Danish Energy Agency

Directorate General
of Electricity

Ea Energy Analyses

Technology Cost Perspectives in the Indonesian Power Sector: A Comparative Techno-Economic Analysis

May 2024

Foreword

The present analysis complements the launch of the newly updated Technology Data for the Indonesia Power Sector (version 2024)[1]. The two documents have been prepared in parallel during 2023, which shall be considered the analysis' base year, and finalised in the beginning of 2024.

The main purpose of this report is to communicate the latest technology cost trends to the public, aiming to support well-informed decisions in current energy planning discussions and future policy making.

An evaluation of technology-specific cost data via the metric of Levelised Cost of Electricity (LCOE) and a series of sensitivity analyses on various key parameters are undertaken. This material shall raise choice awareness and provide the reader with an overall cost perspective across key technologies and uncertainty factors within the power system, outlining important takeaways in consideration of the energy transition planning in Indonesia. Some of the vital parameters examined include fuel prices, cost of capital and operational patterns, e.g. capacity factors.

The content of the analysis is divided as follows:

I. Current and future costs of investments in new generation units
II. Cost comparison of new investments against existing coal and gas power plants
III. Options for repurposing the existing generation fleet
IV. Overview of storage and hybrid plants development

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Technology Data for the Indonesian Power Sector 2024

Catalogue for Generation and Storage of Electricity

Disclaimer

The following report is prepared by partners of the Indonesian-Danish Energy Partnership Programme (INDODEPP) in close collaboration with Ea Energy Analyses and targets a broad audience of stakeholders who might consider the findings on power technologies relevant.

Conclusions of the present report reflect the views of the authors, via cost-based evaluations and comparisons of individual technologies. The illustrated figures discuss the annualised costs of each technology, based on a number of simplifications such as assuming a flat operation curve across their lifetime. System-wide aspects are not captured due to an absence of detailed power system modelling, which would highlight the actual necessary operating levels of each unit and therefore accurate production-related expenditures.

The main sources of information used in preparation of the ‘Technology Data for the Indonesian Power Sector’ report and consequently the present study are: Multi-stakeholder involvement via Focus Group Discussions (FGDs), internal discussions/workshops with the General Directorate of Electricity and the Ministry of Energy and Mineral Resources (MEMR) within the INDODEPP framework, as well as international/local market analyses performed by the Danish Energy Agency and Ea Energy Analyses.

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Analysis Inputs & Assumptions

Technology Catalogue Background

The cost data utilised in the present report consist an integral part of the newly issued Technology Data for the Indonesian Power Sector[1], a revised and updated version of the previous report issued in 2021. The update seeks to produce and establish an up-to-date overview of power generation and storage technologies, in terms of price and performance, aiming to assist well-informed decision making in regard to long-term energy planning.

The Technology Catalogue contains data that have been scrutinised and discussed by a wide range of relevant stakeholders including, but not limited to, DG Electricity, MEMR, PLN and NEC. The broad engagement is essential for the transparency, quality and acceptance of the end-product, as one of the main objectives is anchoring the technology catalogue well amongst all relevant stakeholders.

Technologies described in this catalogue cover both mature technologies and technologies which are expected to improve significantly over the coming decades, both with respect to performance and cost. Investment cost projections from different sources are compared, when relevant. If available, local projects are included along with international projections from accredited sources (e.g. IEA[6], IRENA[7]). Additionally, cost projections are also estimated to reflect future cost trends.

This updated version of the Technology Catalogue will continue assisting the long-term energy modelling in Indonesia and support government institutions, private energy companies, think tanks and others in developing relevant policies and business strategies to achieve the government's renewable energy targets and, not least, bring Indonesia closer to their Net-Zero aspirations.

Note: For further details over the adopted methodology, please refer to the Technology Data Catalogue report[1].

Technology Development In 2023 & 2050: Catalogue Input Data

A brief overview of a number of central technologies for the current analysis is presented on the following table. Key technical and economic data are listed, in an attempt to shed light on cross-technology differences as well as the cost factors that plants of different purposes have to overcome in their lifetime before proven profitable. All costs reflect a 2022 price level. Today's values (2023) are listed next to their 2050 projections (in brackets). For a more detailed description of each field please refer to the Technology Data Catalogue report[1].

2023 (2050) Technology	Type	Representative Plant Size (MWe)	Lifetime (y)	Construction Duration (y)	Electric Efficiency (%)	Capex (m$/MW)	Fixed O&M (k$/MW/y)	Variable O&M ($/MWh)*	Start-up ($/MW/y)	Other Costs (m$/MW)	FLHs (h/y)
Conventional Power Plants											
Coal	*Subcritical*	300 (300)	30 (30)	3.0 (3.0)	34% (36%)	1.9 (1.8)	51.6 (48.6)	1.5 (1.4)	125 (125)	- (-)	- (-)
	Supercritical	600 (600)	30 (30)	4.0 (3.0)	37% (39%)	1.6 (1.5)	47.0 (44.1)	1.4 (1.3)	57 (57)	- (-)	- (-)
	Ultra-supercritical	2,000 (2,000)	30 (30)	4.3 (3.0)	42% (44%)	1.7 (1.6)	64.5 (60.6)	1.3 (1.1)	57 (57)	- (-)	- (-)
	IGCC	600 (600)	30 (30)	4.0 (4.0)	40% (43%)	2.7 (2.3)	68.4 (64.3)	13.70 (12.90)	114 (114)	- (-)	- (-)
Natural Gas	*SCGT*	200 (200)	25 (25)	1.5 (1.5)	33% (39%)	1.1 (1.0)	26.5 (24.9)	3.6 (3.4)	25 (25)	- (-)	- (-)
	CCGT	400 (400)	25 (25)	2.5 (2.5)	56% (60%)	1.1 (1.0)	26.8 (25.2)	2.60 (2.40)	90 (90)	- (-)	- (-)
Diesel	*Fuel-oil based*	14 (14)	25 (25)	1.0 (1.0)	45% (47%)	0.9 (0.9)	9.1 (8.8)	7.30 (6.61)	- (-)	- (-)	- (-)
Baseload Low Carbon & RE Power Plants											
Hydro	*Micro/mini*	1 (1)	50 (50)	2.0 (2.0)	80% (80%)	2.7 (2.4)	60.4 (54.0)	0.57 (0.51)	- (-)	- (-)	4,468 (4,468)
	Large	200 (200)	50 (50)	4.0 (4.0)	95% (95%)	2.2 (2.0)	43.0 (38.0)	0.74 (0.66)	- (-)	- (-)	4,468 (4,468)
Geothermal	*Small*	20 (20)	30 (30)	2.0 (2.0)	10% (12%)	5.5 (5.0)	145.0 (130.5)	0.39 (0.35)	- (-)	0.32 (0.30)	7,008 (7,008)
	Large	110 (110)	30 (30)	2.0 (2.0)	15% (17%)	4.4 (4.0)	110.0 (99.0)	0.27 (0.24)	- (-)	0.32 (0.30)	7,008 (7,008)
Biomass	*Small*	25 (25)	25 (25)	2.0 (2.0)	31% (31%)	2.3 (1.8)	54.3 (43.4)	3.4 (2.7)	- (-)	- (-)	- (-)
Nuclear	*SMR*	- (300)	- (50)	- (4.0)	- (30%)	- (7.3)	- (102.0)	- (2.1)	- (-)	- (-)	- (-)
	PWR	2,000 (2,000)	60 (60)	7.4 (7.4)	34% (40%)	9.0 (6.8)	127.0 (113.0)	2.4 (2.2)	- (-)	- (-)	- (-)
VRE Power Plants											
Solar PV	*Rooftop*	0.005 (0.005)	27 (35)	0.1 (0.1)	- (-)	1.2 (0.6)	4.9 (3.9)	- (-)	- (-)	- (-)	1,791 (1,891)
	Ground-mounted	50 (100)	27 (35)	0.5 (0.5)	- (-)	1.0 (0.5)	7.5 (6.1)	- (-)	- (-)	- (-)	1,791 (1,891)
	Industrial	0.1 (0.1)	27 (35)	0.5 (0.5)	- (-)	1.1 (0.5)	4.7 (3.7)	- (-)	- (-)	- (-)	1,791 (1,891)
	Floating	30 (100)	27 (35)	0.5 (0.5)	- (-)	1.2 (0.5)	9.0 (6.1)	- (-)	- (-)	- (-)	1,841 (1,990)
Wind Turbines	*Onshore (Small)*	13 (19)	27 (30)	1.0 (1.0)	- (-)	4.2 (3.0)	83.5 (60.1)	- (-)	- (-)	- (-)	2,384 (3,081)
	Onshore (Large)	70 (120)	27 (30)	1.5 (1.5)	- (-)	1.7 (1.0)	40.0 (30.0)	- (-)	- (-)	- (-)	2,384 (3,081)
	Offshore (Bottom-fixed)	240 (600)	27 (30)	3.0 (2.5)	- (-)	4.1 (2.9)	118.8 (81.3)	5.50 (3.90)	- (-)	- (-)	2,934 (3,473)
	Floating	35 (1,000)	20 (30)	3.0 (2.5)	- (-)	5.5 (3.0)	155.0 (65.0)	- (-)	- (-)	- (-)	2,945 (3,343)

Note(*): Variable O&M costs do not include fuel expenses. Such costs are additional and many times plant specific, as will be addressed in the "Assumptions and Uncertainties" section. Absence of variable O&M costs for VRE plants corresponds to their inclusion within the fixed O&M figure.

Emerging And Future Technologies: New Additions To The Technology Catalogue

A series of new technological additions are included in the newest version of the Indonesian Technology Catalogue. A summary is displayed on the table to the right.

- Most of the new electricity-producing technologies, listed to the right, may offer opportunities for Indonesia to decarbonise its power system and bring it closer to its emission pledges. However, these technologies also face challenges and limitations that may hinder excessive development, such as technical issues and economic risks:
  - Technological maturity, thus cost data accuracy, performance and construction time is tied to high uncertainty levels as indicated in the full report as well. Retrofitted co-firing units based on green ammonia or green hydrogen are also liable to an immature fuel supply market and potentially high costs.
  - CCS technologies are found to considerably reduce the original plant's conversion efficiency while also reflect increased and uncertain investment costs.
  - Nuclear SMR units have not yet shown the performance and cost level that developers have predicted in the previous years, according to available literature. Large overruns of construction time and costs are being experienced, to a higher degree than expected during FID. Even at higher maturity levels, similar to the ones reflecting the PWR reactors, investment costs remain considerably higher than VRE plants.
- In relation to variable renewable energy (VRE) units, such as solar PV and wind turbines, the new additions pose some advantages in terms of better regulation possibilities. Therefore, comparisons with storage-coupled VRE technologies should be undertaken before proceeding to final technological conclusions.

New additions to the catalogue	Application
Refurbishing and Co-firing	✓ Lifetime Extensions ✓ Retrofit of coal plants (Biomass/Ammonia co-firing) ✓ Retrofit of natural gas plants (Hydrogen co-firing
CCS	✓ Coal plants (Supercritical & IGCC) ✓ Natural gas plants (CCGT) ✓ Biomass plants
Nuclear	✓ Pressurised Water Reactors (PWR) ✓ Small Modular Reactors (SMRs)

Levelised Cost of Electricity (LCOE)

LCOE is a measure of costs which attempts to bring different methods of electricity generation on a comparable basis. The LCOE represents the plant-level unit costs ($/MWh) over its lifetime by accounting for all costs such as capital expenditure, operational and maintenance costs, fuel costs, and others. The upside of the LCOE metric is the provision of a comparison basis among entities of different characteristics, e.g. of different capacities, lifetime, cost of capital etc.

Two of the most commonly used calculation methodologies for LCOEs are the "Discounting" and the "Annuitising"[10,11].

$$LCOE_{Discounting} = \frac{PV_{Costs}}{PV_{Outputs}} = \frac{\sum_{y=0}^{n} \frac{C_y}{(1+r)^y}}{\sum_{y=0}^{n} \frac{E_y}{(1+r)^y}}$$

$$LCOE_{Annuitising} = \frac{Ann_{Costs}}{Ave_{Outputs}} = \frac{Capex \cdot \frac{r \cdot (1+r)^n}{(1+r)^n - 1} + fO\&M + O_c}{\frac{\sum_{y=1}^{n} E_y}{n}} + vO\&M + F_c$$

Where: Present Value (PV), Total costs in year y (C_y), Energy Production in year y (E_y), Number of Investigated Years (n), Discount Rate (r), Annuitised (Ann), Average (Ave), Fixed O&M (fO&M), Other annual costs (O_c), variable O&M (vO&M), Fuel cost per MWh output (F_c). The factor multiplied to the Capex is the Capital Recovery Factor which is a ratio of a constant annuity to the present value of receiving that annuity for a given length of time. Note that in the annuitising formula, more costs can be added.

The "annuitising" methodology has also been previously used for hybrid applications where storage technologies are combined with power sources[12]. On the whole, the two methods give the same levelised costs when the utilised discount rate is the same and the annual energy output remains constant over the lifetime of the plant. With both assumptions holding true across the present report, the "Annuitising" methodology is used to produce the presented results.

Assumptions & Uncertainties (1/2)

A series of cost and performance decisions have to be selected as input to any LCOE model. In the context of the present analysis, the following aspects have to be kept in mind while following and interpreting the illustrated results.

- The price level of all inputs costs as well as the depicted results reflect a USD2022 price level.
- A uniform Weighted Average Cost of Capital (*WACC*) of 10% in real terms has been utilised, in order to maintain the undertaken comparison on a technological cost basis. Sensitivity analyses present an overview of broader WACC ranges for different technologies of interest.
- The capital expenditure of each invested unit is uniformly distributed across the technical lifetime based on the calculated capital recovery factor (*annuity*).
- The annual production of each unit is assumed flat across its lifetime based on the investment year's technical characteristics. Full Load Hours (*FLHs*) of VRE & Baseload RE units are based on the Technology Catalogue's capacity factor estimations, while the residual plants (coal, natural gas, biomass, nuclear) reflect FLHs according to market expectations and cost-based operational patterns. The used assumptions are listed in the table to the right.

FLHs	Plant Type	2023	2030	2050
Conventional Plants				
Coal	*All types*	7,000	7,000	7,000
Natural Gas	*All types*	5,000	5,000	5,000
Baseload RE Plants				
Hydro	*Micro/mini*	4,468	4,468	4,468
	Large	4,468	4,468	4,468
Geothermal	*Small, Large*	7,000	7,000	7,000
Biomass	*Small*	5,000	5,000	5,000
Baseload Low Carbon Plants				
Nuclear	*SMR, PWR*	7,000	7,000	7,000
VRE Plants				
Solar PV	*Rooftop*	1,791	1,841	1,891
	Ground-mounted	1,791	1,841	1,891
	Industrial	1,791	1,841	1,891
	Floating	1,841	1,891	1,990
Wind Turbines	*Onshore (Small)*	2,384	2,739	3,081
	Onshore (Large)	2,384	2,739	3,081
	Offshore (Bottom-fixed)	2,934	3,134	3,473
	Floating	2,945	3,176	3,343

Note: FLHs of weather-dependent units represent locations with good resource potential for the specific technology types, as described in the Technology Catalogue. Sensitivity analyses on the annual FLHs can be found in upcoming sections of the present report.

