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Economic Impact of the Early Retirement of Fossil Power Plants

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Economic Impact of the Early Retirement of Fossil Power Plants

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List of Abbreviations

ASEAN	Association of Southeast Asian Nations
CCGT	combined cycle gas turbine
BAU	business-as-usual scenario
EU	European Union
EU-ETS	European Union Emission Trading System
GDP	gross domestic product
GHG	greenhouse gas
IPP	independent power producer
LCOE	levelized cost of electricity
LNG	liquified natural gas
NDC	nationally determined contribution
NPV	net present value
PDP8	8th Power Development Plan (Viet Nam)
PLN	Perusahaan Listrik Negara
PPA	power purchase agreement
PV	photovoltaic
sub-C	subcritical coal power generation

Executive Summary

Reducing fossil fuel consumption as soon as possible is better when addressing climate change. On the other hand, we can see this differently in terms of investment. For instance, an owner or financier of a project will suffer a loss if existing fossil power plants stop operation before investment is recouped. Member states of the Association of Southeast Asian Nations (ASEAN) have many young fossil power plants constructed to supply rapidly growing electricity demand in recent years. Earlier retirement of such young power plants will cause economic loss and, thus, impact a country's economy. If a power plant is an independent power producer (IPP) with power purchase agreements, economic loss would be compensation for the claim. Economic loss will increase fiscal burden if a national company owns a power plant. As such, it is essential to accurately understand the negative economic impact when designing an early retirement policy for existing fossil power plants.

The analysis revealed that the early retirement of existing fossil power plants has no small impact. Under the assumed conditions, a significant operation period reduction of 15 years would result in losses equivalent to a few percent of gross domestic product (GDP). Losses will not be mitigated even if replaced with a solar PV power plant after decommissioning the coal-fired power plant. On the other hand, in theory, losses could be compensated by higher carbon prices. In such a case, the carbon price should be about \$50–\$60/tonne-CO_2 for coal-fired thermal power and about \$100/tonne-CO_2 for gas-fired thermal power. This analysis does not include commercial losses such as cancelling existing power purchase agreements (PPAs) and associated compensation. With these analyses, the study produced three policy recommendations.

1) Implementing a policy for early retirement of existing fossil power plants should be carefully considered.
2) Carbon pricing can be a mechanism to compensate for anticipated economic loss arising from early retirement.
3) Preventing the reduction of the energy system's resilience due to loss of diversity should be considered.

Chapter 1

Background and Purpose

Climate change is a common challenge for humankind, and many countries, including ASEAN member states, share the goal of addressing the issue. Meanwhile, paths towards decarbonising the energy system differ naturally by country as the circumstances are unique.

When aiming to mitigate the effects of climate change, it is better to reduce fossil fuel consumption as soon as possible. On the other hand, we can see this differently in terms of investment. For instance, an owner of a project or financier will suffer a loss if a fossil energy facility stops operation before investment is recouped. ASEAN member states have relatively many young fossil power plants that were constructed to supply the rapidly growing electricity demand in recent years. Earlier retirement of such young power plants will cause economic loss, thus impacting a country's economy. If a power plant is an IPP with a PPA, the economic loss would be compensation for the claim. If a national company owns a power plant, the economic loss would be a reduced capability of re-investment or an increased fiscal burden. As such, it is essential to accurately understand the negative economic impact when designing an early retirement policy for fossil energy systems.

With this background, this study tries to quantify the negative economic impact caused by the earlier retirement of fossil energy systems focusing on power plants. The result of the study is expected to provide useful information for designing an early retirement policy for fossil power plants.

Chapter 2

Overview of the ASEAN Region

1. Population and Economy[1]

The population of ASEAN countries grew by almost 50% in 30 years – from 431 million in 1990 to 643 million in 2020 – roughly half the people of the two largest countries, China and India. In terms of population growth rate, Singapore, Malaysia, and the Philippines increased by about 70% to 90%; even Thailand, with a relatively low growth rate, increased by about 20%. The future population outlook is expected to increase by about 18% in 30 years, from 643 million in 2020 to 758 million in 2050.

ASEAN is where the most remarkable economic development in the world is taking place. The size of the economy also increased by about 300% in 30 years, from $720 billion in 1990 to $2,846 billion in 2020. Per capita GDP rose from $1,700 in 1990 to $4,400 in 2020, an increase of about 160% in 30 years, and could be further developed. In terms of prospects for future economic development, GDP is expected to reach $9,557 billion in 2050, up about 240% in 30 years from $2,846 billion in 2020.

2. Energy

With economic development, ASEAN's energy consumption is also increasing. Primary energy consumption increased by about 190% in 30 years – from 231 million tonnes of oil equivalent (toe) in 1990 to 673 million toe in 2020. Per capita primary energy consumption increased from 0.54 toe in 1990 to 1.05 toe in 2020, about a 100% increase in 30 years. This corresponds to about 35% that of Japan, about 40% that of China, and about 160% that of India. Primary energy consumption is expected to increase from 673 million toe in 2020 to 1.42 billion toe in 2050, an increase of about 110% in 30 years, and per capita primary energy consumption from 1.05 toe in 2020 to 1.87 toe in 2050, an increase of about 80% in 30 years.

Along with its economic development, ASEAN is also facing environmental problems experienced by developed countries. In particular, increased consumption of fossil fuels has led to increased emissions of greenhouse gases (GHGs) and air pollutants associated with combustion. Among them, CO_2 emissions reached 1,071 Mtoe CO_2 in 2010, up about 60%, and 1,507 Mtoe CO_2 in 2020, up nearly 120%, from 682 Mtoe CO_2 in 2000. GHG is the cause of global

[1] IEEJ (2022, 2023); IEA (2022b); ASEAN (2021).

warming overall, bringing about intensified natural disasters. On the other hand, air pollutants directly impact the human body, which becomes apparent with health problems. Due to low electrification rates, some countries use wood such as firewood as fuel for domestic cooking, and deforestation, increased GHGs, and the health effects of burning can never be ignored. Even with the development of hydropower resources, which have a high potential for renewable energy, their amount, although abundant, is exhaustible, and there is a high risk that haphazard use may cause the depletion of such resources.

3. Electric Power

ASEAN is a region where electricity demand has increased significantly against the backdrop of economic development. In terms of total power generation, ASEAN as a whole is expected to grow from 370 TWh in 2000 to 675 TWh in 2010, about 80% increase, to 1,075 TWh in 2020, about 190% increase, and to 3,161 TWh in 2050, a further expansion of about 750%.

The power generation mix in Southeast Asia as of 2020 shows that thermal power accounted for 78%, with coal-fired power accounting for 45%, natural gas–fired power for 32%, and oil-fired power for 1%.

In the 1990s, oil accounted for about 40% of ASEAN's electricity generation. Since the 2000s, the share of natural gas has increased to about 40%. Coal has risen since 2010 to surpass natural gas, accounting for about 45% as of 2020. The dependence on coal and natural gas is expected to remain the same, with natural gas accounting for about 36% and coal for about 34%, according to the 2050 forecast. In addition, the introduction of nuclear power after the 2040s, to a lesser extent, is being considered.

Electricity increased by about 600% in 30 years, from 154 TWh in 1990 to 1,075 TWh in 2020. It corresponds to about 106% that of Japan, about 14% that of China, and about 70% that of India.

Meanwhile, there are differences in the electrification rate, depending on the country. As of 2017, the electrification rate was about 70% in Myanmar and about 93% in the Lao PDR and the Philippines, with many households in rural areas without access to electricity. Per capita electricity consumption is far from high.

