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Chapter 6
The Role of Battery Energy Storage Systems and Market Integration in Indonesia's Zero Emission Vision

Pramudya, Muhammad Indra al Irsyad, Han Phoumin, and Rabindra Nepal

Abstract Indonesia has committed to achieving net zero emissions by 2060, with emphasis on the electricity sector eliminating harmful gas emissions by that year. Using the Balmorel energy model, this study simulated the impact of the target on optimal capacity expansion, electricity production mix, emissions, and electricity supply costs across 230 grid systems. The results indicate the substantial benefits of integrating solar photovoltaics (PV) and Battery Energy Storage Systems (BESS). Solar energy sees a remarkable capacity increase, reaching 288.7 GWp by 2060. Other renewable sources, including hydro and wind energies, also exhibited significant growth, increasing from 6.2 GW and 130 MW in 2030 to 29.4 GW and 22.5 GW, respectively, by 2060. Intermittent renewables' growth necessitates a rise in BESS capacity from 1 MW in 2022 to 73.4 GW by 2060. The study also underscores to replace phased-out coal-fired power plants with nuclear power by 2060. The study concludes with policy implications arising from these findings.

Keywords Balmorel energy model · Regional electricity systems · Power plant expansion · Electricity production cost · Super grids

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Pramudya
Directorate General of Electricity, Ministry of Energy and Mineral Resources, Jakarta, Indonesia

M. Indra al Irsyad (✉)
Faculty of Technology, Policy and Management, Delft University of Technology, NL-2600 GA Delft, The Netherlands
e-mail: mind001@brin.go.id

Research Center for Behavioral and Circular Economics, National Research and Innovation Agency, Jakarta, Indonesia

H. Phoumin
Economic Research Institute for ASEAN and East Asia (ERIA), Jakarta, Indonesia

R. Nepal
School of Business, University of Wollongong, Wollongong, NSW, Australia

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Abbreviations

ABB e7	The ASEA Brown Boveri (ABB) Ability e7 platform modeling software
ABM	Agent-Based Modelling
AIM	Asia-Pacific Integrated Model
BESS	Battery Energy Storage System
CCS	Carbon Capture Storage
CF	Capacity Factor
CFPP	Coal-Fired Power Plants
CGE	Computable General Equilibrium
CO_2e	Carbon dioxide equivalent
EV	Electric Vehicles
ExSS	Extended Snapshot Tool
HSD	High-Speed Diesel
IAM	Integrated Assessment Model
IESR	Institute for Essential Services Reform
IPP	Independent Power Producers
JAMALI	Java-Madura-Bali
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
LEAP	Long-range Energy Alternatives Planning system/Low Emissions Analysis Platform
LPG	Liquefied Petroleum Gas
MEF	Ministry of Environment and Forestry
MEMR	Ministry of Energy and Mineral Resources
NPP	Nuclear Power Plants
NZE	Net Zero Emission
OSS	Online Single Submission
PLN	State-owned Electric Company
PPA	Power Purchase Agreement
PPU	Private Power Utility
PtX	Power to Hydrogen
PV	Photovoltaic
REBED	Renewable Energy-Based Economic Development
REBID	Renewable Energy-Based Industrial Development
ROR	Run-Off-River
RUKN	National Electricity General Plan
RUPTL	Electricity Supply Business Plan
Simple-E	Simple Econometric Simulation System
TIMES	Integrated MARKAL-EFOM1 System
VRE	Variable Renewable Energy
WASP	Wien Automatic System Planning
WH	Wellhead
ZE	Zero Emissions

1 Introduction

The threat of climate change has led to a global call for action to reduce emissions in all economic sectors, including energy. East Asian countries, including Indonesia, face similar concerns, with a projected increase in emissions from two million tons CO_2e in 2018 to 25 million tons in 2050 due to energy consumption and the absence of effective intervention (Kimura and Phoumin 2021). Indonesia, the world's largest coal exporter, confronts unique challenges in providing clean energy to its 272 million population. Coal remains the primary source of power in the country, accounting for 62% of electricity generation in 2020, causing emissions levels of 273 million tons CO_2e in 2019 (MEF 2021b).

Indonesia is currently committed to ensuring zero emissions in its electricity sector by 2060, with one proposed solution being to phase out coal-fired power plants and increase renewable energy utilization. Whileeveral studies have explored optimal low-carbon energy mixes for Indonesia's power plants, only a few have analyzed optimal generation expansion plans for regional electricity systems (Al Irsyad et al. 2019, 2020; IESR et al. 2021; PLN 2021). The PLN (2021) study was the most comprehensive, as it analyzed isolated small systems, although it focused only on PLN's electricity supply without giving due consideration to CCS.

This study aims to address gaps in previous research by asking the following questions about Indonesia's goal of achieving net zero emissions in the electricity sector by 2060: What the optimal generation expansion plan under the NZE target would be, how much BESS capacity said plan would require, and what impact would CCS have on these. The hypothesis is that VRE capacity will increase significantly. The rests of this study are as follows: Literature review in Sect. 2, data and methodology in Sect. 3, findings in Sect. 4, policy implication discussions in Sect. 5, and conclusions in Sect. 6.

2 Literature Review

Indonesia has set an ambitious target of achieving NZE in all economic sectors by 2060, as shown in Table 1. Food and land use sectors are expected to play a significant role in reaching this target, reaching negative emissions by 2030. The energy sector, including electricity, industry, transportation, and buildings, is expected to follow, reaching peak emissions by 2030 before gradually declining to 153 million tons CO_2e by 2060. The electricity sector alone is expected to reach zero emissions by 2060 after peaking at 1022 million tons CO_2e by 2030, resulting in − 6 million tons CO_2e net emissions by 2060.

Several studies have explored low-carbon generation expansion plans in Indonesia using different energy models, as outlined in Table 2. Siagian et al. (2017) used the AIM/CGE global energy model and recommended geothermal and hydropower development to reduce emissions. Van Soest et al. (2021) analyzed the possibility of

Table 1 Indonesia's proposed NZE roadmap by economic sector

Sector	2010	2020	2030	2040	2050	2060
Energy	453	688	1022	978	684	153
• Electricity	140	198	421	342	140	0
• Industry	145	208	241	345	312	62
• Transportation	96	151	191	102	94	65
• Buildings	73	132	169	189	138	26
Agriculture	84	88	94	98	102	101
Food and land use	470	98	– 140	– 246	– 304	– 326
Industrial processes and product use	35	55	62	55	50	45
Waste	89	139	198	170	120	87
Net emissions (million tons of CO_2)	**1131**	**1068**	**1244**	**1038**	**540**	**– 6**

Source MEF (2021a)

achieving NZE in the energy sector by 2070, sooner than the 2080 global average forecast, using six IAM models to evaluate carbon neutrality targets for 10 major emitting countries. Fragkos et al. (2021) applied the AIM/ExSS to predicted that the NZE vision would drive renewable energy share to at least 30% of primary energy consumption by 2050. Reyseliani and Purwanto (2021) used the TIMES model and reported that the including nuclear power in the 100% renewable energy 2050 vision would potentially reduce electricity production costs by 9.7% over the same vision without nuclear.