Assumptions & Uncertainties (2/2)

- In the context of the present analysis, the utilised fuel prices match the latest prices of national power system modelling activities, which feed the General Plan for National Electricity (RUKN) and are derived from discussions with key stakeholders and market data. The effects of fuel pricing on the observed LCOEs are discussed in a separate section. The fuel prices reflect what can be considered the opportunity costs of the given fuels, rather than the current regulated pricing for power generation (currently a maximum price of approx. 45 $/ton for the given type of coal is stipulated as part of the DMO scheme).
- The effects of an active carbon pricing scheme are not evaluated in the main section of the report due to the lack of an established system. Perspectives are however provided in an attempt to assess the potential of CCS technologies within a carbon framework.
- Potential costs for other externalities, such as human health and environmental impact of emissions to air or water, are also not included.
- A pre-considered number of annual start-up costs are already incorporated in the Technology Catalogue's cost figures for conventional units. Analysis of more explicit operational patterns have not been considered in the present report.

Fuel Type	2023	2030	2050	Units	Conversion to GJ
Typical Unit Measurement (USD_{22})					
Coal (4,500 kcal/kg)	70.0	70.0	70.0	$/ton	18.83 GJ/ton
Natural Gas	11.5	11.5	11.5	$/MBtu	0.95 MBtu/GJ
Diesel	79.0	92.0	89.0	$/barrel	5.86 barrels/GJ
Nuclear	1.1	1.1	1.1	$/GJ	-
Biomass (3,585 kcal/kg)	70.0	70.0	70.0	$/ton	15.00 GJ/ton

Fuel Type	2023	2030	2050
USD_{22}/GJ			
Coal (4,500 kcal/kg)	3.7	3.7	3.7
Natural Gas	10.9	10.9	10.9
Diesel	13.5	15.7	15.2
Nuclear	1.1	1.1	1.1
Biomass	4.7	4.7	4.7

Indonesia's Power System Transition: Exponential Demand Growth and Net Zero Emission Considerations

National Emission Targets

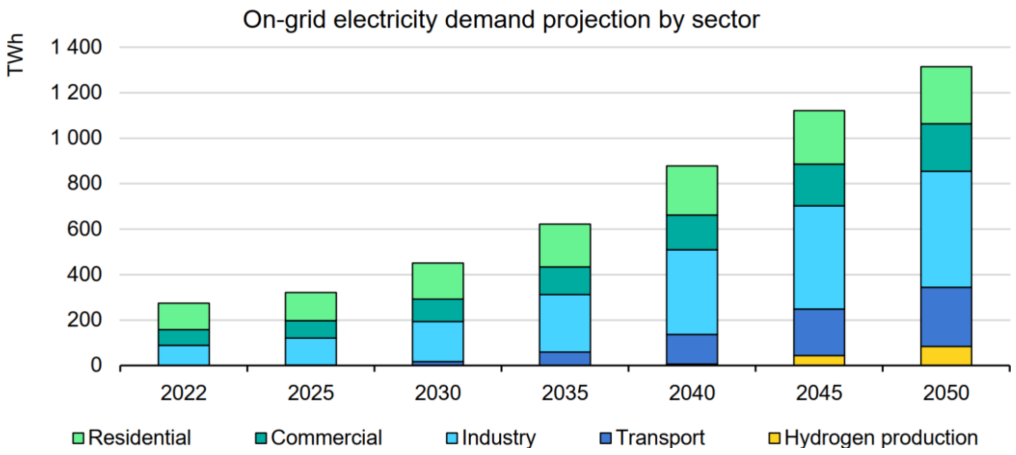
Indonesia has showed a strong commitment to reducing national emissions by ratifying the Paris Agreement in Law no. 16/2016. The first Nationally Determined Contribution (NDC) pledges in 2016, which set as a target an emission reduction rising to 29% through own efforts and 41% with necessary international assistance by 2030, was further increased to 31.9% unconditionally and 43.2% conditionally in September 2022[8].

The Government of Indonesia has also set a target to achieve a net zero emission energy system by 2060. The Just Energy Transition Partnership (JETP) is an initiative aiming to accelerate the transition to reach net zero in the power sector latest by 2050, by providing financial support for implementation of projects in Indonesia[9].

Demand Projections

With the national power demand levels projected to increase significantly in both the short and long term, today's generation fleet will need to undergo major expansions to ensure an efficient power system adequacy. Such expansion could rely on both retrofitting options and newly invested units. A mix of renewable/low carbon power sources side by side with CCS-coupled conventional generators is likely to constitute the generation mix on the long run.

Therefore, cost competitiveness considerations among various key technologies are vital going forward for the Indonesian future energy planning and this analysis aims to provide relevant insights.



Example of electricity demand projections estimating a near 5x increase by 2050 compared to today.

Source: JETP Comprehensive Investment and Policy Plan 2023

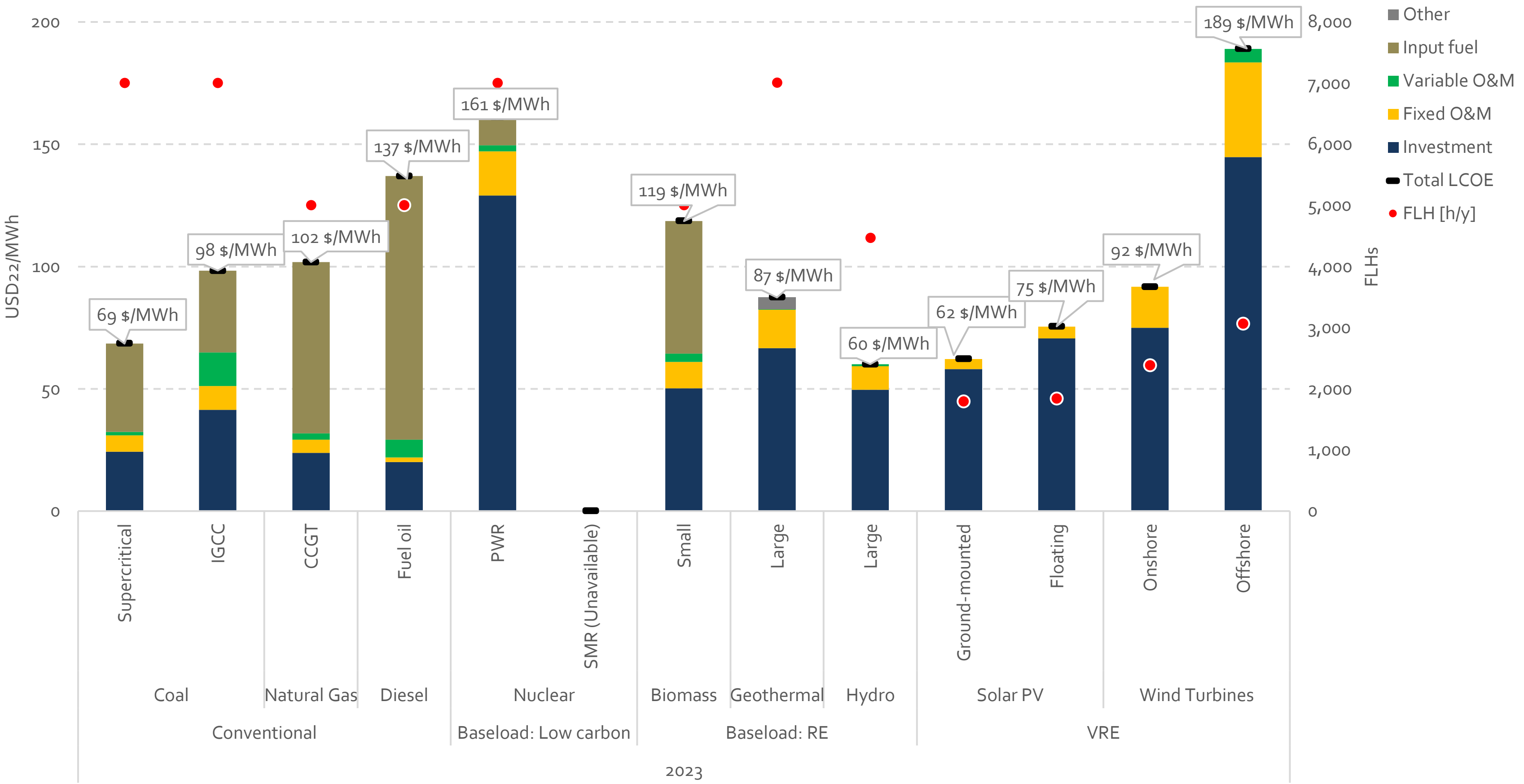
Power Generation Cost Perspectives

LCOEs Of New Conventional Plants Are Higher Than Most Of The Renewable Technologies Already by 2023 Due To Fuel Costs And Conversion Efficiencies

By evaluating the cost development of the technologies listed in the Indonesian Technology Catalogue, cost competitiveness of specific technologies can be assessed. The figures on the right (current and next slide) present the LCOEs of newly invested units under the current (2023) market data and cost development expectations by 2050. Note that only the most relevant technologies of the Indonesian power sector have been included in this analysis, while a wider range of technologies is described in the full report. Via the illustrated LCOEs, a key conclusion could be drawn:

- Investments in new conventional units are already in 2023 relatively more expensive compared to most of the RE technologies. A combination of costly input fuels, e.g. natural gas and diesel, and relatively low transformation efficiencies, e.g. coal and diesel, increase the necessary operational costs considerably, with investment and other O&M costs worsening the resulting LCOEs even further.

Newly Invested Units: 2023



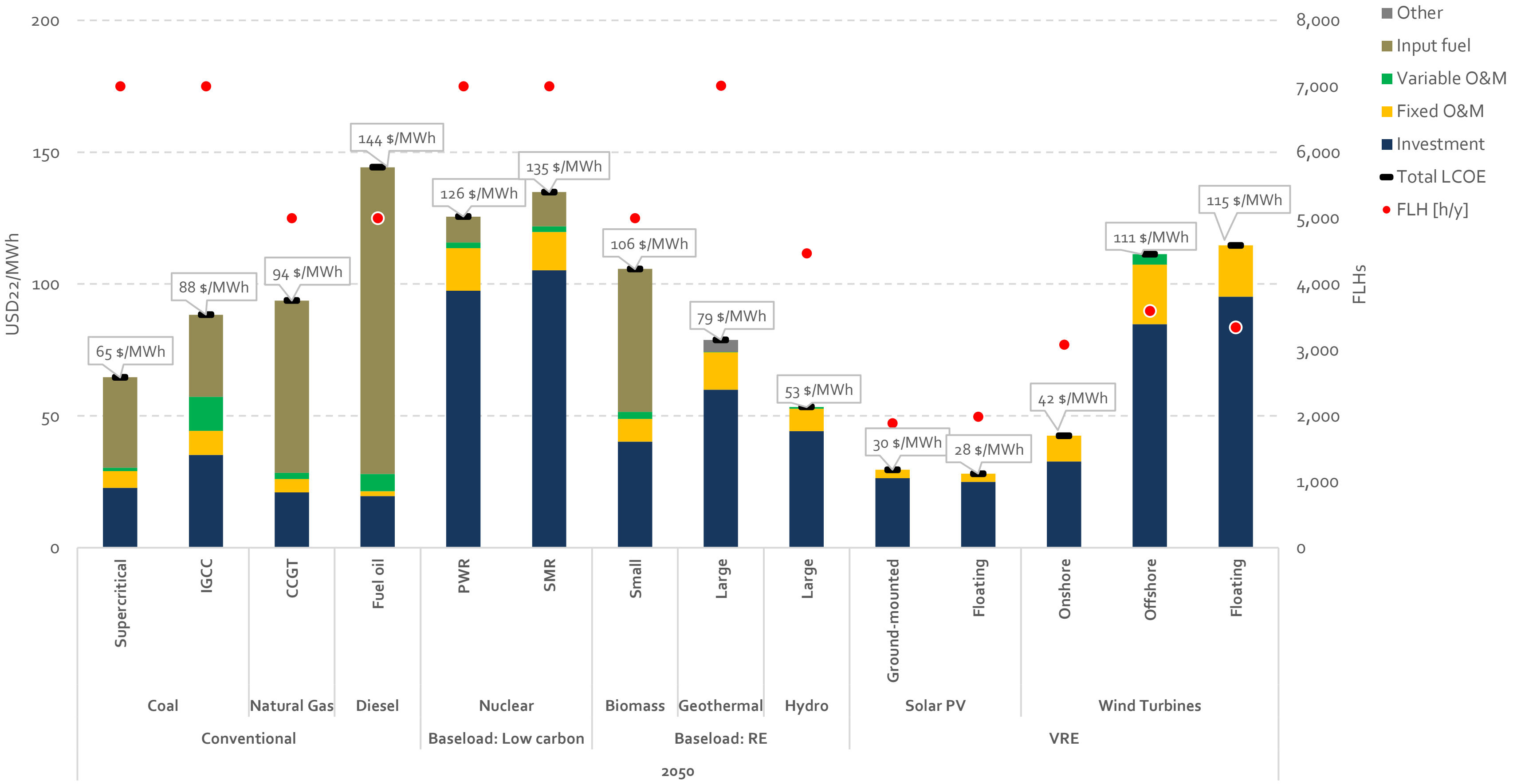
Note: The LCOE of floating wind turbines has been excluded from the figure for better visual differentiation between the residual technologies. Its LCOE rises to 272 $/MWh in 2023, attributed to ~80% investment and ~20% O&M, when operating at 2,945 FLHs.

VRE Technologies Showcase A Sharp LCOE Decrease By 2050, Unmatched By Any Dispatchable Unit

- Solar PV and onshore wind showcase a sharp LCOE drop towards 2050, mainly due to capex reductions. This does not apply to conventional baseload units. The investment cost reductions come as a result of increased installations of the given technology (learning rate effects and economies of scale). Security of supply considerations might prove to be vital for the role/competitiveness of baseload units against VRE technologies coupled with storage systems.

- Utilisation of the existing power fleet (mainly coal and natural gas units) with lifetime extensions and retrofits, has the potential to be cost competitive (at least up to 2030*) against new technological investments, due to low capital expenditure needs. For such reasons, further examinations will follow in upcoming sections.

Newly Invested Units: 2050



Note(*): LCOEs of technologies reflecting the projected maturity of 2030 can be found in the Appendix.

The Projected Trajectory of VRE Investment Costs Leads To A Sharp Decrease Of LCOEs Ranging Between 41% And 63% By 2050

On the whole, roughly similar techno-economic tendencies are expected in upcoming years for the Indonesian power sector.