Resource holdings vary widely from country to country, with some countries rich in fossil fuels and others located in water-rich river basins, while some have extremely small land areas and few resources.

The increasing electricity demand is attributed to the development of industries, such as manufacturing and mining, in the region and the rising demand for housing and other buildings. Manufacturing, in particular, is expected to see further development due to the shift from China, where labour costs are rising.

Correspondingly, cross-country power interchange within the region is increasing, and some countries, backed by their abundant hydropower resources, are placing more emphasis on policies to export renewable power actively to neighbouring countries.

4. Energy Development[2]

For ASEAN's further development, the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016–2025 Phase II: 2021–2025 lists seven initiatives.

1. ASEAN Power Grid – to expand regional multilateral electricity trading, strengthen grid resilience and modernisation, and promote clean and renewable energy integration
2. Trans-ASEAN Gas Pipeline – to pursue the development of a common gas market for ASEAN by enhancing gas and liquified natural gas (LNG) connectivity and accessibility
3. Coal and clean coal technology – to optimise the role of clean coal technology in facilitating the transition towards sustainable and lower emission development
4. Energy efficiency and conservation – to reduce energy intensity by 32% in 2025 based on 2005 levels and encourage further energy efficiency and conservation efforts, especially in the transport and industry sectors
5. Renewable energy – to achieve the aspirational target for increasing renewable energy component to 23% by 2025 in the ASEAN energy mix, including increasing the share of renewable energy in installed power capacity to 35% by 2025.
6. Regional energy policy and planning – to advance energy policy and planning to accelerate the region's energy transition and resilience
7. Civilian nuclear energy – to build human resource capabilities on nuclear science and technology for power generation

[2] ASEAN (2021).

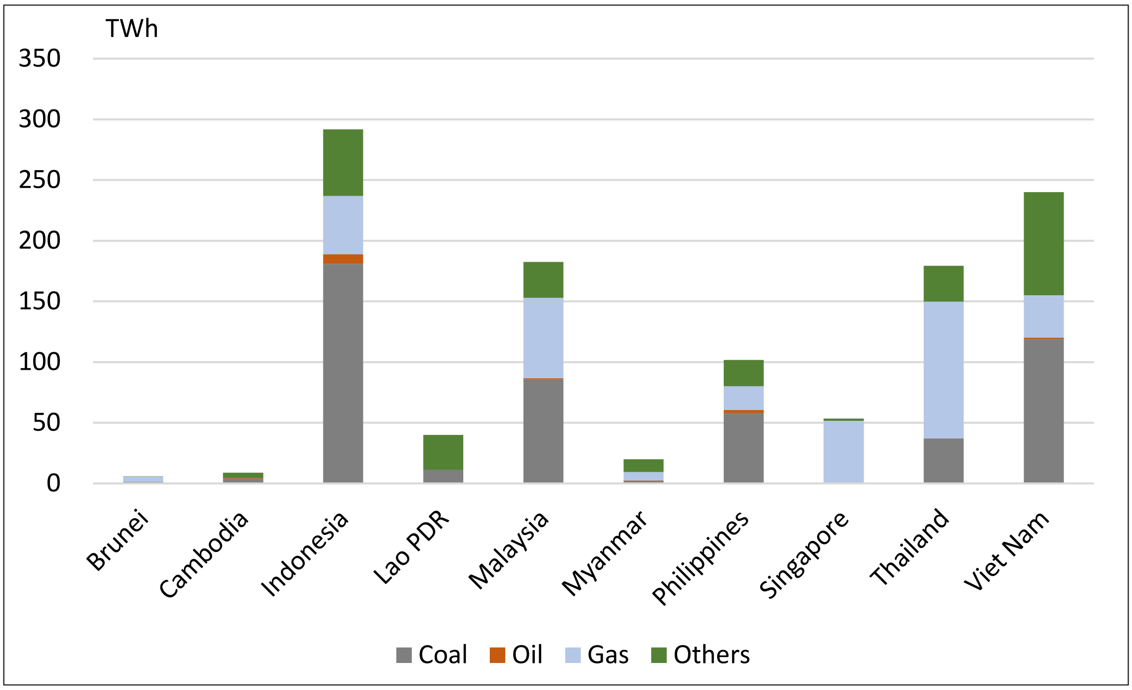
Chapter 3

Fossil Power Generation in ASEAN

1. ASEAN Overview

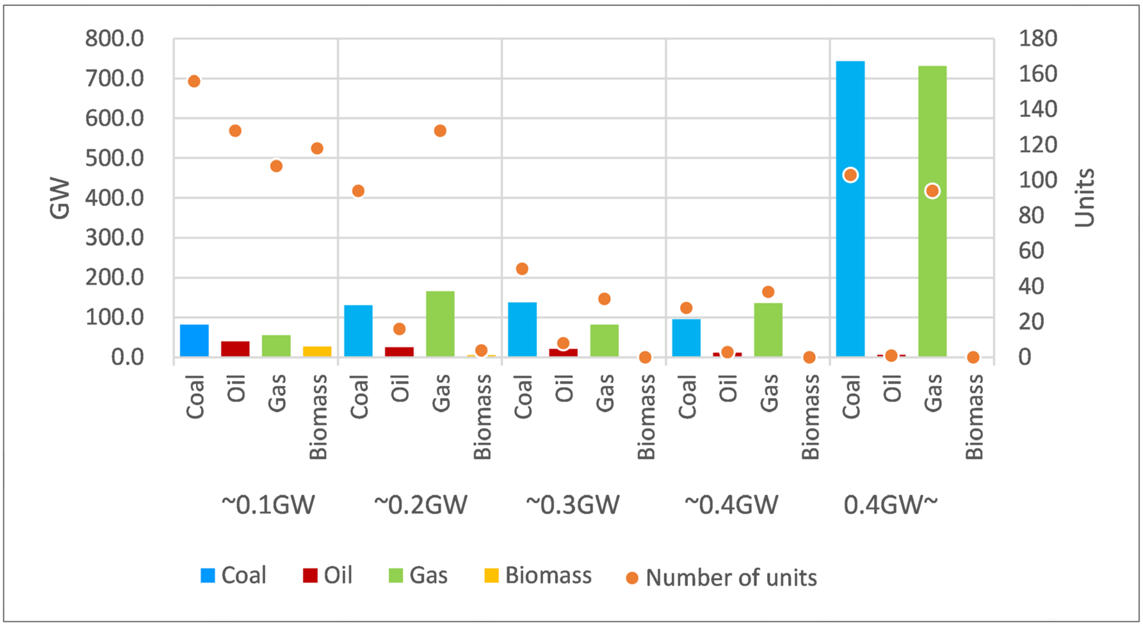
ASEAN is a region where electricity demand has increased significantly against the backdrop of economic development. The number of thermal power plants has increased since 1990 to meet this growing demand. By power source, gas-fired thermal power accounted for a large share from 1990 to 2010, and the share of coal-fired thermal power has increased since 2010. Gas-powered and coal-fired power plants tend to be relatively large; in particular, many coal-fired power plants are quite new within 10 years of construction. Many small power plants have been built for oil-fired thermal power, which do not have the capacity of gas-fired or coal-fired thermal power plants. Biomass power generation, although much smaller in capacity than oil-fired thermal power, has been steadily increasing since 2000.