Studies shown in Table 2 using bottom-up energy models provide a more detailed analysis of Indonesia's electricity systems. The energy model commonly used in developing countries is LEAP (Al Irsyad et al. 2017), as applied by Kumar (2016) to estimate the impact of renewable energy development on emissions reductions in Indonesia and Thailand. Phoumin et al. (2020) used it to appraise the potential hydrogen production from renewable energy development in the Association of Southeast Asia Nations (ASEAN) region. Kimura and Phoumin (2021) used LEAP to update the long-term energy outlook for the East Asia Summit plus the United States (US) (EAS17). Handayani et al. (2022) applied it to assess ASEAN member states' roadmaps to NZE in electricity sector, projecting that solar capacity and storage would reach 78% of total installed power by 2050.

Other bottom-up energy models may provide more robust, detailed analyses. Al Irsyad et al. (2019, 2020) developed PowerGen-ABM, a hybrid energy model, to optimize power plants owned by PLN, IPP/PPU, and rental services in 15 primary electricity systems. Their studies projected high electricity shares from solar energy in North Sulawesi, Southeast Sulawesi, East Nusa Tenggara, Maluku, and North Maluku. IESR et al. (2021) applied the LUT Energy System Transition Model to analyze seven main electricity systems in eight regions; it was the only study to consider rooftop solar PV in Indonesia's optimal generation expansion plan.

Table 2 Studies of power plant expansions in Indonesia

Energy model	Study	NZE	Multi-country analysis	Regional electricity system	Energy storage	Rooftop solar PV	Nuclear power plant	Electricity grid integration	CCS
ABM	Al Irsyad et al. (2019, 2020)	×	×	✓	×	×	×	×	×
AIM/CGE	Siagian et al. (2017)	×	×	×	×	×	✓	×	✓
AIM/ExSS	Fragkos et al. (2021)	✓	✓	×	×	×	✓	×	✓
Balmorel	MEMR (2019)	×	×	✓	✓	×	×	✓	×
Balmorel	Prasodjo et al. (2016)	×	×	×	×	×	×	×	×
IAM	Van Soest et al. (2021)	✓	✓	×	×	×	×	×	✓
LEAP	Handayani et al. (2022)	✓	✓	×	✓	×	✓	×	✓
LEAP	Kimura and Phoumin (2021)	✓	✓	×	×	×	✓	×	×
LEAP	Kumar (2016)	×	✓	×	×	×	✓	×	×
LEAP	Phoumin et al. (2020)	×	✓	×	✓	×	✓	✓	✓
LUT energy system transition model	IESR et al. (2021)	✓	×	✓	✓	✓	✓	✓	×
TIMES	Reyseliani and Purwanto (2021)	✓	×	×	✓	✓	✓	×	✓
WASP	PLN (2021)	×	×	✓	×	×	✓	×	×

The official bottom-up energy models for the generation expansion plan in Indonesia are WASP and Balmorel. PLN (2021) used WASP together with ABB e7 and Energy Exemplar Plexos to prepare RUPTL, with due consideration for programs related to electric vehicles (EV), rooftop solar PV, pumped storage, BESS, and electricity systems in each province. Meanwhile, MEMR officially used Balmorel for Energy Outlook Indonesia (Prasodjo et al. 2016) and RUKN (MEMR 2019). While Prasodjo et al. (2016) integrated Balmorel and LEAP, their analysis neglected regional electricity systems, energy storage, rooftop solar PV, and system integration. MEMR (2019) projected power plants operated by PLN and PPU in every province, albeit similarly overlooking nuclear. This study aims to extend MEMR (2019), which was conducted to analyze power plant expansions, to meet the NZE vision by duly encompassing nuclear power plants, CCS, green hydrogen, and power plants owned by PLN and PPU in its analysis.

3 Methodology and Data

3.1 Methodology

Figure 1 shows that there are two stages in this analysis, electricity demand projections and the optimal generation expansion plan. Electricity demand projections combine the results of Simple-E, LEAP, and additional exogenous electricity demand from priority programs such as smelter projects, new industrial clusters, special economic zones, priority tourism locales, and integrated fishery and marine centers. First, Simple-E was used to estimate electricity demand models on residential, commercial, public, and industrial sectors using 20 years of provincial data on consumption, numbers of customers, gross domestic product (GDP), inflation, population, and average electricity prices.

Second, econometric regression analysis was applied to Simple-E to estimate the sectoral electricity demands for 230 electricity grid systems in 34 provinces. The electricity demand projections were later aggregated into total national electricity demand projections and used as an input in LEAP. This was followed by the re-estimating total electricity demand projection in LEAP by considering the impact of energy switching programs, including replacing LPG stoves with induction cookers, EV, new energy development including green hydrogen and green fuel, and energy conservation programs. Additional exogenous electricity demand was added from various prioritized development programs to the 230 grid systems. The total electricity demand projection from LEAP was migrated again to Simple-E and disaggregated to provide projections for the aforementioned 230 electricity grid systems. Transmission and distribution losses are forecast to decline from 9% in 2021 to 4.5% by 2060.

The Balmorel model (Wiese et al. 2018) was later used to simulate the optimal generation expansion plan from 2022 to 2060 for the 230 grid systems. comprising 39

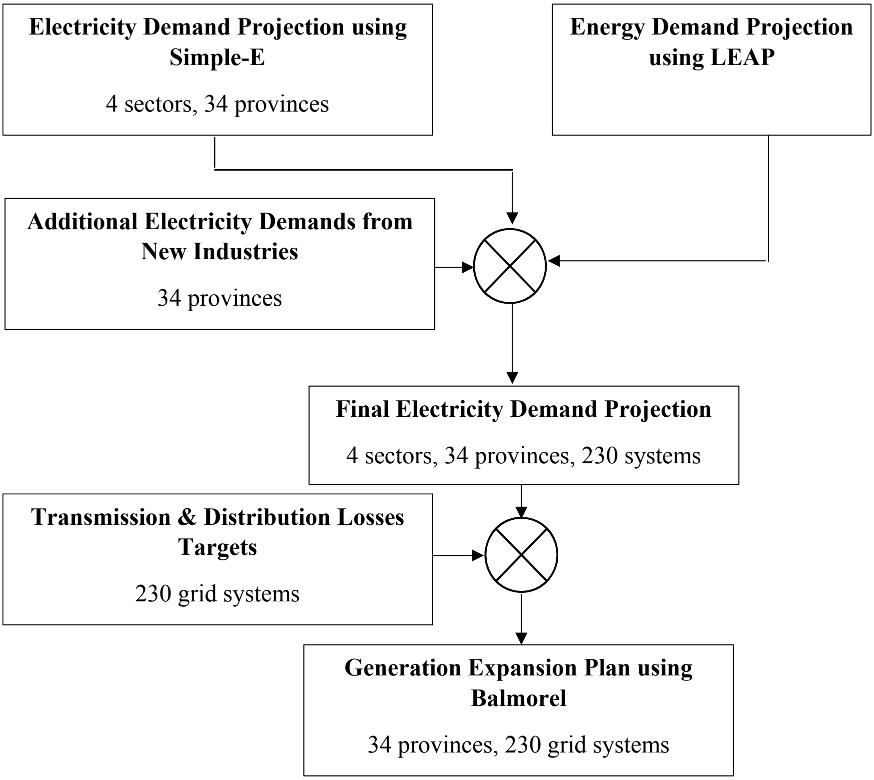

Fig. 1 Analysis flowchart

national PLN, 90 remote PLN, and 101 PPU grid systems. The simulations used more than 1000 power plants, 208 time slices, and 8736 hourly dispatches, annually. The objective function of the model was to minimize the Z costs of capacity expansion costs, unit commitment, and economic dispatch on system y in year t:

$$\begin{aligned} Min\ Z_y = &\ electricity\ production\ cost + hydrogen\ production\ cost + fuel\ cost \\ &+ new\ power\ plant\ investment\ cost \\ &+ new\ transmission\ investment\ costs + Unit\ starting\ cost \\ &+ Online\ O\&M\ cost \end{aligned}$$

$$\begin{aligned} Min\ Z_y = &\sum_{g,t} c^e_{g,t} \cdot G^e_{g,t} + \sum_{g,t} c^h_{g,t} \cdot G^h_{g,t} + \sum_{g,f,t} c^f_{g,t} \cdot F^f_{g,t} + \sum_{g} \left(a \cdot c^I_g + c^{fix}_g\right) I_g \\ &+ \sum_{g} a \cdot c^I_x \cdot I_x + \sum_{g,t} c^s_{g,t} \cdot S_{g,t} + \sum_{g,t} c^o_{g,t} \cdot O_{g,t} \end{aligned}$$

Key:

Indexes					
g:	Technology	h:	Hydrogen	x:	Transmission line
c:	Cost	f:	Fuel	a:	Areas
e:	Electricity	t:	Time	w:	Emissions
Coefficients/relationships					
a:	Annual capacity recovery	κ:	Nominal unit size	Loss:	Loss factor
η:	Marginal efficiency	r:	Variable resource	A:	Annual resource
c:	Extraction coefficient	K:	Capacity	T:	Target
c^e:	Back pressure coefficient	m:	Minimum unit load	W:	Emission factor
k:	Idle fuel consumption				
Variables (endogenous)					
G:	Generation (MW)	I:	Investment (MW)	O:	Units online (units)
D:	Demand (MW)	S:	Start units (units)	L:	Storage level (MWh)
X:	Transmission (MW)	Dn:	Shutdown (units)	Z:	System costs

Subject to:

(a) Balance of electricity supply, i.e., electricity production and imported electricity, and demand, i.e., exported electricity + local electricity demand:

$$\sum_g G^e_{g,t} + (1 - loss_x)X^{Import}_{x,t} = \sum_x X^{Export}_{x,t} + D^e_t$$

(b) Balance of hydrogen supply and demand:

$$\sum G^h_{g,t} = D^h_t$$

(c) Fuel costs for generating electricity, hydrogen, and idle fuel consumption:

$$F^f_{g,t} = G^e_{g,t} \Big/ \eta^e_g + G^h_{g,t} \Big/ \eta^h_g + k^f_g . \kappa^f_g . O^f_{g,t}$$

(d) Fuel input of power plant g at hour t should be adequate for the minimum electricity production, i.e., the product of minimum unit load, nominal unit size, and the number of online units):

$$F^{f}_{g,t} \geq m_g \cdot \kappa^{f}_{g} \cdot O_{g,t}$$

(e) Total availability of fuel f cannot exceed the annual resource of fuel f:

$$\sum_{g\,f,t} F^{f}_{g,t} \leq A_f$$

(f) For the power plant, g, electricity production and its hydrogen production at hour t cannot exceed the power plant capacity K:

$$G^{e}_{g,t} - c^{v}_{g}.G^{h}_{g,t} \leq K^{e}_{g}$$

The electricity production at hour t is greater than or equal to its hydrogen production:

$$G^{e}_{g,t} \geq c^{b}_{g}.G^{h}_{g,t}$$

(g) The capacity of the hydrogen generator is equal to electricity demand divided by generator efficiency:

$$G^{h}_{g,t} = \frac{D^{e}_{g,t}}{\eta_h}$$

(h) Total capacity of new and existing power plants cannot exceed the annual resource of fuel f:

$$\sum_{g\,f} \left(K_g + I_g\right) \leq A_f$$

(i) Tal capacity of new and existing power plants should be greater than or equal to the capacity target of power plant g:

$$\sum_{g\,f} \left(K_g + I_g\right) \geq T^{K}_{f}$$

(j) Total electricity production in each hour t should be greater than or equal to the full load hour requirement:

$$\sum_{t} G^{e}_{g,t} \geq FLH_g \cdot \left(K_g + I_g\right)$$

(k) Electricity production of VRE g at hour t cannot exceed variable resources f multiplied by the sum of power plant capacity and investment:

$$G_{g,t} \leq r_t^f \cdot \left(K_g + I_g\right)$$

(l) Energy storage level L of hydropower plant g in the following year (t + 1) is the sum of the energy storage level in year t and hydro energy production minus electricity production from hydro:

$$L_{g,t+1} = L_{g,t} + r_t^{HY}.\left(K_g + I_g\right) - G_{g,t}^e$$

(m) Transmission capacity X is less than or equal to existing transmission capacity K plus new transmission line capacity:

$$X_{x,t} \leq K^x + I^x$$

(n) Total emissions, i.e., the product of emission factor W and fuel consumption f, cannot exceed the emission target:

$$\sum_{g \sim f} W_w^f \cdot F_{g,t}^f \leq T_w$$

The Balmorel model was used to simulate the NZE scenarios defined in Table 3. The BaU scenario was not focused on achieving NZE, which is why it allows new CFPP construction, whereas the ZE scenario prohibits new CFPP construction beyond the commitment made and under construction as stated in the RUPTL PLN 2021–2030. The phasing-out of fossil-fueled power plants was based on a lifespan of 30 years for coal-fired and 25 years for gas- and oil-fueled. The NZE scenario does not strictly aim for zero electricity emissions, and offers possible reduction of residual emissions in other sectors. This scenario thus allows construction of new CFPPs equipped with CCS. Both ZE and NZE scenarios allow only renewable power plant construction after 2030.

Sensitivity analysis was conducted by changing electricity demand projections, solar capacity growth limit, and demand flexibility. Assumptions low and high electricity demands in 2060 were 1942 TWh and 2366 TWh, respectively. The low electricity demand scenario considered increased energy efficiency in all sectors, whereas the high scenario anticipated a massive shift in industrial energy demand from gas and coal to electricity causing an increase in the electricity share to 80% of total industrial energy demand by 2060 compared with 51% in the BaU scenario. As recorded solar PV capacity in 2021 stood at only 190 MWp and significant growth in the near future was deemed unrealistic, maximum solar PV growth in 2060 was limited to 200 GWp (low), 400 GWp (medium), and 600 GWp (high).