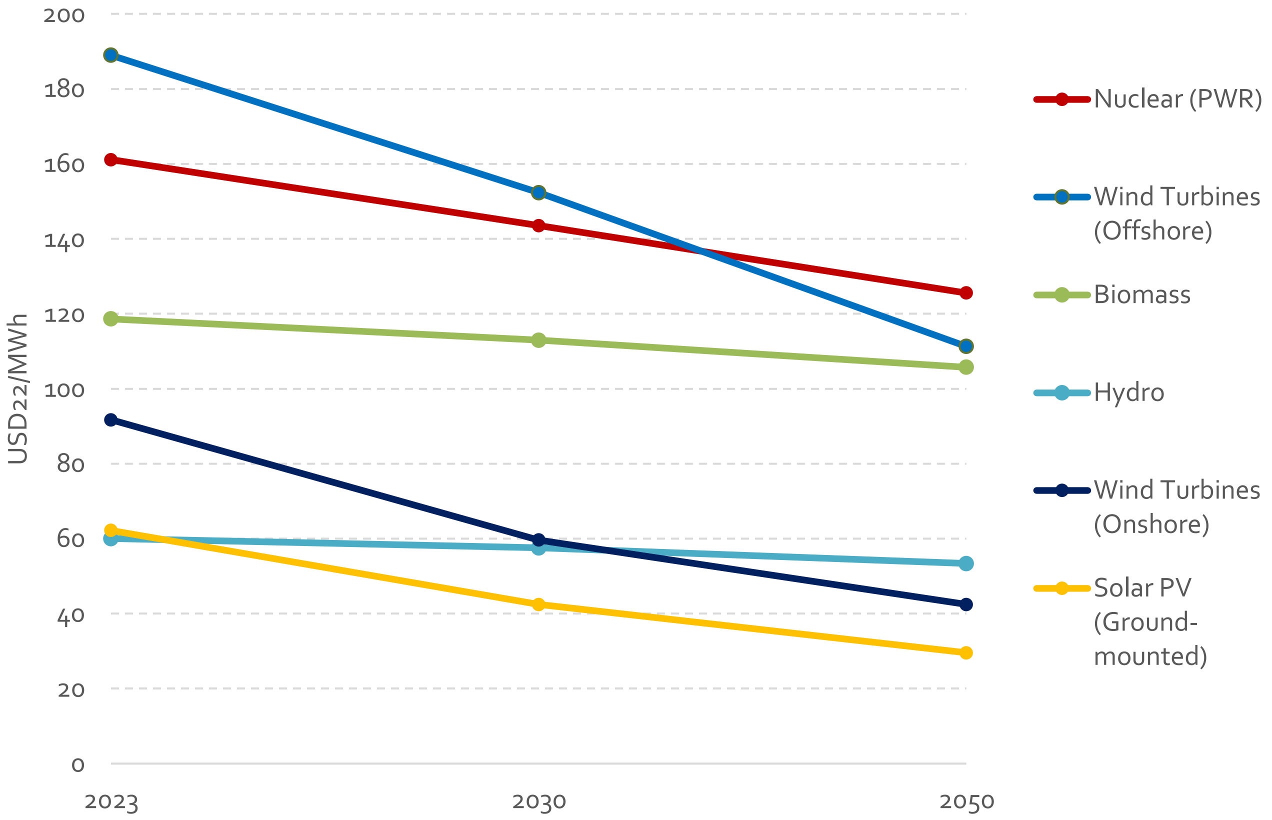
- Solar PV and Onshore Wind technologies steadily remain as the cheapest sources of additional power, after a LCOE decrease of ~33 & 49 $/MWh respectively against their 2023 value.
- The improvement of LCOEs for dispatchable units like biomass and nuclear-powered plants doesn't exceed 22% according to the estimates of the Technology Catalogue.
- On the other hand, offshore installations showcase a rapid decrease of LCOEs by 2050, ranging between 41 and 63%. Especially for floating wind turbines, a drop of 157 $/MWh between 2023 and 2050 sets the technology in a more competitive position.

An overview of LCOE tendencies across the represented years can be found below:

LCOE ($22/MWh)	2023	2030	2050	2050 vs 2023 (%)	2050 vs 2023 ($/MWh)
Nuclear (PWR)	161	144	126	-22%	-36
Nuclear (SMR)	-	173	135	-22%*	-38
Biomass	119	113	106	-11%	-13
Geothermal	87	87	79	-10%	-9
Hydro	60	58	53	-11%	-7
Solar PV (Ground-mounted)	62	42	30	-52%	-33
Solar PV (Floating)	75	45	28	-63%	-47
Wind Turbines (Onshore)	92	60	42	-54%	-49
Wind Turbines (Offshore)	189	152	111	-41%	-78
Wind Turbines (Floating)	272	178	115	-58%	-157

Note(*): Nuclear SMR technology is considered unavailable in 2023, so the comparison is on the basis of 2030 values.

LCOE Development for Selected Technologies



Insights on the Indonesian Energy Transition

Short & Long-term Priorities

A series of considerations and challenges emerge when trying to shape energy transition pathways within a given energy system:

Short-term Considerations

- How cost competitive is the existing power generation fleet?
- What retrofitting measures can be both relevant and cost competitive?
- What is the horizon that existing/retrofitted generators could operate while being cost competitive?
- What are the options for decommissioning plants with active power generation contracts and residual functional lifetime? How will the system's BPP get affected and how would any sunk costs potentially be managed?

Long-term Considerations

- How will security of supply be achieved in a heavily VRE penetrated system. Will storage coupled VRE systems be cost competitive to other baseload Low Carbon/RE technologies?
- How much further flexible capacity will be required in the power system after considering interconnections, PtX assets and Demand-Side Response (DSR) measures?
- Where do the best RE locations lie in relation to major demand centers? What transmission grid reinforcement needs emerge and what are the system cost implications shaping the optimal balance between transmission distance and VRE Full Load Hours?
- What emerging technologies may be key actors for the energy transition?

These pivotal considerations, among others, should be on the forefront of existing and future policy-making discussions. The upcoming sections aim to address a number of these concerns.

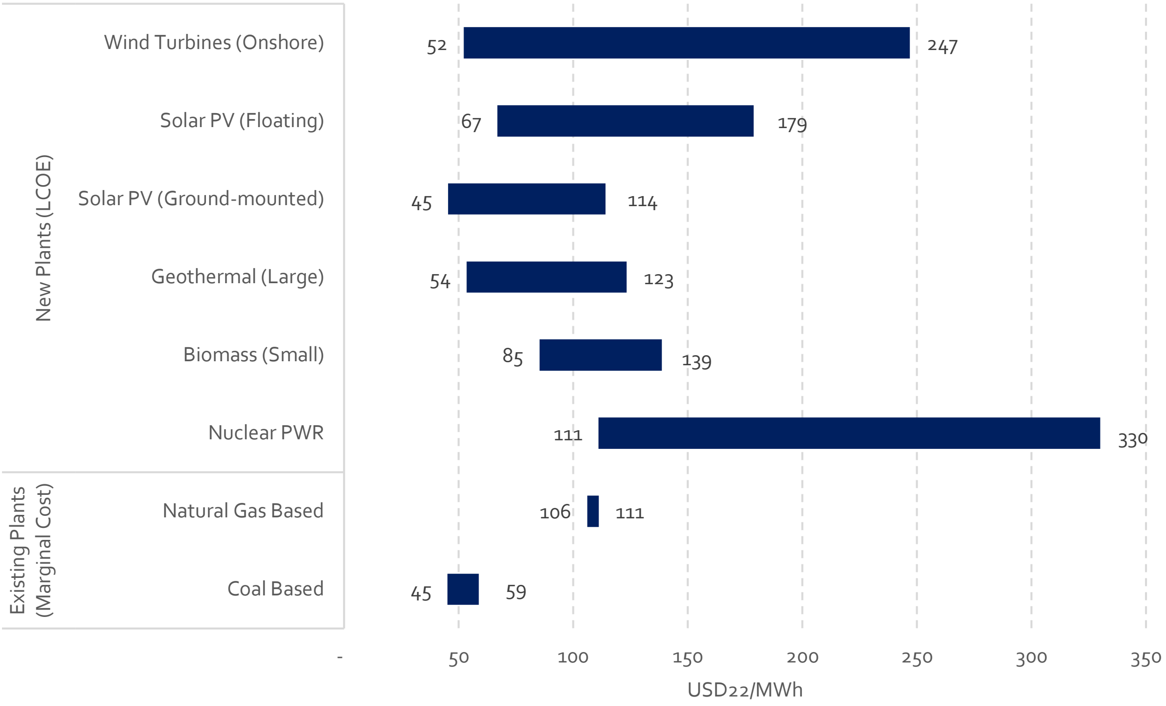
The Operational Costs Of Existing Coal Generators Can Compete Against Best-Case Unit Investments In 2023

Evaluating the cost state (marginal costs) of the existing power generators in Indonesia, and therefore aiming to feed into the conversation of the optimal timing for a potential fleet replacement would require a direct comparison with economic data of available technologies on the market and their corresponding LCOEs. Such a comparison can be derived by following today's data (2023) as presented in the Indonesian Technology Catalogue across their uncertainty spectrum. An "optimistic" and a "pessimistic" scenario will be evaluated on the basis of the following elements, presenting the best and worst expected case scenarios. As the Catalogue discusses technological cost developments, the impacts of uncertain fuel pricing will be evaluated in upcoming sections.

2023	Optimistic			Pessimistic		
Element	*Capex [m€/MW]*	*Fixed O&M [k€/MW/y]*	*Capacity Factor*	*Capex [m€/MW]*	*Fixed O&M [k€/MW/y]*	*Capacity Factor*
Wind Turbines (Onshore)	1.2	30.0	35%	2.4	70.0	15%
Solar PV (Floating)	1.2	4.5	22%	1.9	13.5	14%
Solar PV (Ground-Mounted)	0.8	3.8	24%	1.5	11.3	17%
Geothermal (Large)	3.3	82.5	100%	5.5	137.5	70%
Biomass (Small)	1.5	43.0	85%	2.6	72.0	50%
Nuclear (PWR)	7.0	20.0	85%	12.0	180.0	50%
Existing Natural Gas Plant	-	19.0	85%	-	33.5	50%
Existing Coal Plant	-	35.2	85%	-	80.7	50%

Note: Cost data for existing plants represent the lower and upper cases of the existing fleet. The assumed fuel pricing follows the already presented values of 3.7 USD/GJ (coal at 33% efficiency), 10.9 USD/GJ (natural gas at 39% efficiency), 1.1 USD/GJ (nuclear at 34% efficiency) and 4.7 USD/GJ (biomass at 31% efficiency).

LCOE Uncertainty Ranges (2023)



A number of renewable and low carbon technologies showcase LCOEs that are already today cost-competitive to the marginal costs of a part of the existing fleet (natural gas generators). Well developed VRE technologies such as large-scale ground-mounted solar PV and onshore wind turbines can already compete with some existing coal generators, if they could benefit from low market costs while taking advantage of the best potentials across the country.

On the flipside, the general approach of locating RE generators offshore when the onshore potentials are getting exhausted, prove to be highly uncertain, due to the low level of "learning effects" in 2023 but also the relatively low offshore wind potential in Indonesia.

Existing Coal-Fired Plants Might Operate At 20 - 151 $/MWh, While Natural Gas-Based Units Range Between 38 and 214 $/MWh

With the input fuels of conventional power plants being subject to both spot market pricing variations as well as national policies, a wide range of potential operational costs arise for the short but also long-term future. A short summary of the possible fuel pricing ranges that highly utilised generators might face and the corresponding operational costs is highlighted on the right.

Coal

The main types of utilised coal in Indonesia revolve around the calorific value range of 4,200 to 4,600 kcal/kg. National policies are in place to regulate a price ceiling for the domestic market of around 45 $/ton for the type of coal assumed in this analysis (4,500 kcal/kg). Indications of the market prices can be seen from the ICI II market index where the price of 4,200 kcal/kg coal hovered around 50 $/ton for the last 4-5 years. During extreme energy price periods, high prices of 130 $/ton have been observed. Efficiencies of existing coal plants can range from 20% for older subcritical up to 45% for ultra supercritical units.

- Within the context of the present study, a reference coal price of 70 $/ton will be assumed (4,500 kcal/kg), as previously described, alongside a conversion efficiency for existing plants of 33%. In parallel, the resulting operational costs for a wider range of possible input fuel prices across the current Indonesian fleet is being assessed, revealing that the operational costs of coal plants may vary from 20 to 151 $/MWh.

Natural Gas

Two types of natural gas sourcing is present in Indonesia. Pipeline gas sourcing at 6 $/MBtu (policy-regulated price) and LNG sourcing for upcoming plants in new areas with a price reference of approximately 12 $/Mbtu, reflecting the average historical Asian LNG trade. Nevertheless, the average value of the Asian spot prices has climbed to levels ~30 $/MBtu for the period 2021-2022. However, it should be considered that the largest part of natural gas quantities is being traded over long term contracts, ensuring less volatile prices. Efficiencies of existing natural gas plants can range from 30% for simple cycle turbines up to 60% for newer combined cycle plants.

- For the presented analysis, a reference natural gas price of 11.5 $/MBtu will be assumed, based on the latest market projections, with existing plants operating at a representative efficiency of 39%. Varying this price and plant efficiencies can bring the operational cost of such units anywhere between 38 and 214 $/MWh.

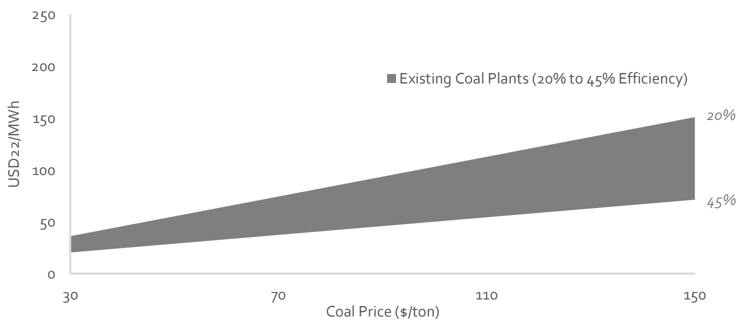
Biomass

One of the most commonly used, bar with limited potential, biomass type in Indonesia is wood waste with medium-high calorific values such as palm kernels. The corresponding national market price lies around the level of 70 $/ton, with other biomass types ranging from ~45 (lower cost agricultural waste like rice husk) to 80 $/ton (forest sawdust). International grade wood pellets in global markets such as South Korea or Japan can reach prices as high as 185 $/ton at 4,400 kcal/kg.

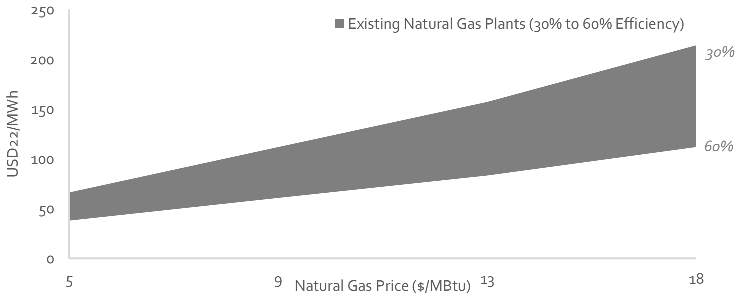
- For the presented analysis, a reference biomass price of 70 $/ton will be utilised representing higher calorific value products (3,585 kcal/kg). Exploring the price and plant efficiency ranges brings the operational cost of biomass units between 95 and 209 $/MWh.

Note: Background material for all of the utilised fuel price ranges can be found in the Appendix.