Figure 3.1. Power Generation Mix of ASEAN Countries (2020)



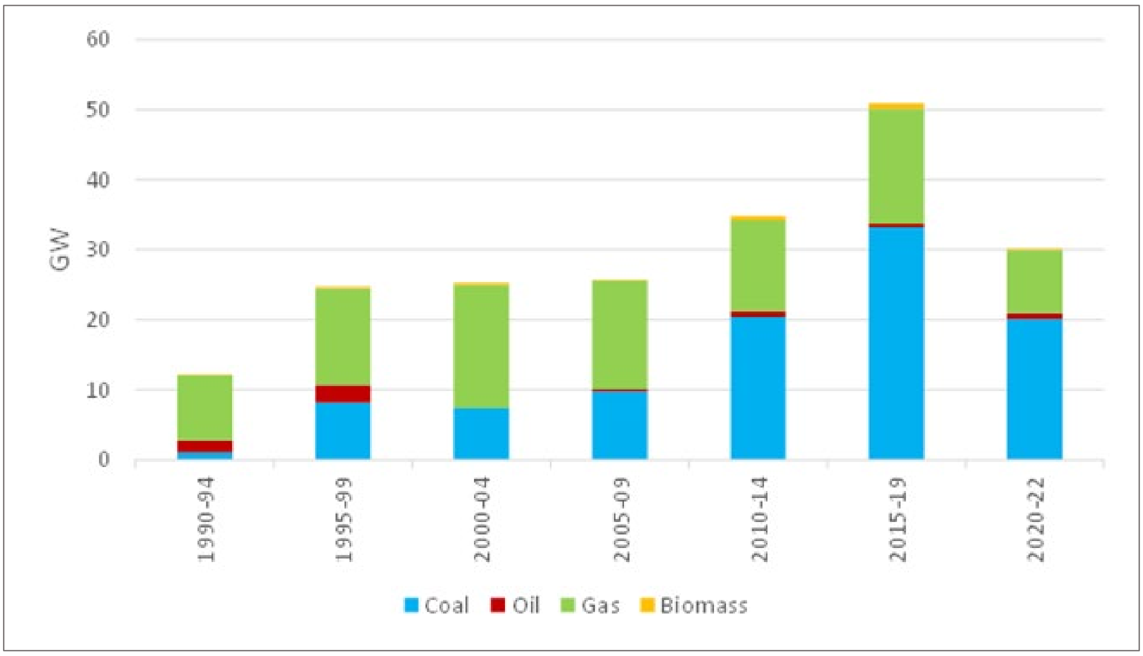
Source: IEA (2022a).

Figure 3.2. Existing Power Generation Capacity by Size and Fuel (Total ASEAN, 2022)



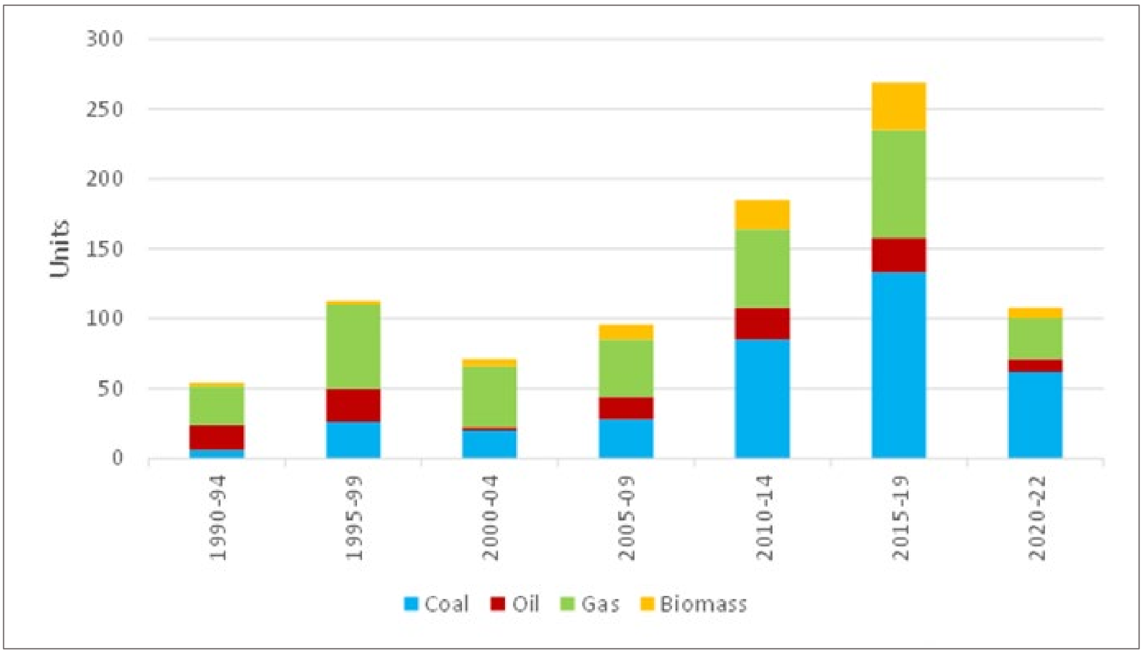
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.3. Additional Power Generation Capacity by Year and by Fuel (Total ASEAN)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.4. Additional Power Generation Unit by Year and by Fuel (Total ASEAN)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

2. Brunei Darussalam

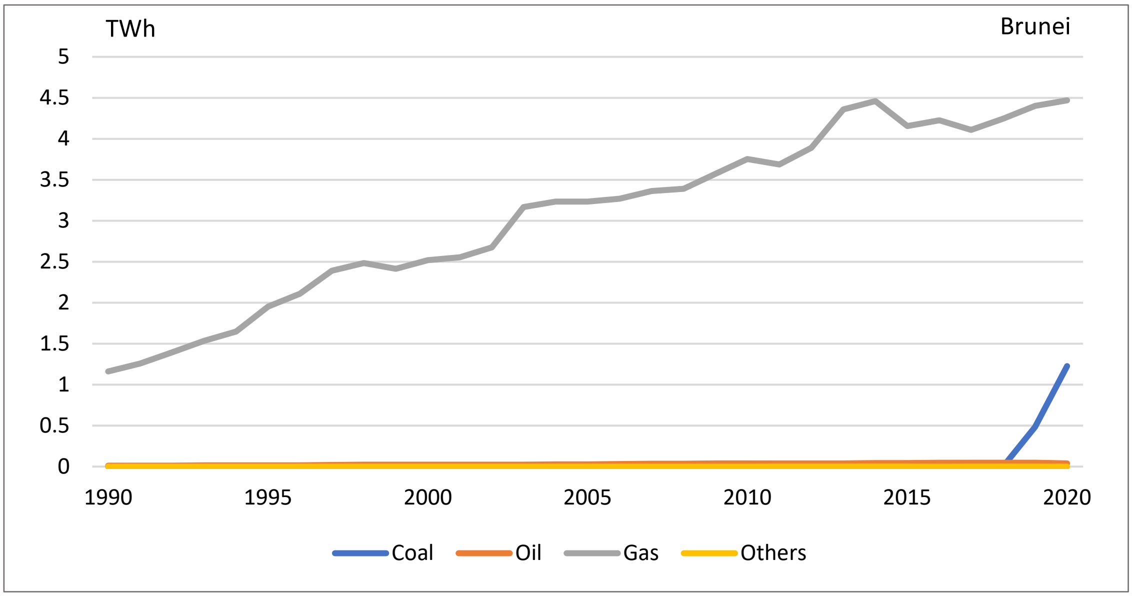
2.1. History of Power Generation Mix

Brunei has oil, natural gas, and coal resources. Oil has been exported, and natural gas has been mainly used for domestic power generation. In recent years, the use of coal has also begun, accounting for about 20% of electricity generated as of 2020.