Last, the electricity load pattern was changed by shifting portions of evening peak loads to daytime. This scenario was used to anticipate naturally flexible electricity

Table 3 Scenario definitions

Scenario	BaU	ZE	NZE
NZE target	No emission reduction target	Zero carbon by 2060 or earlier	Residual carbon sink by other sectors
New CFPP	Yes	No, except as stipulated in RUPTL	Only CFPP with CCS
CCS	Yes	No	Yes
NPP	Yes	Yes	Yes
Initial capacity	Existing, ongoing, committed, and planned power plants in RUPTL	Existing, ongoing, committed, and planned power plants in RUPTL	Existing, ongoing, committed, and planned power plants in RUPTL
Investments	No constraints	• No new investments in coal and diesel power plants • Investments for other fossil energy power plants allowed until 2030 • Investments beyond 2030 only for renewables and NPP	• No new investments in CFPP without CCS and diesel power plants • Investments for other fossil energy power plants allowed until 2030 • Investments beyond 2030 only for renewables, NPP, and CCS
Flexible electricity demand	None	• EV smart charging • Green hydrogen plants • Super grid infrastructure	• EV smart charging • Green hydrogen plants • Super grid infrastructure

demand and EVsmart charging, PtX, flexible demand response, and super grid, which is the interconnection of electricity grid systems in 51 regions to transmit renewable energy production among same. It was hypothesized that the flexible demand could reduce power plant peak load and energy storage requirements.

3.2 Data

Data for the simulation were obtained from sources including retrieval of technology and cost data from DEA et al. (2021), which provided a power plant technology and cost database for Indonesia. In Fig. 2, the LCOE of intermittent renewables was projected to decline over time between 2020 and 2060. Solar power plants incur added technology cost when equipped with BESS. Energy storage LCOS was also projected to show a decline from US \$0.127/kWh in 2020 to US \$0.086/kWh in 2030, US \$0.069/kWh in 2040, and US \$0.052/kWh in 2050–2060. Figure 2 also

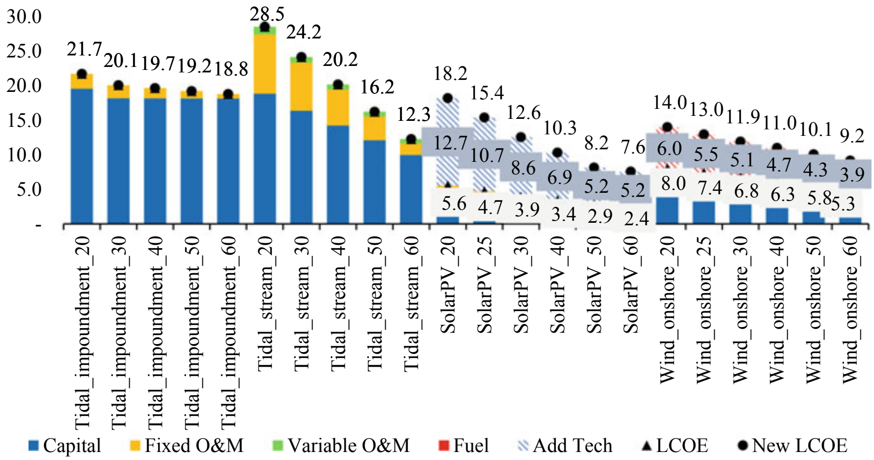

Fig. 2 LCOE (¢US$/kWh) for tidal, solar energy, and wind turbine. *Source* DEA et al. (2021)

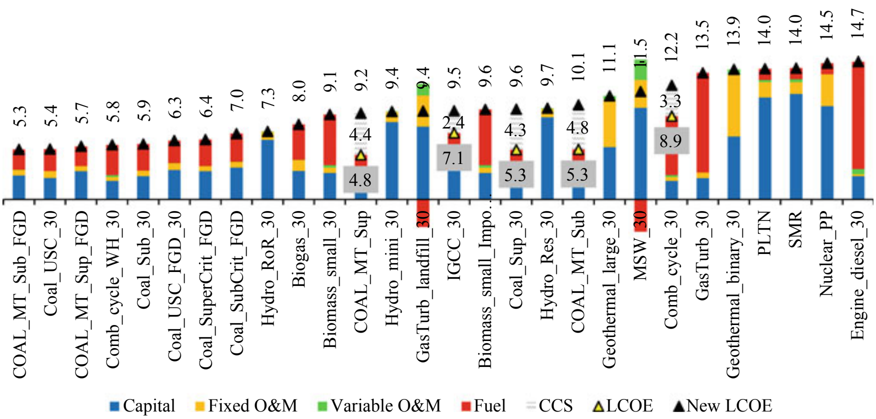

Fig. 3 LCOE (¢US$/kWh) for dispatchable power plants. *Source* DEA et al. (2021)

shows added technology cost for offshore wind turbines, which are considered more expensive than onshore. Figure 3 shows the possibility of the assumed LCOE of dispatchable power plants increasing due to the higher fuel costs. This study further assumed that the CFs are 80% for most power plants, except gas engine/turbine at 40%, diesel engine at 50%, reservoir type hydro at 42%, mini- and ROR- hydro at 50%, geothermal at 95%, nuclear at 90%, tidal at 35%, solar PV at 18%, and onshore wind turbines at 31%.

DEA et al. (2021) also provided assumptions for energy prices from 2022 to 2060, in which real prices for imported biomass, local biomass, mine-mouth coal, gas, well-head gas, biogas, and municipal solid waste (MSW) were relatively stable at US \$96/ton, US \$80/ton, US \$32/ton, US \$12/MMBTU, US \$6/MMBTU, US

Table 4 Renewable energy potentials

Renewable	Potential (GW)	Utilization in 2021 (MW)
Solar	3295	203.7
Hydro	95	6601.9
Bioenergy	57	1920.4
Wind	155	154.3
Geothermal	24	2276.9
Ocean	60	0
Total	**3686**	**11,157**

$2/MMBTU, and US $-32/ton, respectively. The negative MSW price indicates its application as energy to generate income of US $32/ton processed. Average real coal price was projected to decline from US $130/ton in 2022 to US $74/ton in 2025 and 2060. Average real prices for fuel oil and gasoil were assumed to fluctuate, with the former falling from US $88/barrel in 2022 to US $81/barrel in 2025, then rising to US $98/barrel in 2030 before gradually falling again to US $95/barrel by 2060. A similar trend was assumed for the gasoil price, which was projected to decline from US $60/barrel in 2022 to US $53/barrel in 2025, rising to US $70/barrel in 2030, and falling again to US $67/barrel by 2060. The assumed price for uranium was US $1540/kg.