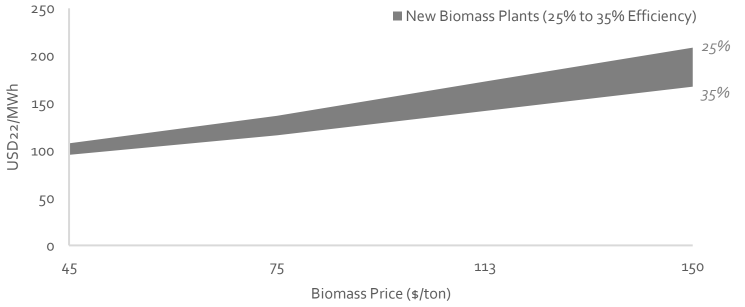
Coal Based Units: Operational Cost Range



Natural Gas Based Units: Operational Cost Range



Biomass Based Units: Operational Cost Range

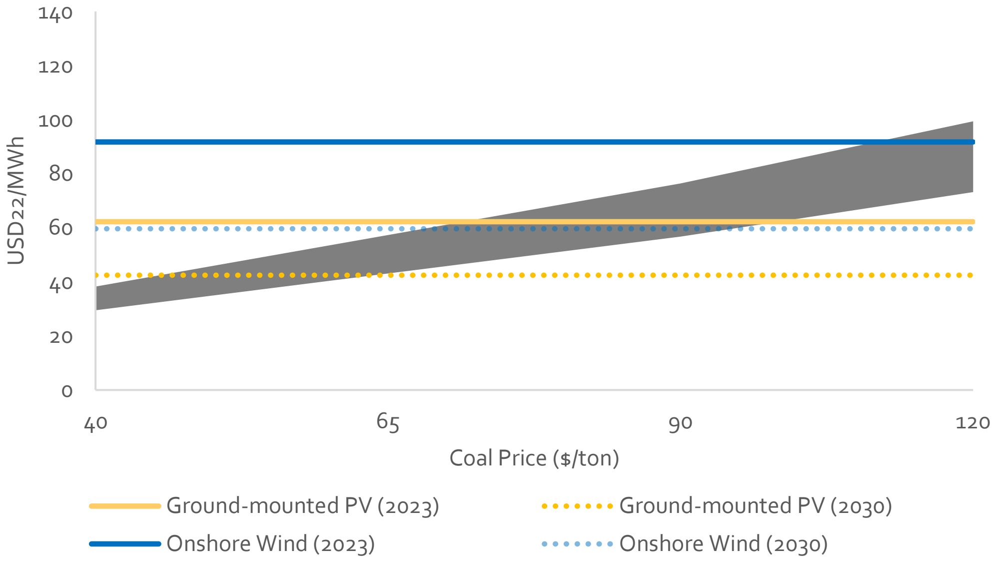


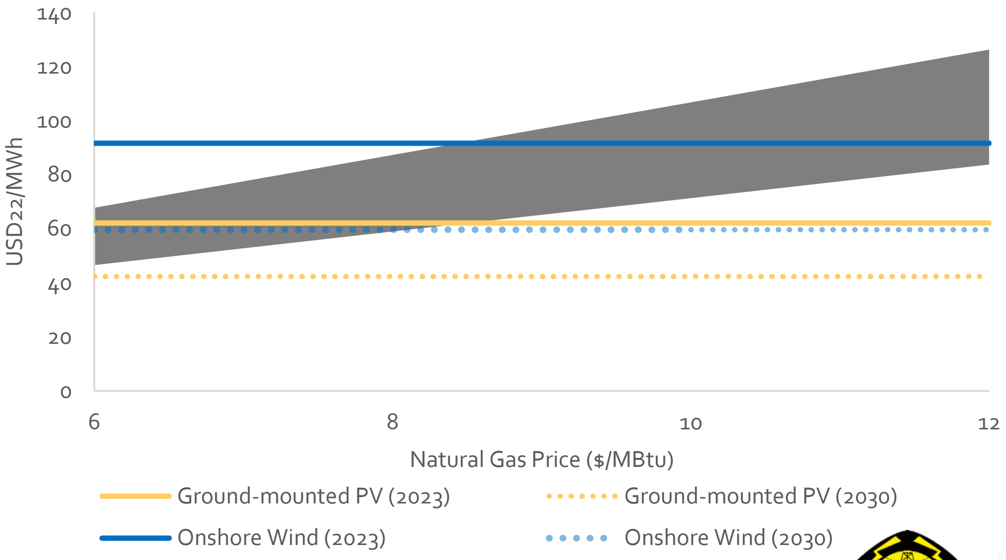
Solar PV And Onshore Wind Can By 2030 Conditionally Compete With The Existing Fleet

With the capital heavy VRE technologies proving to be cost competitive to the existing fleet already on the short-term future, the fuel-related properties of conventional existing generators (fuel cost & input-to-output conversion efficiencies) rise to the forefront of importance when assessing cost competitiveness. An analysis of the resulting marginal costs of existing plants against the LCOEs of different types of newly installed VRE generators can be seen below. The analysis is based on the Technology Catalogue data for VRE plants, while for existing units the following parameters are evaluated, reflecting the representative operational conditions of the existing fleet in Indonesia:

- **Conversion efficiencies:** Upper and lower ranges of the existing fleet.
- **Input fuel costs:** Based on ranges from local markets and policies:
    - *Coal*: 40 to 120 USD/ton
    - *Natural Gas: 6* to 12 USD/MBtu.

Evidently, coal-based generators prove to be competitive against new VRE investments on the short run (mainly before 2030), under a variety of fuel cost and efficiency occasions. The scenery changes post 2030 under the current assumptions and projections where solar PV LCOE declines even further and outperforms the largest part of the illustrated coal-based LCOE range. At the same time, the marginal costs of existing natural gas-based power plants is at the best case ~4 $/MWh more expensive than the LCOEs of new large-scale solar PV investments in 2030, while competing with the reference 2030 onshore wind investments up to a gas price of ~8 $/MBtu.


Coal Based LCOE Competitiveness


Natural Gas Based LCOE Competitiveness

Investor Risks And Operational Levels Constitute The Main Drivers Of New Investments

Plant specific expenditures (capex, connection to transmission network, storage-coupling, etc), financing conditions (WACC) as well as the expected FLHs of newly installed units can highlight the actual competitiveness that such plants are able to provide to the power system. A summary of the impact that specific factors impose on the LCOE values can be found on the table to the right. Cost considerations of retrofitting the existing fleet as well as VRE coupled with storage are discussed in upcoming sections[a,b].

A series of analyses have been undertaken over the past few years in regards to the financing conditions of VRE and low emission power plants across the world. An estimation of the expected ranges of nominal after-tax WACC according to those references can be seen below:

Source	Location	Investment Year	Solar PV	Onshore WT	Nuclear
IEA[13,14]	Indonesia	2022	6.4 to 14.0%	6.4 to 14.0%	6.5 to 14.8%
ICL[15]	ASEAN	2022	6.1 to 8.5%	6.7 to 9.6%	-
	Indonesia	2022	6.3 to 8.7%	6.8 to 9.6%	-
IRENA[16]	Indonesia	2021	4.5 to 7.5%	5.1%	-
IAEA[17]	ASEAN	2018	-	-	3.0 to 12.0%
AURES[18]	Europe	2019	2.3 to 12.1%	1.3 to 10.0%	-
OECD[19]	Viet Nam	2017	10.4%	-	-
	Across Markets	2010 to 2018	2.0 to 13.5%	2.0 to 13.0%	-

WACCs can be historically found between 1.3 to 14.8%, according to the invested technologies across the world. Therefore, the LCOEs of key renewable/low emission technologies will be evaluated within the range of 1.0% to 15.0%. Additional consideration will be given on the impacts of high/low plant utilisation (TC-based ranges for VRE, 40 to 85% capacity factors for nuclear and biomass), on plant efficiencies as well as on fuel pricing against international values.

Overall, the impact of both WACC and annual operation levels (especially of non weather-related technologies) prove to dictate the competitiveness of each project, at a considerably larger magnitude than fuel prices and conversion efficiencies.

Technology Sensitivities (2030)	Parameter Type	Parameter Value	LCOE ($/MWh)	Delta vs Reference
Ground-mounted Solar PV	Reference	80 MW, 10% WACC, 1,841 FLHs	42	-
	Small Scale (MW)	0.10	46	+ 8%
	Low WACC (%)	1.0%	18	- 58%
	High WACC (%)	15.0%	59	+ 40%
	Low FLHs (h/y)	1,522	51	+ 21%
	High FLHs (h/y)	2,174	36	- 15%
Onshore Wind	Reference	90 MW, 10% WACC, 2,739 FLHs	60	-
	Small Scale (MW)	0.90	164	+ 175%
	Low WACC (%)	1.0%	30	- 49%
	High WACC (%)	15.0%	80	+ 34%
	Low FLHs (h/y)	2,190	75	+ 25%
	High FLHs (h/y)	3,504	47	- 22%
Palm oil or Rice husk Biomass Plant	Reference	25 MW, 10% WACC, 5,000 FLHs , 31% Efficiency, 70 $/ton	113	-
	Low WACC (%)	1.0%	86	- 24%
	High WACC (%)	15.0%	131	+ 16%
	Low FLHs (h/y)	3500	137	+ 21%
	High FLHs (h/y)	7,500	94	- 16%
	Low Efficiency (%)	25%	126	+ 12%
	High Efficiency (%)	35%	107	- 5%
	Low Fuel Price ($/ton at 15GJ/ton)	45	94	- 17%
	High Fuel Price ($/ton at 15GJ/ton)	150	175	+ 55%
Nuclear	Reference	2,000 MW, 10% WACC, 7,000 FLHs , 36% Efficiency, 1.1 $/GJ	144	-
	Small Scale	300	173	+ 20%
	Low WACC (%)	1.0%	55	- 61%
	High WACC (%)	15.0%	200	+ 39%
	Low FLHs (h/y)	3,500	274	+ 91%
	High FLHs (h/y)	7,500	135	- 6%
	Low Efficiency (%)	33%	144	+ 1%
	High Efficiency (%)	40%	142	- 1%
	Low Fuel Price ($/GJ)	0.8	141	- 2%
	High Fuel Price ($/GJ)	1.4	146	+ 2%
Existing Coal Plant	DMO	7,000 FLHs, 33%, Efficiency, 45 $/ton	34	-

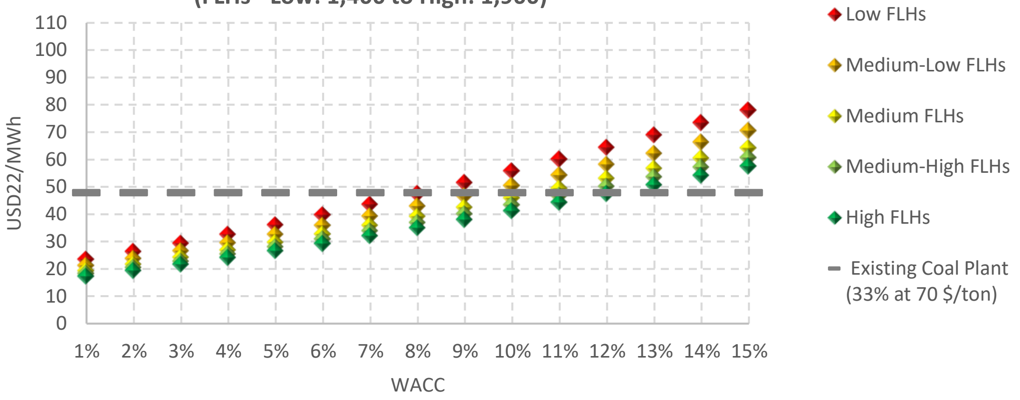
VRE Investments Would Require WACCs Below 8% For Solar PV & 3% For Onshore Wind To Compete With Coal in 2030. For Best Available Resource Potentials, These May Rise To 11% And 8% Respectively

With the reference VRE technologies being able to compete by 2030 with specific efficiency/fuel price combinations of the existing coal-based fleet in terms of LCOE, as discussed in previous sections, the natural next step would be the evaluation of the conditions which could make VRE investments less costly than the reference coal plants, operating at approximately 48 USD/MWh (33% efficiency, 70 $/ton at 4,500 kcal/kg).

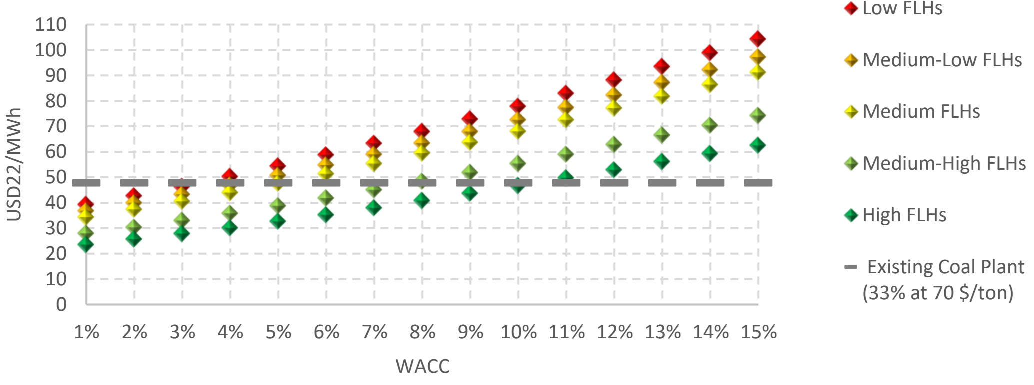
It can be seen on the right that utility scale solar PV plants can reflect a LCOE lower than the operational cost of existing coal plants, even at locations with low FLHs, for a WACC below or equal to 8%. Onshore wind would require significantly better financing conditions (WACC ≤3%) to directly compete with the existing coal fleet. Zooming in on areas with annual potentials of at least medium-high conditions, the competitive WACC ceilings can rise to 11 and 8% respectively for solar PV and onshore wind plants.

Of course, a series of considerations revolve around the feasibility of such assumptions, especially in areas with high annual capacity factors. Proximity to demand centers as well as efficient surrounding transmission grid capacity make or break the success of a business case.

Furthermore, a 1:1 comparison between VRE capacities and existing conventional plants cannot be directly drawn. Due to the climate-related nature of VRE technologies, complementarity of installed units has to be achieved to ensure high security of supply levels even in bad weather years. For such reasons, the additional costs of storage coupling (evaluated in upcoming sections) or additional power reserves should be also factored into the power system cost equation.



Conditions for Solar PV Competitiveness to Existing Fleet (2030)
(FLHs - Low: 1,400 to High: 1,900)



Conditions for Onshore WT Competitiveness to Existing Fleet (2030)
(FLHs - Low: 2,100 to High: 3,500)

Note: The selected FLHs represent a narrowed down selection of the Technology Data Catalogue's optimistic & pessimistic ranges.

Regulatory, Political and Off-Taker Considerations Are At The Forefront Of Improving Investment Conditions In Indonesia

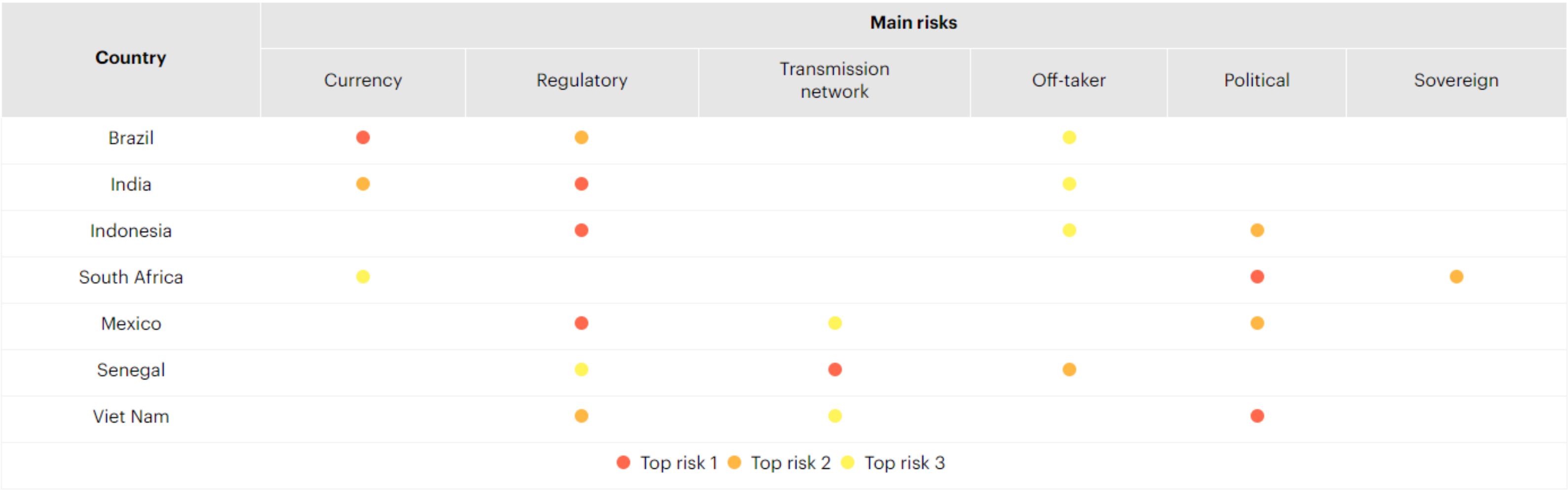
With WACC being one of the factors that showcase the highest potential of impact across multiple technologies' LCOEs, and with the assumed nominal after-tax WACC in Indonesia rising to 10% within the present study, it becomes evident that any improved financing conditions over specific technologies could provide an edge to specific investments. WACC is a function of the cost of capital and cost of debt that an investor faces, or in other words the interest rates over which money sourcing is taking place. Less risky projects allow cheaper debt lending and therefore lower project returns for breaking even.