Oil and natural gas exports account for about 60% of GDP and about 90% of total exports. Since the 1990s, electricity demand has increased. But with no other major industry in sight, growth has been modest.

Coal was used until 1924, then suspended until recently. From an energy mix perspective, it started again in 2019.

Figure 3.5. Trajectory of Power Generation Mix in Brunei Darussalam



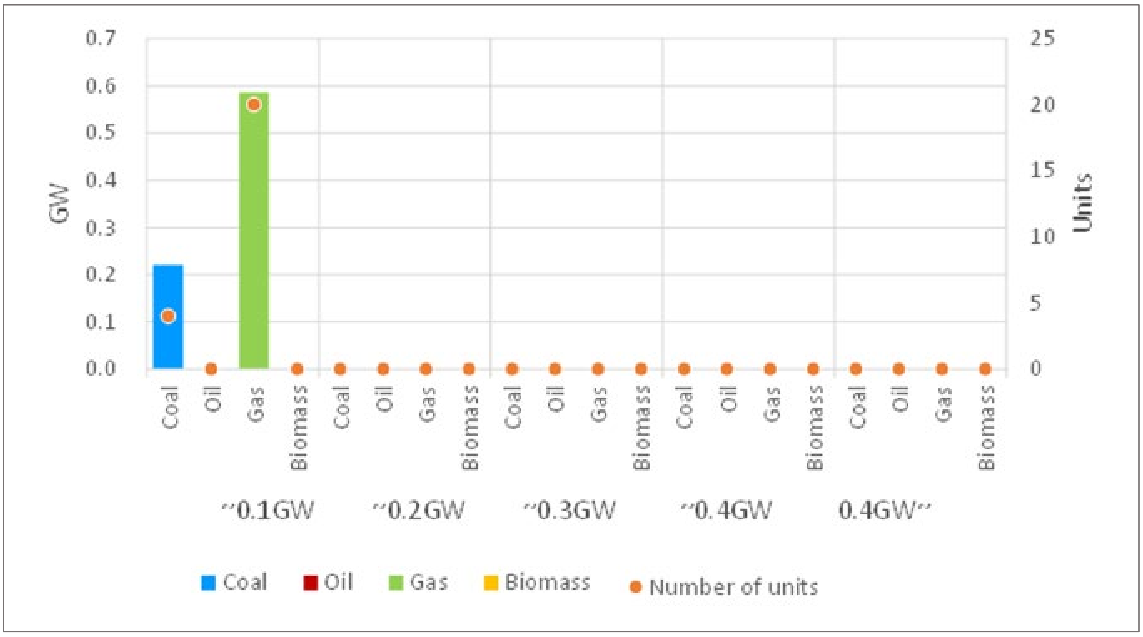
Source: IEA (2022a).

2.2. Existing Fossil Power Plants

Gas-fired thermal power is generated in the most significant quantity, 0.6 GW (20 units), followed by coal-fired thermal power, 0.2 GW (4 units); oil-fired thermal power cannot be confirmed. Gas-fired and coal-fired thermal power is dominated by small units with a capacity under 0.1 GW.

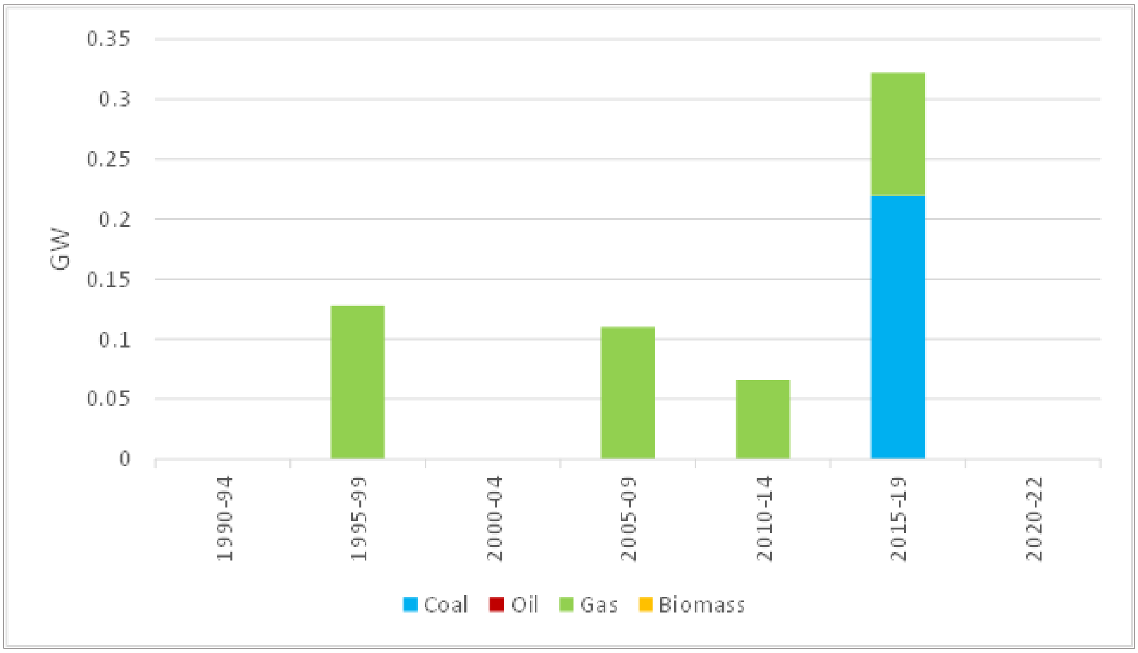
A look at the history of thermal power generation shows that gas-fired power plants were built every 10 years or so on the assumption that natural gas produced in Brunei would be used. Coal-fired power plants were built with Chinese capital to supply electricity to the petrochemical plant and have been in operation since 2019.

Figure 3.6. Existing Power Generation Capacity by Size and Fuel (Brunei Darussalam, 2022)



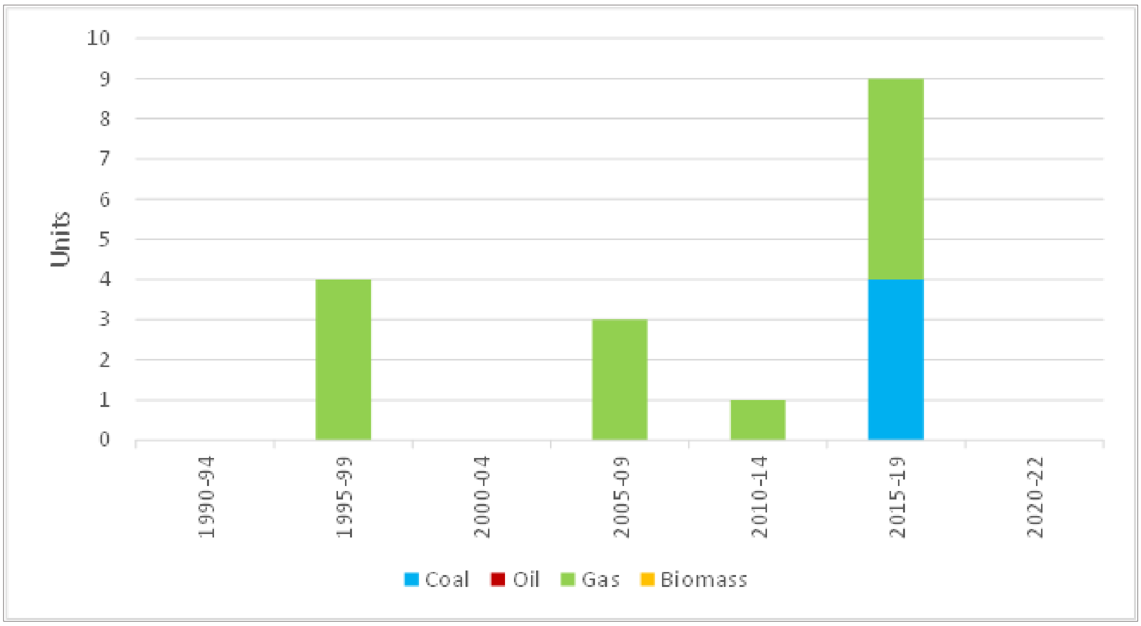
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.7. Additional Power Generation Capacity by Year and by Fuel (Brunei Darussalam)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.8. Additional Power Generation Capacity by Year and by Fuel (Brunei Darussalam)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