Table 4 shows renewable potential data provided by the Survey and Testing Agency for Electricity, New-Renewable Energy, and Energy Conservation. The largest renewable potentials were recorded for solar energy at 3295 GWp, with the highest solar potential observed in East Nusa Tenggara, West Kalimantan, and Riau. The second largest potential was wind energy at 155 GW, and East Nusa Tenggara, South Kalimantan, West Java, South Sulawesi, Aceh, and Papua were observed to have the highest such values. Hydro energy potential was recorded at 95 GW, mainly in North Kalimantan, Aceh, West Sumatera, North Sumatera, and Papua. Tidal is potentially available in all regions, especially Maluku, East Nusa Tenggara, West Nusa Tenggara, and Bali, with a total of 60 GW. Bioenergy and geothermal potentials were estimated at 57 and 24 GW, respectively, with the latter scattered along the ring of fire in Sumatera, Java, East Nusa Tenggara, and Maluku. Only 0.3% of this potential has been utilized, making increases in massive renewable energy exploration technically feasible. Indonesia also has uranium and thorium resources estimated at 89,483 tons and 143,234 tons, respectively.

4 Results

4.1 National Aggregated Results

Total electricity demand under BaU was projected to increase from 322 TWh in 2021 to 578 TWh in 2030, 1050 TWh in 2040, 1588 TWh in 2050, and 1942 TWh in 2060, as shown in Fig. 4. Demand growth arises from implementation of such policies as increase in electricity share of total industrial energy demand, power to green hydrogen, 100% EV sales by 2040, and the program to substitute LPG cookers with induction cookers, which are projected to increase the electricity share to 51% of total energy demand by 2060. Electricity demand per capita will increase from 1.2 MWh per capita in 2021 to 2 MWh in 2030, 3.4 MWh in 2040, and 5.9 MWh by 2060. Total electricity demand in the high-demand scenarios were estimated to be 2366 TWh or 7.1 MWh per capita by 2060.

Coal-fired power plant capacity was projected to increase continuously from 43.3 GW in 2022 to 103 GW by 2060 in the BaU scenario, as shown in Fig. 5. Other power plant technology capacities also increased, except for gas- and HSD-fueled. Total power plant capacity in 2060 was estimated at 456.6 GW, with 76% sourced from renewable sources. Solar energy had the most remarkable capacity increase, from 490 MWp in 2022 to 17.3 GWp in 2030, 66.9 GWp in 2040, 161.6 GWp in 2050, and 288.7 GWp by 2060. Others showing significant increases include hydro and wind energies, from 6.2 GW and 130 MW in 2030 to 29.4 GW and 22.5 GW by 2060, respectively. Such increases in intermittent renewables' capacities will lead to an increase in BESS capacity from 1 MW in 2022 to 5.6 GW in 2030 and 73.4 GW by 2060. Figure 5 also shows that coal-fired power plants had the highest electricity production share, contributing 51% to the 1456 TWh total electricity production in

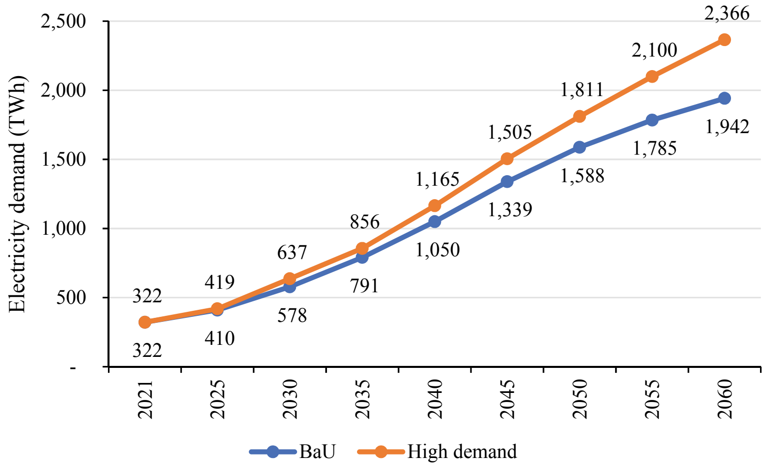

Fig. 4 Electricity demand projection

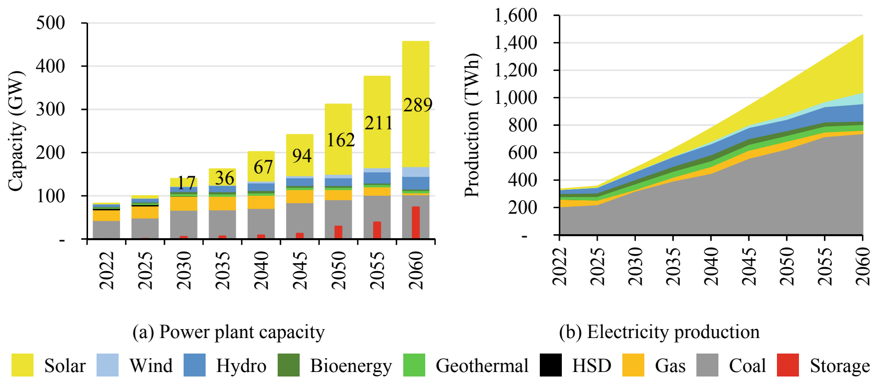

Fig. 5 Power plant capacity expansion and electricity production—BaU scenario

2060, while solar energy, hydro, and wind accounted 29%, 9%, and 6% respectively. Other renewable energy shares will be less than 3% each.

Phasing-out of coal-fired power plants in the ZE scenario requires constructing massive new capacities for renewable sources, specifically VRE, as shown in Fig. 6. By 2060, all power plants will be operating on new and renewable energy, with a total capacity of 708 GW. The capacity for solar, wind, hydro, bioenergy, nuclear, geothermal, and ocean energy will be 421 GW, 94 GW, 72 GW, 60 GW, 31 GW, 22 GW, and 8 GW, respectively. Electricity production in 2060 was projected at 2080 TWh, the highest share going to solar at 29%, followed by bioenergy at 22%, wind and hydro at 14% each, nuclear at 12%, geothermal at 8%, and tidal at 1%. Storage capacity required in the ZE scenario was projected at 61 GW. Conversely, peak coal-fired electricity will be 350 TWh in 2025, gradually declining to zero in 2060, also as shown in Fig. 6. Gas-based electricity generation was forecast to peak at 191 TWh by 2045 before eventually declining to zero by 2060. All oil-fueled power plants were forecast to shut down by 2030.

In the NZE scenario, CCS was found to be more competitive than nuclear and tidal. Figure 7 shows that the simulation conducted with due consideration for CCS technology recommended excluding nuclear and tidal in achieving the NZE target. CCS reduced the emission factor of a coal-fired power plant, and therefore, the capacity of coal-fired power plants was forecast to increase to 88 GW by 2060. Electricity generated from coal-fired power plants was thus forecast to increase from 205 TWh in 2022 to 229 TWh in 2030 and 654 TWh by 2060. CCS also allows low-emission electricity from gas-fueled power plants, leading to a projection of 168 TWh by 2040 before an eventual decrease to 5 TWh by 2060. The coal and gas electricity share in 2060 was forecast to be 13% of the 2088 TWh total, while required energy storage was found to be 54 GW, which was lower than the ZE scenario.