It should of course be stressed that bibliographic WACCs of VRE technologies rarely reflect investments exposed to merchant conditions with high price and contracted volume volatility (wholesale short-term markets), or in other words increased investor risk. The underlying business models of such projects in developing economies are feed-in tariffs, long-term power purchase agreements (PPAs) or contract for differences (CfDs) providing a long term revenue certainty for investors over the project's lifetime. Merchant business cases are expected to naturally involve higher WACC factors, especially for the front-runners.

As expected, country and policy related risks are key factors of WACC levels. Competition between debt institutions could decrease the offered debt interest rates in the research of bankable projects. In parallel, the increased interest of private companies towards a green profile could also suppresses the available cost of equity and leading obtainable WACCs to lower levels.

In a recent survey, IEA summarised the top risks that selected economies have to overcome in the hunt of improved national investment conditions. For Indonesia, regulatory, political and power off-taking factors seem to rank first in investor concerns, therefore those fields could prove to be the basis of future improvement.

Risks that need to be addressed first to reduce the cost of capital in selected economies



Country	Main risks					
	Currency	Regulatory	Transmission network	Off-taker	Political	Sovereign
Brazil	🔴	🟠		🟡		
India	🟠	🔴		🟡		
Indonesia		🔴		🟡	🟠	
South Africa	🟡				🔴	🟠
Mexico		🔴	🟡		🟠	
Senegal		🟡	🔴	🟠		
Viet Nam		🟠	🟡		🔴	

🔴 Top risk 1 🟠 Top risk 2 🟡 Top risk 3

Source: IEA, 2023

Retrofitting Options for the Existing Fleet

With a number of already existing power plants installed across the country, an evaluation of their cost competitiveness in future years, while taking into account necessary plant upgrades, would be the natural next step to consider.

A series of available plant upgrade options and their subsequent cost considerations, according to the Technology Catalogue, can be seen on the below. Evaluation of those against new types of investments can be found in the next slides.

While simple cost estimates can provide an overview of each upgrade's competitiveness against new investments, a series of deliberations can prove to be pivotal in the realisation of such fleet changes:

- ○ Flexibility of retrofitted plants.
- ○ Fuel supply risks.
- ○ CCS uncertainties.
- ○ Emission measures.

	Technology 2030 (2050)	Capex (m$/MW)	Fixed O&M (k$/MW/y)	Variable O&M ($/MWh)	Electric Efficiency (%-pt.)*
Coal	20-year Lifetime Extension	+ 0.28 (+ 0.28)	+ 3%	-	-1 %
	20% Ammonia Co-firing	+ 0.15 (+ 0.14)	+ 5%	+ 5%	- 1%
	100% Ammonia	+ 0.34 (+ 0.33)	+ 10%	+ 10%	- 2%
	20% Biomass Co-firing	+ 0.16 (+ 0.15)	+ 3%	+ 3%	- 1%
	100% Biomass	+ 0.36 (+ 0.36)	+ 5%	+ 5%	- 2%
	Supercritical CCS	+ 1.91 (+ 1.27)	+ 98% (+ 65%)	+ 211% (+ 185%)	- 9%
Gas	20% Hydrogen Co-firing	+ 0.09 (+ 0.08)	+ 3%	+ 3%	-
	100% Hydrogen	+ 0.31 (+ 0.29)	+ 5%	+ 5%	-
	CCGT CCS	+ 1.12 (+ 0.70)	+ 93% (+50%)	+ 74% (+ 51%)	-9 %

Note(*): Data reflect cost changes on top of existing power plants, based on the values of the Technology Catalogue. Coal data represent Supercritical power plants, while natural gas data represent Combined Cycle Gas Turbines (CCGT). Electric efficiency comparisons represent percentage point changes, while Fixed and Variable O&M reflect percentage differences. CCS investment costs do not include transportation and storage expenditures.

Electrolysis With Solar PV Can Be Cheaper Than International H_2 Shipping Prices In 2030, Unlike NH_3 Synthesis

Hydrogen (H2) and Ammonia (NH3) are considered key options for low carbon fuels and energy carriers in the broader energy system transition. Electrolysis and steam methane reforming are two of the most widely studied methods of H2 production, with the former tending to be at the forefront of most analyses. With electrolysis operating on the basis of splitting water via electricity, and ammonia being produced by mixing hydrogen and nitrogen, the role of the anticipated power pricing in the upcoming years highly affects the expected green fuel pricing and stresses the competitiveness against imports from other countries.

Examples of expected cost ranges are provided on the right, comparing domestically produced fuels to imported ones. In a global market by 2030, IEA's estimations[20] of shipping costs (excluding production) per 10,000km of low-cost fuel rise to approximately 14-19 USD/GJ for H2 (1.7-2.3 USD/kg H2) and 2-3 USD/GJ for NH3 (0.04-0.06 USD/kg NH3). The liquefaction step and precautionary conditions for the low-temperature storage of H2 make the H2 shipping significantly more expensive than ammonia. Therefore, one option for long distance transport is to convert H2 to NH3 for the shipping and do a reconversion of NH3 to high-purity H2 after transport, which however, incurs further costs and losses.

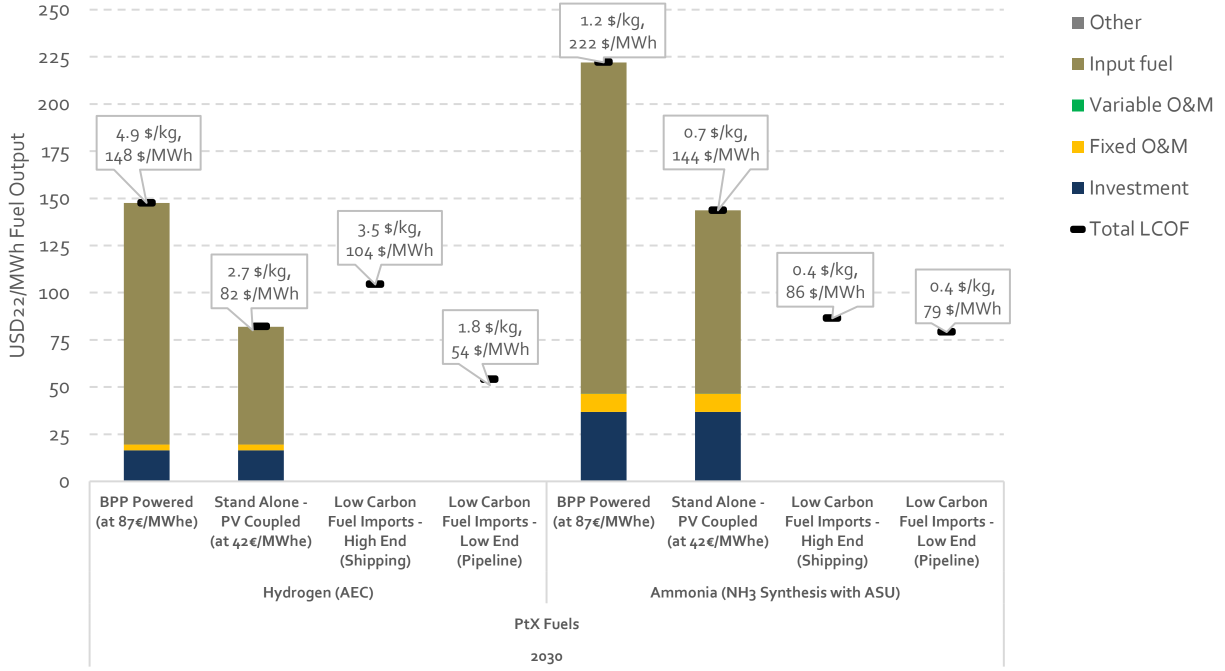
Locally produced H2 could potentially be cost competitive to external shipping costs by approximately 22 USD/MWh H2 when fed directly by solar PV-generated power at 42 USD/MWh and operating at 5,000 FLHs. However, further conversion to NH3 doesn't prove to be beneficial against imports. Therefore, the end-use of H2 could be a decisive factor on Indonesia's PtX strategy.

Overall, the resulting PtX fuel pricing would directly affect any considerations around existing plant retrofitting to PtX fuel co-firing (e.g. green ammonia with coal), as it will be examined in upcoming slides.

It should, although, be noted that the development/repurposing of a national hydrogen transmission network would surface significant additional costs for Indonesia. Especially in the case that H2 generation facilities are located far from the proximity of the demand centers or/and a potential hydrogen infrastructure, additional connection costs would reduce the gap between local production and shipping-import prices.

In any case, even considering the lower end of expected production costs of H2 and NH3, it is expected that utilising them towards power generation will prove more expensive, compared to conventional input fuels such as coal, natural gas or biomass, as it will be examined next.

Comparison of PtX Fuel Costs Depending on Production Method: 2030



Note: The "Stand Alone – PV Coupled" cost of 42 $/MWh reflect the LCOE of a newly invested ground-mounted PV plant in 2030. AEC and NH3 costs & efficiencies derived from the most recent (2023) Vietnamese Technology Catalogue for Energy storage, Renewable fuels and Power-to-x. Investment costs: AEC: 0.747 $mUSD_{19}/MW_{H_2}$, NH3 Synthesis: 1.530 $mUSD_{20}/MW_{NH_3}$ with a mark up factor of 1.09 for the incorporation of an Air Separation Unit (ASU).

H_2 And NH_3 Are Not Well Suited As Power Generation Fuels, Whereas Biomass Retrofitting Can Be Cheaper Than New Baseload Investments

While the preservation of existing natural gas-based units is already challenged in 2030 (prior to any retrofitting expenditures*) by a maximum of 52 USD/MWh from the LCOEs of new baseload-capable RE technologies e.g. biomass, geothermal and hydro (where applicable), a promising retrofitting potential for coal-fired power plants can be observed.

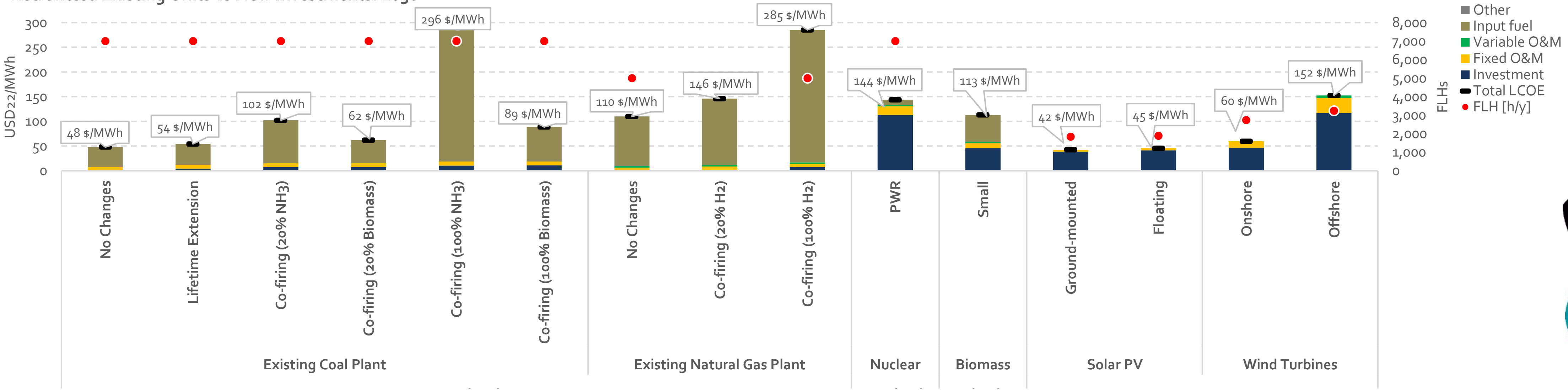
Under the evaluated cost terms, the marginal costs of existing coal-based units, including necessary life extension expenditures, are falling short to the LCOE of the most competitive VRE technologies (solar PV) by 12 USD/MWh, while outcompeting onshore wind by 6 USD/MWh in 2030.

Of course, any replacement possibilities of existing coal-based units should be set side by side with power generators which can operate by demand and are not solely weather driven, in order to ensure security of supply aspects. VRE technologies can be considered for such replacement options only when coupled to storage units, which introduce a flexible operation aspect to them while increasing the resulting LCOE/S. Further analysis of storage coupling impacts can be found in upcoming sections.

PtX-fuel fired options prove to be costly for the power system, prohibitively increasing the marginal cost of retrofitted units beyond 285 $/MWh in cases of a complete (100%) fuel shift under market terms. The utilised H2 and NH3 input fuel pricing matches the shipping options that IEA[20] estimated for 2030 at 29 and 24 $/GJ respectively. Therefore, utilisation of PtX fuels in the power system doesn't prove to be competitive with other power sources under the current cost assumptions and should only be considered in cases of peak load units supporting the system during extreme hours (i.e. operating at considerably low FLHs).

On the other hand, retrofitting of existing coal plants to co-firing (20%) or complete fuel shift (100%) to biomass can be cost competitive in 2030 against almost all baseload technologies at the illustrated FLHs. Interestingly, retrofitting of existing coal plants to 100% biomass fuel (wood pellets fueled at 6.1 $/GJ, including lifetime extension costs) emerges as a cheaper option to the installation of new biomass plants (palm oil / rice husk fueled) by approximately 24 $/MWh. Considerations of sustainable biomass use are key factors when further evaluating this option but is out of the scope of the present analysis.

Retrofitted Existing Units vs New Investments: 2030



Note (*): Existing natural gas units are assumed to have enough life expectancy for a residual 20y operation without any additional necessary lifetime extension expenditures. Coal based retrofitting reflects both lifetime extension and retrofitting capital expenditure costs.

CCS Cost Competitiveness is Influenced by CO_2 Pricing, But Remains Well Above The LCOEs of Solar PV and Onshore Wind

Due to the fact that a carbon emission scheme is not in place in Indonesia at the time of the present report, CO2 cost considerations were disregarded in the already discussed sections. Nevertheless, with the ambitious Net-Zero Emission targets of Indonesia, an introduction of a CO2 pricing mechanism would highly affect the marginal costs, and therefore competitiveness, of the existing fleet from 2030 and onwards.

