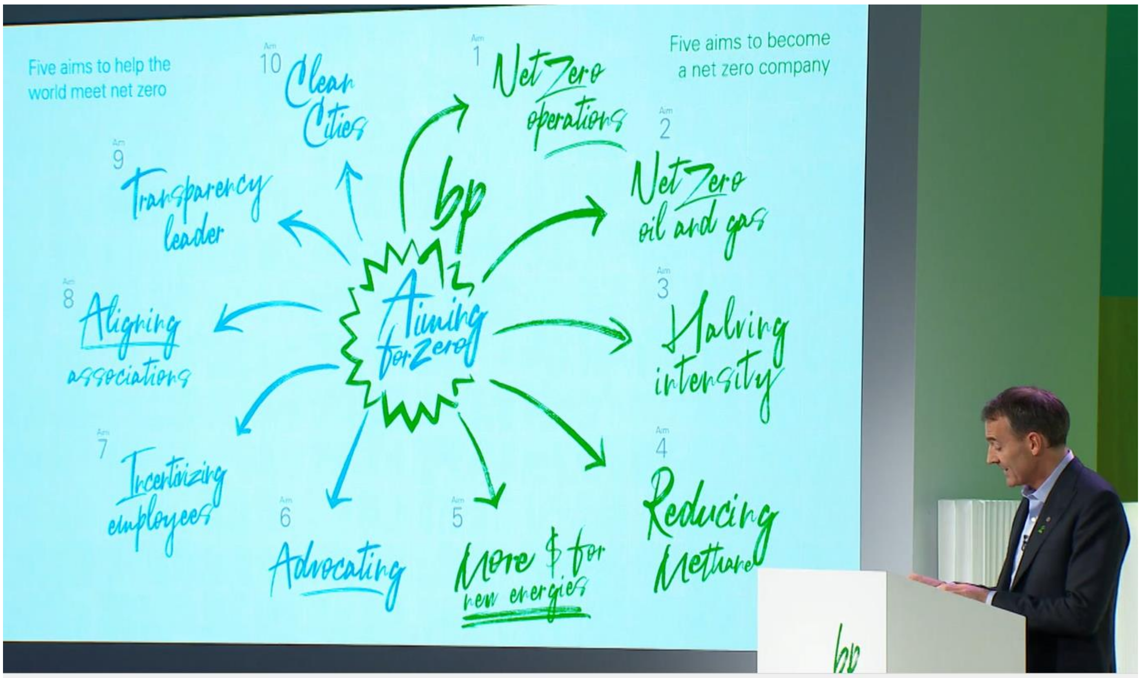
In Chapter 2, we examine the IOC's global strategy as a preparation for considering the IOC's activities in Indonesia, such as BP, Shell, Eni, Chevron, ConocoPhillips and INPEX. In light of the energy crisis that has occurred, some European IOCs have once again somewhat increased their oil and gas activities. In addition, some U.S. oil and gas companies have been greatly expanding the scale of their production through M&A. It should be added, however, that each company is also taking carbon neutrality into consideration.

1, BP's Global Strategy

BP (formerly The British Petroleum Company) is a British multinational company, engaged in oil & gas, refining & gas station and low carbon energy such as Solar Power, Wind Power and Bio energy. BP is one of the "Oil & Gas Majors"; other majors include ExxonMobil, Chevron, Shell, and TotalEnergies. BP has the Tangguh LNG project in Indonesia.

BP announced its "Net Zero Ambition by 2050" in 2020, and its content was the most proactive among the Majors on decarbonization. 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. As a supplement, BP held shares in Russian Rosneft at the time, and BP's total production volume, including its stake in Rosneft, was 3.7 mmboe/d.

Fig.2.1. BP announced Net Zero Ambition by 2050

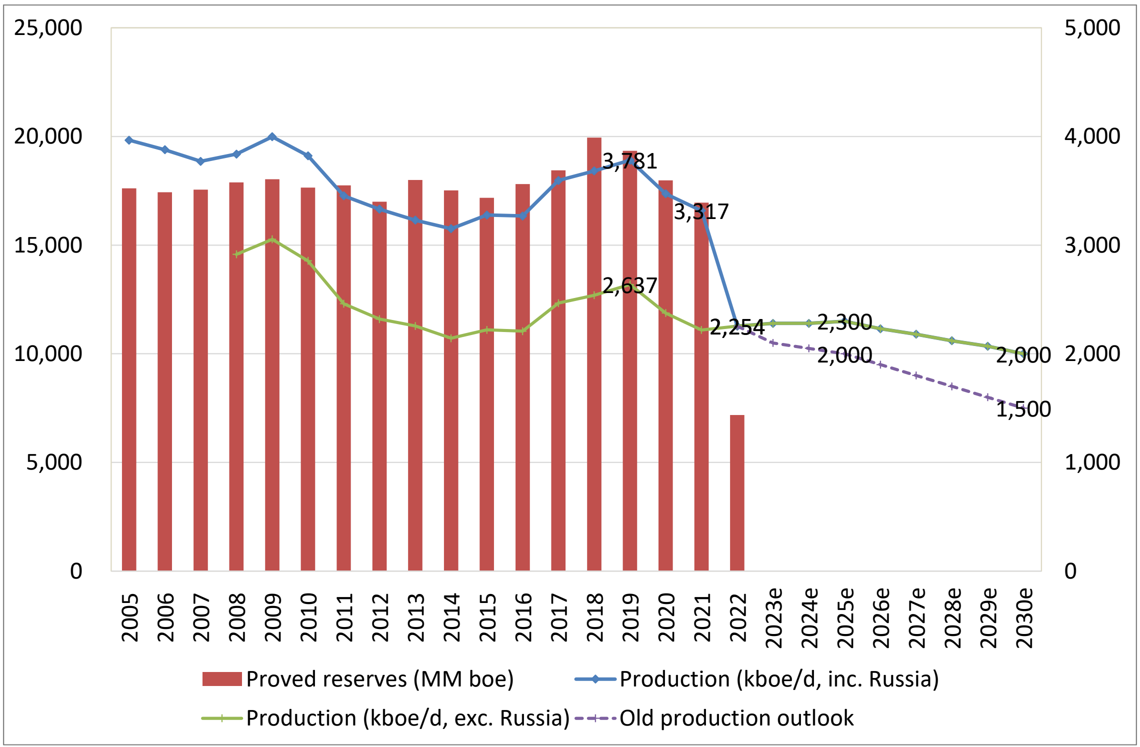


Source: BP (2020/2)

https://www.bp.com/en/global/corporate/investors/results-reporting-and-presentations/archive.html#tab_2020

However, in February 2023, BP revised its oil and gas production reduction target in light of the energy crisis, and specifically increased its production target for 2030 from 1.5 mmboe/d to 2 mmboe/d. Following Russia's invasion of Ukraine in 2022, BP sold its Rosneft holdings, so BP's total production in 2022 was 2.2 mmboe/d, which it intends to reduce slightly to 2 mmboe/d in 2030. This upward revision of the production target came as a surprise, as BP has been the most proactive in decarbonizing within majors.

Fig.2.2. BP's oil & gas production (right axis) and proved reserves (left axis)

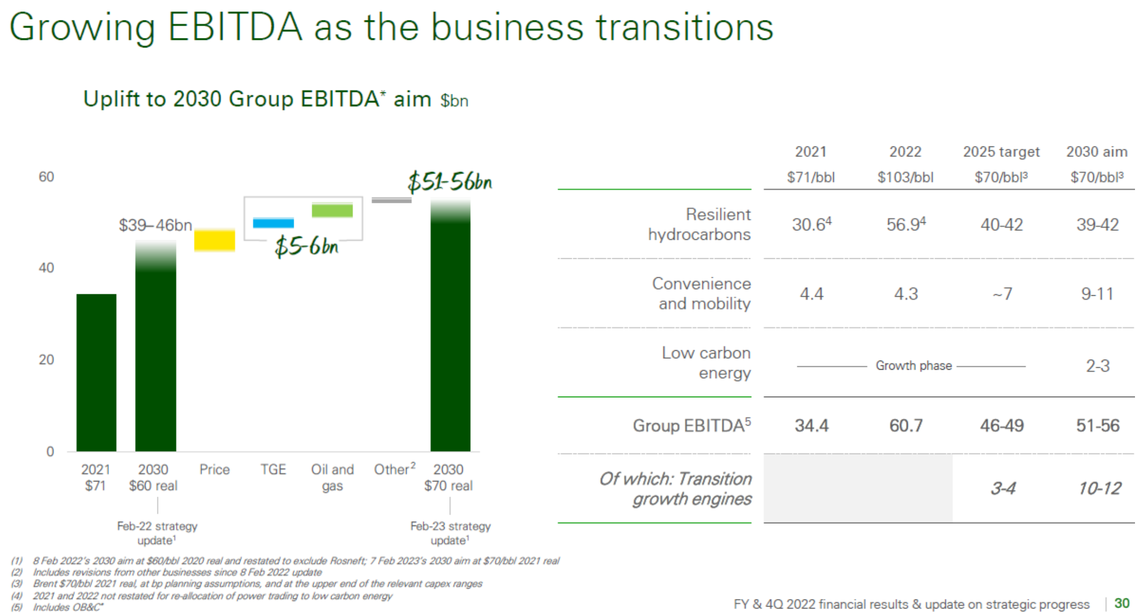


Source: INPEX Solutions

The author believes that this upward revision of BP's oil and gas production target is not only due to the energy crisis, but also from a business return perspective. BP has been increasing the weight of investment in low carbon energy business, but for the time being, returns are not expected. EBITDA (Earnings before Interest, Tax, Depreciation and Amortization) in 2030 is expected to be only $2-3 billion. Note that companywide EBITDA in 2030 is expected to be $51-56 billion, of which $39-42 billion is expected to come from oil and gas.

BP, as well as other companies, 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 low carbon energy business.

Fig.2.3. BP's EBITDA outlook by business



Source: BP (2023/2)

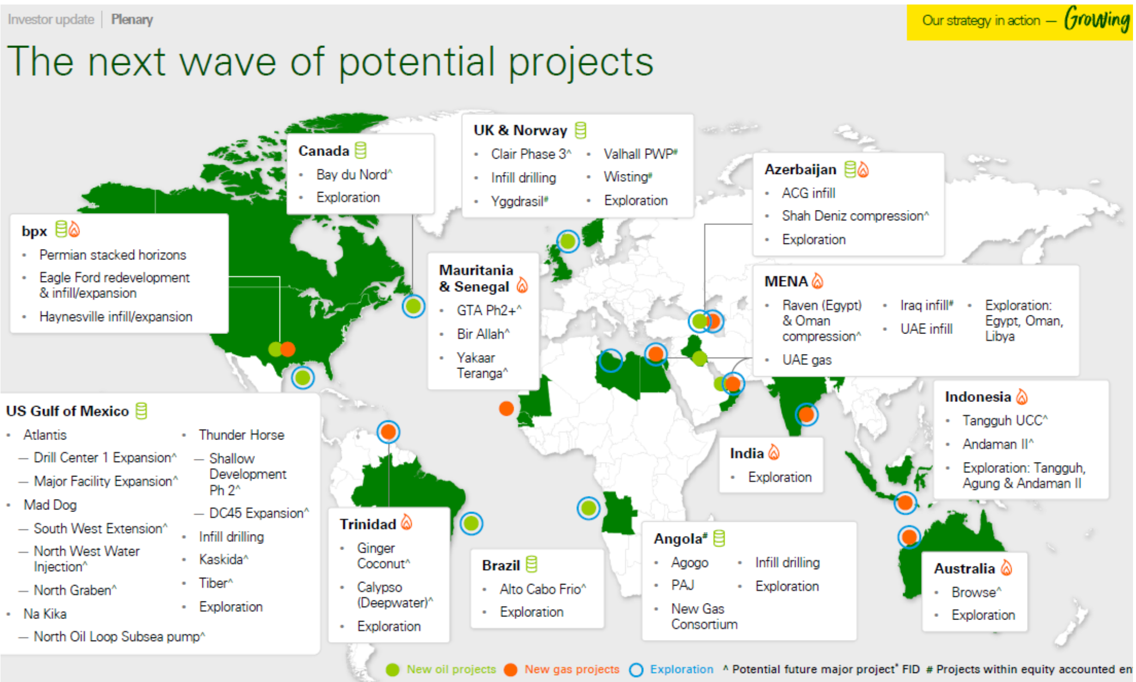
https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/investors/bp-fourth-quarter-2022-results-presentation-slides-and-script.pdf

BP has the following candidate projects to achieve production of 2.0 million boe/d in 2030 compared to 2.2 million boe/d in 2022, as shown in the figure below. The existing core areas of the U.S. (shale and Gulf of Mexico) and MENA (Middle East and North Africa) are the main areas with new projects, and the existing assets and infrastructure will be used to promote new projects and exploration around them.

In oil, BP expects U.S. shale oil production to expand from about 120 kb/d in 2022 to about 240 kb/d in 2030, U.S. Gulf of Mexico production to expand from about 250 kboe/d in 2022 to about 350 kboe/d in 2030, and Middle East (UAE and Iraq) production is expected to expand from about 220 kboe/d in 2022 to about 320 kboe/d in 2030.

BP also has a new project in Indonesia, Tangguh UCC, which is discussed in the next chapter.

Fig.2.4. BP's potential projects of oil & gas



Source: BP (2023/10)

https://www.bp.com/en/global/corporate/investors/results-reporting-and-presentations/investor-update-2023.html

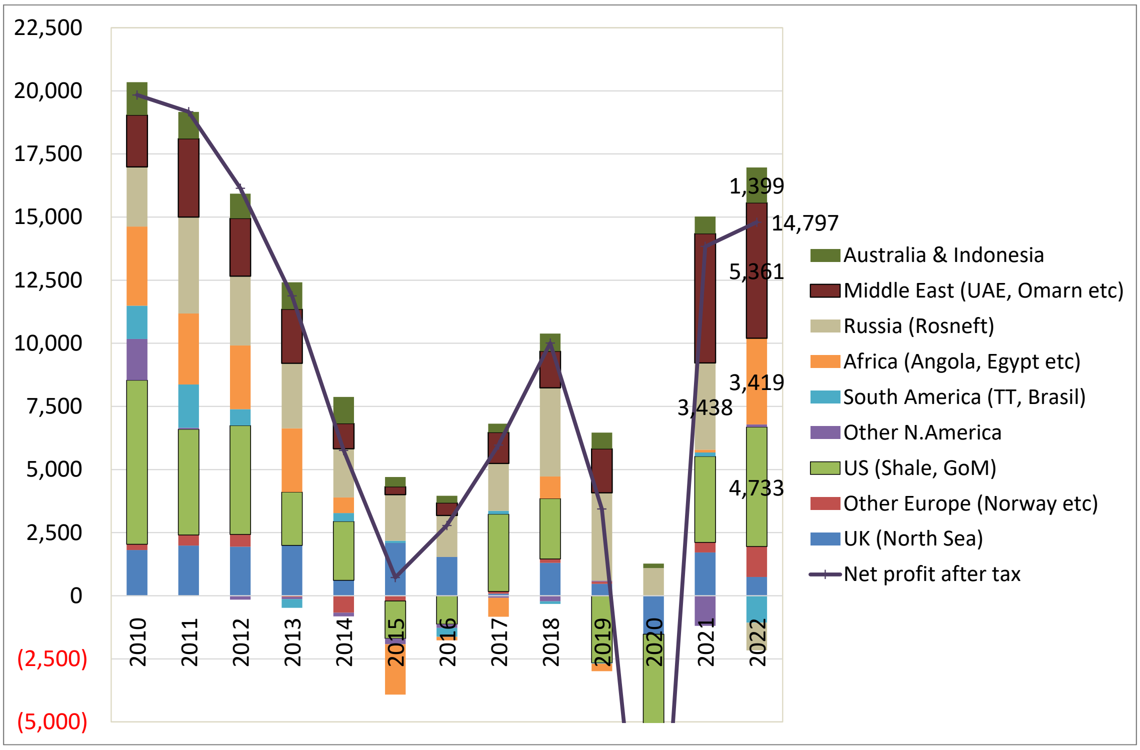
BP earns about 80% of its companywide net income from oil and gas operations and about 20% from downstream-related activities. The chart below shows the net income of the oil and gas business by region. Of the total net income of US$14.8 billion, the United States (US$4.7B), the Middle East (US$5.4B), and Africa (US$3.4B) are the main sources, while Australia & Indonesia (US$1.4B) is relatively low in 2022.

As will be explained in detail in the next chapter, Shell, Chevron, and ConocoPhillips have withdrawn from the Indonesian E&P business, while BP will continue the Indonesian E&P business. The author believes that the reasons why BP continues to operate the Indonesian E&P business are as follows, even though the profits from the Indonesian E&P business account for a relatively small proportion of the total.

First, as Russia invaded Ukraine, BP sold its Rosneft equity interest, and BP lost its equity profit, which had contributed significantly to profits, so BP would like to maintain its Indonesian E&P business as important profit source.

Second, from 2020 to 2022, BP focused on shifting to renewable energy, etc., so there are relatively few new projects pipeline in the oil and gas business, so BP would like to promote new projects in Indonesia as well.

Fig.2.5. BP's Net profit of oil & gas (US$ million)



Source: INPEX Solutions

2, Shell's Global Strategy

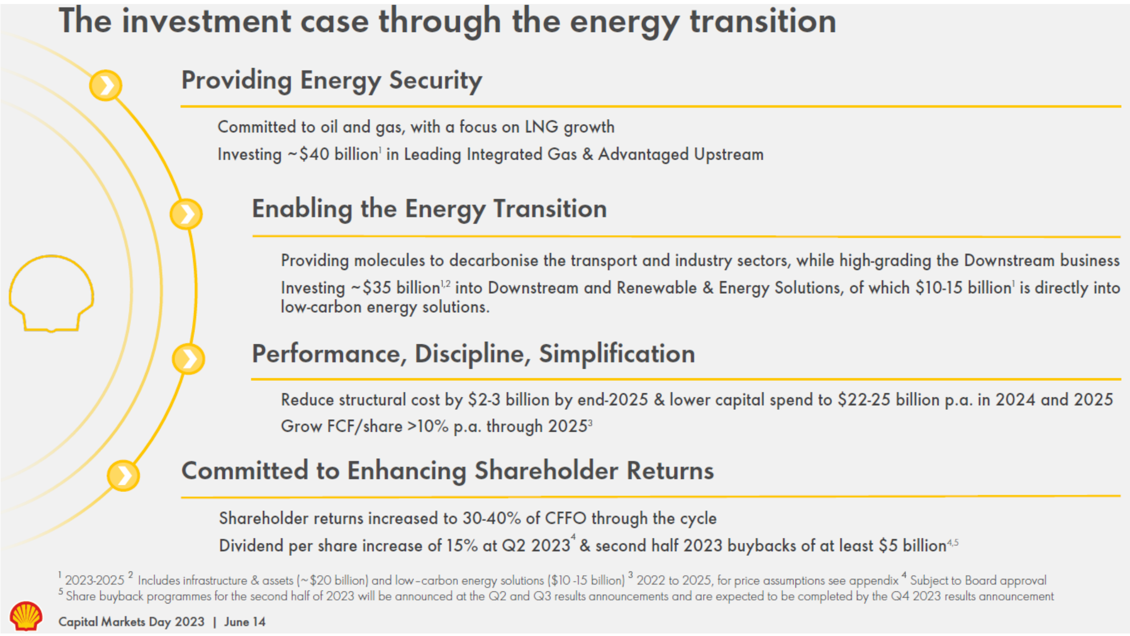
Shell is also a British multinational company, engaged in oil & gas, refining & gas station and low carbon energy such as Solar Power, Wind Power etc. Shell has sold its equity interest in the Abadi LNG project in Indonesia and exited the upstream business in Indonesia.