The results also showed that emissions from electricity without the reduction target increased from 226 million tons CO_2e in 2022 to 674 million tons by 2060, as shown in Fig. 8. The ZE scenario was forecast to produce zero emissions by

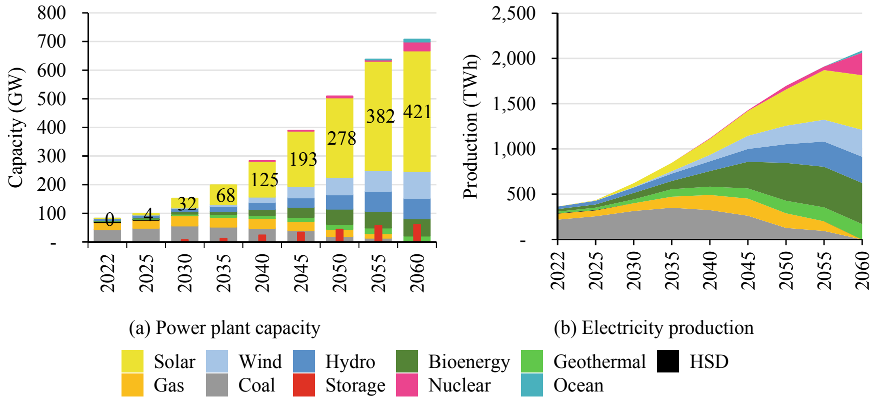

Fig. 6 Power plant capacity expansion and electricity production—ZE scenario

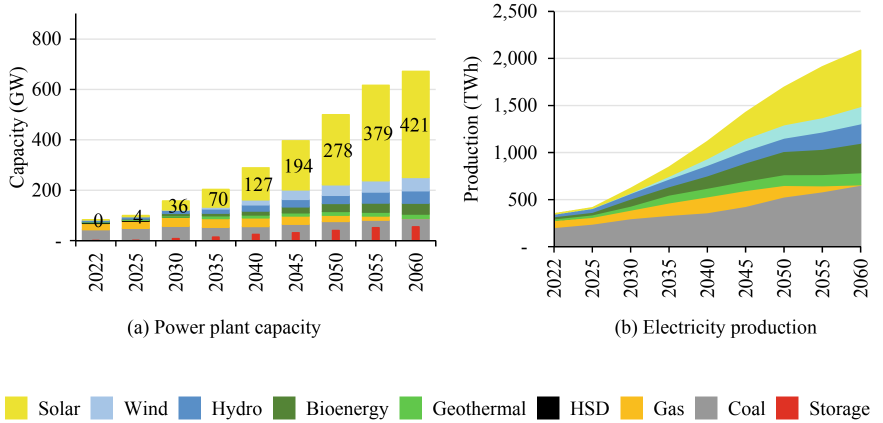

Fig. 7 Power plant capacity expansion and electricity generation—NZE scenario

2060 with a projected peak recorded in 2035 at 395 million tons CO_2e. Meanwhile, emission peak in the NZE scenario was projected to occur in 2040 at 385 million tons of CO_2e, with further emissions in 2060 of 108 million tons CO_2e due to coal and gas production. It was forecast that the forestry sector would compensate for these residual emissions.

Figure 8 compares the electricity supply costs across the scenarios. In the BaU scenario, costs would decline significantly, from US $0.065/kWh in 2022 to US $0.048/kWh in 2040, due to more low-cost electricity generated by coal-fired power plants, increasing slightly thereafter to US $0.051/kWh between 2050 and 2060, due to rising coal prices. While the ZE scenario had the highest electricity supply cost due to having the highest capacities of renewables, energy storage, and nuclear. Initially, the cost would decline to US $0.052/kWh by 2030 due to an increased share of

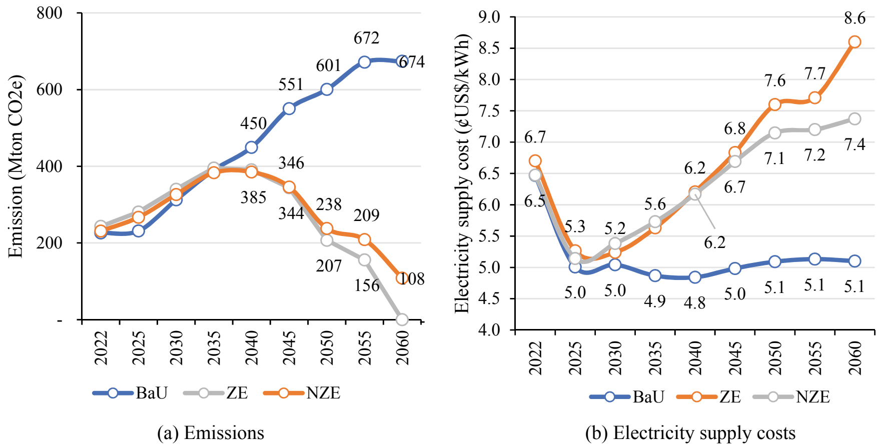

Fig. 8 Emissions and electricity supply costs

coal-based electricity supply, but thereafter, the cost gradually would increase to US \$0.086/kWh by 2060. The findings showed that the NZE scenario had a relatively lower electricity supply cost by 2060 compared to ZE of US \$0.074/kWh due to CCS-equipped coal-fired power plants generating 13% of the total electricity supply as described above.

4.2 Regional Results

Figure 9 compares the regional energy mix in 2020 and 2060 for each scenario. The BaU scenario shows a lower coal share in almost all regions except Sumatera, where the coal share increases from 38% in 2022 to 47% by 2060 as indicated in Fig. 9b versus the data for 2020 as shown in Fig. 9a. Solar energy was projected to grow significantly in Nusa Tenggara to a 57% share by 2060, while hydro energy was forecast to increase tremendously in Kalimantan, from 3% in 2022 to 39% by 2060. Another renewable source with a significant share increase will be wind, especially in Java and Bali, where it was projected to contribute 9% to the regional energy mix, followed by Sulawesi with 12% and Nusa Tenggara with 5%.