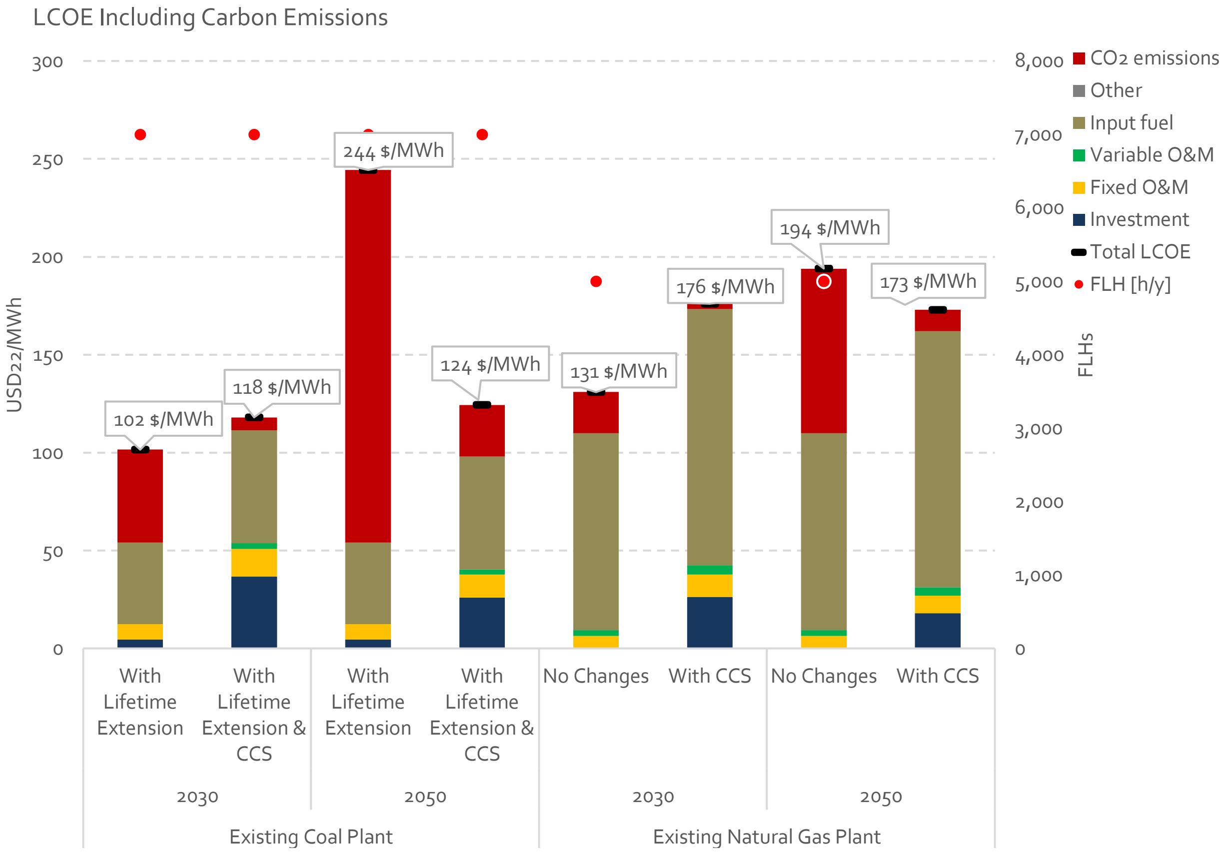
According to the latest World Energy Outlook 2023[23] by the International Energy Agency, based on the scenario structured on countries' Announced Pledges (APS), the CO2 pricing level for "*emerging markets and developing economies with net zero emission pledges*" rises to:

- **2030**: 40 USD/ton CO2
- **2050**: 160 USD/ton CO2

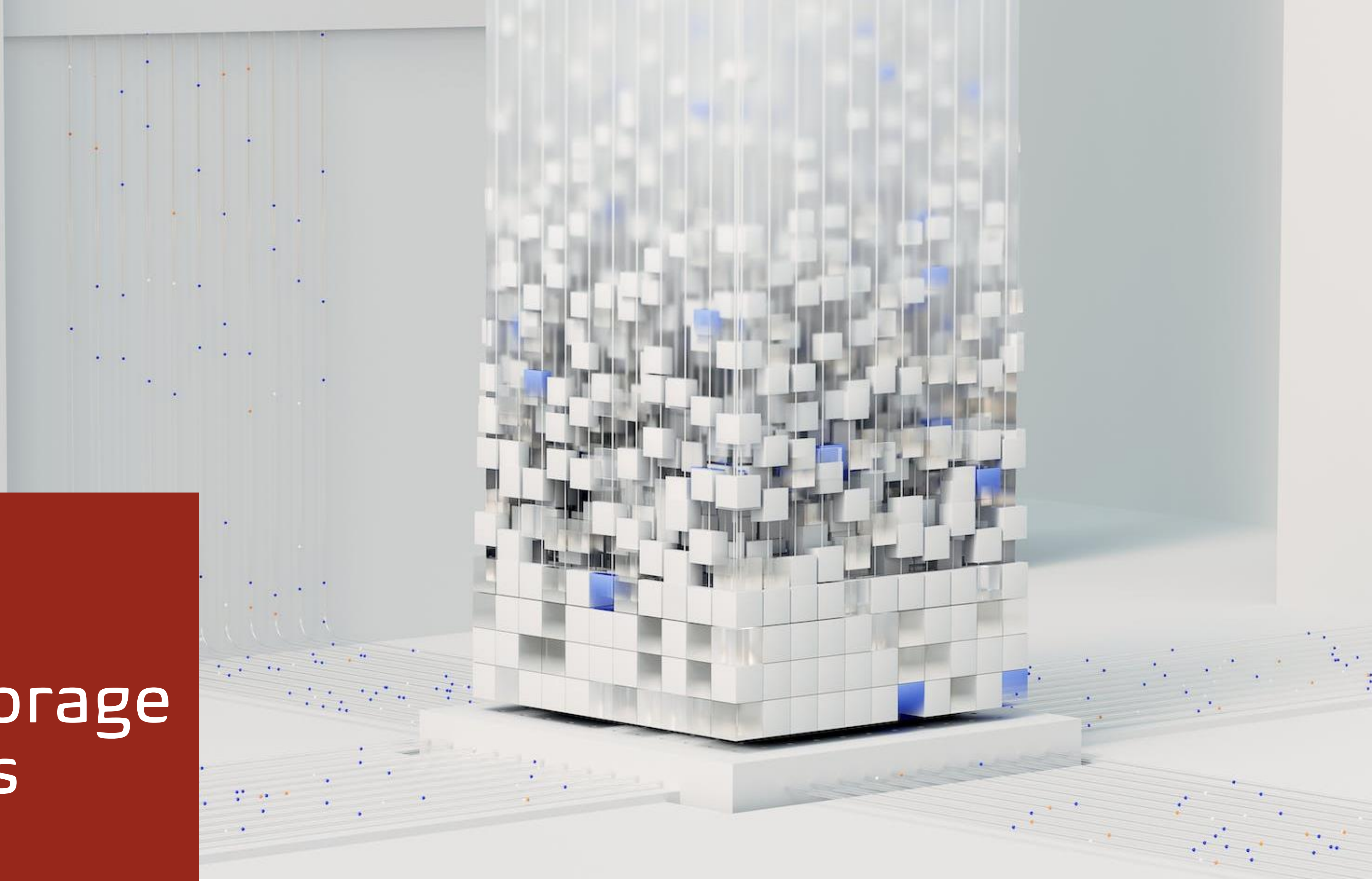
Based on such considerations, introduction of capital heavy Carbon Capture technologies to the existing fleet would translate to marginal costs >120 USD/MWh in both 2030 and 2050, a level significantly higher than the already presented LCOEs of most of the onshore VRE and Baseload technologies.

Conditionally to the available national carbon budget, operation of existing coal-based power plants in 2030 can still prove to be cost competitive to newly invested RE and Low Carbon baseload technologies even after the "penalisation" of a CO2 emission price. With an estimated LCOE of 102 $/MWh, nuclear and offshore wind installations remain more expensive on the initial assumption of a flat 10% WACC.

Overall, subject to carbon emission pricing schemes, conventional power plants with CCS reflect lower LCOEs in 2050 than their reference installations, with savings beyond 120 $/MWh for coal-based generators and 20 $/MWh for natural gas fired plants. The resulting LCOEs, however, are standing well above the LCOEs of new onshore VRE investments in 2050.



Note: Existing natural gas units are assumed to have enough life expectancy for a residual 20y operation without any additional necessary lifetime extension expenditures. Coal based retrofitting reflects both lifetime extension and retrofitting capital expenditure costs. CCS investment costs do not include transportation and storage expenditures.



Power Storage Costs

Perspectives on Electricity Storage

Storage enables electricity systems to remain in balance despite variations in wind and solar availability. From a system perspective, they appear as valuable balancing assets for periods of both shortage and abundance of power, being able to act as power generators as well as consumers with rather quick response times. From a private economic perspective, the flexibility of storages and their wide range of business opportunities in well-developed sequential electricity markets (capacity availability markets, load-shifting arbitrage, etc.) make them an attractive investment in modern portfolios.

Highly VRE penetrated energy systems are expected to heavily rely on power balancing measures, therefore the cost competitiveness of electric storage against flexible consumers (PtX assets, demand-side response (DSR)), cross-regional and international interconnections, but also green fuel based peak load generators will shed light on the role and magnitude of the presence of electric storages in the system.

Furthermore, electric storage can emerge as a pivotal actor for applications in detached/off-grid areas, directly competing with the necessities of long-range power transmission expenditures. With some of the best solar and wind potentials found in such areas, storage coupled PV and WT plants can prove to be cost competitive, especially in less densely populated regions. Diversified off-grid hybrid plant combinations such as coupled existing diesel generators / solar PV / electric storage systems could lead to reduced system costs (BPP) on the long run. Nevertheless, a more detailed analysis of such layouts is out of the scope of the present report.

Lithium-Ion Battery Investment Costs Are Projected To More Than Halve By 2050

The Indonesian Technology Catalogue includes information on two types of electric storages: lithium-ion batteries (LIB) and pumped hydro storage (PHS). Both types can provide most types of grid services, including black start. However, they reflect different characteristics in terms of discharging time and energy storage duration, which should be taken into consideration when evaluating the performance of the two.

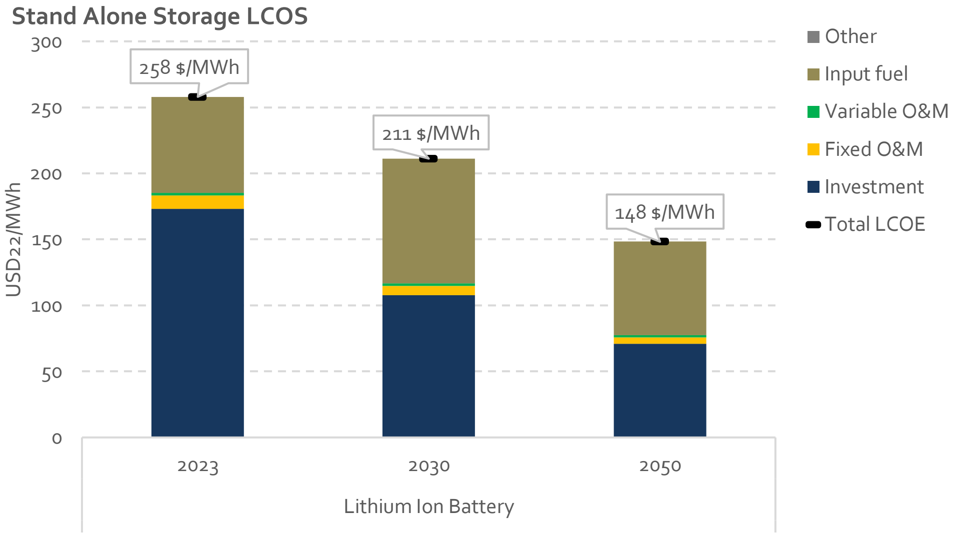
- LIB are typically configurated with a discharge time between 1 and 4 hours, while PHS typically with a discharge between 7 and 30 hours.
- LIB are suitable for full daily charge and discharge cycles (~80% depth of discharge) , while PHS applications focus on longer term energy storage.

A rough cost evaluation of a stand-alone grid-connected battery (4MWh/1MW) can be seen on the bottom right figure. The battery is assumed to be charging at 75% of the average annual system price, or in other words at 65 $/MWh, performing roughly 1 full cycle per day.

- A considerable cost decrease of the estimated stand-alone LCOS is illustrated towards 2050, mainly due to investment cost reductions and the expansion of the battery's lifetime from 15 to 25 years, leading to an LCOS (under the given assumptions) of 148 $/MWh.
- A sensitivity analysis of the 2030 LCOS as a function of electricity input prices and annual cycles can be seen below. The range of the resulting LCOS can conditionally go down to ~100 $/MWh, with the lowest values achieved at high cycling rates, which in turn leads to faster degradation of the battery or in other words lower efficiency and lifetime. A more detailed evaluation of the battery's cycling strategy is out of the scope of the present analysis.

Electric Storage Technology 2023 (2050)	Lithium-ion	Pumped Hydro
Representative Plant Volume (MWhe)	4 (4)	10,000 (10,000)
Representative Plant Capacity (MWe)	1 (1)	1,000 (1,000)
Lifetime (y)	15 (25)	60 (60)
Construction Duration (y)	0.2 (0.2)	6.0 (4.0)
Roundtrip Efficiency (%)	92% (92%)	80% (80%)
Capex	0.47 (0.23) (m$/MWh)	1.2 (1.2) (m$/MWe)
Fixed O&M (k$/MW/y)	15.0 (7.4)	18.7 (18.7)
Variable O&M ($/MWh)	2.0 (1.6)	0.94 (0.94)

	Grid-Connected LCOS ($/MWh)			**Cycles Per Year**		
	2030	**100**	**200**	**300**	**400**	**500**
Input Price $/MWh	**10**	432	222	152	117	96
	20	442	233	163	128	107
	30	453	244	174	139	118
	40	464	255	185	150	129
	50	475	266	196	161	140
	60	486	276	207	172	151
	70	497	287	218	183	162
	80	508	298	228	193	173
	90	519	309	239	204	183
	100	529	320	250	215	194
	110	540	331	261	226	205
	120	551	342	272	237	216
	130	562	353	283	248	227
	140	573	363	294	259	238
	150	584	374	304	270	249

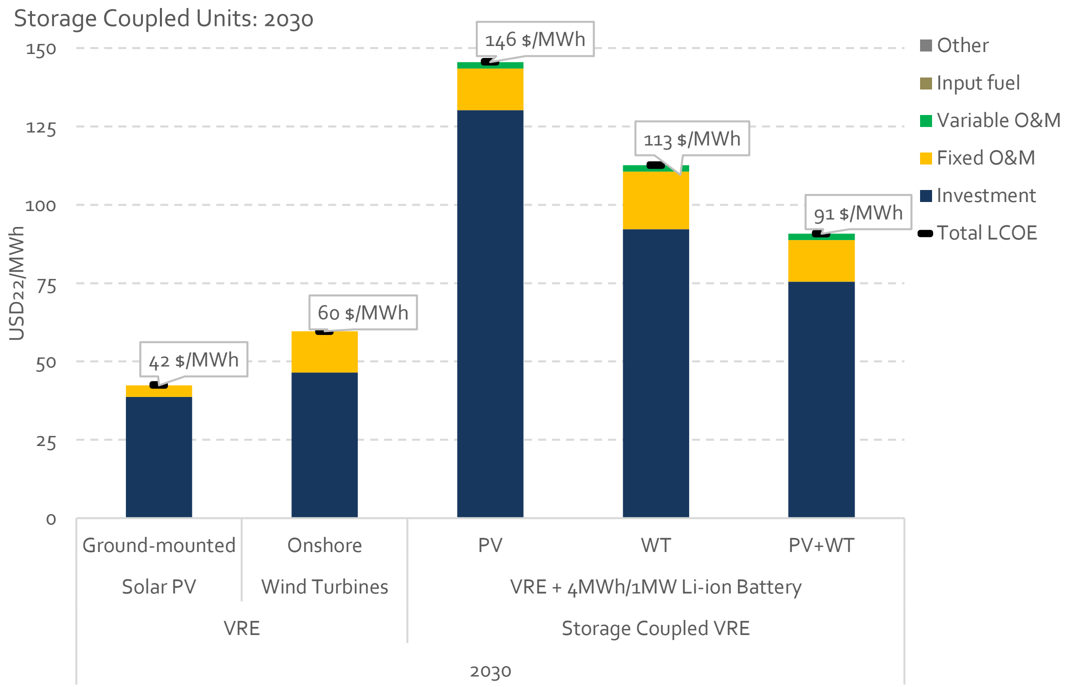


Storage Coupling With Power Generators Requires Careful Analysis, Conditional To The Desirable End Purpose Of The Stored Energy

An LCOS methodology follows the described LCOE methodology, with the only difference being that the calculation relies on the discharged electricity quantities. Evaluating the levelised cost of a coupled plant (e.g. solar PV with Lithium-ion battery) constitutes a hybrid calculation which includes the consideration of all capital and operational expenditures of both plants as well as the total generated and discharged electricity quantities after losses. The volume to capacity ratio of the battery directly affects the total investment costs as well as its utilisation strategy, therefore careful examinations of its dimensioning should be followed according to the ultimate operation purposes. Indicatively, a 1 to 1 ratio to the generating source's capacity would not necessarily translate to optimal dimensioning. Hourly generation/demand patterns alongside the needs of load shifting and peak shaving would shed light on the ideal storage characteristics.