In 2021, Shell also announced a plan to increase its investment ratio in "Renewable & Energy Solutions" and decrease its investment ratio in "Upstream" in light of the momentum of the Energy Transition in Europe and other regions. "Energy Solutions" business include Hydrogen and CCS etc.

However, due to the energy crisis, Shell revised its strategy slightly in June 2023, and stated 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 low carbon business.

More specifically, Shell commented at results IR meeting in February 2023, “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 the 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” (excerpts).

Fig.2.6. Shell’s overall strategy

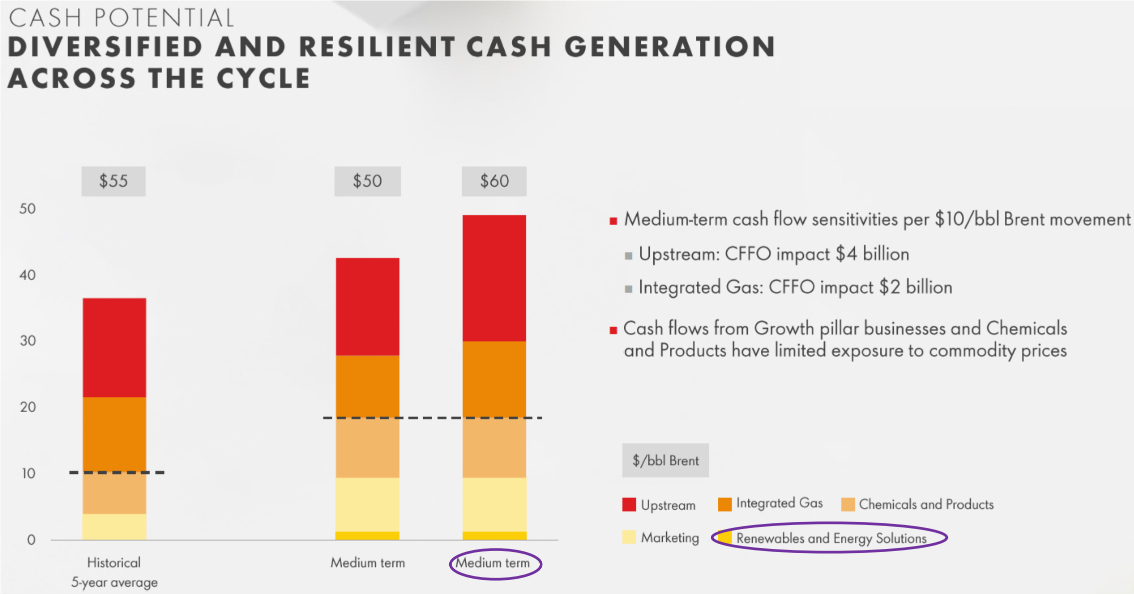


Source: Shell (2023/6)

https://www.shell.com/investors/investor-presentations/capital-markets-day-2023.html

Shell had explained a bit about the profit outlook for the low carbon business in February 2021, as shown in the figure below. Shell explained that the midterm cash potential of "Renewables and Energy Solutions" would be marginal. The author believes that the net income of Renewables and Energy Solutions will be even smaller, since the net income will be the Cash (=Cash Flow) minus depreciation and amortization.

Fig.2.7. Shell's cash potential by business segment

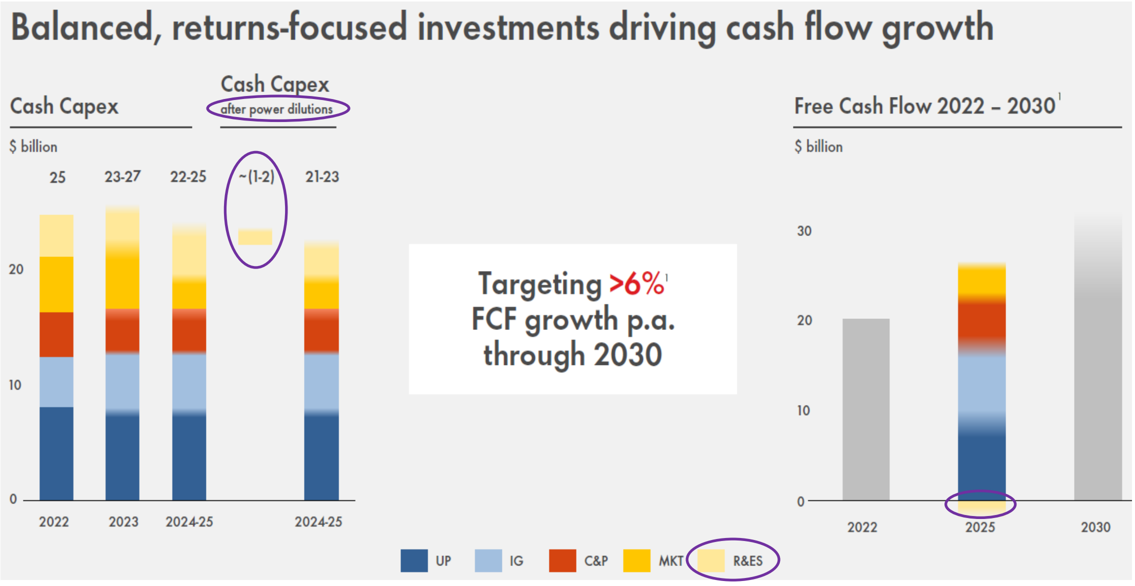


Source: Shell (2021/2), circle added by INPEX Solutions

https://www.shell.com/investors/investor-presentations/2021-investor-presentations/strategy-day-2021.html

With this slight revision to its strategy, Shell said that its future investment plans will be balanced and focused on returns. Specifically, investment in Upstream and Integrated gas in 2024-2025 will be flat from 2022-2023. In Renewable & Energy Solutions, on the other hand, the company is considering a reduction in investment due to the partial sale of the Power business (indicated as "after power dilutions" in the chart below).

Fig.2.8. Shell's Capex plan



Source: Shell (2023/6), circle added by INPEX Solutions

https://www.shell.com/investors/investor-presentations/capital-markets-day-2023.html

Finally, we examine the actual business activities. In its Integrated gas and Upstream businesses, Shell is somewhat more focused on its LNG business. Equity volumes of LNG, which means Shell invest own money into the LNG project, will grow from about 30 million tons per annual, mtpa, in 2022 to about 38 mtpa in 2030 through SELECTIVE investment, such as LNG Canada Train 1-2, NLNG Train 7, Qatar North Field East and South Expansion. And Contracted volume of LNG, which means Shell made agreement to purchase LNG from 3rd party, will grow from about 30 mtpa in 2022 to about 35 mtpa in 2030. On the other hand, Liquids, such as Oil and Natural Gas Liquids, production is expected to remain flat at 1.4 mmboe/d through 2030.

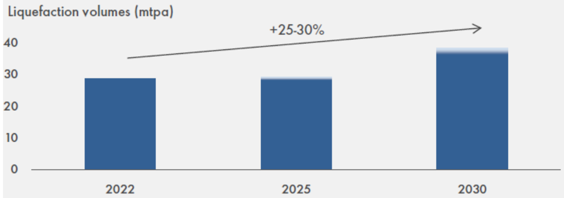
Shell sold its interest in Abadi LNG in 2023, removing Abadi LNG as a candidate for new LNG projects Shell explained that this decision is in line with Shell's focus on disciplined capital allocation.

Fig.2.9. Shell's LNG projects

Integrated Gas and Upstream

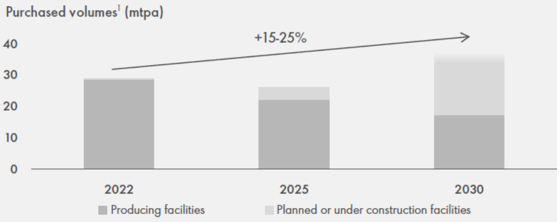
Integrated Gas volumes will grow through end of decade

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

Source: Shell (2023/6)

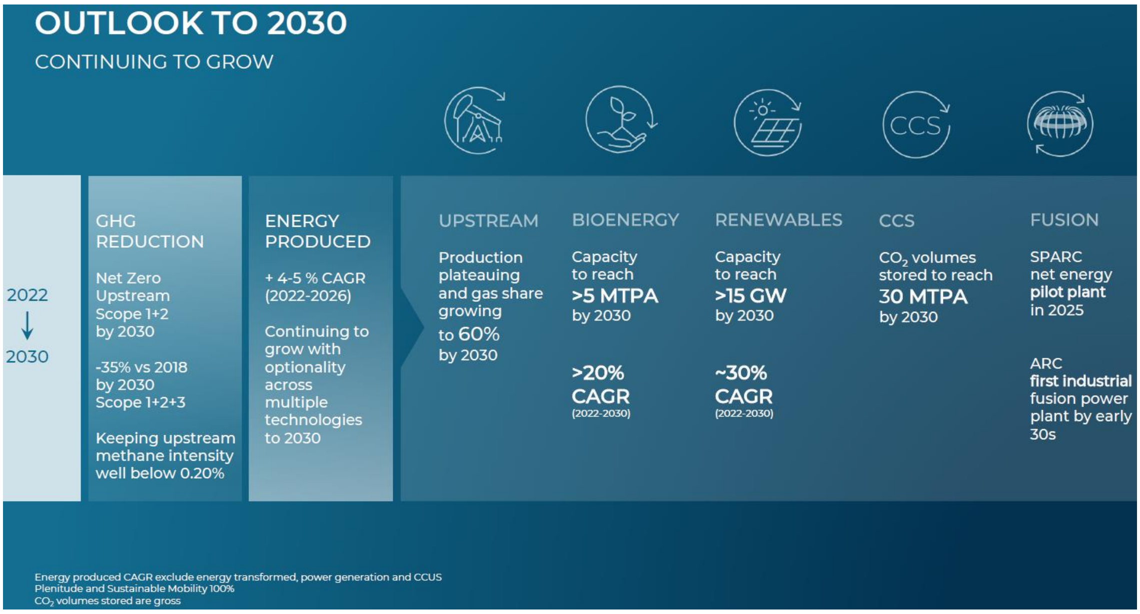
https://www.shell.com/investors/investor-presentations/capital-markets-day-2023.html

3, Eni's Global Strategy

Eni is an Italian multinational company, engaged in oil & gas, refining & gas station, chemical and low carbon energy such as Solar Power, Wind Power etc. Eni is not classified as a "Majors" company, such as Shell and BP, but has a production volume slightly below that of "Majors" and can be classified as a "2nd Tier" company. Eni is expanding its oil and gas business in Indonesia, for details, see Chapter 3.

Eni had also announced an ambitious and aggressive decarbonization and Energy Transition strategy. Specifically, Net Zero GHG (Greenhouse Gases) of Upstream Scope1+2 by 2030, by using CCS (Carbon Capture and Storage) of 30 MTPA (million tons per annual) by 2030 and so on. Secondly, Renewables, such as Solar and Wind power generation, capacity to reach >15 GW by 2030. And Eni targets to achieve Bioenergy's capacity of >5 MTPA by 2030.

Fig.2.10. Eni's outlook to 2030



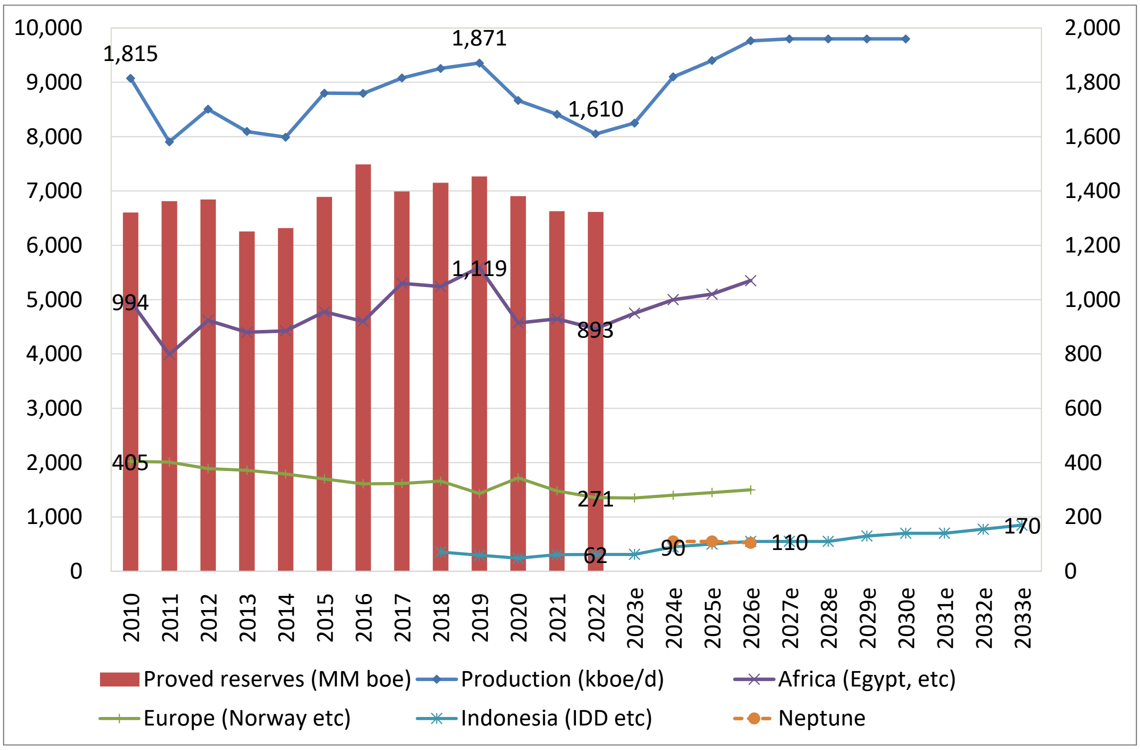
Source: Eni (2023/2)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/2023-capital-markets-update/2023-Capital-Markets-Update-presentation.pdf

Eni has stated that it will expand its Renewables and Bioenergy businesses. However, in 2021 and 2022, about 95% of the company's net income will come from E&P and LNG. Therefore, the author believes that the 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, then plateau until 2030, and increase the gas share (gas as a percentage of total production) to 60% by 2030. The ambitious and aggressive decarbonization and Energy Transition strategy announced does not mean that oil and gas production will be reduced in the foreseeable future.

Fig.2.11. Eni's oil & gas production (right axis) and proved reserves (left axis)



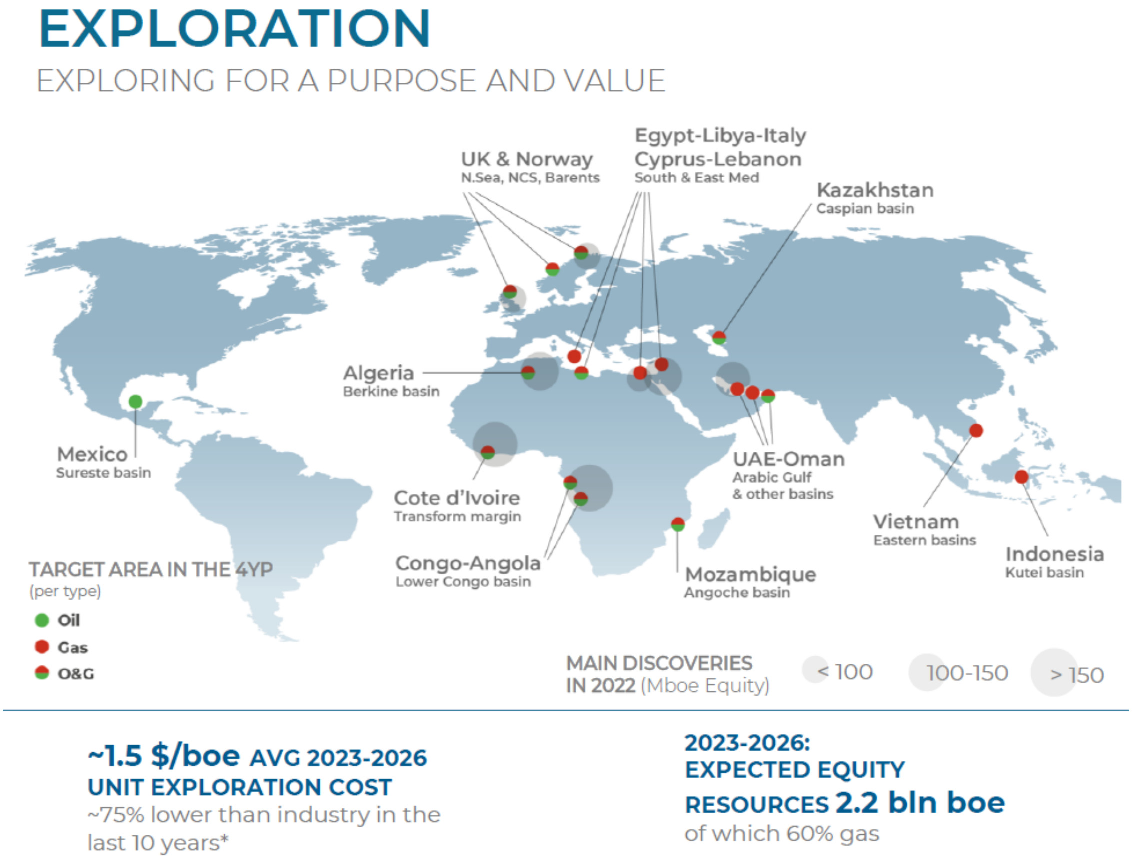
Source: INPEX Solutions

Eni's strength is in oil and gas exploration, with particular in 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, which will be discussed in more detail in the next chapter.

On the other hand, the author believes that the weakness of Eni's oil and gas business may be that its production areas are a little too dispersed around the world. Eni's producing countries include Italy, Norway, Algeria, Libya, Egypt, Angola, Congo, Nigeria, Kazakhstan, Indonesia, UAE, the United States, and Venezuela. The author believes that the area where Eni does E&P business is a little too dispersed out, probably because Eni has strength in exploration and has made many discoveries in exploration in new areas.

Therefore, Eni merged its Angolan and Norwegian E&P operations with other companies operating E&P businesses in the same region, making them equity method subsidiaries of Eni. The businesses in each area have been able to scale up and operate independently through this means.