2.3. Power Development Plan

Brunei submitted its nationally determined contribution (NDC) in December 2020, setting a target of 20% reduction compared with the business-as-usual scenario (BAU) level by 2030. As of December 2021, no long-term strategy had been submitted, nor can the declaration of carbon neutrality be confirmed.

Electricity is generated and distributed by the Department of Electrical Services (DES), under the jurisdiction of the Ministry of Energy. While DES provides electricity to the homes of ordinary customers, Berakas Power Management Company, a private power company, provides electricity to airports, government facilities, and other facilities.

Power generation sources are mainly natural gas, but the government is diversifying its power generation mix to include renewable energy. Brunei is also considering importing electricity from Malaysia.

As for the power development plan, the government plans to construct new gas-fired power plants, regenerate existing thermal power plants, and review their operation to meet the increasing demand every year. The government is also considering introducing renewable energy sources and importing electricity from neighbouring countries.

Future plans for the power sector can be partially confirmed in the Brunei Darussalam National Climate Change Policy, on which the NDC was based. Brunei plans to increase the generation capacity of new and renewable energy to at least 30% of its total installed power generation capacity by 2035, based on solar power.

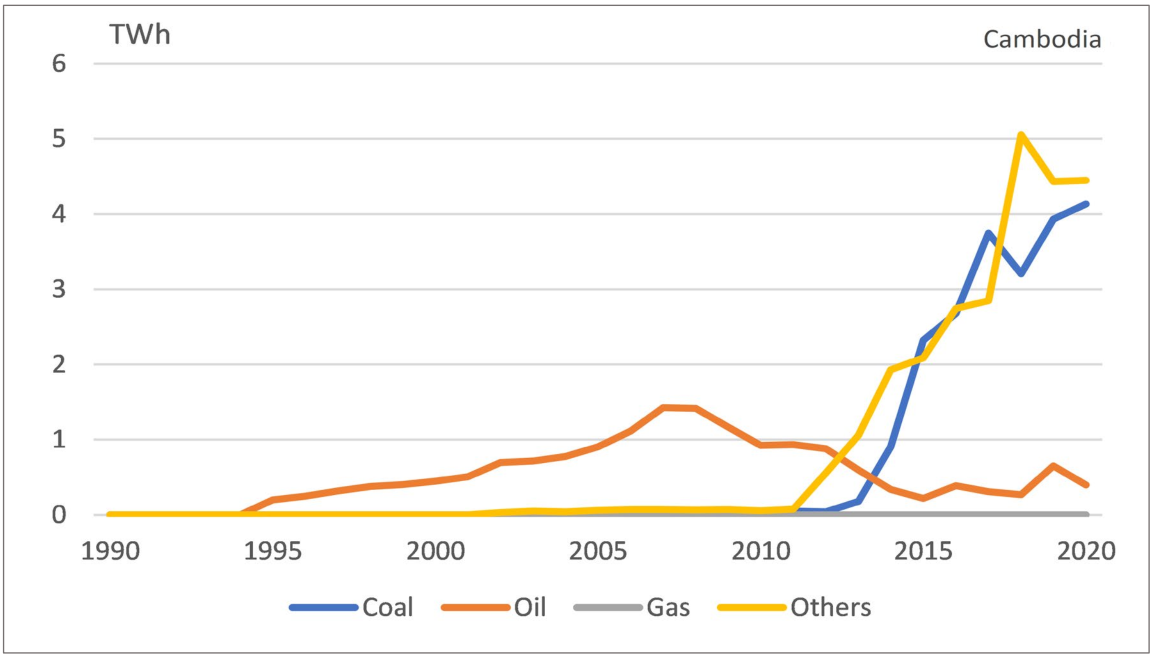
3. Cambodia

3.1. History of Power Generation Mix

Cambodia is dependent on imports for energy. It relied heavily on oil-fired power generation until 2010. Since 2015, it has aggressively introduced hydroelectric and coal-fired thermal power. As of 2020, the share of electricity generated was 46% from coal-fired thermal power and 45% from hydropower, compared with 4% from oil-fired thermal power.

As for renewable energy, Cambodia is working on solar and biomass power generation.

Figure 3.9. Trajectory of Power Generation Mix in Cambodia



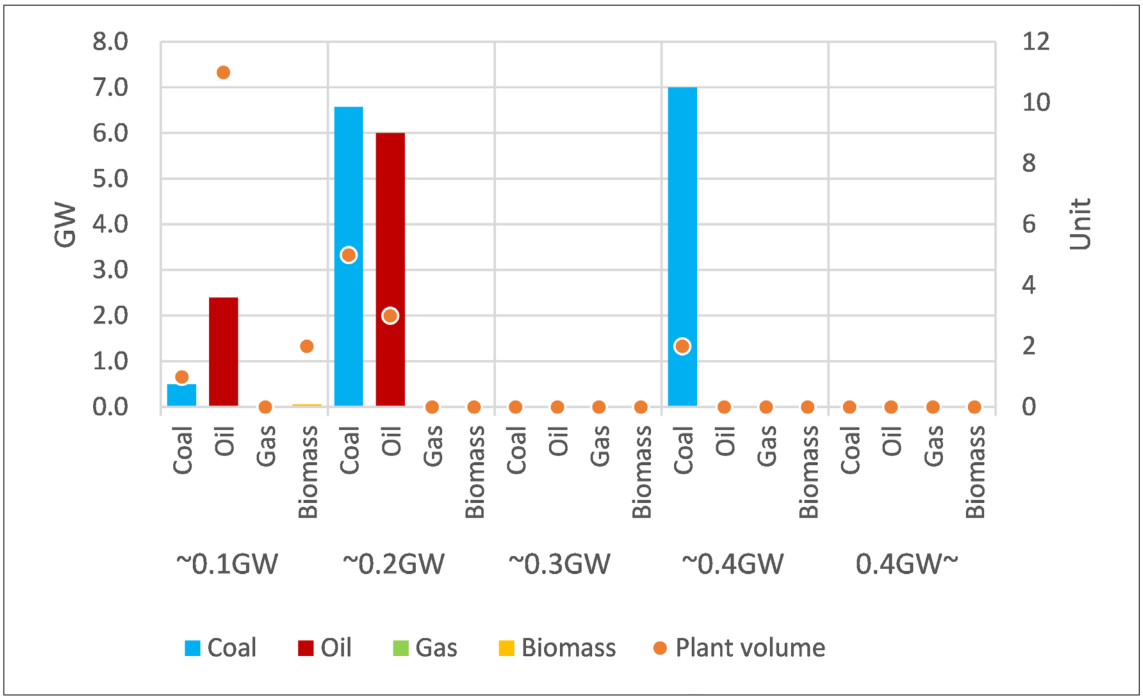
Source: IEA (2022).