An example is illustrated on the right for a VRE-coupled LIB of 4MWh/1MW in 2030. In the LCOS calculation it is assumed that the storages deliver the same discharged energy (MWh) per capacity (MW) per year. In other words, the annual production of the storage corresponds to the equivalent of 1,460 full load hours per year, i.e. an average of 4 discharging hours at full capacity per day. In such a setup, the LIB is almost fully charged and discharged once every day. Such a factor could directly influence the longevity of the storage, while also allow for more versatile applications. In addition, a PHS would be able to harvest the benefits of charging and discharging at more favourable times (electricity prices), making the returns on investment more favourable. However, such an aspect is not included in the present calculations. Note that under the described conditions, the total cycle-lifetime of the storages is not exceeding the ones suggested by the manufacturer.

On the whole, LIB with solar PV configurations are well-suited due to the diurnal solar patterns that dictate their operation. Wind turbines, on the other hand, reflect daily or weekly generation variations creating favourable conditions for PHS coupling. Further analysis on the dimensioning and coupling of PHS with WT in Indonesia is out of the scope of the present analysis.



Note: The figure serves as a rough cost based example without the presence of sophisticated battery modelling (charging/discharging patterns). A 1:1 sizing of the battery''s hourly capacity against the power generation source(s) is assumed. The aggregated LCOE is calculated as the total system expenditures, divided by the total "useful" electricity ending up to the grid, i.e. after efficiency losses.

Solar PV Coupled VRE Can Be Cost Competitive To New Dispatchable Units By 2050, Given A Correct Sizing And Operational Strategy

A growth of VRE penetration in a power system alongside the improvement and maturity of storage technologies usually contribute to a surge in hybrid power plant installations. Solar PV coupled batteries consist the most frequent type of investment up to date. According to Berkeley Lab[24], "*at the end of 2022, there were 374 hybrid plants (>1 MW) operating across the United States (+25% compared to the end of 2021), totaling nearly 41 GW of generating capacity (+15%) and 5.4 GW/15.2 GWh of energy storage (+69%/+88%). PV+storage plants are by far the most common, dominating in terms of plant number (213), storage capacity (4.0 GW/12.5 GWh), storage:generator capacity ratio (49%), and storage duration (3.1 hours).*"

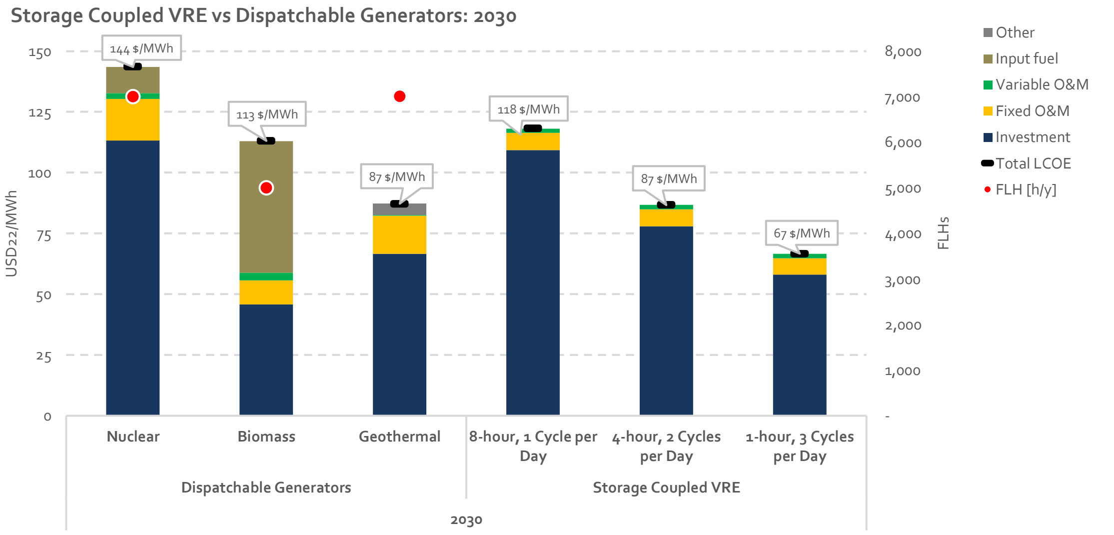
A series of different applications can consist the main business strategy of a storage asset, according to the available power market structure(s):

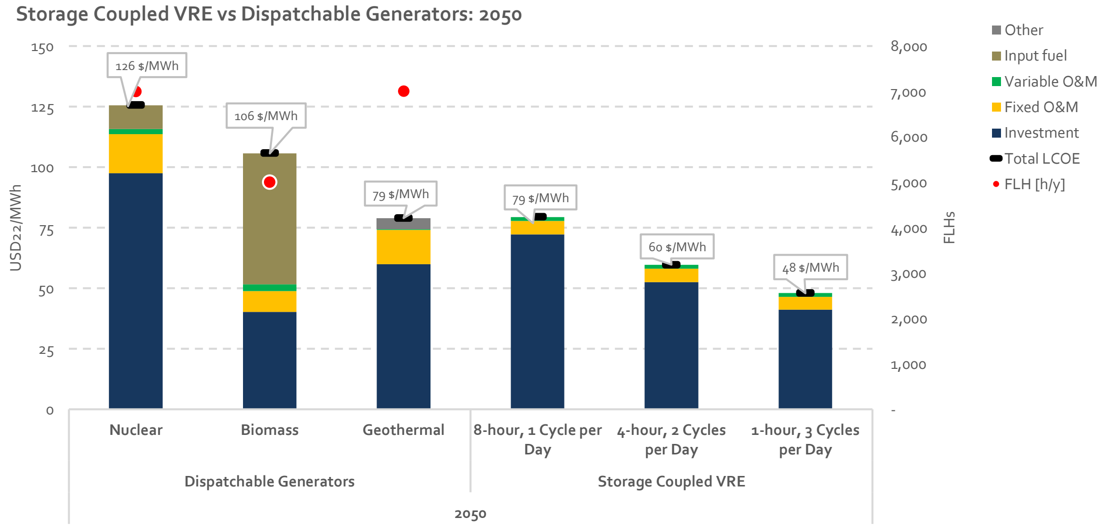
- Frequency regulation (rapid adjustments to grid frequency), peak shaving (smoothing out demand peaks), arbitrage (taking advantage of differences in energy market prices), backup power (emergency use for grid reliability), smoothing (balancing variability in renewable energy generation), capacity firming (ensuring consistent capacity availability), time-shifting (storing energy during low-demand periods), etc.

Indicatively, an example of a solar PV coupled lithium ion battery is being examined for 2050, under different volume to capacity ratios and cycling assumptions. The ratio of storage to power generator capacity will be set to 50%, following Berkeley Lab's observations[24]. Three types of storage strategies are being evaluated:

1. 8-hour battery at 1 cycle per day: charging during peak generation hours and discharging during the night.
2. 4-hour battery at 2 cycles per day: charging during demand off-peak hours and discharging during peak demand hours.
3. 1-hour battery at 3 cycles per day: imitating arbitrage-driven operations.

It becomes apparent that storage coupled VRE have the potential to compete with the LCOEs of newly invested dispatchable generators under different sizing options in 2050, mainly driven by the decreased investment costs of both generation and storage sides. Nevertheless, more thorough hourly modelling would be required to establish the optimal sizing and operational strategy of such plants as well as their position in the future Indonesian power system.


Storage Coupled VRE vs Dispatchable Generators: 2030


Storage Coupled VRE vs Dispatchable Generators: 2050

Conclusions

Following the launch of the updated Indonesian Technology Catalogue[1], which reflects the most updated market data & cost projections, a series of key conclusions can be drawn based on the undertaken Technology Cost Analysis, at an absence of a carbon emissions scheme:

I. With the Indonesian power demand projected to quintuple in the next 30 years, an expansion/replacement of the existing power fleet will be necessary. Its size and form can vary according to political action/strategies and the realized technology cost developments.

II. Low LCOE VRE investments (e.g. ground mounted solar PV, based on 10% WACC assumptions) can be cost competitive with currently operating coal and natural gas-based units already by 2030. High perception of investment risks and low FLHs consist the main drivers of the resulting competitiveness. For new VRE to be competitive with existing coal plants in 2030, WACCs below 8% and 3% for solar PV and onshore wind respectively are required. The corresponding WACC levels can rise to 11% and 8% when focusing in areas with at least medium-high full load hours (>1,550 & 2,550), pointing to potential economic benefits when utilising best available sites, condition to adequate grid infrastructure in place.

III. The cost of electricity utilised for PtX applications constitutes the main driver of the expected PtX fuel prices. Already by 2030, local H_2 generation via electrolysis can be cheaper than international shipping import estimations by as much as $22\ \$/\text{MWh}_{H_2}$, at 5,000 operational FLHs. Further conversion of H_2 to NH_3 cannot however compete with international prices. Therefore, the end use of the generated H_2 alongside the national security of supply aspects are of key importance for shaping the future Indonesian PtX strategy.

IV. Complete fuel shift of the existing fleet to PtX fuels towards power generation is prohibitively expensive under market terms, raising the operational costs of such plants beyond 285 $/MWh in 2030. However, biomass co-firing on existing coal-fired power plants (wood pellets at 6.1 $/GJ) emerges as a cost competitive option against most new baseload investments, while also being cheaper by 24 $/MWh to the LCOE of new biomass plant investments. Retrofits on existing natural gas units do not prove to be a viable option for the system.

V. CCS installations on the existing fleet of coal and gas plants results in LCOE-levels well above those of VRE, but can be cost-competitive to existing plants if a significant CO_2-pricing scheme is considered.

VI. While VRE investments are at the forefront of cost savings when considering new investments towards 2050, flexible operation via storage coupling inevitably increases the expected levelised costs. Nevertheless, storage-coupled solar PV plants reflect the potential to be cost competitive against a series of newly invested dispatchable generators, given the correct sizing according to their end goal strategy.

Supplementary Material

Glossary and Abbreviations

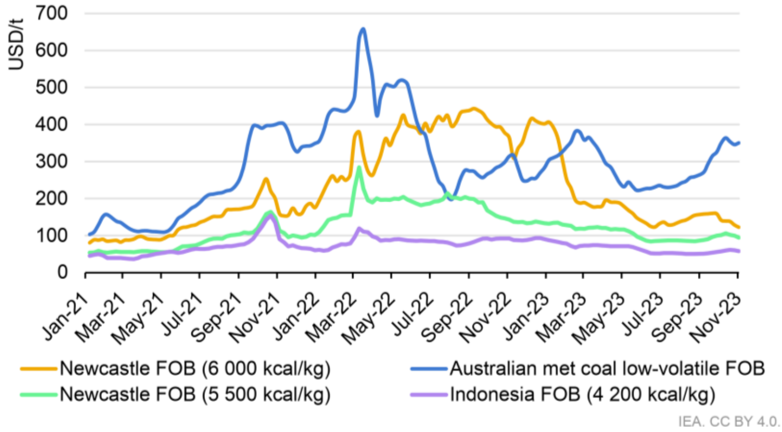
Weighted Average Cost of Capital (WACC)	*The weighted average cost of capital (WACC) is a calculation of a firm's cost of capital in which each category of capital is proportionately weighted.* *Formula notation: E and D are the total Equity and Debt, R_e and R_d the return on equity and debt respectively and T the tax rate in the country.*	$\boldsymbol{WACC} = \frac{E}{E+D} * R_e + \frac{D}{E+D} * R_d * (1 - T)$
Full load hours and Capacity factor	*Full load hours (FLH) is a convenient notion expressing the equivalent number of hours of production at rated capacity that would give the same annual generation. Multiplying the FLH value by the installed capacity gives the production throughout one year. The concept is equivalent to that of capacity factor (%); to convert capacity factor to FLH simply multiply the capacity factor by the total number of hours in a year (8760).*	$\boldsymbol{FLH}\ [h] = \frac{Annual\ generation\ [MWh]}{Rated\ power\ [MW]}$ $\boldsymbol{CF}[\%] = \frac{FLH}{8760}$

List of Acronyms

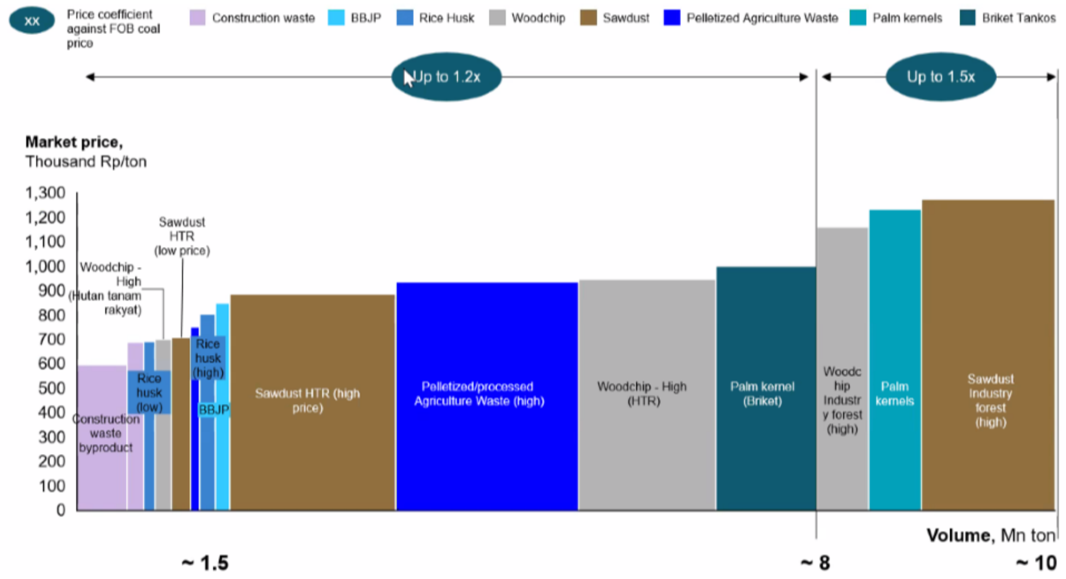
AEP	*Annual Energy Production*
BPP	*Average Production Cost (Biaya Pokok Produksi)*
CAPEX	*Capital Expenditures*
CCS	*Carbon Capture and Storage*
CF	*Capacity Factor*
FID	Financial Investment Decision
H_2	Hydrogen
LCOE	Levelized Cost Of Electricity
NH_3	*Ammonia*
OPEX (O&M)	*Operational Expenditures*
PP	*Power Plant*
PPA	*Power Purchase Agreement*
PtX	*Power-to-X*
PV	*Photovoltaics*
PWR	*Pressurised Water Reactor*
TC	*Technology Catalogue*
USD	*United Stated Dollars*
(V)RE	*(Variable) Renewable Energy*
WACC	*Weighted Average Cost of Capital*
WT	*Wind Turbines*