Fig.2.12. Eni's oil & gas business area



Source: Eni (2023/2)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/2023-capital-markets-update/2023-Capital-Markets-Update-presentation.pdf

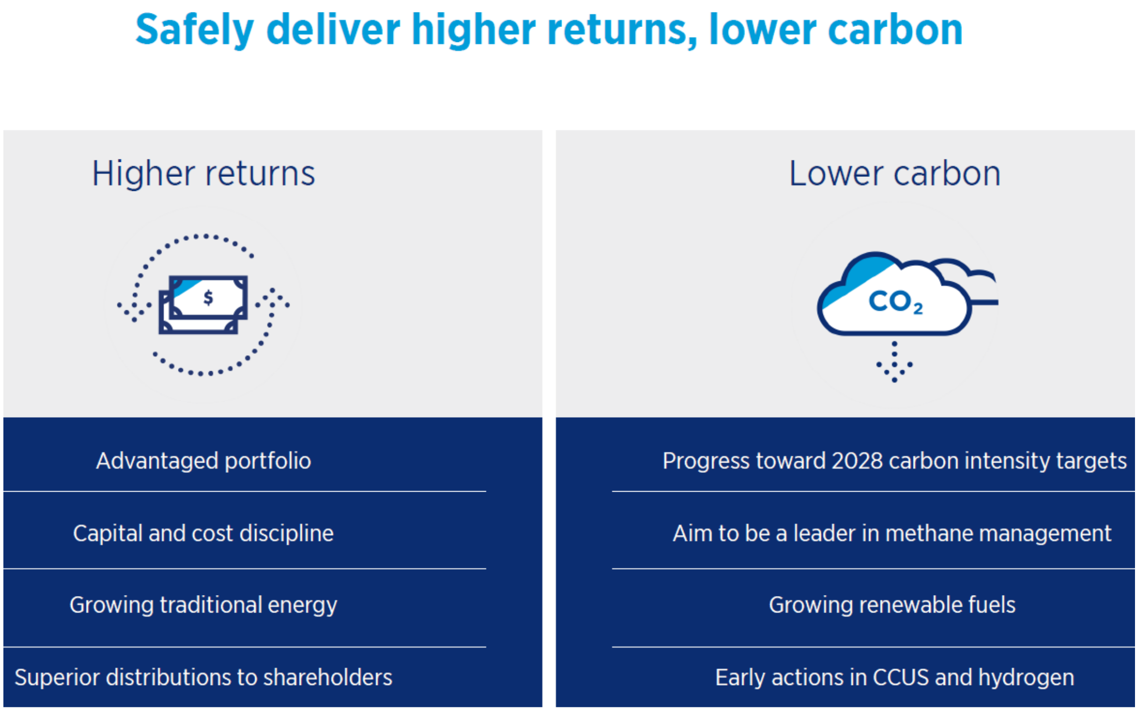
4, Chevron's Global Strategy

Having looked at European companies so far, we now move on to U.S.-based companies. Chevron is American multinational company, engaged in oil & gas, refining & gas station, and recently focus on U.S. shale upstream business, including Permian basin, is a feature and a strength. Chevron sold its interest in the IDD project in Indonesia to Eni in July 2023, exiting the Indonesian oil and gas business, for details, see Chapter 3.

Chevron's global strategy is titled HIGHER RETURNS & LOWER CARBONS. As for higher returns, Chevron is advancing its oil and gas business portfolio, i.e., strengthening its 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.

As lower carbon, Chevron is reducing GHG emissions intensity from upstream by reducing methane emissions, among other things. On the business side, Chevron is involved in renewable fuels such as biofuels and also considering hydrogen and CCS. On the other hand, Chevron is not in the Solar or Wind power generation business, as it does not have differentiated strengths of its own.

Fig.2.13. Chevron's overall strategy



Source: Chevron (2023/2)

https://www.chevron.com/investors/events-presentations

Chevron is active in mergers and acquisitions of oil and gas companies. In May 2023, Chevron announced to acquire PDC energy in an all-stock transaction, M&A in exchange for Chevron's issuance of new shares, valued at $6.3 billion. By this acquisition, Chevron could increase production volume of DJ (Denver Julesburg) basin, one of the major U.S. shale plays, from 150 thousand barrels oil equivalent per day (kboe/d) to 350 kboe/d and it will grow to 400 kboe/d in 2027.

In October 2023, Chevron announced to acquire Hess Corporation in an all-stock transaction valued at $53 billion, this is a big deal. Main purpose of this acquisition may be to acquire Guyana, world-class asset. Chevron already had exploration block in Suriname, which is next to

Guyana, so by this deal Chevron could strengthen Gayana/Suriname area.

Fig.2.14. Chevron's M&A with Hess

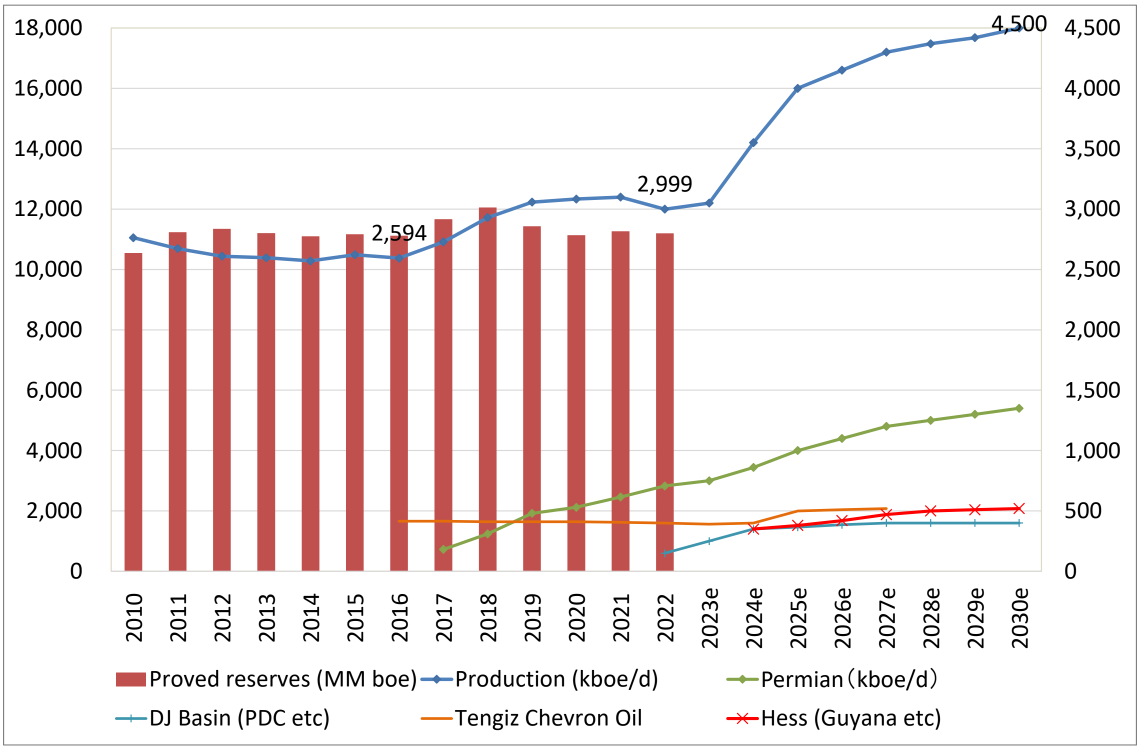
Source: Chevron (2023/10)

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 mmboe/d in 2022 to 4.5 mmboe/d in 2030. Chevron's production has hovered between 2.5 mmboe/d and 3 mmboe/d for the past 20 years, so the production expansion outlook is a very significant change.

As shown in the chart below, Chevron has large core areas of 500 kboe/d to 1,500 kboe/d each, including the US shales Permian and DJ Basin, the Tengiz project in Kazakhstan, and Guyana, which it will acquire through the Hess acquisition. In this way, Chevron is strengthening its efforts by selecting promising core areas. As discussed in the next chapter, Chevron withdrew from the Indonesian E&P business, and the author believes that this was because Indonesia did not fall under Chevron's core area.

Fig.2.15. Chevron's oil & gas production (right axis) and proved reserves (left axis)



Source: INPEX Solutions

5, ConocoPhillips's Global Strategy

ConocoPhillips is an American multinational corporation engaged in oil & gas exploration and production. ConocoPhillips is not "Majors", such as ExxonMobil and Chevron, but has a production volume slightly below that of "Majors" and can be classified as a "2nd Tier" company. ConocoPhillips is not currently in the oil refining and gas station business, as it has sold those businesses in the past. In recent years, ConocoPhillips has been focusing on the U.S. shale business, mainly in the Permian basin. ConocoPhillips divested its interest of Indonesian oil & gas asset, for details, see Chapter 3.

ConocoPhillips mandate to raise Competitive Returns by striving to supply energy in line with the actual Energy Transition, while maintaining Net Zero ambitions. ConocoPhillips is focused on returns, commitment to disciplined investment, based on cost of supply analysis of each asset. As a results, ConocoPhillips has strong track record of active oil & gas portfolio management.

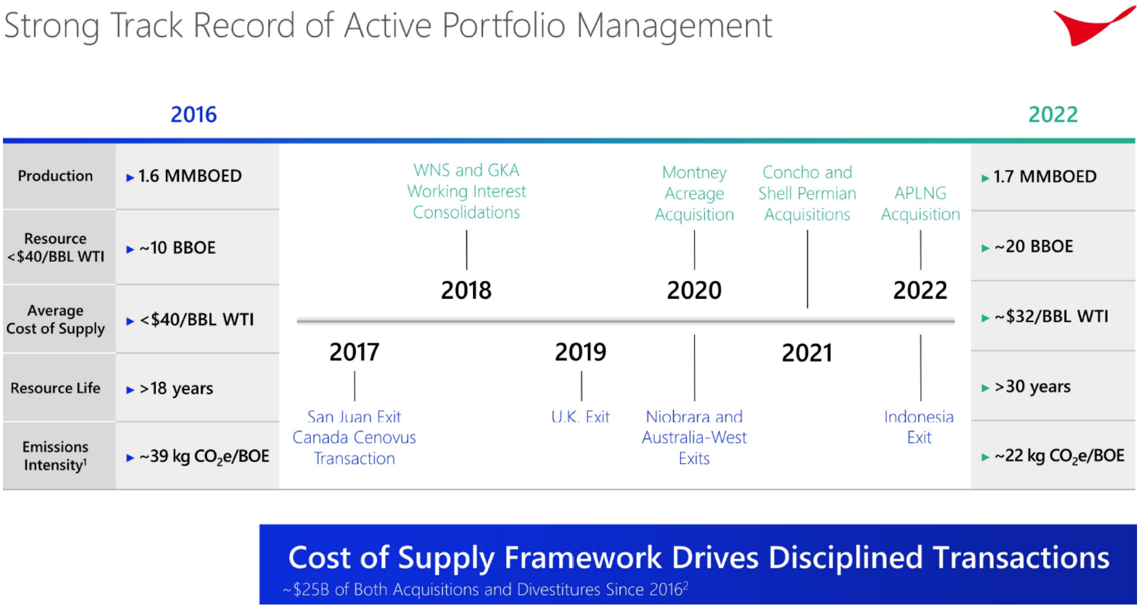
Fig.2.16. ConocoPhillips' overall strategy

Source: ConocoPhillips (2023/4)

https://www.conocophillips.com/investor-relations/investor-presentations/

Regarding this portfolio management, ConocoPhillips divested and exited U.K. upstream in 2019 and Australia-West assets in 2020. On the other hand, ConocoPhillips acquired Concho, U.S. Shale company mainly in Permian basin, and Shell's Permian basin assets in 2021. By these transactions, ConocoPhillips is shifting more focus on its core area, U.S. Shale business. In 2022, ConocoPhillips divested its interest of Corridor, Indonesian gas asset. On the other hand, ConocoPhillips increased its interest of APLNG (Australia Pacific LNG). This means that ConocoPhillips preferred APLNG than Corridor.

Fig.2.17. ConocoPhillips's active portfolio management of oil & gas



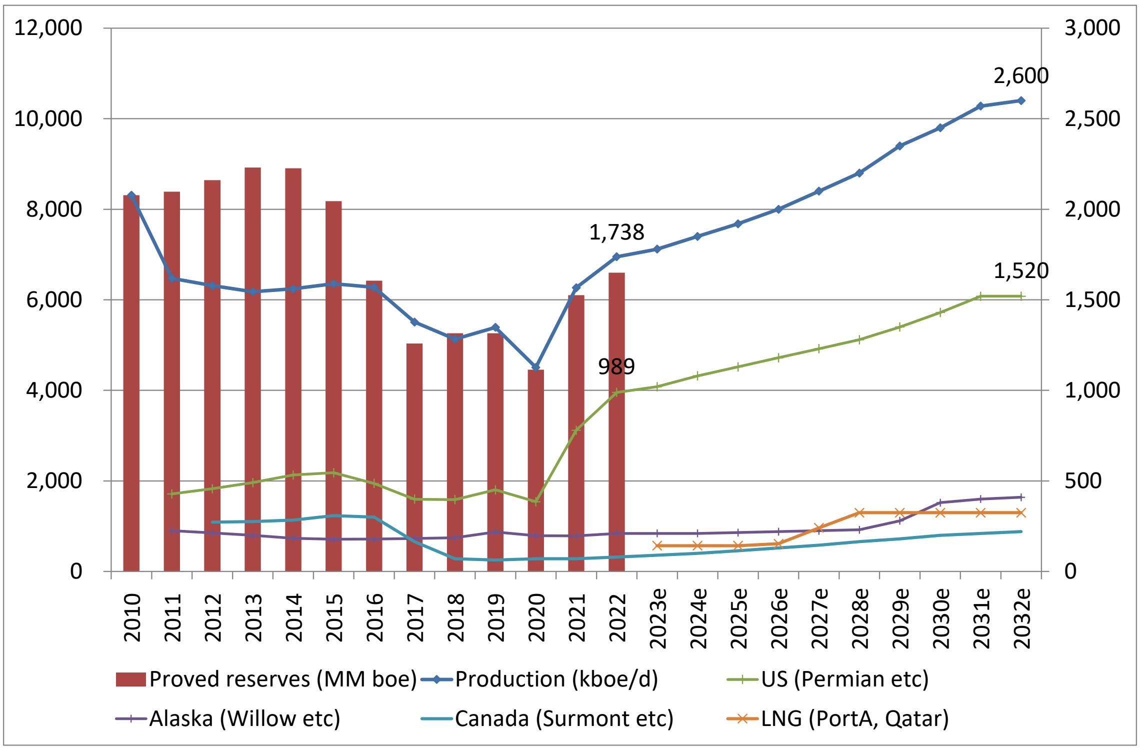
Source: ConocoPhillips (2023/4)

https://www.conocophillips.com/investor-relations/investor-presentations/

Overall, with these transactions, ConocoPhillips' upstream portfolio has focused on following 4 areas, U.S. Shale such as Permian, Alaska such as Willow project, Canada such as Surmont oil sand and Montney Shale, and LNG such as APLNG, Port Arthur LNG and Qatar LNG. By these 4 areas, ConocoPhillips plans to increase oil & gas production volume from 1.7 mmboe/d in 2022 to 2.6 mmboe/d in 2032, this is a significant growth.

Since ConocoPhillips is concentrating on these four core areas, the author believes that it is unlikely to return to the Indonesian E&P business once it has withdrawn.

Fig.2.18. ConocoPhillips's oil & gas production (right axis) and proved reserves (left axis)



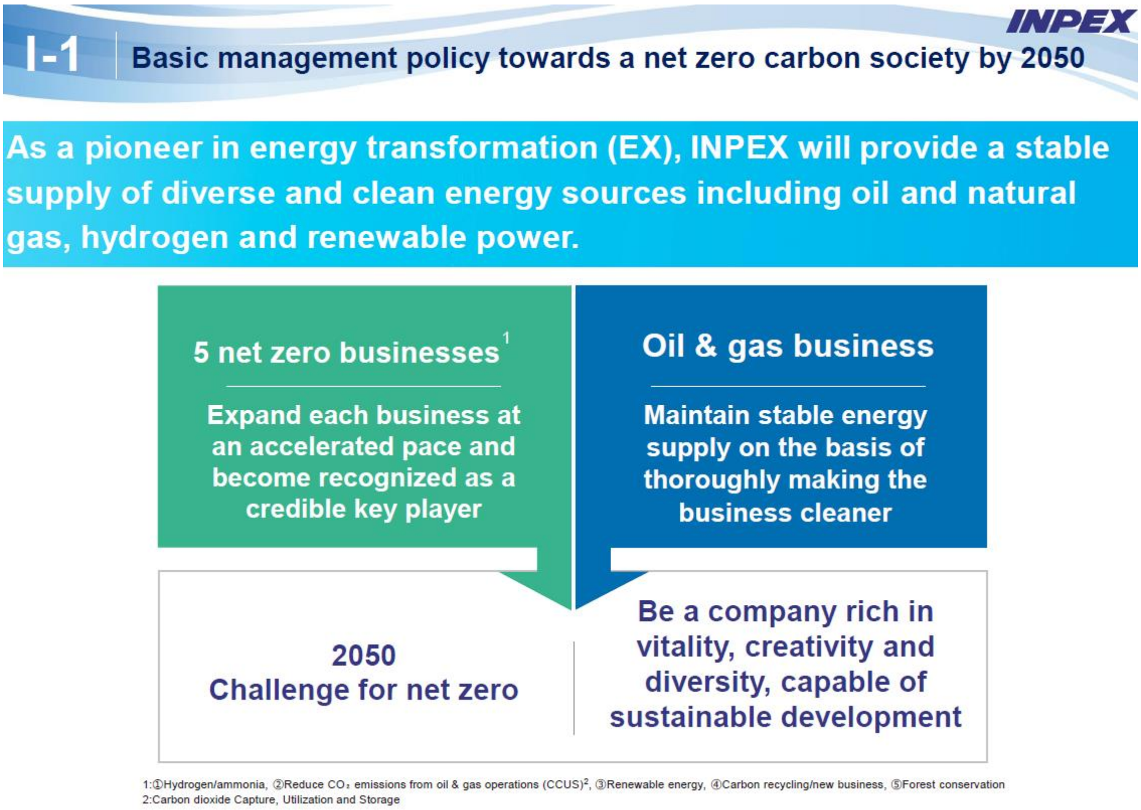
Source: INPEX Solutions

6, INPEX's Global Strategy

INPEX is a Japanese multinational corporation engaged in oil & gas exploration and production, its marketing and net zero businesses, such as Geothermal, Solar and Wind power. INPEX is not "Majors", such as ExxonMobil and Shell. And INPEX's oil and gas production is less than ConocoPhillips and Eni.

In February 2022, INPEX announced "INPEX Vision @2022" which include Long-term Strategy and Medium-term Business Plan. As a basic management policy towards a net zero carbon society by 2050, INPEX will provide not only stable supply of Oil & gas but also "5 net zero" businesses.