3.2. Existing Fossil Power Plants

Coal-fired and oil-fired thermal power plants account for most of Cambodia's thermal power generation. There is small-scale biomass power generation, but gas-fired power generation cannot be confirmed. Most of the coal-fired thermal power plants, seven units, have a capacity of 0.1 GW to 0.4 GW, with one unit having a capacity under 0.1 GW. For oil-fired power plants, 11 units have a capacity of under 0.1 GW, and 3 units have a capacity of under 0.2 GW.

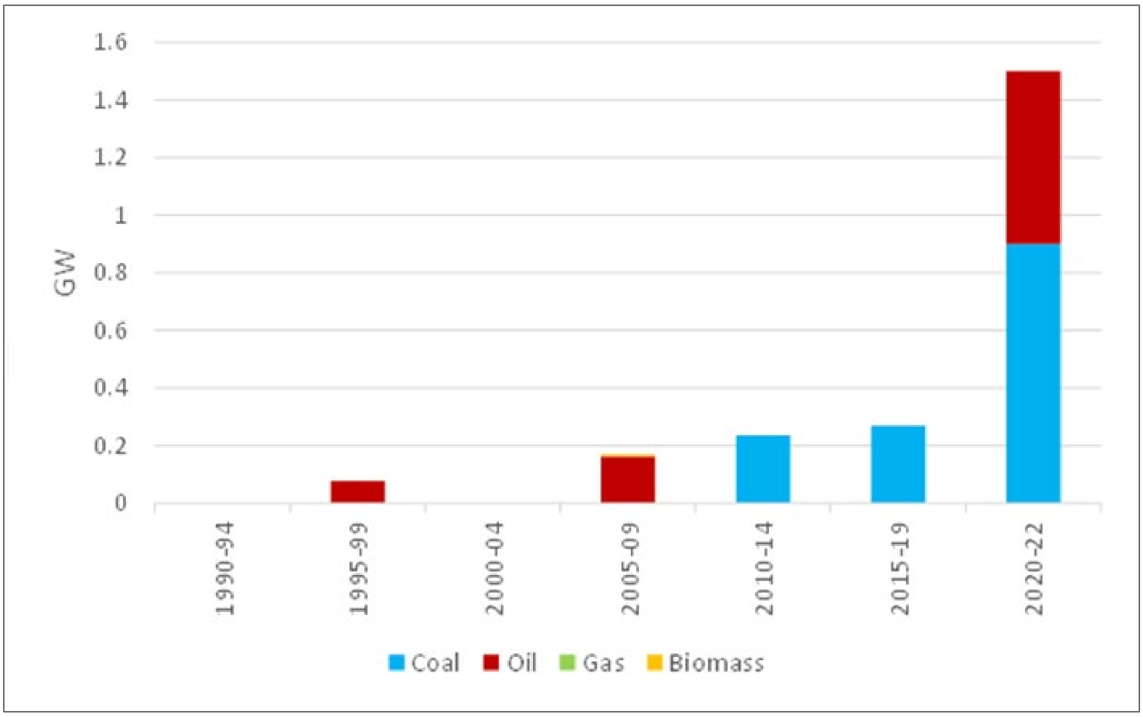
A look at the history of thermal power generation shows that a large part of it is composed of young thermal power plants built after 2014. From the 1990s to 2010, thermal power was mostly oil-fired, with some biomass power plants being built. From the late 2010s, oil-fired thermal power plants were built for a time, but coal-fired thermal power plants have increased recently.

Figure 3.10. Existing Power Generation Capacity by Size and Fuel (Cambodia, 2022)



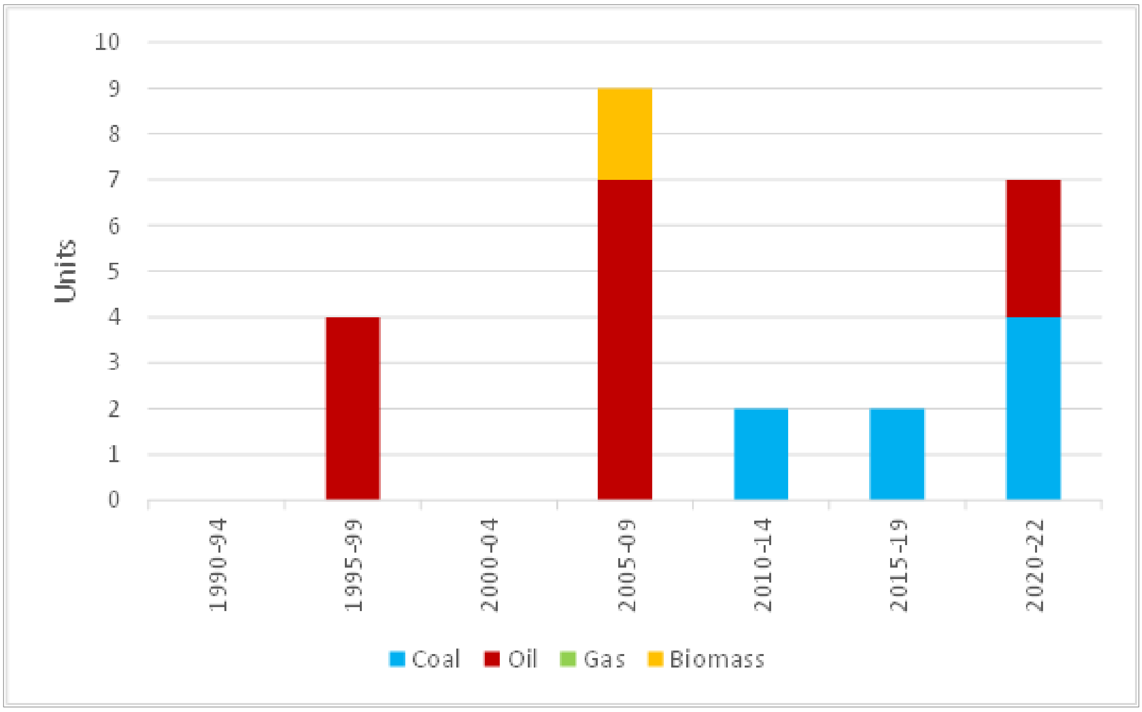
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.11. Additional Power Generation Capacity by Year and by Fuel (Cambodia)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.12. Additional Power Generation Unit by Year and by Fuel (Cambodia)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