The ZE scenario will generate zero coal share in all regions by 2060, as shown in Fig. 9c. The scenario calls for solar energy to have the largest regional energy mix shares in Nusa Tenggara at 50%, Maluku and Papua at 46%, Sumatera at 37%, and Java and Bali at 31%. The second largest renewable sources by share will be wind, with Nusa Tenggara at 33% and Java and Bali at 27%, and bioenergy, with Maluku and Papua at 31% and Sumatera at 27%. Sulawesi is also forecast to rely on bioenergy at 33%, wind at 22%, and solar at 21%. Kalimantan was found to have the largest hydropower share at 33%, with nuclear at 33%, solar at 15%, and bioenergy

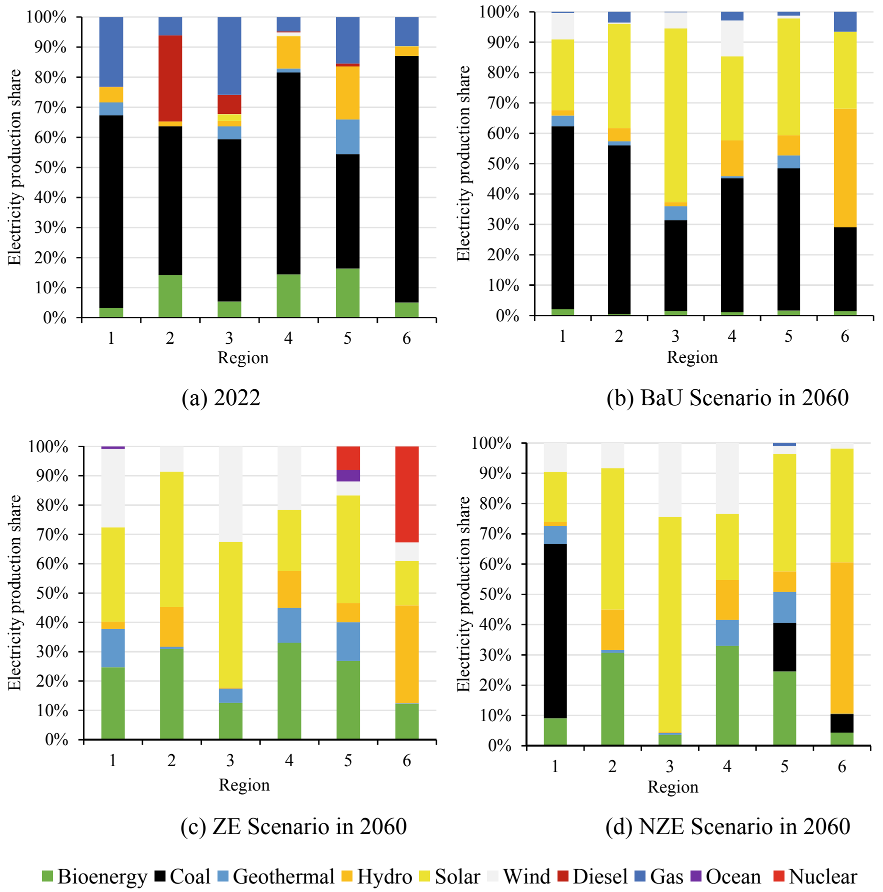

Fig. 9 Regional electricity production mix. *Legend* (1) Java and Bali; (2) Maluku and Papua; (3) Nusa Tenggara; (4) Sulawesi (5) Sumatera; (6) Kalimantan

at 12%. The ZE scenario calls for a nuclear plant to be constructed in Sumatera that would generate 8% of its energy mix by 2060.

The NZE scenario suggested coal share to reach 58% in Java and Bali, 16% in Sumatera, and 6% in Kalimantan by 2060 as shown in Fig. 9d, with no coal-fired power plants operating elsewhere. Renewables increased significantly in all regions, with Nusa Tenggara having the largest portions, solar at 71% followed by wind at 24%. Sulawesi is projected to have bioenergy at 33% followed by the second largest wind share at 24%. Hydropower is expected to contribute 50% of Kalimantan regional energy mix, followed by solar at 38%.

Table 5 shows that higher VRE capacity does not always require higher BESS capacity. The flexible electricity demands in the ZE and NZE scenarios may potentially reduce the BESS required to 56.3 GW and 50.2 GW respectively, while the BESS capacity in BaU is 69.4 GW in 2060. However, BESS capacity in the ZE and

Table 5 Energy storage by type in 2060

Region	BESS (GW)			PS (GW)		
	BaU	ZE	NZE	BaU	ZE	NZE
Java and Bali	21.8	3.5	2.2	3.7	3.7	3.7
Maluku and Papua	4.3	8.4	8.5	–	–	–
Nusa Tenggara	2.9	17.6	14.5	–	–	–
Sulawesi	8.0	4.5	5.3	–	–	–
Sumatera	24.7	20.4	14.9	0.5	0.5	0.5
Kalimantan	7.9	1.8	4.7	–	–	–
Total	**69.4**	**56.3**	**50.2**	**4.2**	**4.2**	**4.2**

NZE scenarios is expected to be higher than the value for BaU in Maluku, Papua, and Nusa Tenggara, due to their relatively low electricity demand and lack of connection to larger grid systems, signifying that they are forecast to have low grid flexibility in 2060.

5 Sensitivity Analysis

The simulation results showed that only the ZE scenario reaches zero emissions due to substantial increases in solar and energy storage capacities. The sensitivity analysis was thus limited to these together with nuclear and electricity supply cost in this scenario. Figure 10a shows that while the increase in solar PV capacity was sensitive to solar PV growth limit assumption, it was less sensitive to changes in electricity demand growth and flexibility. Figure 10b shows that CCS substitutes perfectly for nuclear, as shown in the NZE scenario analysis. Another alternative is solar PV, such that increasing its capacity was discovered to reduce nuclear capacity and vice versa. Energy storage capacity was most sensitive to demand flexibility as shown in Fig. 10c, while also highly sensitive to solar PV capacity growth. Demand flexibility thus significantly influences electricity supply cost, as shown in Fig. 10d. Supply cost was also forecast to increase with higher electricity demand and lower solar PV capacity growth limits, driving the simulation to select other plants with higher LCOE.

6 Policy Implications

The ZE scenario's flexible electricity demands require super grid infrastructure to transmit electricity from sources to regions, as shown in Fig. 11. PLN (2021) includes a 500 kV interconnection grid project for Sumatera-Malaysia and 150 kV for