Fig.2.19. INPEX's basic management policy towards a net zero carbon society by 2050

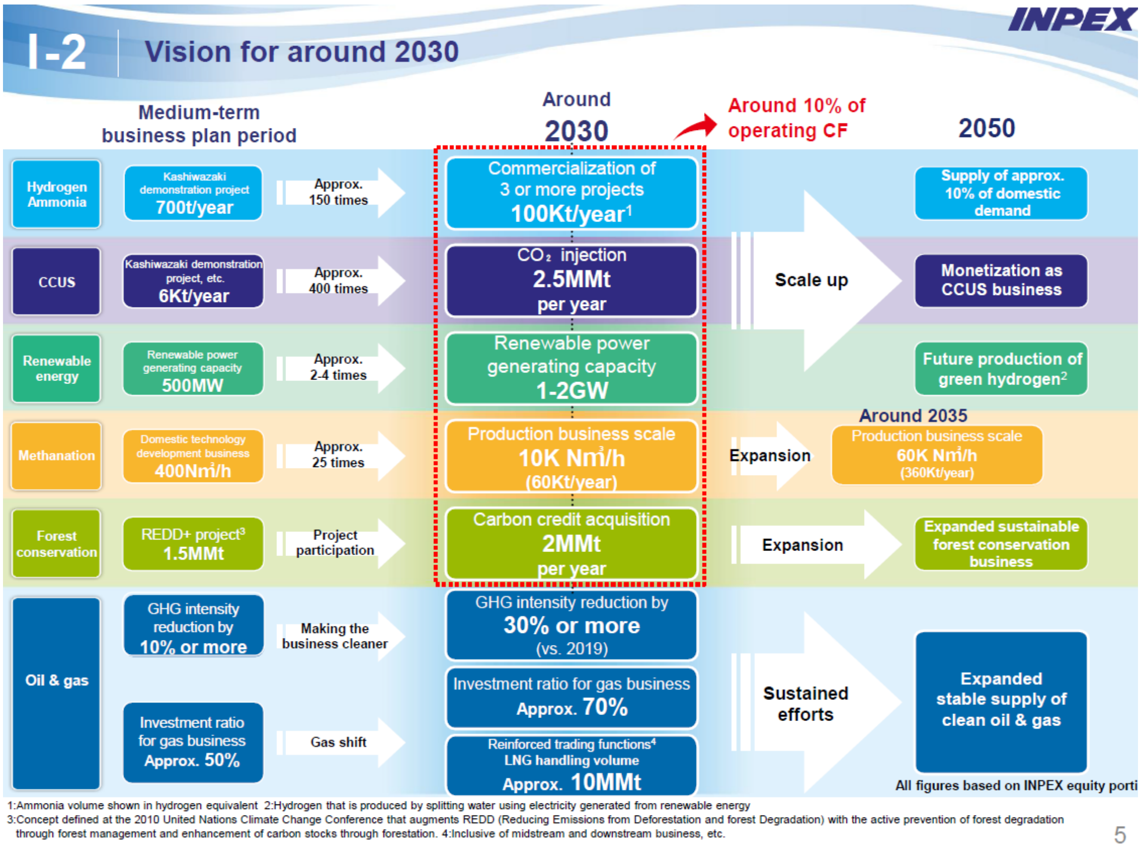


Source: INPEX (2022/2)

https://www.inpex.co.jp/english/company/pdf/inpex_vision_2022.pdf

Regarding this "5 net zero" businesses, INPEX is engaging in Hydrogen & Ammonia, CCUS, Renewable energy, Methanation and Forest conservation, and target around 10% of operating cash flow in 2030. In terms of actual business activities, demonstrative production facility in Niigata, Japan, and some feasibility study in overseas in hydrogen and ammonia business area. In CCUS business area, targeting implementation of CCS at Ichthys LNG in Australia, and 2 Japanese CCS projects ideas are passed screening process by JOGMEC. And in Renewable Energy, INPEX acquired some stakes of geothermal power projects in Indonesia, and some shares of European Wind farm projects.

Fig.2.20. INPEX's Vision for around 2030



Source: INPEX (2022/2)

https://www.inpex.co.jp/english/company/pdf/inpex_vision_2022.pdf

In oil & gas business, but also in "5 net zero" business, INPEX focus on "5 core business areas", namely, Japan, Australia, Southeast Asia including Indonesia, Abu Dhabi and Europe, and improve efficiency by centralizing business assets in these areas.

Australia, especially Ichthys LNG project, is the biggest source of net income. INPEX accelerate involvement and development at nearby exploration and discovered assets and further ensure long-term production volume maintenance. INPEX also implement appraisal well drilling and evaluation work towards conducting Ichthys CCS.

In Abu Dhabi, INPEX and its partners are trying to increase production capacity across all producing assets including Abu Dhabi Onshore concession (to 2 mmb/d), Upper Zakum (to 1 mmb/d), Lower Zakum (to 0.45 mmb/d) and Satah, Umm Al Dalkh (to 0.045 mmb/d). INPEX is pursuing clean ammonia and hydrogen business opportunities.

In Southeast Asia, INPEX is aiming to reach Final Investment Decision (FID) of Indonesian Abadi LNG project in the second half of the 2020s. The author believes this may be the biggest issue for INPEX. We will discuss this in more detail in Chapter 3.

In Japan, INPEX owns the Minami-Nagaoka gas field, the Naoetsu LNG receiving terminal and related natural gas trunk pipeline network. INPEX is using these facilities as sites for demonstration tests of methanation, CCUS and other technologies.

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

Fig.2.21. INPEX's core business areas

Source: INPEX (2022/2)

https://www.inpex.co.jp/english/company/pdf/inpex_vision_2022.pdf

7, Summary of IOCs' global strategy

As summarized in the chart below, in Chapter 2 we discussed the global strategies of BP, Shell, Eni, Chevron, ConocoPhillips, and INPEX. The author believes there are two key points.

First, in light of the energy crisis that has occurred, European IOCs have raised their oil and gas production targets somewhat, while U.S.-based IOCs have also engaged in M&A 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 (somewhat) raised their production targets, Shell, Chevron, and ConocoPhillips exited the E&P business in Indonesia. This is because the companies are focusing on core areas and adhering to investment discipline. On the other hand, Eni and INPEX are trying to develop new projects in Indonesia. In the next section we will discuss in detail the E&P business of each company in Indonesia.

Fig.2.22. IOC's global strategy

BP	Revise up oil & gas production target in light of the energy crisis. New oil & projcts including Indonesian Tangguh UCC.
Shell	Contineu to proudly deliver oil & gas that the world needs. Selectively investing in LNG Canada, Qatar LNG Expansion etc. Sold interes of Abadi LNG in Indonesia.
Eni	Oil & Gas produciton growth of 3-4% per year in 2022-2026. Net zero emission of Upstream Scope 1+2 by 2030. CCS and Nature based solution is important.
Chevron	Significant Oil & Gas produciton growth by Permian and M&A. Focus on core areas. Exited Indonesia E&P.
ConocoPhillips	Significant Oil & Gas produciton growth by Permian etc. Focus on core areas. Exited Indonesia E&P.
INPEX	5 Net zero business including CCUS, Hydrogen etc. 5 Core areas such as Southeast Asia including Indonesia.

Source: INPEX Solutions.

Chapter 3

International Oil Companies' oil and gas business activities in Indonesia

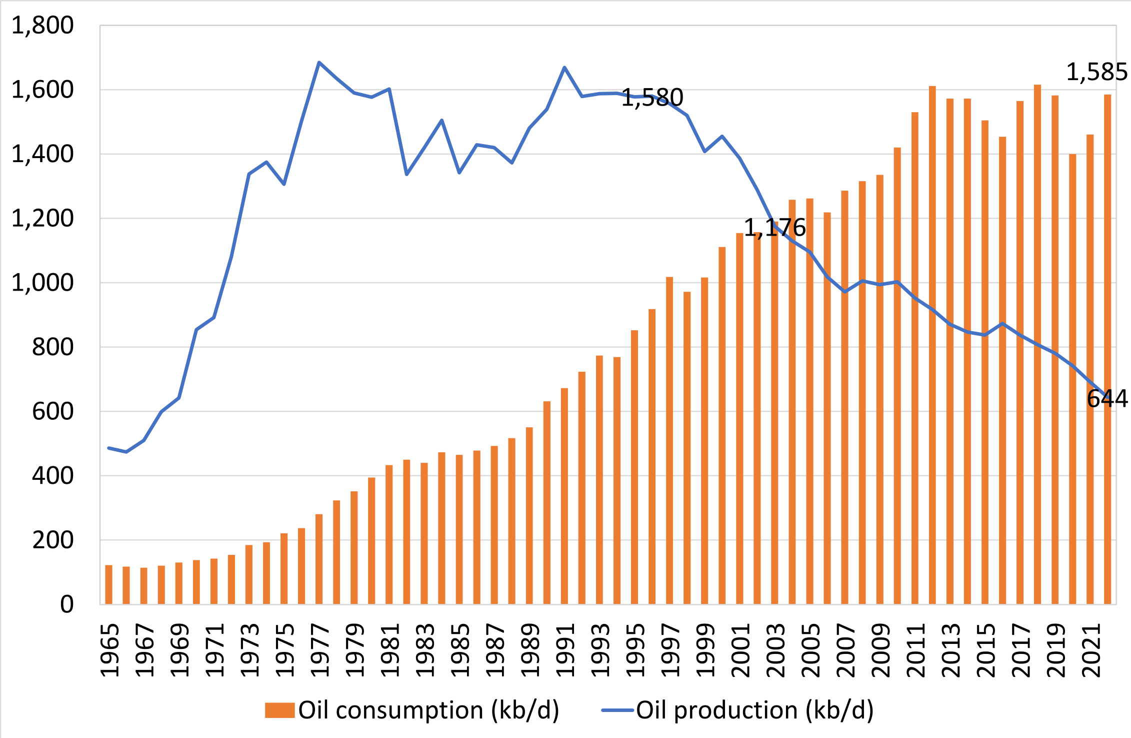
We discussed Global Energy Situation such as decarbonization and Energy Crisis in Chapter 1, and International Oil Companies' (IOC's) Global Strategy in Chapter 2. Based on this information, in Chapter 3, we examine IOC's oil and gas business activities in Indonesia, one of the major Oil and Gas producing country in ASEAN. In light of the energy crisis, many IOCs have increased their oil and gas activities, among which Chevron, ConocoPhillips, and Shell have withdrawn from the E&P business in Indonesia. This is to focus more on the core areas of each company with an emphasis on profitability, and the author believes that it is unlikely that they will return to E&P activities in Indonesia again. On the other hand, Eni and INPEX are trying to develop new projects in Indonesia, and it's important to make it a win-win situation for them and the Indonesian government.

1, Trends in Indonesia's oil and gas production

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

Indonesian government has set the target to achieve oil production of 1 million barrels per day (mboe/d) by 2030. To achieve this target, Indonesia government needs to increase oil production 1.55 times in 8 years from 644 kboe/d in 2022.

Fig.3.1. Indonesia's Oil production and consumption (kboe/d)



Source: INPEX Solutions based on Statistical Review of World Energy 2023 (2023/6)

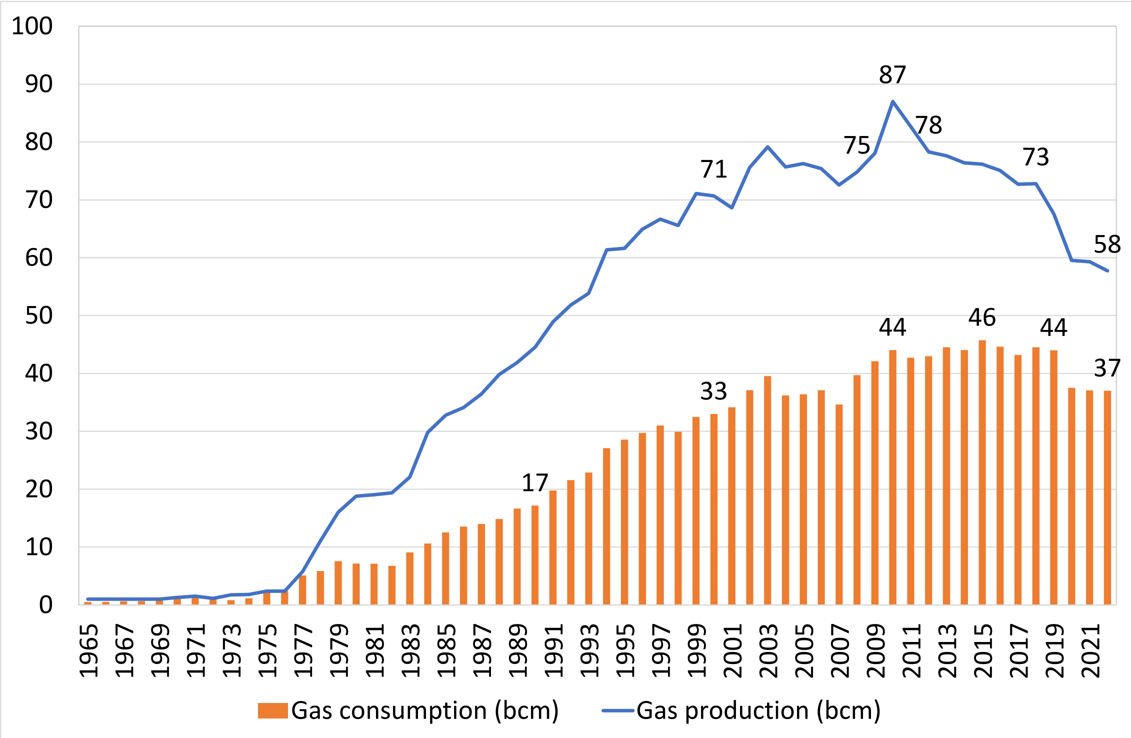
After increasing from the 1980s to the 1990s, Indonesia's gas production remained at a high level of about 70-80 bcm/year from 2000 to 2018. One of the projects that contributed to this is Tangguh LNG Train 1-2, which started production in 2009 and continues to produce about 12 bcm/year. Additionally, Tangguh LNG Train 3 stared operation in October 2023. However, after 2019, Indonesia's gas production declined and was 58 bcm in 2022. The author believes that one of the reasons for this decline is Mahakam, which was one of the largest gas production fields for a long time but matured and declining recently, and other small gas field's production is declining too.

As explained later some IOCs have exited Indonesian E&P business, and one of the reasons is that Indonesian Oil and Gas production is declining because of limited reserves and new exploration findings.

Gas consumption in Indonesia continued to increase in the 1990s and 2000s, remained flat in the 2010s and declined after 2020 to 37 bcm in 2022. The author believes that the reason for this slowdown in gas consumption, in addition to the impact of the COVID-19, is due to the slowdown in Indonesian domestic gas "production". 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 is an increase in the consumption of domestically produced coal.

Indonesia government has set the 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, Indonesia government needs to increase natural gas production 2.11 times in 8 years from 58 bcm in 2022.

Fig.3.2. Indonesia's gas production and consumption (bcm)



Source: INPEX Solutions based on Statistical Review of World Energy 2023 (2023/6)

2, Major oil and gas assets in Indonesia

Indonesia's major oil fields are Rokan on Sumatra Island and Cepu on Java Island, which together account for about half of total domestic oil production of 644 kboe/d. Rokan was a huge oil field from the 1960s to the 1990s, but production has generally continued to decline since 2000, and is likely to decline further in the future. Chevron has been the operator of Rokan for many years, but in August 2021, Pertamina took over the stakes and became the operator. Cepu is relatively newer than Rokan, and its production ramped up in the 2010s and will remain high production level for a few more years, but after which production is likely to decline. Cepu is operated by ExxonMobil with 45% stakes and its partner is Pertamina with 45% stakes.

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

Fig.3.3. Map of major oil and gas fields in Indonesia

Note: Gas pipeline (red line), Gas field (red circle), Oil field (green circle), LNG receiving termina in operation (green hexagon), LNG receiving terminal in plan (pink hexagon), LNG liquefaction terminal in operation (blue star), LNG liquefaction terminal in plan (pink star).

Source: JOGMEC (2022/2), some additions by the INPEX Solutions

https://oilgas-info.jogmec.go.jp/seminar_docs/1009240/1009273.html

Fig.3.4. Explanation of oil and gas fields in Indonesia

	Field name	Description	Operator etc
Oil	Rokan	It was huge oil field from 1960s to 1990s but production is declining since 2000	Chevron → Pertamina (2021-)
	Cepu	production ramped up in the 2010s	ExxonMobil
Gas LNG	Tangguh LNG Train 1 -3	About 19 bcm annually	BP
	Corridor	likely to continue production decline	ConocoPhillips → Medco (2022)
	Mahakam (Bontang LNG)	likely to continue production decline	Total, INPEX →Pertamina (2018-)
	Donggi Senoro LNG	About 3 bcm annually	Mitsubishi
New Gas LNG	IDD	Indonesia Deepwater Development	Chevron → Eni (2023-)
	Abadi LNG	Revised development plan approved in 2023	INPEX
	Geng North	Discovered in 2023	Eni

Source: INPEX Solutions

3, Some IOCs have exited Indonesian E&P business

As shown in the table below, some IOCs have exited Indonesian E&P business. For example, Chevron could not extend Rokan block's production license and Indonesia's Pertamina took over Rokan block's operations from Chevron in 2021. Chevron had operated the Rokan field for many years, and when the field contract expired in 2021, Chevron applied to the Indonesian government for an extension. However, the Indonesian government rejected Chevron's application and selected Pertamina as the future operator. According to the government, this is because Pertamina offered better economic terms to the Indonesian government than Chevron. Chevron also sold its interest in IDD to Eni in 2023. The author believes this is because Chevron no longer considers Indonesia as a core area due to its failure to renew the Rokan contract. As a result, Chevron withdrew from the Indonesian E&P business.

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

ConocoPhillips sold its interest in Corridor to MedcoEnergi in 2021, exiting the E&P business in Indonesia. At about the same time, ConocoPhillips increased its equity interest in APLNG in Australia. The author believes that ConocoPhillips sold Corridor because Corridor is expected to experience a production decline in the near future so ConocoPhillips preferred APLNG than Corridor.

Shell sold its interest in Abadi to Petronas and Pertamina in 2023, exiting the E&P business in Indonesia. Shell 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 Abadi project have not taken Final Investment Decision, the start of project development, so far.

Thus, Chevron, TotalEnergies, ConocoPhillips, and Shell, the major Western IOCs, have withdrawn from the E&P business in Indonesia. On the other hand, ExxonMobil, BP, and Repsol are continuing their existing E&P projects in Indonesia. Eni and INPEX are about to start new E&P projects. In the next section, we will look at Eni and INPEX individually.

Fig.3.5. Some IOCs have exited Indonesian E&P business, others have not.