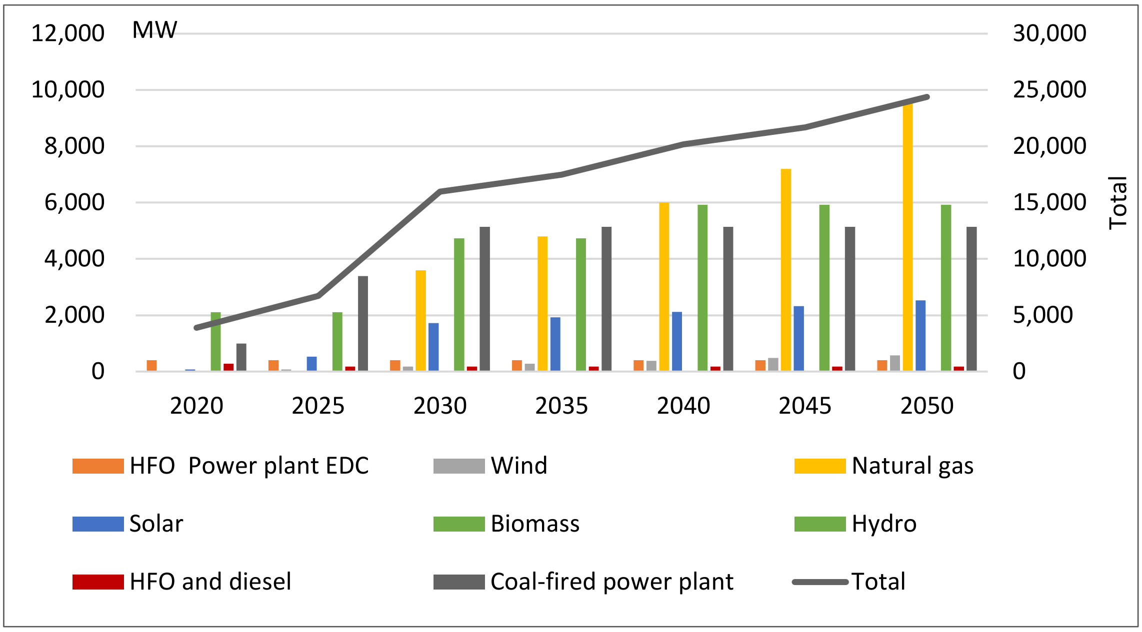
3.3. Power Development Plan

Cambodia submitted its first NDC in February 2017. It submitted its first update in December 2020, in which Cambodia set a goal of reducing GHG emissions by 42% relative to BAU levels by 2030.

The long-term strategy was submitted in December 2021. In the strategy, efforts in six sectors to achieve carbon neutrality in 2050 are described, and planned coal-fired power plants will be built, but no new projects will be added. The declaration of carbon neutrality could not be confirmed as of December 2021.

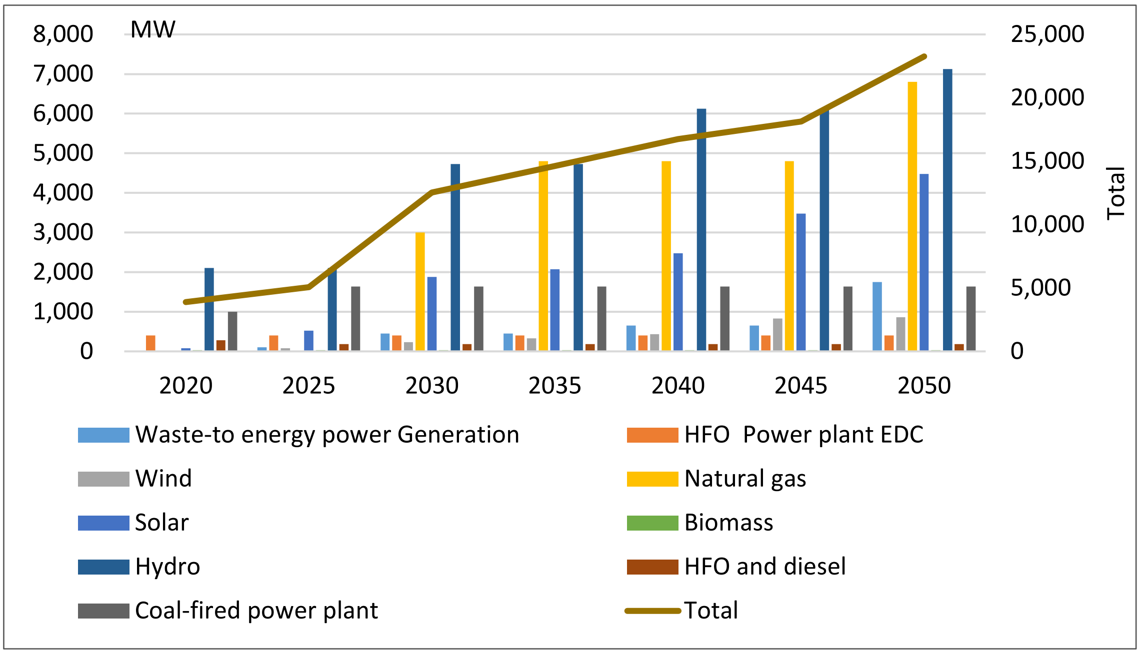
As for the power development plan, the government plans to construct new coal-fired or gas-fired thermal power plants, to meet the increasing yearly demand. The BAU scenario calls for introducing gas-fired power plants by 2030, with an increase of 20% to 30% every 5 years after that (Figure 3.13). Under the conditional scenario, Cambodia plans to introduce gas-fired power aggressively until 2035 and then focus on hydropower and solar power generation until 2045 (Figure 3.14).

Figure 3.13. Prospects of Installed Capacity in Cambodia (BAU)



Source: Theangseng (2021).

Figure 3.14. Prospects of Installed Capacity in Cambodia (Alternative Policy Scenario)



Source: Theangseng (2021).

4. Indonesia

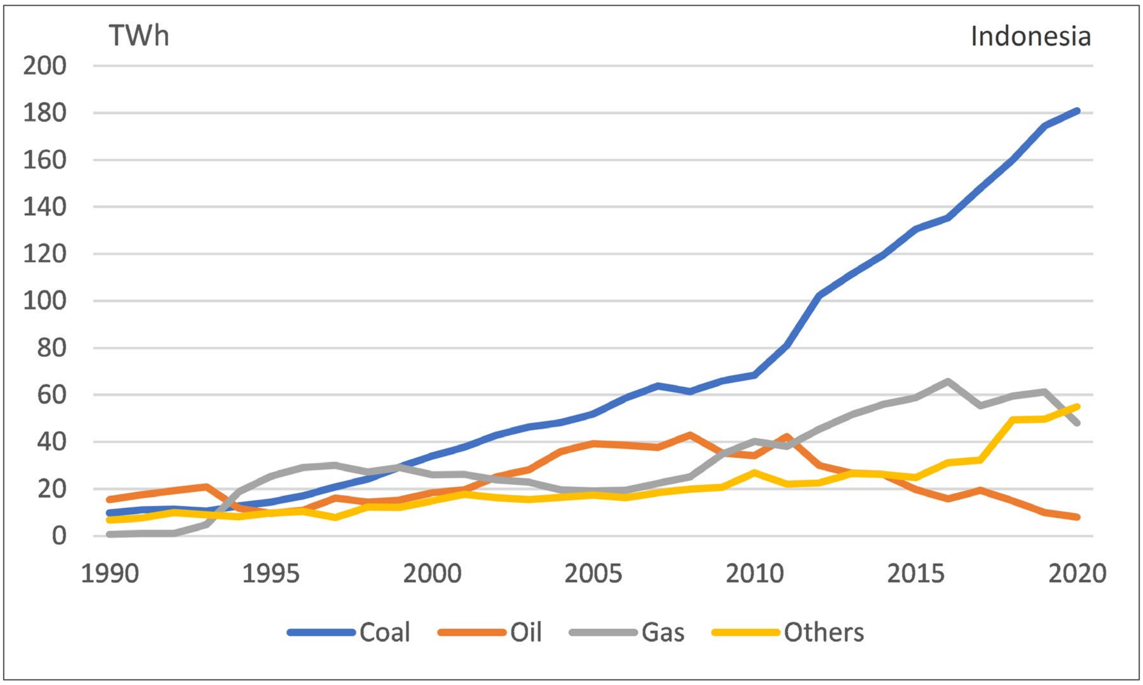
4.1. History of Power Generation Mix

Indonesia is a resource-rich country in Asia. In addition to fossil fuels such as oil, natural gas, and coal, it is also blessed with renewable energy sources such as hydropower and geothermal power. It also exports oil, natural gas, and coal.