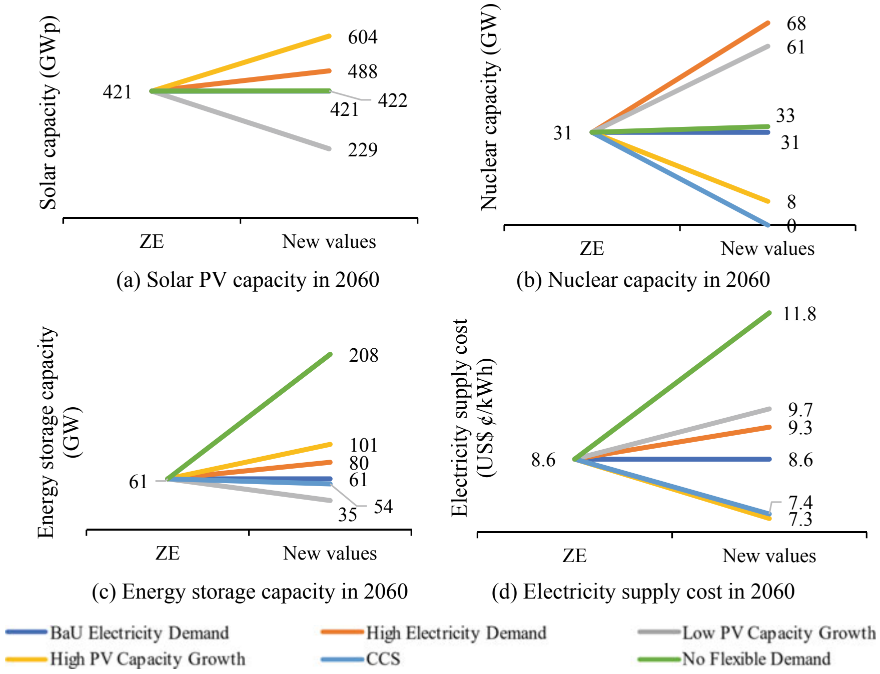

Fig. 10 Sensitivity analysis results for ZE scenario

Sumatera-Bangka, Kalimantan, and North Sulawesi-South Sulawesi. Other potential grid projects requiring further analysis include interconnections for Sumatera-Singapore, Sumatera-Java, Bali-Lombok, Bangka-Belitung, Belitung-Kalimantan, and Bau-Bau-South Sulawesi. Beyond these, based on the ZE scenario as shown in Fig. 11, this study proposes super grid projects connecting Kalimantan–Java, South Kalimantan–South Sulawesi, Bali–West Nusa Tenggara–East Nusa Tenggara, Maluku, North Maluku, and West Papua–Papua.

Investments required for the ZE scenario 2022–2060 were estimated at US $1.14 trillion, an annual average of US $29 billion as distributed in Fig. 12. Approximately 86% of the total would be for new power plants, specifically nuclear at 9%, hydro at 15%, solar PV and wind at 14%, and bioenergy at 11%. BESS and pumped storage were estimated to require US $37 billion and US $3 billion, respectively, and new transmission grids approximately US $116 billion, or 10% of the total. This last could be reduced by implementing REBID and REBED policies to foster industry and other economic activity close to renewable power plants.

Last but not least, phasing out coal-fired power plants requires a roadmap, government regulations, and presidential decrees to be obeyed by PLN, IPP, and PPU. Regulations should clearly state that IPP- owned coal-fired power plant contracts cannot be extended beyond existing PPAs, and that granting of new operational permits for those owned by PPU is prohibited. The Ministry of Investment's OSS system must also block all new permit applications related to coal-fired power plants.

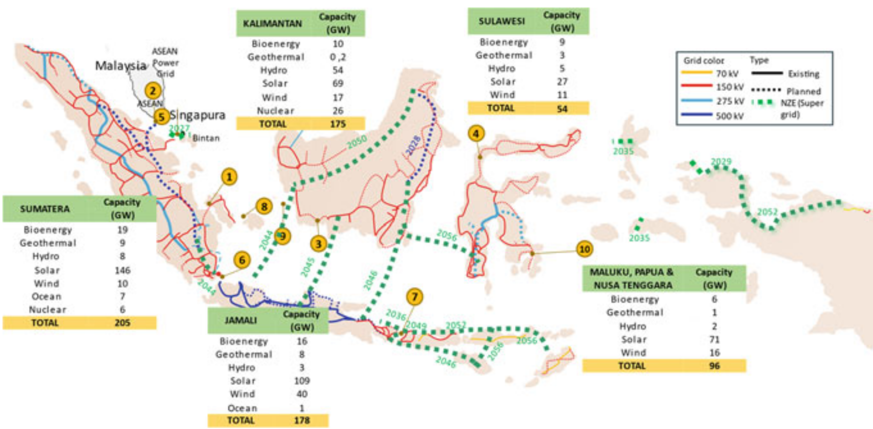

Fig. 11 Proposed super grids for implementing the ZE scenario

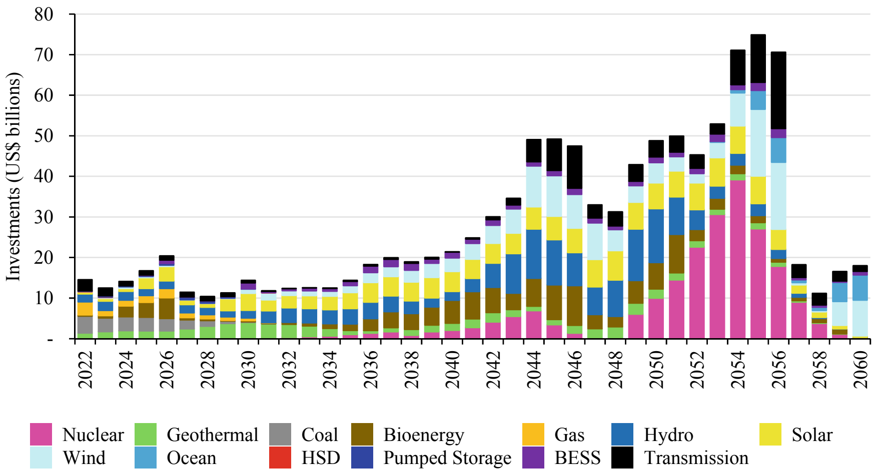

Fig. 12 Estimated investment requirements for ZE scenario electricity generation expansion 2022–2060

7 Conclusions

This study used the Balmorel model to estimate the impact of Indonesia's ZE vision on electricity generation expansion between 2022–2060. The most comprehensive analysis was provided with due consideration for all power plant owners, i.e., PLN, IPP, and PPU, nuclear power, CCS, and green hydrogen as an energy storage option. The simulation was conducted using BaU, ZE, and NZE scenarios, followed by a sensitivity analysis based on electricity demand growth, solar PV growth limits, CCS, and demand flexibility for ZE.

The results showed that the BaU and NZE scenarios generated emissions totaling 674 million tons and 108 million tons CO_2e, respectively. The remaining NZE emissions should be compensated by reductions in other sectors. While the ZE scenario generates zero emissions, it incurs the highest electricity supply cost, as indicated by the projections of US $0.086/kWh for 2060 versus US $0.051/kWh and US $0.074/kWh recorded for the BaU and NZE scenarios, respectively. The ZE scenario forecast constructing renewable power plants beginning with solar PV, followed by onshore and offshore wind turbines. Green hydrogen plants and BESS systems are to be deployed extensively in 2031 and 2034 respectively, to support intermittent renewables plants. Geothermal sources are to be gradually exploited and hydropower potential should be also exploited. Electricity generated thereby should be transmitted to other islands in order to balance intermittent renewables supply. The simulation also recommended constructing hydro-pumped storage beginning in 2025 and continuous nuclear development beginning in 2039 to achieve total capacity of 31 GW by 2060.

This study has two shortcomings that are associated with the Balmorel model. First, it does not have a feature for modeling BESS capability to smoothen and balance the frequency of electricity grids. In this light, BESS was treated as a power plant technology with larger required capacity than needed for frequency balancing alone. Future studies should consider this shortcoming and revise the Balmorel algorithms to take this into account. Second, the model was unable to simulate annual dynamic load demand profile. While this study applied different profiles for each electricity system grid, profiles were fixed during the analysis periods, i.e., 2022 and 2060.

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