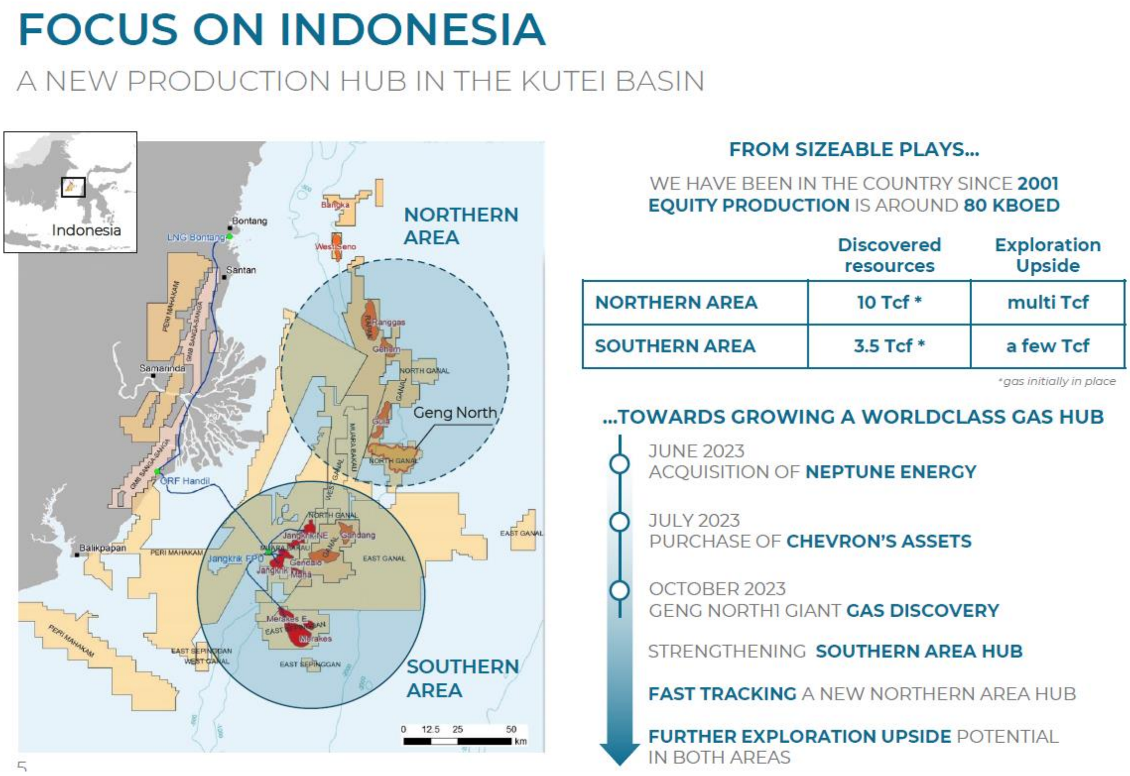
Chevron	Rokan could not extend	IDD divest	Exit
TotalEnergies	Mahakam could not extend		almost Exit
ConocoPhillips		Corridor divest	Exit
Shell		Abadi divest	Exit
ExxonMobil	Cepu		Continuing
BP	Tangguh LNG		Continuing
Repsol	Corridor		Continuing
Eni		IDD Geng North	New project
INPEX	Mahakam could not extend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

Source: INPEX Solutions

4, Eni is expanding its Indonesian E&P business

Eni has been involved in E&P business in Indonesia since 2001, and there were several actions to expand E&P business in Indonesia in 2023. Specifically, in June, Eni announced the acquisition of Neptune Energy, which has several interests in Indonesia. Also in July, Eni acquired Chevron's interests of IDD. In addition, in October, Eni discovered a huge gas resource through exploration in Geng North. All three of these actions are in Indonesia's Kutei Basin, which will allow the company to strengthen its focus on the Basin. As a result, Eni has 10 Tcf, Trillion cubic feets, of discovered gas resources in the Northern Area of the Kutei Basin and 3.5 Tcf in the Southern Area. We will look at each action one by one below.

Fig.3.6. Eni is expanding its Indonesian E&P business.



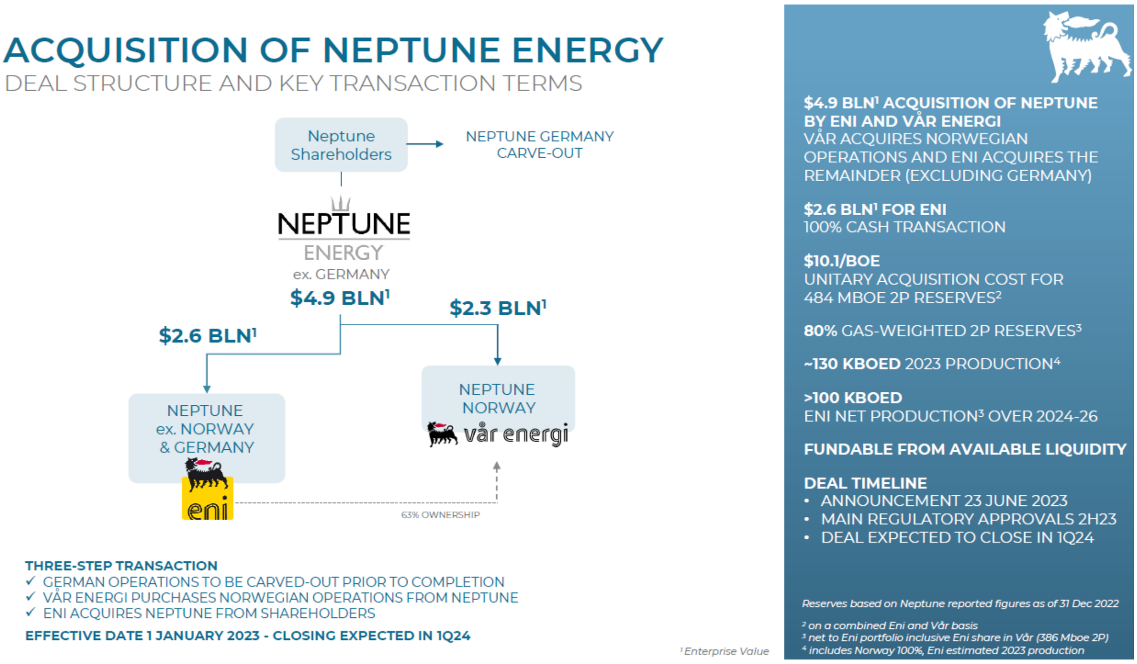
Source: Eni (2023/10)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/third-quarter-2023/third-quarter-2023-results.pdf

Eni acquired Neptune Energy, excluding its German and Norwegian operations, for an Enterprise value of $2.6 Billion. Neptune Energy's Norwegian operations were acquired by Eni's

63%-owned Norwegian subsidiary Var Energi for $2.3 Billion. Thus, Eni also indirectly owns Neptune Energy's Norwegian assets. Note that Eni had merged its Norwegian operations with Point Resources, which is primarily Norwegian-focused, to form Var Energi in 2018. 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.

Fig.3.7. Eni acquired Neptune Energy.

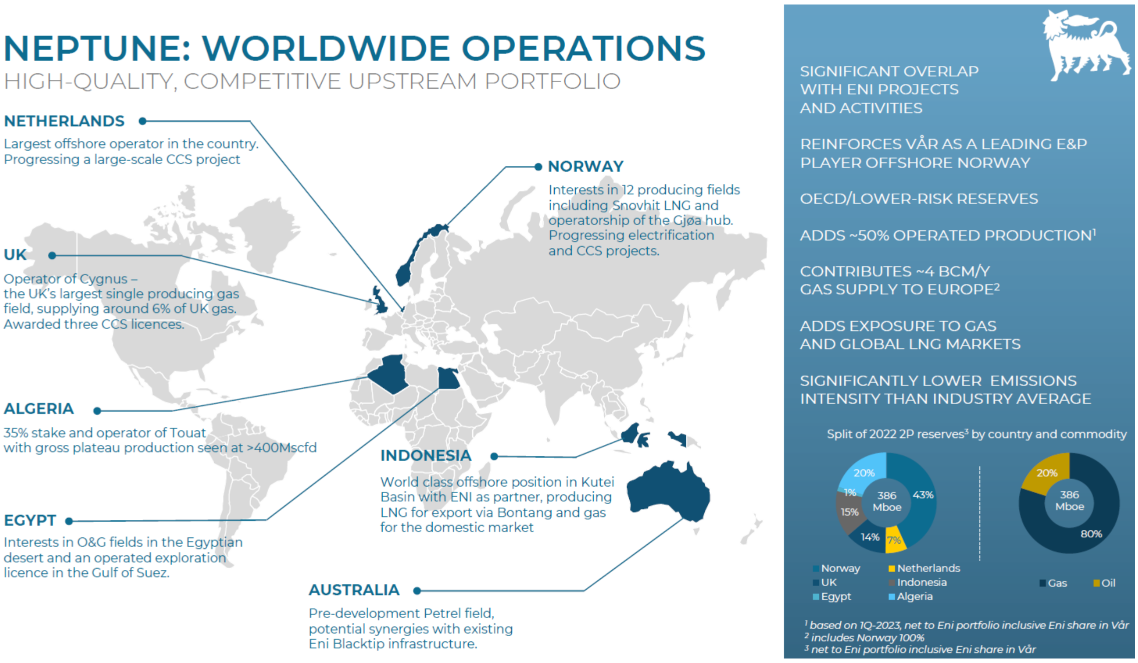


Source: Eni (2023/6)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/23-june-2023/Eni-to-acquire-Neptune-Energy.pdf

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

Fig.3.8. Neptune Energy's worldwide oil & gas assets.



Source: Eni (2023/6)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/23-june-2023/Eni-to-acquire-Neptune-Energy.pdf

In Indonesia, Eni had owned 55% Muara Bakau, 50.22% North Ganal, 40% West Ganal, 70% East Ganal, and 65% East Sepinggan. With the acquisition of Neptune Energy, Eni will acquire Muara Bakau 33.33%, North Ganal 38.04%, West Ganal 30%, East Ganal 30%, and East Sepinggan 20%, total production volume was 22.7 kboe/d in 1Q 2023. Thus, Eni will be able to increase its interests in each of the existing assets.

Fig.3.9. Eni's Indonesian business is strengthened by acquisition of Neptune Energy.

Source: Eni (2023/6)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/23-june-2023/Eni-to-acquire-Neptune-Energy.pdf

Secondly, Eni announced the acquisition of Chevron interests in the Indonesian Blocks named Ganal PSC (Chevron 62%), Rapak PCS (Chevron 62%) and Makassar Straits PSC (Chevron 72%) in the Kutei Basin, offshore East Kalimantan. Eni already had a 20% interest in the Ganal and Rapak Blocks. These are the part of IDD project, Indonesia Deepwater Development, with estimated reserves of approximately 2 Tcf. Eni will increase its interests in each of the blocks and take operatorship by this acquisition.

The IDD project as a whole has yet to make a final investment decision nor development. Therefore, Eni expects that this acquisition will allow Eni to fast track the development of the IDD project, leveraging synergies with Eni-operated Jangkrik infrastructures and the existing Bontang LNG facility, as you can see in the Figure in two pages later.

Fig.3.10. Eni acquired Chevron's assets in Indonesia.

	Ganal PCS	Rapak PSC	Makassar Straits PSC
Chevron	62%	62%	72%
Eni (existing)	20%	20%	0
Eni + Chevron	82%	82%	72%

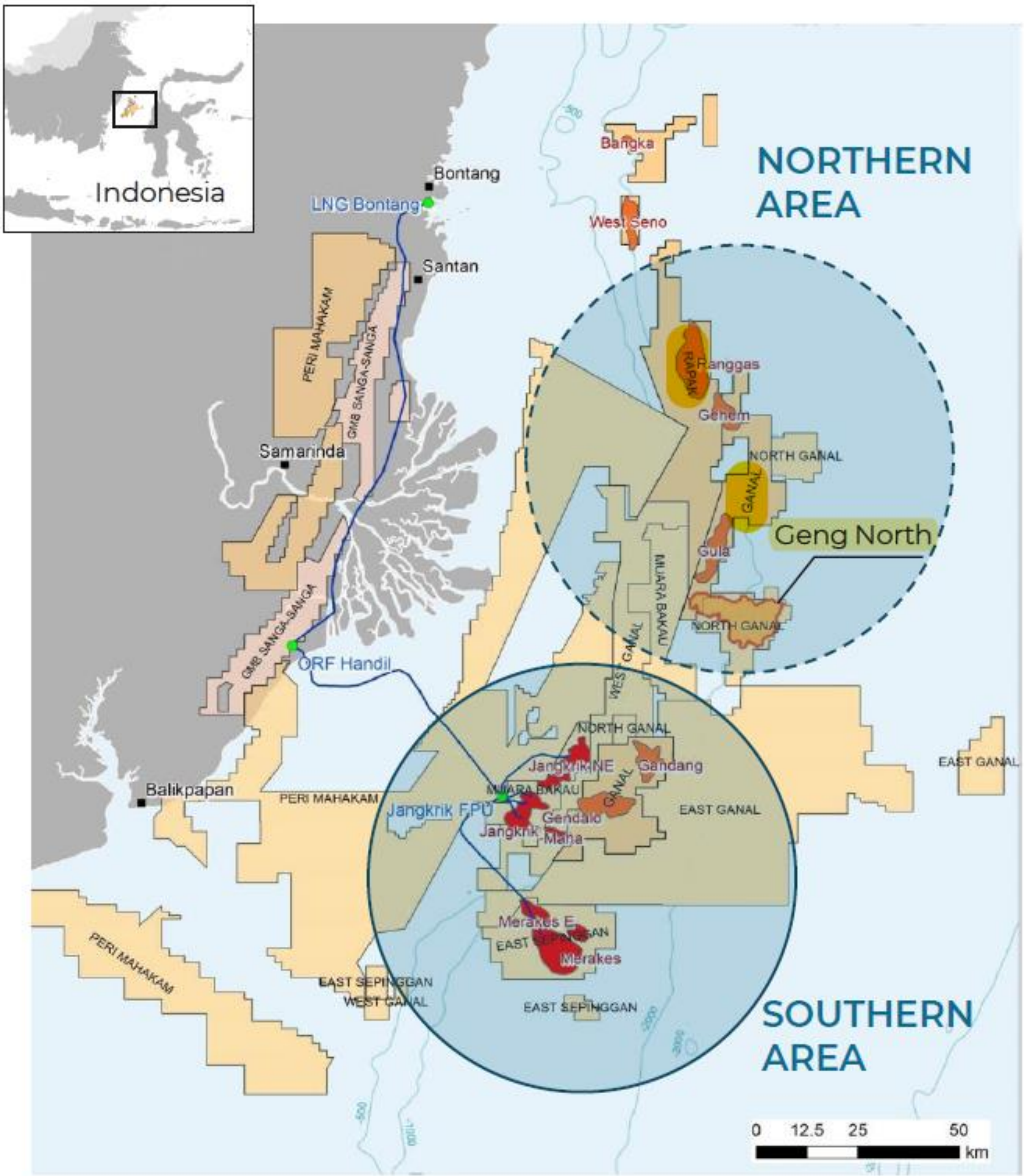
Note: These are part of IDD (Indonesia Deepwater Development)

Note: Estimated natural gas reserves of approximately 2 Tcf

Source: INPEX Solutions

Finally, Eni announced a significant gas discovery from 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 facilities, as you can see in the map below. Also the Geng North discovery is located next to the IDD area, Ganal and Rapak, so significant synergies between the two areas could be expected in terms of gas development options.

Fig.3.11. Eni's oil & gas fields and infrastructure in Indonesia

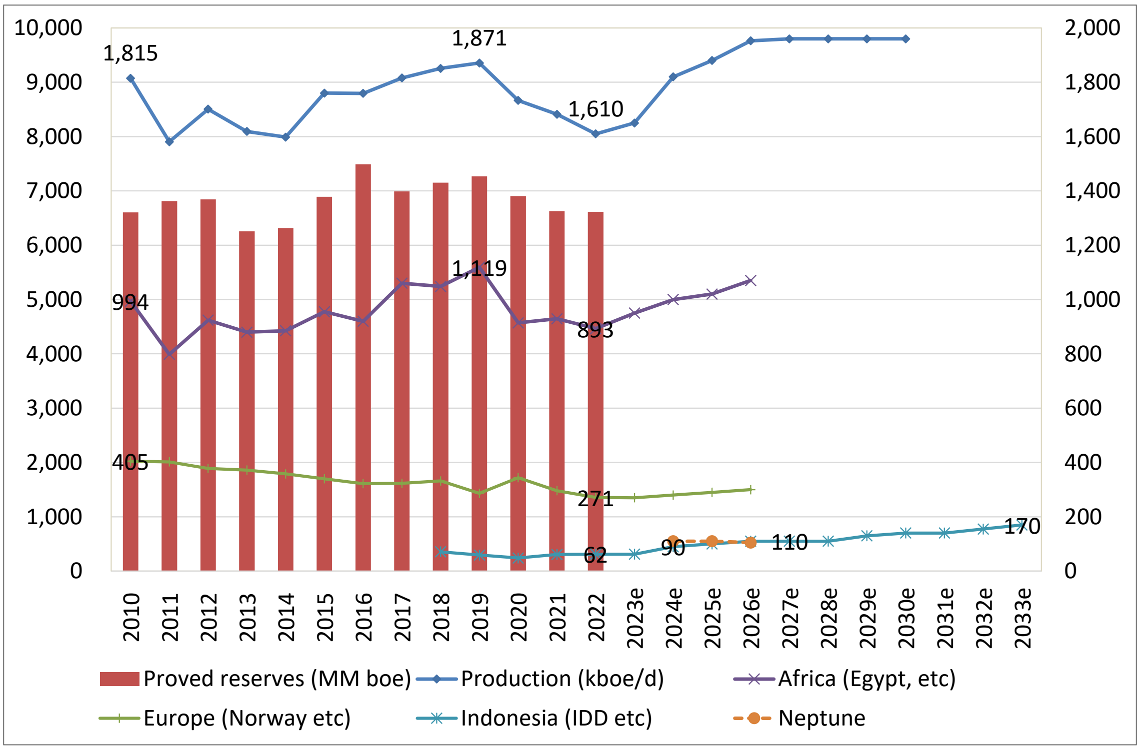


Source: Eni (2023/6)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/23-june-2023/Eni-to-acquire-Neptune-Energy.pdf

Based on the above, we will discuss the percentage of Eni's Indonesian business to Eni's total E&P business and its future potential. Eni's oil & 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, author believes. Eni is progressing new projects, such as Merakes East (15 kboe/d, Eni 65%, Start up in 2025) and Maha (34 kboe/d, Eni 60%, Start up in 2026), so Indonesian production could go up to about 110 kboe/d. How much Eni's production in Indonesia can expand after that time depends on IDD and Geng North, but the author believes it can expand to about 170 kboe/d. That is, at the present time, Indonesia's production accounts for a small 4% of total Eni's total production and may expand to some degree to about 9% around 2033.

Fig.3.12. Eni's oil & gas production (right axis) and proved reserves (left axis)

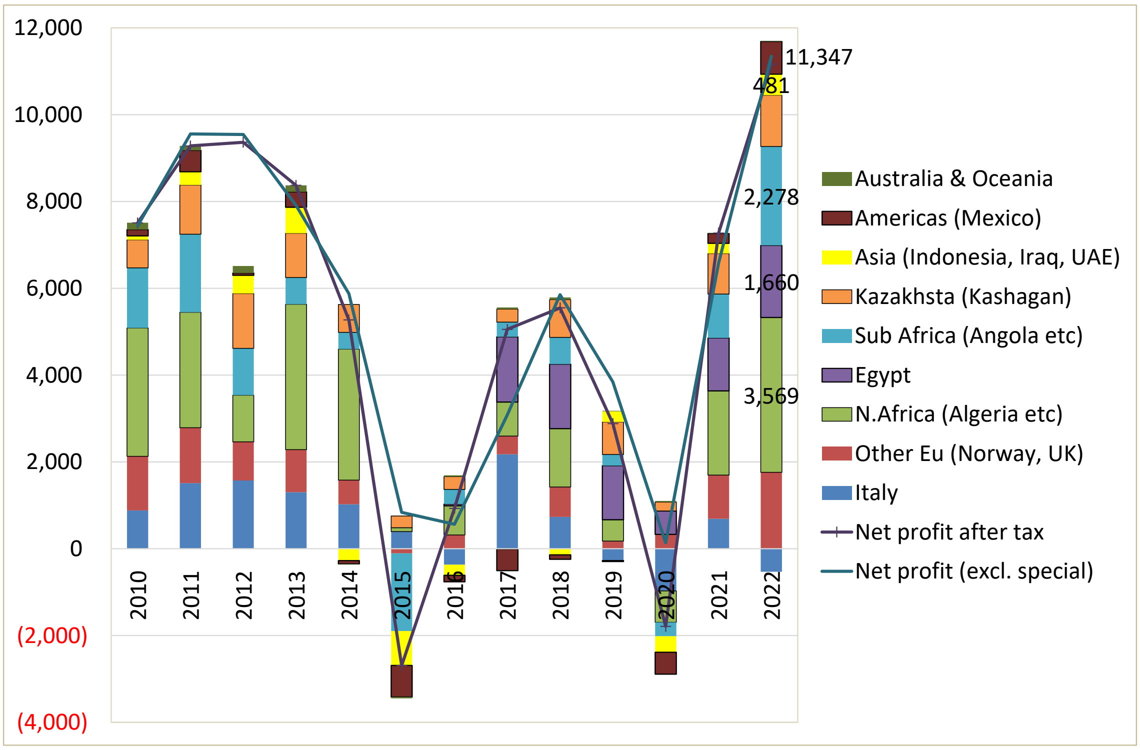


Source: INPEX Solutions

Next, let's look at Eni's net income from its oil and gas business by region, as shown in the figure below. In 2022, "North Africa," consisting of Algeria and Libya, earned US$3.6 billion, "Egypt" earned US$1.7 billion, and "Sub-Saharan Africa," consisting of Angola, Congo, Mozambique, and Nigeria, earned US$2.3 billion. These three together accounted for 66% of the total net income of US$ 11.3 billion, indicating that "Africa" is Eni's core area.