Fuel Pricing Benchmarking

Price markers for different types of coal in the Pacific Basin, 2021-2023



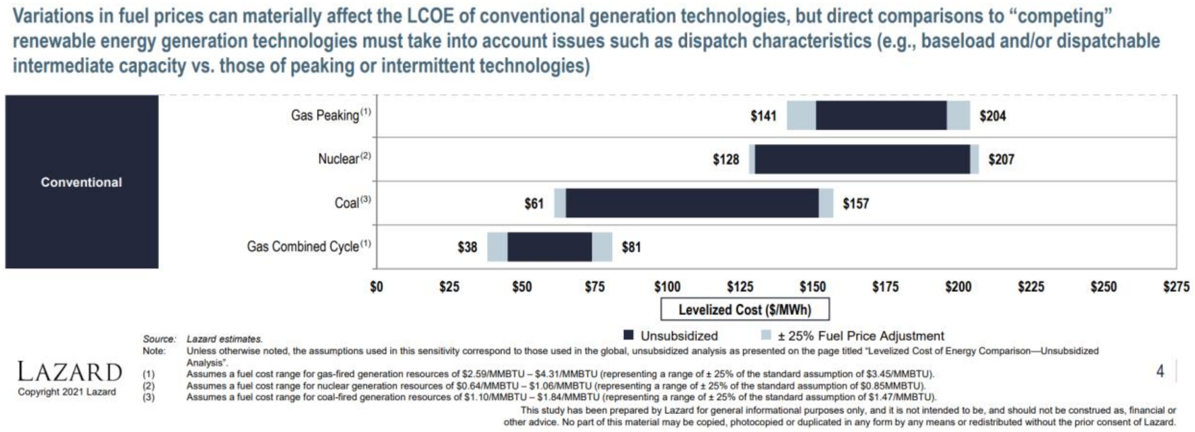
Note: FOB = free on board. Newcastle = port on the east coast of Australia.
Source: IEA analysis based on Argus Media Group. All rights reserved.



Source: PLN

Main spot and forward natural gas prices, 2020-2023

Note: Future prices are based on forward curves as of the end of September 2023 and do not represent a price forecast.
Sources: IEA analysis based on CME Group (2023), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements, LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; Powernext (2023), Spot Market Data; S&P Global (2023), Platts Connect.



Variations in fuel prices can materially affect the LCOE of conventional generation technologies, but direct comparisons to "competing" renewable energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. those of peaking or intermittent technologies)

Source: *Lazard estimates.*
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the global, unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".
(1) Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a range of ± 25% of the standard assumption of $3.45/MMBTU).
(2) Assumes a fuel cost range for nuclear generation resources of $0.64/MMBTU – $1.06/MMBTU (representing a range of ± 25% of the standard assumption of $0.85MMBTU).
(3) Assumes a fuel cost range for coal-fired generation resources of $1.10/MMBTU – $1.84/MMBTU (representing a range of ± 25% of the standard assumption of $1.47/MMBTU).

Sources:
Lazard LCOE version 15.0
Coal 2023 (IEA)
Medium-Term Gas Report 2023 (IEA)
PLN presentation materials

List of References (1/2)

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2	**Perusahaan Listrik Negara (PLN)**	*https://web.pln.co.id/*
3	**DG Electricity (DJK)**	*https://gatrik.esdm.go.id/*
4	**Ministry of Energy and Mineral Resources of the Republic of Indonesia (Kementerian ESDM)**	*https://www.esdm.go.id/*
5	**National Energy Council (Setjen DEN)**	*https://den.go.id/*
6	**International Energy Agency (IEA)**	*https://www.iea.org/*
7	**International Renewable Energy Agency (IRENA)**	*https://www.irena.org/*
8	**Folu Net Sink: Indonesia's climate actions towards 2030 (Ministry of Environment and Forestry, 2023)**	*https://www.menlhk.go.id/cadmin/uploads/PHOTO_BOOK_FOLU_NET_SINK_Indonesia_s_Climate_Actions_Towards_2030_a3d4f1fa43.pdf*
9	**Just Energy Transition Partnership (European Commission, 2022)**	*https://ec.europa.eu/commission/presscorner/detail/en/ip_22_6926*
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12	**A Techno-Economic Analysis of a PV-Battery System in Greece (Kosmadakis I.E., Elmasides C., Eleftheriou D., Tsagarakis K. P., 2019)**	*https://www.mdpi.com/1996-1073/12/7/1357*

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14	Global Energy and Climate Model (International Energy Agency, 2023)	*https://www.iea.org/reports/global-energy-and-climate-model*
15	ASEAN Renewables: Opportunities and Challenges (Imperial College Business School, 2023)	*https://imperialcollegelondon.app.box.com/s/ljbfhcwzkgwjgq0595icicn1wj829vfn*
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19	Assessment of a social discount rate and financial hurdle rates for energy system modelling in Viet Nam (Coleman Brendan, 2021)	*https://www.oecd-ilibrary.org/environment/assessment-of-a-social-discount-rate-and-financial-hurdle-rates-for-energy-system-modelling-in-viet-nam_a4f9aff3-en;jsessionid=MJFlcNzhW4Unb3Hxmby5kqBMpJEybLI7qs4rNzS1.ip-10-240-5-23*
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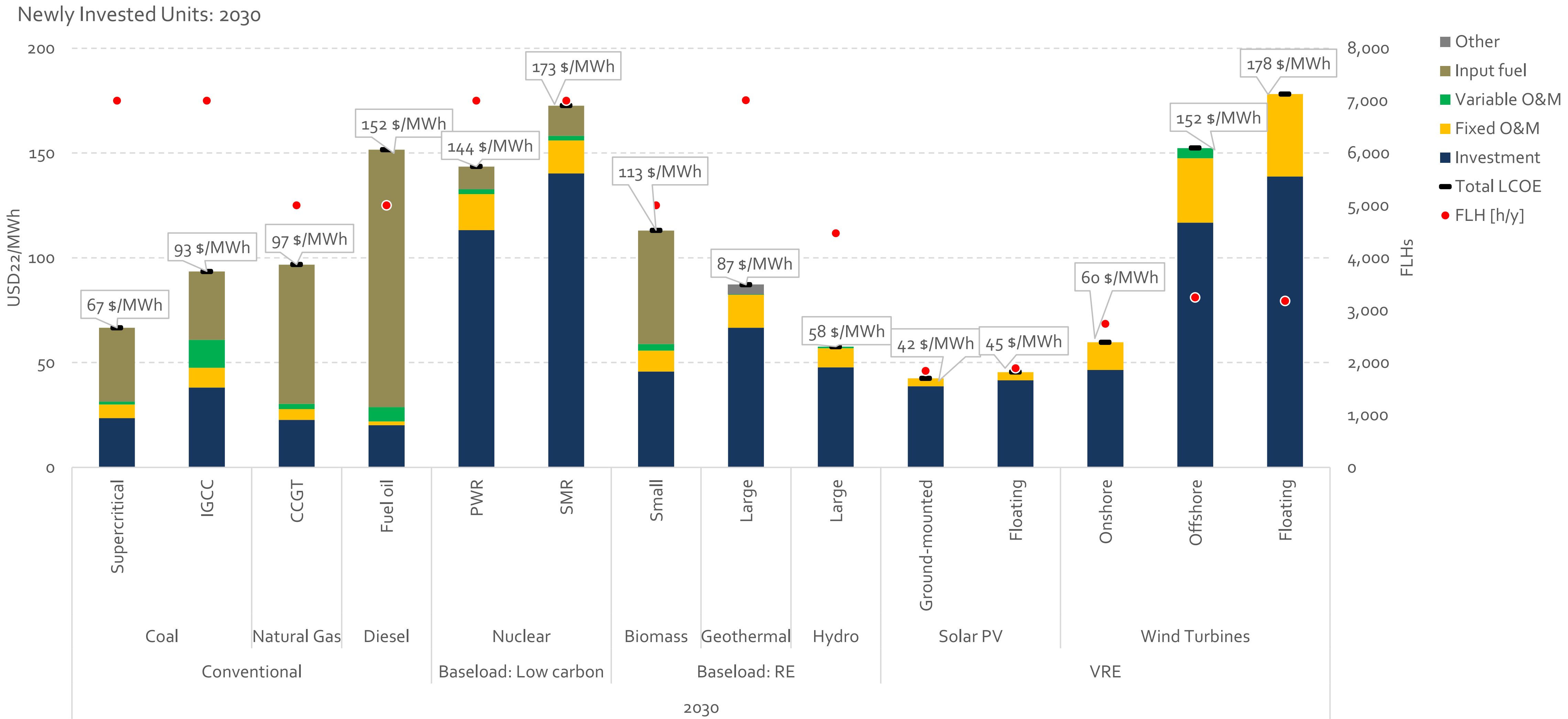
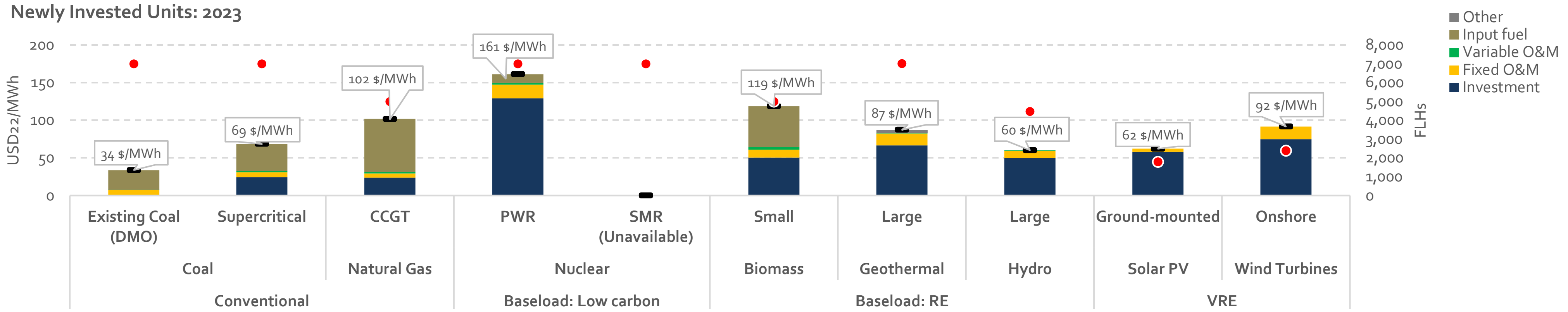
21	Viet Nam Technology Catalogue for Energy Storage, Renewable Fuels and Power-to-X (Danish Energy Agency, 2023)	*https://ens.dk/sites/ens.dk/files/Globalcooperation/viet_nam_technology_catalogue_2023_-_energy_storage_renewable_fuels_power-to-x_eng.pdf*
22	European Hydrogen Backbone (2023)	*https://ehb.eu/files/downloads/ehb-report-220428-17h00-interactive-1.pdf*
23	World Energy Outlook 2023 (International Energy Agency, 2023)	*https://www.iea.org/reports/world-energy-outlook-2023*
24	Hybrid Power Plants: Status of Operating and Proposed Plants (Berkeley Lab, 2023)	*https://emp.lbl.gov/hybrid#:~:text=At%20the%20end%20of%202022,(%2B69%25%2F%2B88%25).*

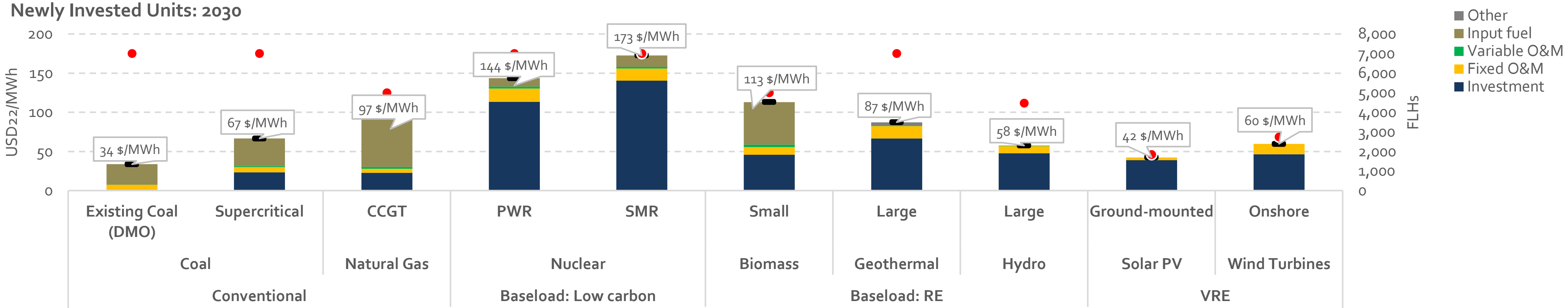
Additional Figures

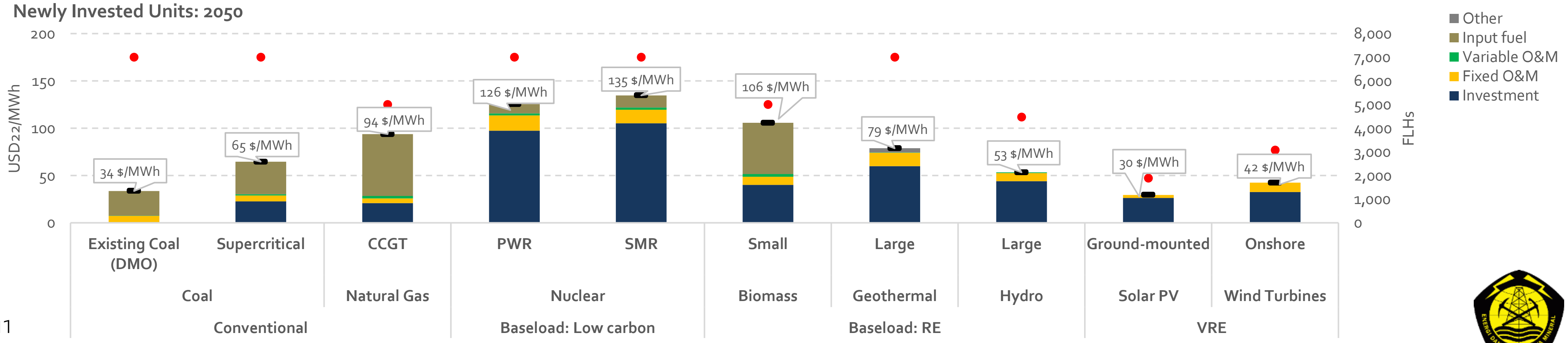
LCOE Of Newly Invested Units In 2030



Power Generation Cost Overview (excl. any Offshore Units)







Note: Existing Coal (DMO) represents a technology with the presented properties but operating at an input fuel cost of 45 $/ton, rather than the 70 $/ton utilised across the present study.

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