Asia," 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 small as a percentage of total, it is not likely that Indonesia is a core area for Eni in terms of scale. However, if the next gas resource is developed with reasonable profitability, Indonesia will become an important area for Eni.

Fig.3.13. Eni's oil & gas net profit by regions (US$ million)



Source: INPEX Solutions

5, INPEX is working on the Abadi LNG project

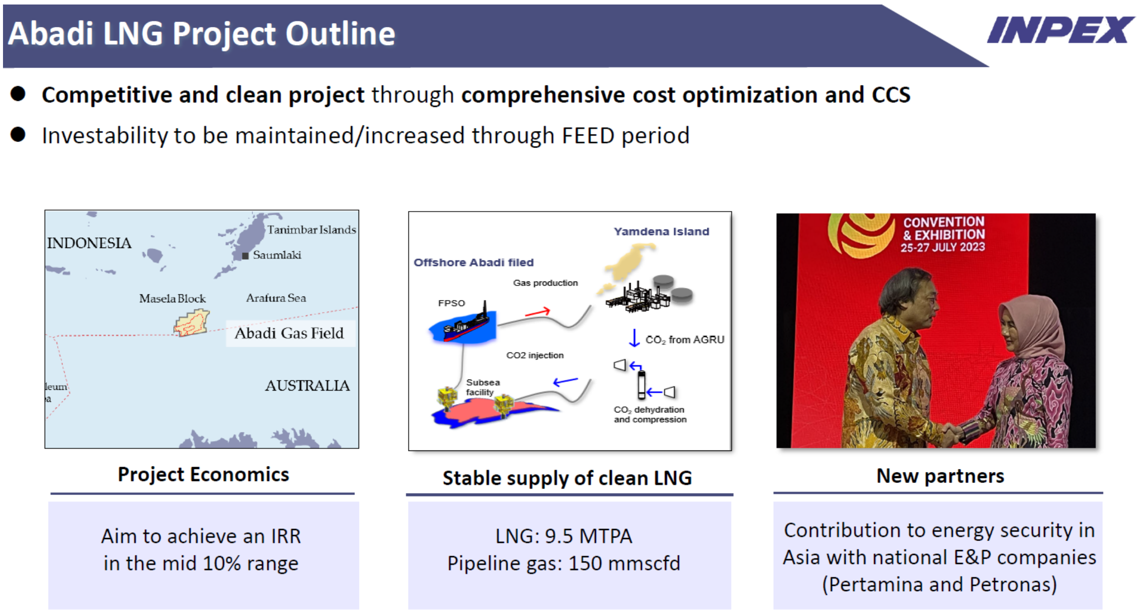
Abadi LNG is a project that has taken a long time to commercialize because a final investment decision (FID) has not yet been made, although gas resources were discovered through exploration in 2000. INPEX acquired a 100% interest in the Masela Block in November 1998 through an open bid conducted by the Indonesian authorities. INPEX 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-FEED work from March to October 2018 based on an onshore LNG development scheme envisaging an annual LNG production capacity of 9.5 million tons. INPEX submitted a revised plan of development in June 2019 and received approval from the Indonesian authorities in July 2019. Alongside the approval of the revised development plan, the Indonesian authorities also approved an extension of the term of the Masela Block Production Sharing Contract (PSC) until 2055.

Detailed survey work in the planned construction site for the LNG plant and its surrounding areas had been underway until it was suspended due to the impact of the COVID-19 pandemic. Subsequently, considering the need to contribute to a net zero carbon society and aspiring to make the project cleaner and more competitive amid energy transition, INPEX has been consulting with the Indonesian authorities on a revised development plan introducing CCS and submitted that plan to the authorities in April 2023. And this revised Plan of Development for the Abadi LNG Project is approved by the Indonesian government authorities in December 2023. With this development plan, INPEX aims to provide a stable supply of clean energy on a large scale with 9.5 million tons of LNG and 150 mmcf/d of pipeline gas.

Indonesia's Pertamina and Malaysia's Petronas are the new partners in the Abadi LNG project. Pertamina and Petronas purchased the shares of Abadi LNG that Shell withdrew when it sold its stake of the project. Pertamina has a very strong presence and experience in oil and gas development in Indonesia and Petronas has experience in LNG operations not only in Malaysia but also globally, so INPEX has been blessed with good partners. Indonesia and Malaysia will have strong demand for LNG in the future, and Abadi LNG can contribute to the stable supply to these energy demand, the author believes.

Project economics is one of the most important factors, and INPEX aims to achieve an IRR (Internal Rate of Return) in the mid 10% range. And not only just aiming, INPEX is actually in discussions with the Indonesian government on project economics in the mid-10% IRR range, and the Indonesian government understands what INPEX is aiming for. What IRR is explained in the next Chapter.

Fig.3.14. Abadi LNG project outline



Source: INPEX (2023/11)

https://www.inpex.co.jp/english/ir/library/pdf/presentation/e-Presentation20231127-a.pdf

Abadi LNG's project development concept consists of SURF (Subsea, Umbilical, Riser and Flowline), FPSO (Floating Production, Storage and Offloading Facility), GEP (Gas Export Pipeline), OLNG (Onshore LNG Plant), and CCS (Carbon Capture and Storage), as shown in the figure below.

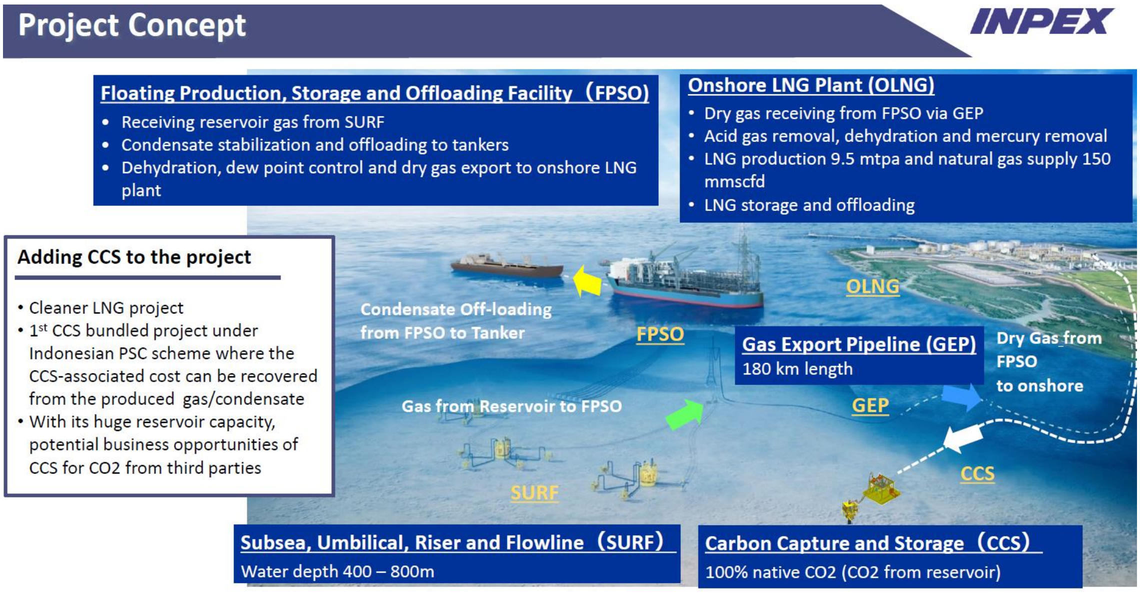
1, The SURF transports gas from a subsea reservoir to the FPSO.

2, FPSO receives reservoir gas from SURF and dehydrate, control the dew point and then export dry gas to onshore LNG plant by Gas Export Pipeline. Reservoir contains not only gas but also condensate, so this condensate is stabilized in FPSO and then offload to tankers.

3, Onshore LNG Plant receives dry gas from FPSO via Gas Export Pipeline and then remove acid gas, dehydrate and remove mercury. This gas is converted into LNG, liquid natural gas, and storage and offload.

4, CCS is added to the project to offset the 100% native CO2 from reservoir. Abadi will be the 1st CCS bundled project under Indonesian PSC, Production Sharing Contract, scheme where the CCS-associated cost can be recovered from the produced gas and condensate. For a supplementary explanation, PSC scheme is a type of upstream oil and natural gas development contract between oil-producing countries and E&P companies. Additionally, with its huge reservoir capacity, INPEX is considering potential business opportunities of CCS for CO2 from third parties.

Fig.3.15. Abadi LNG project development concept



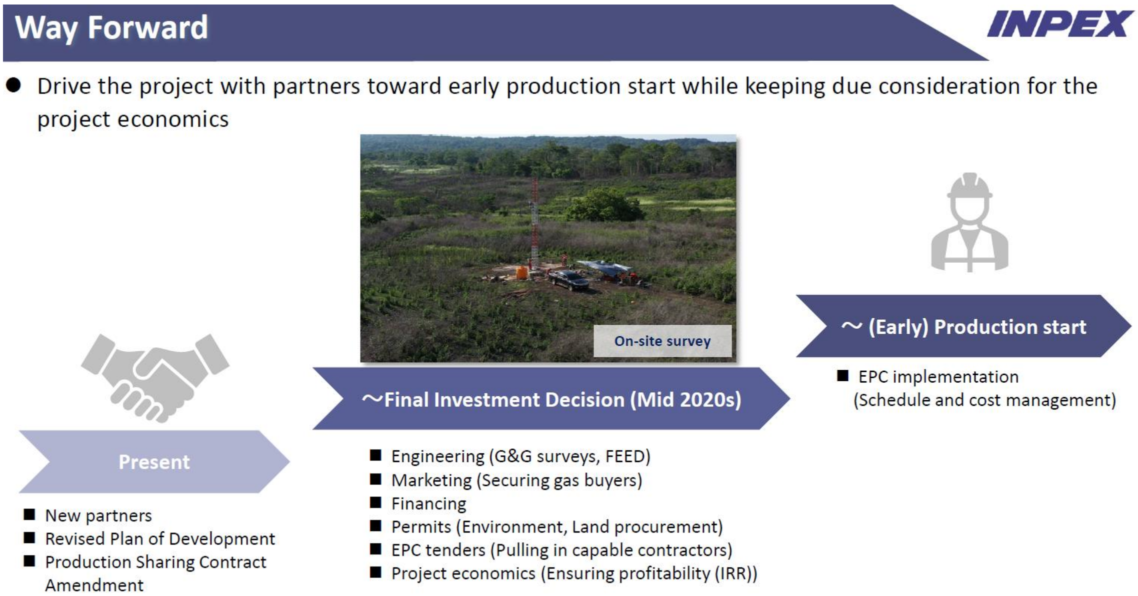
Source: INPEX (2023/11)

https://www.inpex.co.jp/english/ir/library/pdf/presentation/e-Presentation20231127-a.pdf

At present, INPEX could find new partners and revised Plan of Development was approved. As way forward, INPEX will work on FEED, LNG Marketing to secure gas buyers, secure Financing of project’s capex and EPC tenders etc. Based on these tasks, INPEX’s targeting to make the FID, Final Investment Decision in the latter half of the 2020s and then, by EPC implementation, commencing production in the early 2030s.

For a supplementary explanation, FEED is an acronym for Front End Engineering Design. FEED work is done prior to engineering, procurement and construction (EPC) work. FEED work involves field studies and budgeting, including technical issue identification and cost outlines, upon which bidding for EPC work is based. The oil and gas exploration and development business involves the participation of a number of contractors, such as drilling contractors and geophysical exploration subcontractors. Of these, an engineering, procurement and construction (EPC) contractor is in charge of engineering, procurement and construction work.

Fig.3.16. Abadi LNG's way forward



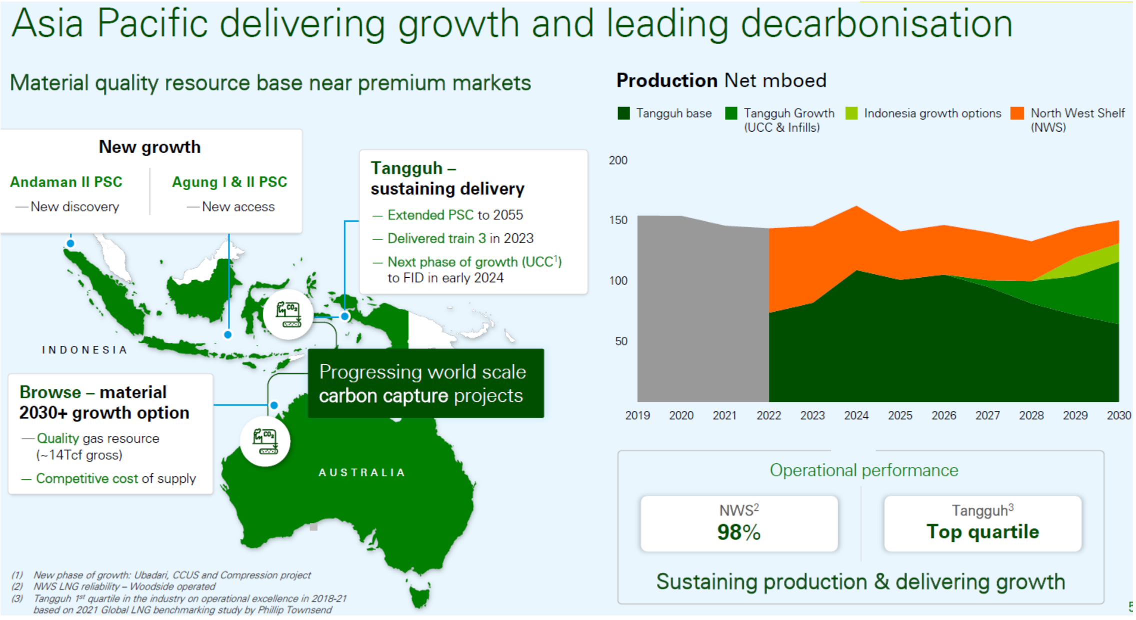
Source: INPEX (2023/11)

https://www.inpex.co.jp/english/ir/library/pdf/presentation/e-Presentation20231127-a.pdf

6, BP plans to sustain Tangguh LNG by UCC & infills

Tangguh LNG, of which BP is the operator, is one of the most important assets in Indonesia. At Tangguh LNG, Expansion project Train 3 will ship its 1st LNG cargo in October 2023 and will be fully operational in 2024. This is represented by the dark green "Tangguh Base" in the figure below. Since production at this "Tangguh Base" is expected to decline from around 2027, BP plans to maintain Tangguh LNG production through the "UCC & infills", Ubadari, CCUS and compression projects. As discussed in detail in the next chapter, this CCUS is one of the most advanced CCS/CCUS projects in Indonesia.

Fig.3.17. BP plants to sustain Tangguh LNG by UCC and infills.



Source: BP (2023/10)

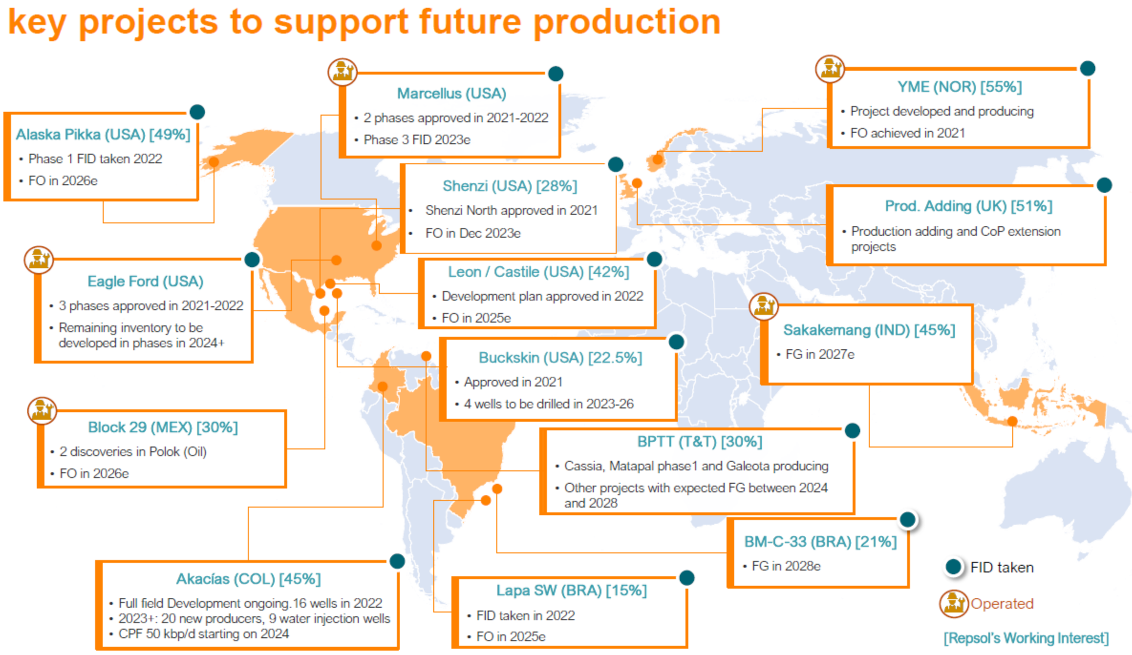
https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/investors/bp-investor-update-2023-gas.pdf

7, Repsol is nearing a final investment decision on the Sakakemang project.

Repsol discovered gas resource in Sakakemang block in South Sumatra in 2019. Although the gas reserves are smaller than originally thought and the CO2 content is higher, Repsol is aiming for a final investment decision in 2024 for the project with CCS, and First Gas in 2027. Gross Capex of this project is about $0.5 billion, Repsol hold 45% of this project so that Repsol's net capex is about $0.2 billion, so this project is not so big.

In its Investor relation material, Repsol explained that its "Core areas" is U.S. (Akaska, Marcellus, Eagle Ford, Gulf of Mexico), Brazil, Norway, UK, and Libya. And Repsol also explained that its "Other areas in the Portfolio" is Indonesia, Canada, T&T, Venezuela, Colombia, Peru, Bolivia, Algeria. Although Indonesia is classified as "Other areas in the Portfolio", Sakakemang is one of the few projects where Repsol is the operator, as shown in the Figure below.

Fig.3.18. Repsol's new oil & gas projects including Sakakemang



Source: Repsol (2023/11)

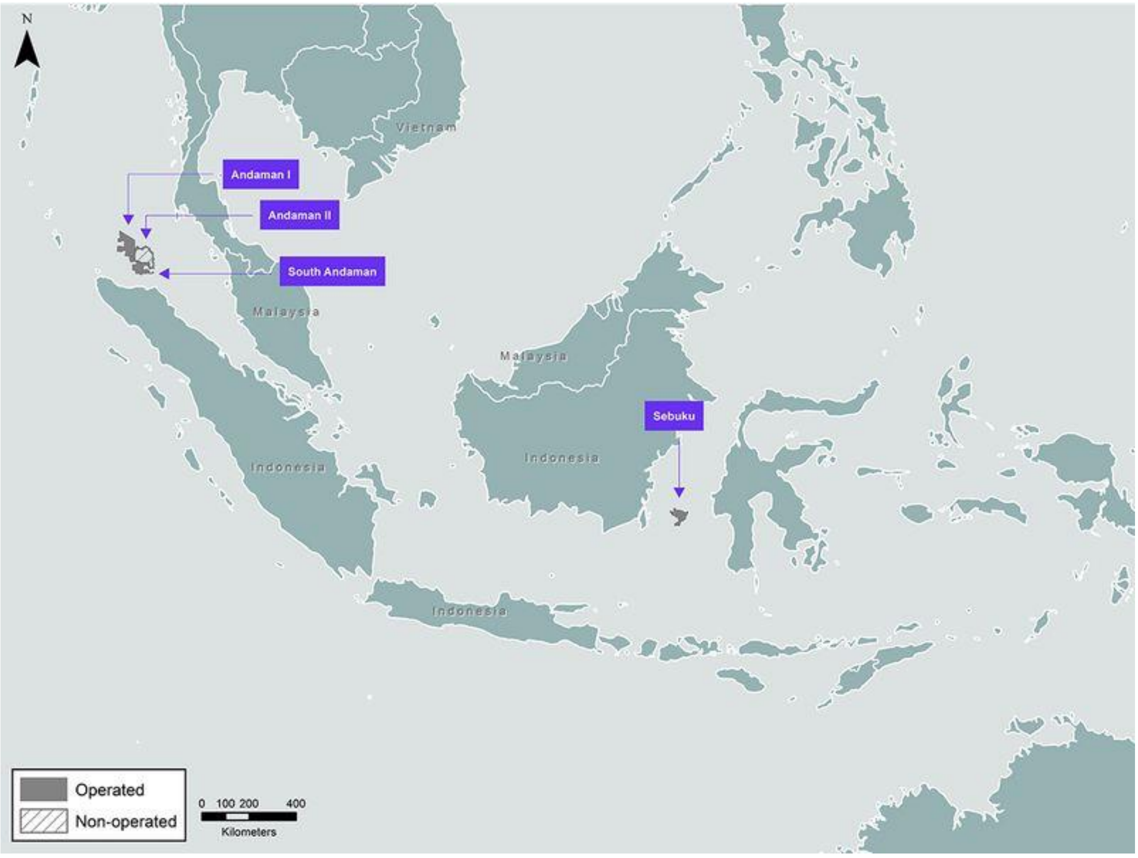
https://www.repsol.com/en/shareholders-and-investors/repsol-as-an-investment/presentations/index.cshtml

8, Mubadala Energy discovered a gas with potential of 6 TCF in Indonesia

Mubadala Energy, the international energy company headquartered in Abu Dhabi, discovered a gas with potential of 6 TCF in South Andaman, about 100 kilometers offshore North Sumatra, Indonesia. Mubadala Energy is the operator of this South Andaman Gross Split PSC with an 80% working interest. This is the second consecutive successful well for Mubadala Energy in the Andaman area, coming after the success of Timpan-1 in Andaman-II.

With Mubadala Energy's gas discovery in South Andaman and Eni's gas discovery in Geng North, the author believes that Indonesia will be one of the top gas resource discoveries in the world in 2023.

Fig.3.19. Mubadala Energy discovered a gas with potential of 6 TCF in Indonesia.



Source: IPA (Indonesian Petroleum Association)

https://www.ipa.or.id/id/news/news/mubadala-energy-announces-major-gas-discovery-in-south-andaman-indonesia

9, Summary of IOCs' oil & gas business activities in Indonesia

In Chapter 3 we discussed IOC's oil and gas business activities in Indonesia. Chevron, ConocoPhillips and Shell have withdrawn from oil & gas business in Indonesia. This is to focus more on their core areas with the investment discipline, and the author believes that it is unlikely that they will return to oil & gas business in Indonesia again. On the other hand, Eni and INPEX are trying to develop new projects in Indonesia and BP is trying to maintain Tangguh LNG by new infills projects, and the author believes that it's important to make it a win-win situation between these IOCs and the Indonesian government.

In the next Chapter, we examine what are the key factors for a win-win situation between the Indonesian government and IOCs that continue to operate in Indonesia.

Chapter 4

The key factors for a win-win situation between the Indonesian government and IOCs that continue to operate in Indonesia.

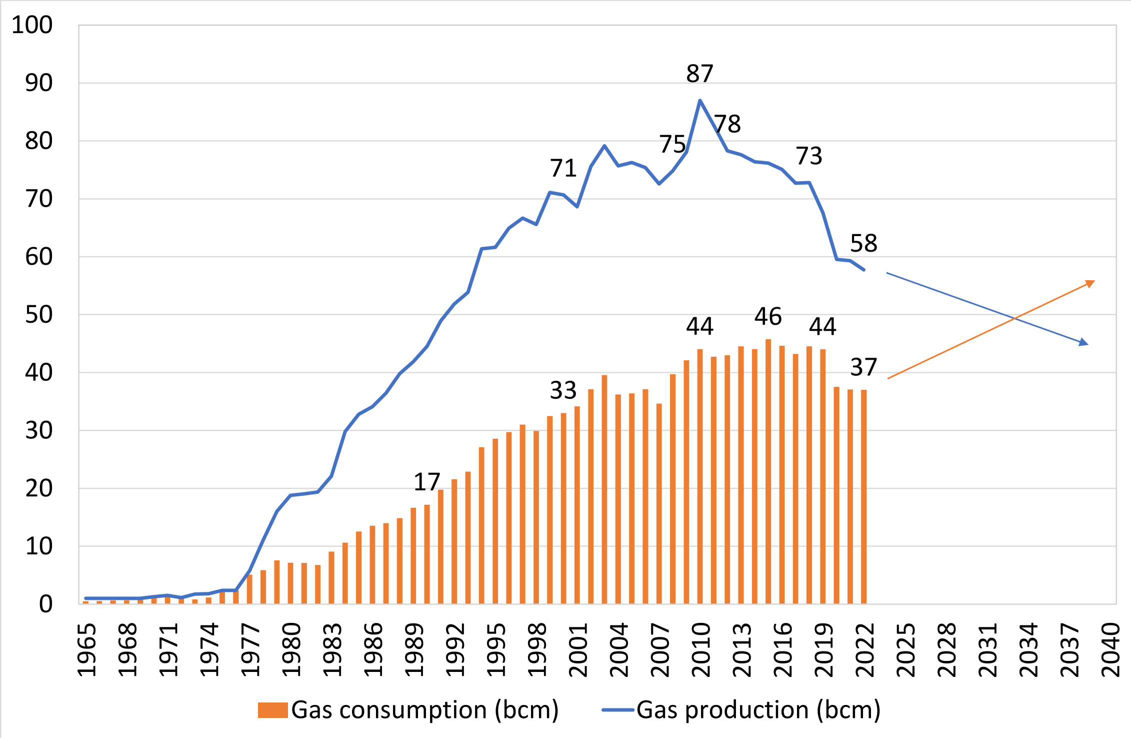
In Chapter 4, we examine what are the key factors for a win-win situation between the Indonesian government and IOCs that continue to operate in Indonesia. Indonesia needs to develop new gas fields to meet the expected increase in domestic gas demand. Eni and INPEX have stated that a reasonable IRR (Internal Rate of Return) is a prerequisite for the development of new projects, so discussions with the government on economic conditions will be a key point. Another key point is the development of regulations for the implementation of CCS, including cross-border storage.

1, Indonesia needs more domestic gas production to meet domestic gas demand growth

The author believes that Indonesia needs more domestic gas production to meet domestic gas demand growth in future. The author believes that Indonesia's domestic gas demand will increase in the late 2020s to 2030s for the following reasons. First, Indonesia's gas demand was sluggish from 2020 to 2022, not only because of COVID-19, but also because of the decline in Indonesian domestic gas production, and if domestic gas production stabilizes or increases, potential gas demand may be strong. Second, Indonesia has great potential for solar power generation, but gas power generation will be needed to back up the fluctuations in solar power generation during cloudy, rainy days and at night. The difficulty of building new coal-fired power plants due to the climate change issues will also affect the need for gas-fired power generation.

If several large new projects are not developed, there is a risk that Indonesia's domestic gas production will decline in the future due to declining production rate from existing gas fields. If this happens, Indonesia's domestic gas demand will exceed its domestic gas production, and Indonesia will need to import LNG. This is the reason why Indonesia needs more domestic gas production.

Fig.4.1. Indonesia's gas production and consumption outlook image (bcm)



Source: INPEX Solutions

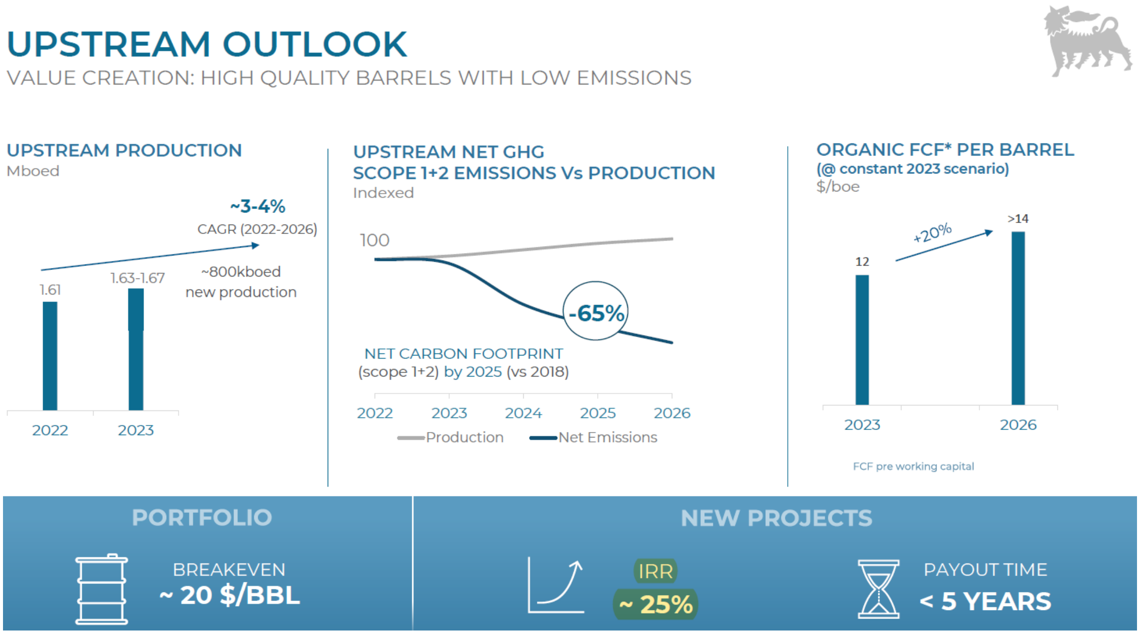
2, Need for IRR improvement of new projects

As mentioned in Chapter 3, INPEX has aimed that the IRR will be in the mid 10% range whether or not Abadi LNG is developed. IRR, Internal Rate of Return, is a metric used in financial analysis to estimate the profitability of potential investments. IRR, simply explained, is the rate of return calculated by comparing the cash flow that can be obtained in the future by investing in a project and the amount invested in the project, as well as the time value of each money is considered. The target IRR for 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 lower than the IRR for E&P as a whole, because LNG projects require investment not only in the development of gas resources but also in facilities to liquefy the gas. Therefore, the target IRR of 15% is not too high, nor is it an easy target to achieve.

Eni has explained that the target IRR for new E&P projects from 2023 to 2026 is just under 25%. The author believes that this does not yet include IDD or Geng North, which are major projects in Indonesia, but does include new projects in Indonesia, Merakes East (15 kboe/d by 65%) and

Maha (34 kboe/d by 40%). IDD and Geng North will use existing Bontang LNG and will not require investment in LNG liquefaction facilities, so their IRRs will be higher than 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 to develop any new development in Indonesia without a reasonably high IRR.

Fig.4.2. Eni's Upstream Outlook including IRR



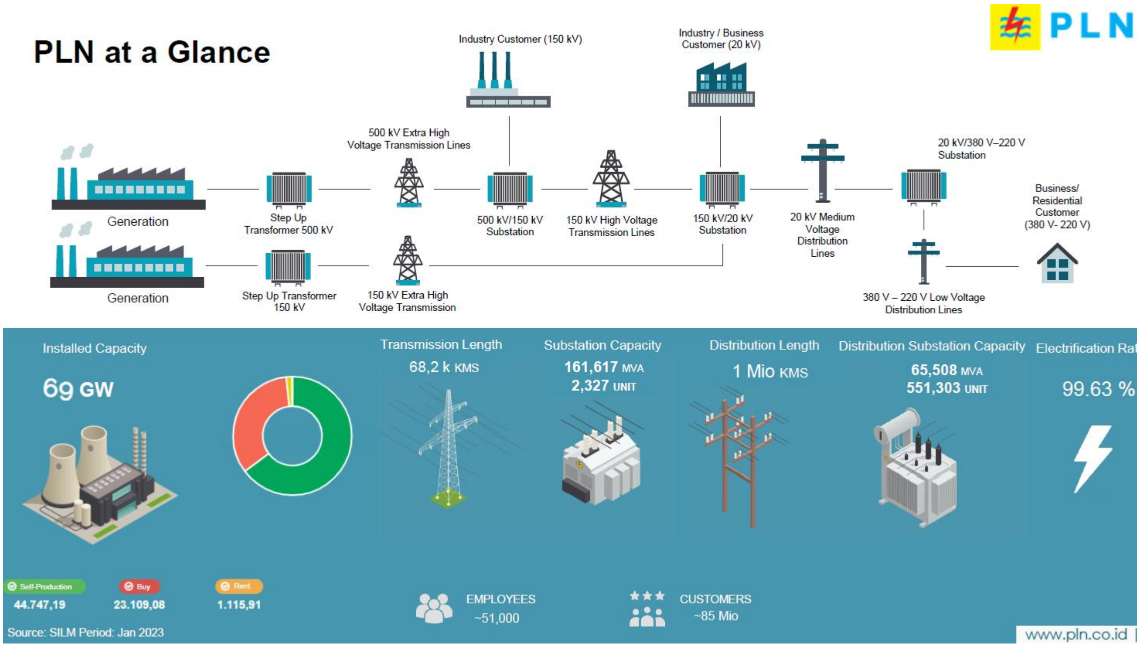
Source: Eni (2023/2)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/2023-capital-markets-update/2023-Capital-Markets-Update-presentation.pdf

3, Indonesian electric power market situation

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

Fig.4.3. PLN at a Glance



Source: PLN (2023)

https://reinvest.id/assets/source/materials/southkorea-2023/PPT%20Mr.%20Harlen%20En,%20Executive%20Vice%20President%20of%20Corporate%20Strategic%20Plannning,%20PT%20PLN.pdf

Indonesia's electricity market and tariffs are regulated by law. PLN conducts public service obligations by law to produce and 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 State Enterprise Ministry, and its auditors and directors are appointed by the Ministry. Domestic electricity retail 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 (deficit), and a subsidy equal to the difference plus a certain margin is provided from the annual state budget.

Fig.4.4. Regulated Electricity Law & Tariff in Indonesia

Regulated Electricity Law & Tariff

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.

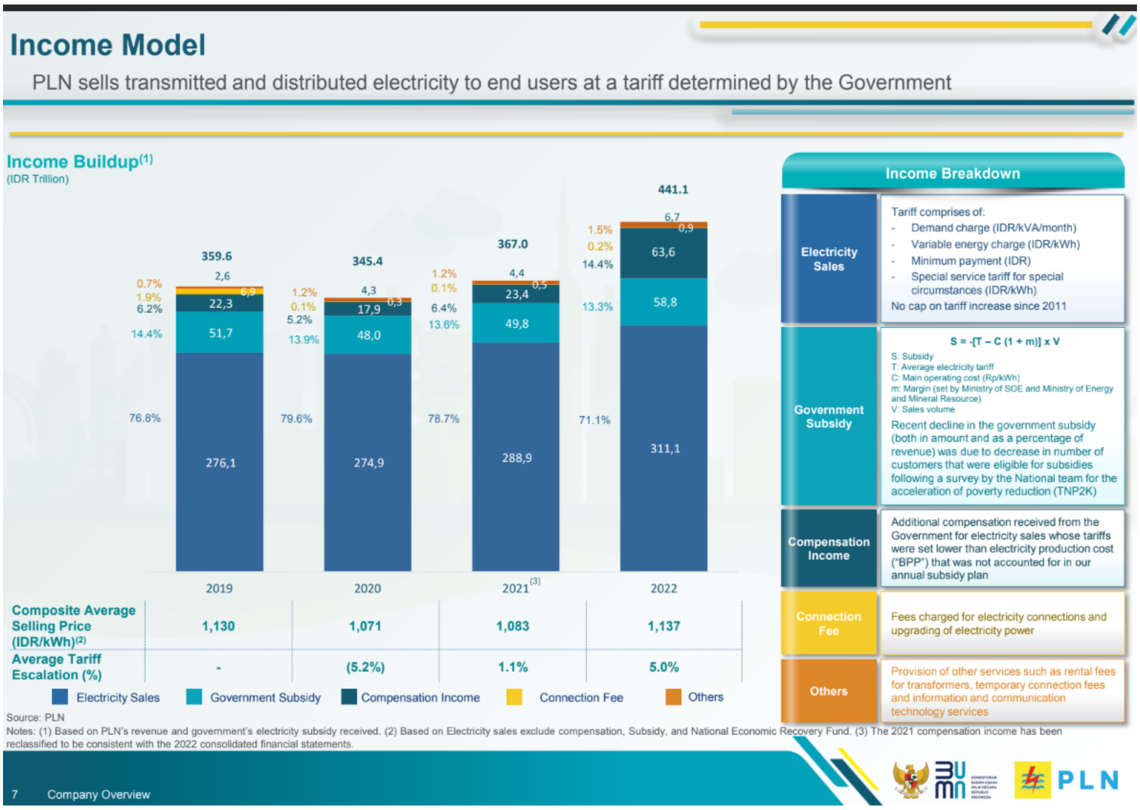
Electricity Tariff Types

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

Source: PLN (2020) IR Website

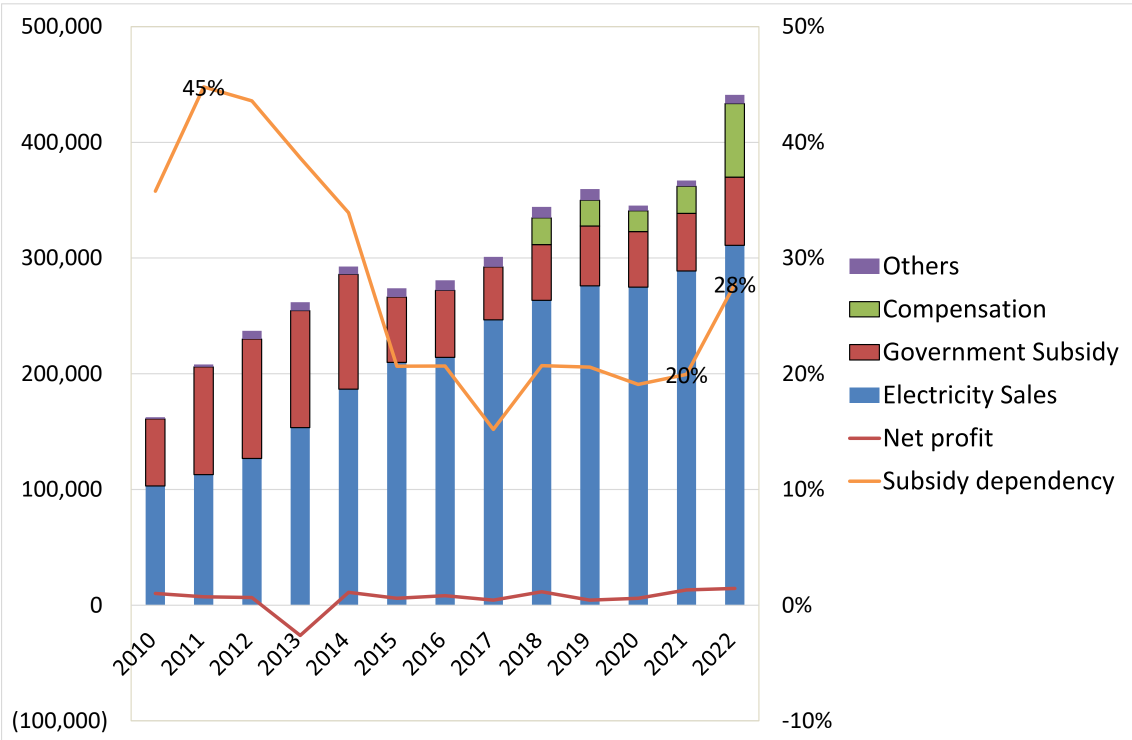
Let's look at the breakdown of PLN's sales: PLN's sales mainly consist of Electricity Sales, Government Subsidy, and Government Compensation Income. The line graph below shows the dependence of the total of these government subsidies and government compensation income on total sales. This dependence fell from 45% in 2011 to 20% in 2015 and has remained at almost 20% since then until 2021. However, this dependence rose to 28% in 2022. The author believes that this is because the global energy crisis has caused fuel prices, including coal, to soar, which cannot be fully passed on to retail electricity prices and has led to an increased reliance on government subsidies and compensation income.

Fig.4.5. PLN's Income model including Government Subsidy



Source: PLN (2023) IR Website

Fig.4.6. PLN's Sales breakdown (billion Indonesian rupiah)



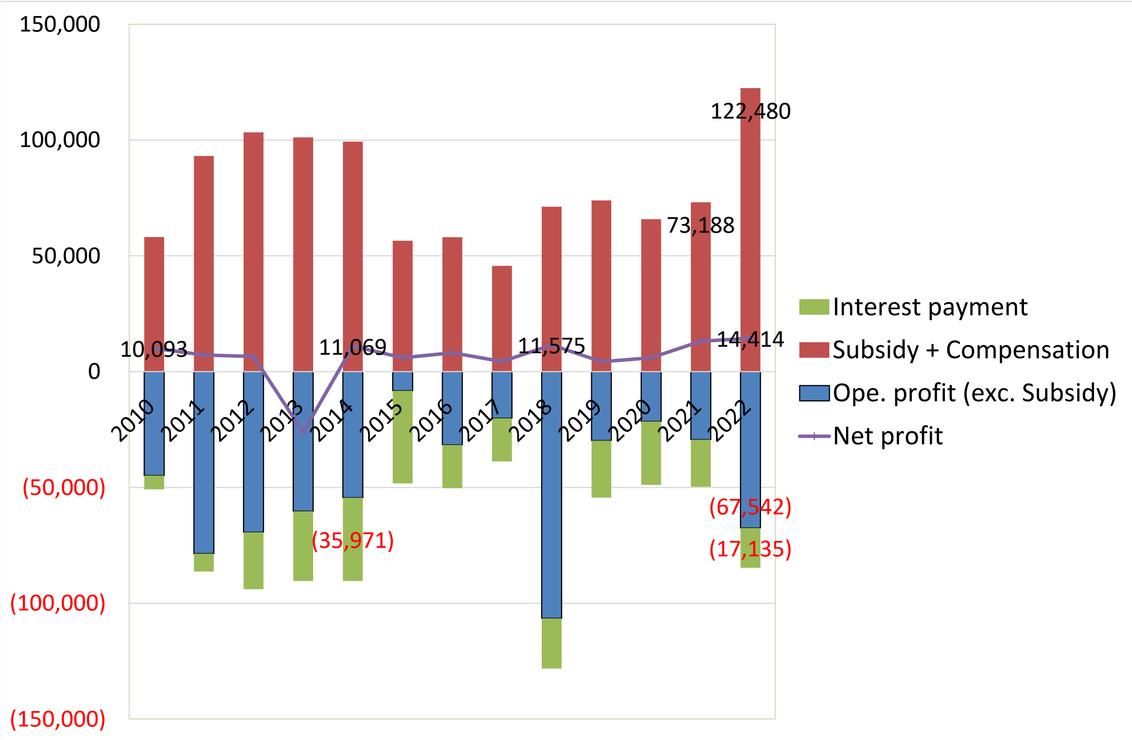
Note: Subsidy dependency % = (Government Subsidy + Compensation) divided by total sales

Source: INPEX Solutions

Let's look at PLN's net income in terms of three components: government subsidy and compensation, operating income excluding government subsidy and compensation, and interest expense. In 2022, PLN had a net income of Rp 14 billion, which was due to government subsidies and compensation of Rp 122 billion, while operating income excluding government subsidy and compensation was a loss of Rp 6.7 billion. 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 natural and unavoidable.

However, if the electricity mix shifts from coal-fired power generation to solar power generation 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 Indonesian government cannot continue to increase subsidies, it will be necessary to raise electricity retail prices appropriately while keeping an eye on economic conditions and other factors, but the author believes that this will be a difficult decision.

Fig.4.7. Breakdown of PLN's Net profit

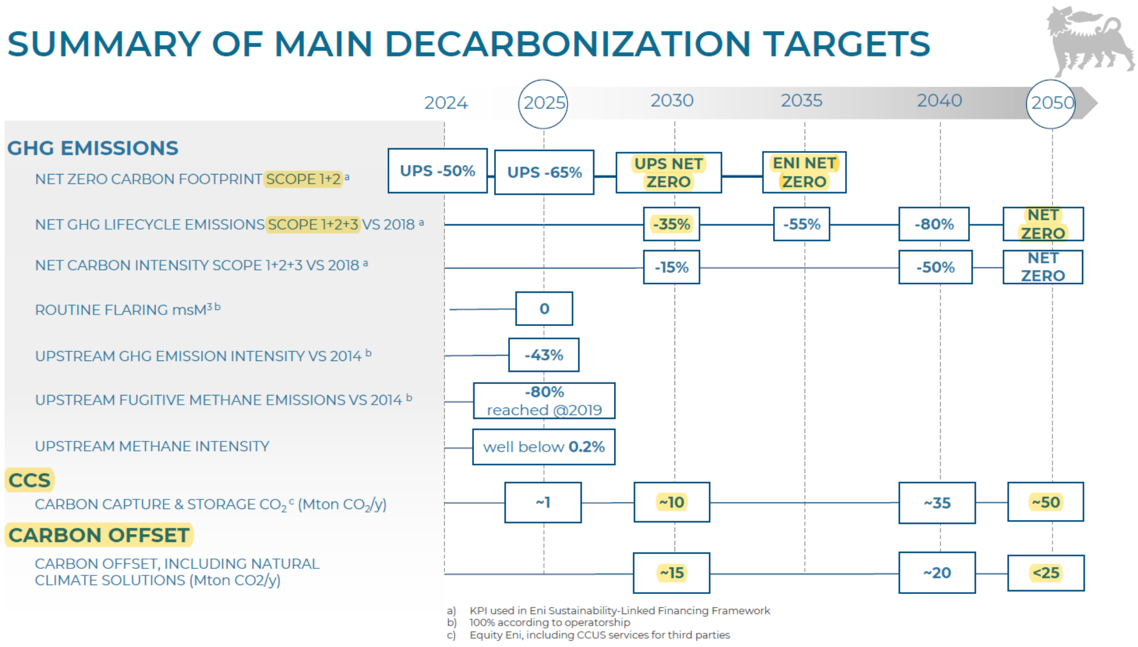


Source: INPEX Solutions

4, CCS is important

CCS is important for the Indonesian government and for IOCs with E&P operations in Indonesia to develop clean energy. As mentioned in the previous section, INPEX plans to attach a CCS to Abadi LNG when it develops the project. As shown in the figure below, Eni is targeting net-zero Scope 1+2 emissions from its Upstream business by 2030. To achieve this goal, Eni intends to establish CCS with a storage capacity of 10 million tons per year by 2030, and to provide 15 million tons per year of Carbon Offsets through Natural Climate Solutions and others.

Fig.4.8. Eni's decarbonization targets



Source: Eni (2023/2)

https://www.eni.com/content/dam/enicom/documents/eng/investor/presentations/2023/2023-capital-markets-update/2023-Capital-Markets-Update-presentation.pdf

According to the Asia CCUS Network, 15 CCS/CCUS projects are in the pipelines in Indonesia at the end of December 2022, as shown in the following map and table. Indonesian government representative said, "Most advanced in terms of implementation, we have Tangguh and the other one is Abadi". And 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 between 25 million and 70 million ton".

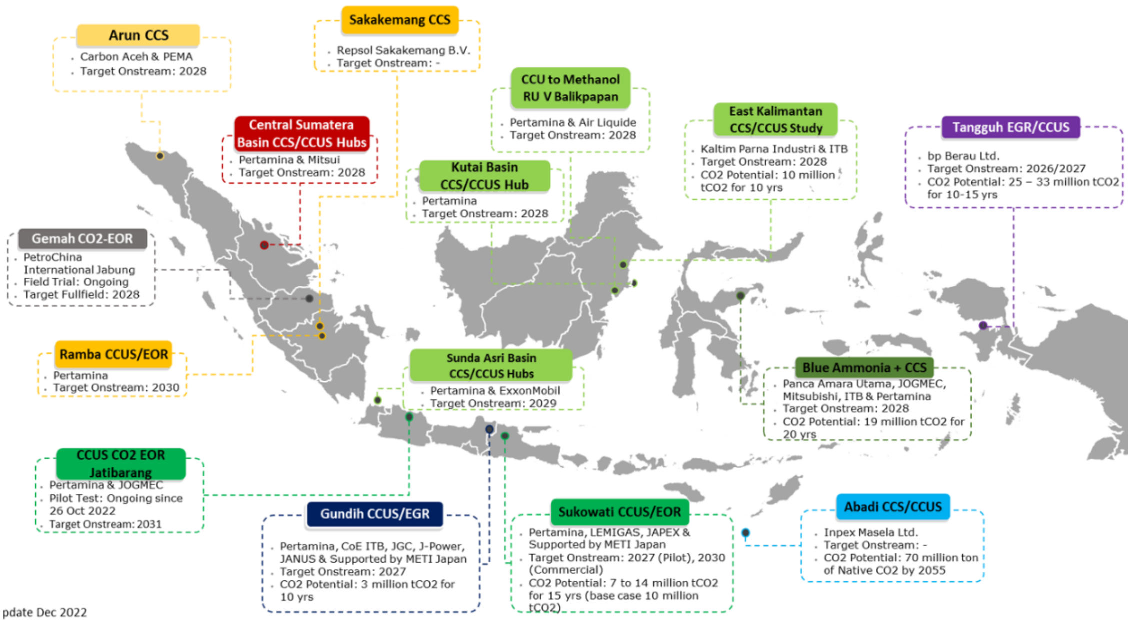
Tangguh EGR/CCUS project is enhanced gas recovery through carbon capture, utilization and storage operated by BP. Tangguh EGR/CCUS is integrated with Ubadari gas field development, and this integrated project will extend the gas feed to Tangguh Train 3 while at the same time, the EGR/CCUS will reduce Tangguh LNG carbon footprint via CO2 sequestration. This integrated project is estimated to be an investment worth about US$2.6 billion and is approved by Indonesian government in 2021, and currently BP are working FEED with target on coming onstream in 2026/2027.

Since the author mentioned Abadi CCS in the previous chapter, here the author will discuss another case, the Sunda Asuri Basin CCS/CCUS Hubs by ExxonMobil and Pertamina. In November 2023, ExxonMobil and Pertamina agreed to continue their collaboration for the CCS Hub evaluation in the Sunda Asri Basin. This CCS Hub is expected to offer significant geological storage, capturing and injecting CO2 from domestic and regional industries. Its CO2 storage capacity is expected to up to 3 gigatons (=3,000 million tons) in saline aquifer, which is huge, and its investment value exceeding US$2 billion, according to Petronas's recent press release.

As mentioned above, Eni is planning to develop a new project in the Kutai basin, but we cannot find any documentation explaining whether or not a CCS will be attached.

According to the map below, Petronas is considering a CCS/CCUS Hub in the Kutai basin, and Eni may be able to collaborate with this CCS project.

Fig.4.9. Map of CCS/CCUS projects pipeline in Indonesia



Source: Asia CCUS Network (2022/12)

https://www.asiaccusnetwork-eria.org/articles/indonesia-tabled-ccs-and-ccus-in-net-zero-emission-road-map

Fig.4.10. Details of CCS/CCUS projects pipeline in Indonesia

No	Project	Expected CO2 Storage	Expected On Stream
1	CCS ARUN, Carbon Aceh and PEMA	Huge, under detail assessment	2028
2	Gemah CO2 EOR (CCUS), PetrochinaIntenational Jabung	Significant,under detail assessment	2028
3	Ramba CO2 EOR (CCUS),	Significant, under detail assessment	2030
4	Central Sumatra Basin CCS-CCUS, Pertamina & Mitsui	Huge, under detail assessment	2028
5	Sakakemang CCS, Repsol Sakakamang	2 million ton per year and 30 million ton in total	2028
6	Jatibarang CO2 EOR (CCUS), Pertamina & Jogmec	14.6 thousand tons/year	2031
7	Gundih CO2 EGR (CCUS), Pertamina, J Power, Janus, CoE CCS	3 million tons for 10 years	2027
8	Sukowati CO2 EOR (CCUS), Pertamina, Lemigas, Japex	7 to 14 million tons for 15 years	2027 Pilot 2030 commercial
9	Sunda Asri Basin, Pertamina and ExxonMobil	6-10 G ton in saline aquifer	2029
10	Kutai Basin CCS – CCUS Hub, Pertamina	Huge, under detail assessment	2028
11	CCU to Methanol, Pertamina Refinery Balikpapan, Pertamina- Air Liquide	Significant, under detail assessment	2028
12	East Kalimantan CCS/CCUS, Kaltim Parna Industry	10 million tons for 10 years	2028
13	Blue Ammonia CCS, Panca Amara Utama, JOGMEC, Mitsubishi, Pertamina	19 million tons for 20 years	2028
14	Tangguh CO2 EGR (CCUS), BP Tangguh	25-33 million tons for 10-15 years	2026/2027
15	Abadi CCS/CCUS, Inpex Masela, Ltd.	70 million tons by 2055	2029

Source: Asia CCUS Network (2022/12)

https://www.asiaccusnetwork-eria.org/articles/indonesia-tabled-ccs-and-ccus-in-net-zero-emission-road-map

There are several challenges to implementing CCS. The first is a COMMERCIAL challenge: 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 themselves? and will they not be able to pass these costs on to the sales price or other means? Or 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 the regulation allow electric utilities to pass on the increased costs of CCS to the price of electricity sold? Will the government continue to cover the cost of CCS through subsidies or tax credits? Or will the end consumer ultimately pay the cost of CCS?

At this time, the answer to this COMMERCIAL challenge is not clear. CCS implementation is still in the early stages in many countries. Japan is trying to implement CCS first with government subsidies, the U.S. 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, etc., but to spread more fully, it will be necessary for the people of each country to have a common understanding that the cost of CCS will ultimately be borne by the end consumer.

As the author explained about Abadi's CCS in previous chapter, Abasi's CCS-associated cost can be recovered from the produced gas and condensate under Indonesian PCS, this means that CCS – associated cost could reduce project IRR if E&P company can't pass on the CCS cost to the users.

The second challenge relates to regulations, laws, and rules. First, is the implementation of CCS mandatory or not? At this time, 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 by nature- based solutions when developing new oil and gas fields. E&P companies are also in positive discussions with their respective governments to ensure that the contribution of CCS implementation is properly recognized in legal terms.

One of the points the companies are discussing with governments is whether CCS operators must monitor and ensure that CO2 is sequestered in the ground forever? If there is a legal responsibility to guarantee that CO2 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 not only store their own CO2 through CCS, but CCS companies also take CO2 emitted by industrial sectors in Indonesia and abroad and store it. When CO2 from industries outside Indonesia is captured and stored at CCS reservoirs in Indonesia, it is necessary to establish laws in each country so that this "cross-border CO2" is legally recognized as a contribution to CO2 reduction without double-counting between the two countries. Indonesia is preparing a presidential regulation to allow this cross-border CCS, which will be greatly welcomed by CCS operators.

The third challenge is a technical challenge, which includes how to reduce costs, how to improve accuracy in estimating underground CO2 storage capacity, and how to prepare pipelines and carriers for CO2 transport. Since E&P companies have experience in implementing CCS/CCUS through EOR (Enhanced Oil Recovery) in oil and gas fields, the author expects that the technical challenges in implementing CCS on a large scale mentioned earlier will be solved little by little.

Fig.4.11. Challenges of CCS

Commercial challenges Who will pay for the cost of CCS ?	E&P compaies pay the cost ? Power company pay the cost ? Government pay the cost ? -Full Subsidy ? Full tax reduction ? Ultimately, the end consumers pay the cost ?
Regulation challenges	Is CCS mandatory or voluntary ? Who is responsible for ensureing CO2 is stored ? Forever ? How to deal with cross-border CO2 ? -No double counting
Technical challenges	Cost down Accuracy of CO2 storage capacity estimation Infrastructure - CO2 pipeline, marine transportation

Source: INPEX Solutions

5, Summary of win-win situation between Indonesian government and IOCs

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 (Internal Rate of Return) is a prerequisite for the development of new projects, so discussions with the government on economic conditions will be a key point. Another key point is the development of regulations for the implementation of CCS, including cross-border storage.

References [Calibri light 16 points, Bold, left aligned]

[References are written in Calibri 11 points, regular font; hanging indentation of 0.5”, single line spacing, 6 points space between entries, both sides justified]

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Appendices/Annexes [Calibri light 16 points, Bold, left aligned, if any]

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*If it contains figures or tables, please use the table/figure template provided above.