With its abundant resources, Indonesia has been using oil, natural gas, and coal in a balanced manner since 1990. Since 2010, it has significantly increased the number of exceptionally low-priced coal-fired thermal power plants while decreasing the number of oil-fired thermal power plants.

As for renewable energy, Indonesia relies on hydroelectric power to a certain extent and has focused on developing non-hydroelectric renewable energy in recent years.

Figure 3.15. Trajectory of Power Generation Mix in Indonesia



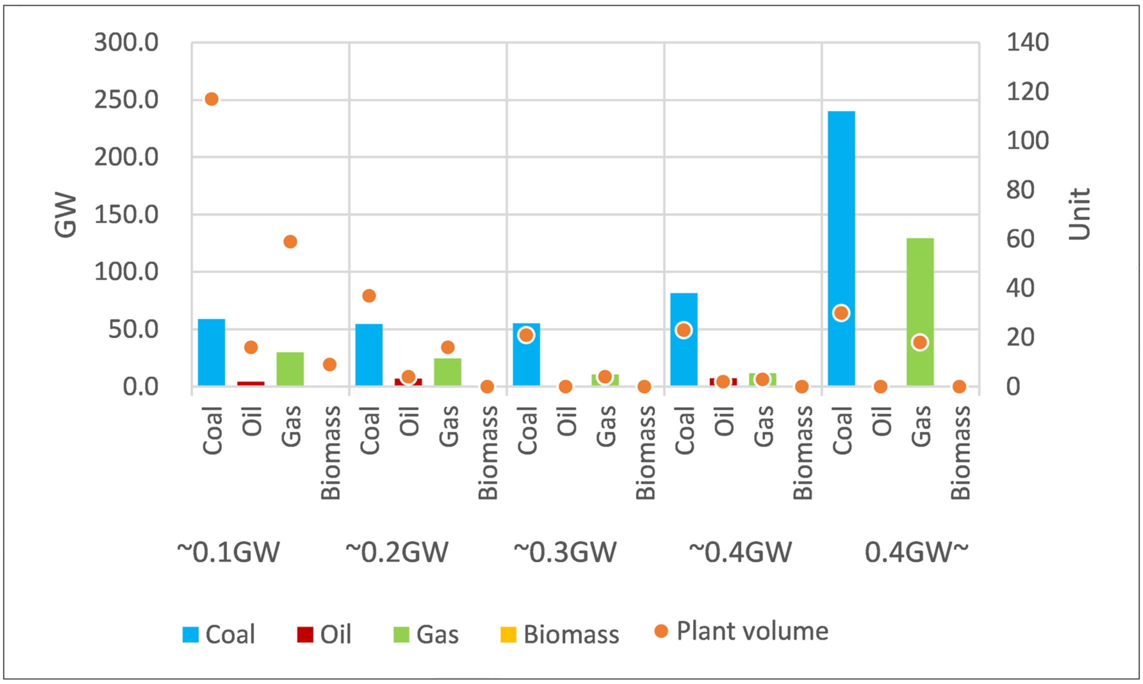
Source: IEA (2022).

4.2. Existing fossil power plants

Coal-fired power generation accounts for the largest share in Indonesia at 228 units, followed by gas-fired plants at 100 units and oil-fired plants at 22 units. Biomass power generation is small at nine units with under 0.1 GW capacity. There are many coal-fired thermal power plants: 117 small-scale units with less than 0.1 GW capacity and 111 units with more than 0.1 GW capacity. Similarly, there are many gas-fired power plants: 59 small-scale units with less than 0.1 GW capacity and 41 units with more than 0.1 GW capacity.

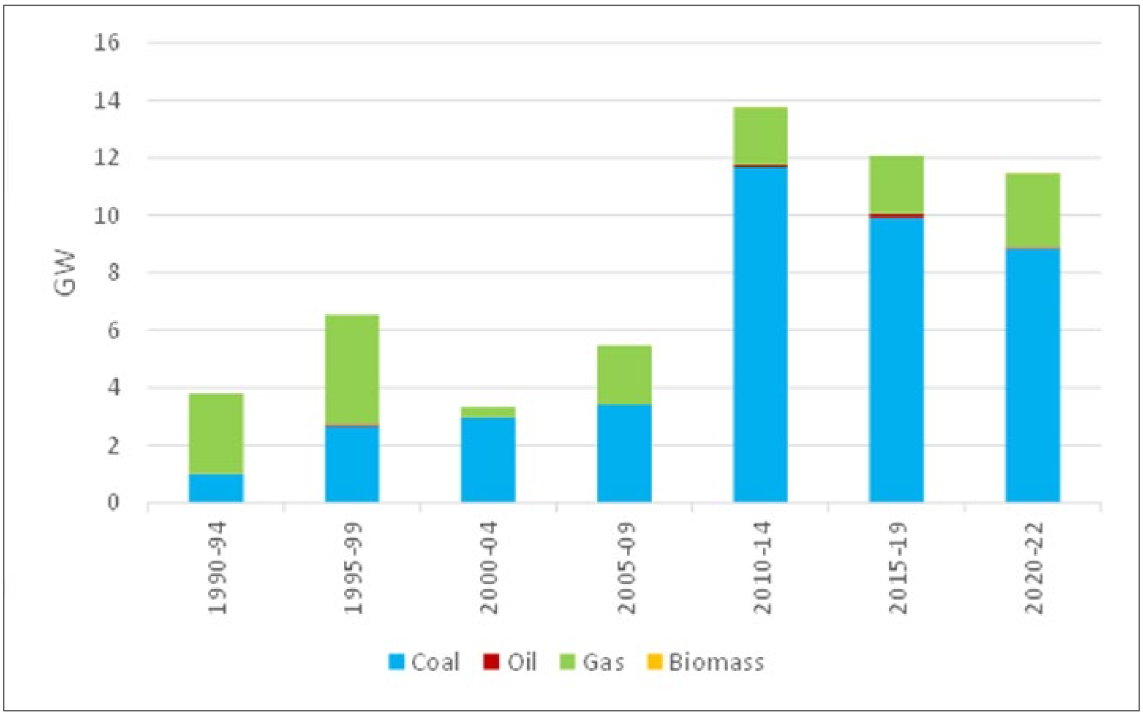
When we look at the history of thermal power generation, coal-fired and gas-fired power generation has been dominant since the 1990s, and the number of coal-fired and gas-fired power plants has been increasing annually, especially in large numbers since 2010. In short, many young coal-fired thermal power plants have operated for only about 10 years. Oil-fired and biomass power generations are also being built sporadically but on a smaller scale per unit and with a modest generation capacity compared to coal-fired and gas-fired power plants.

Figure 3.16. Existing Power Generation Capacity by Size and Fuel (Indonesia, 2022)



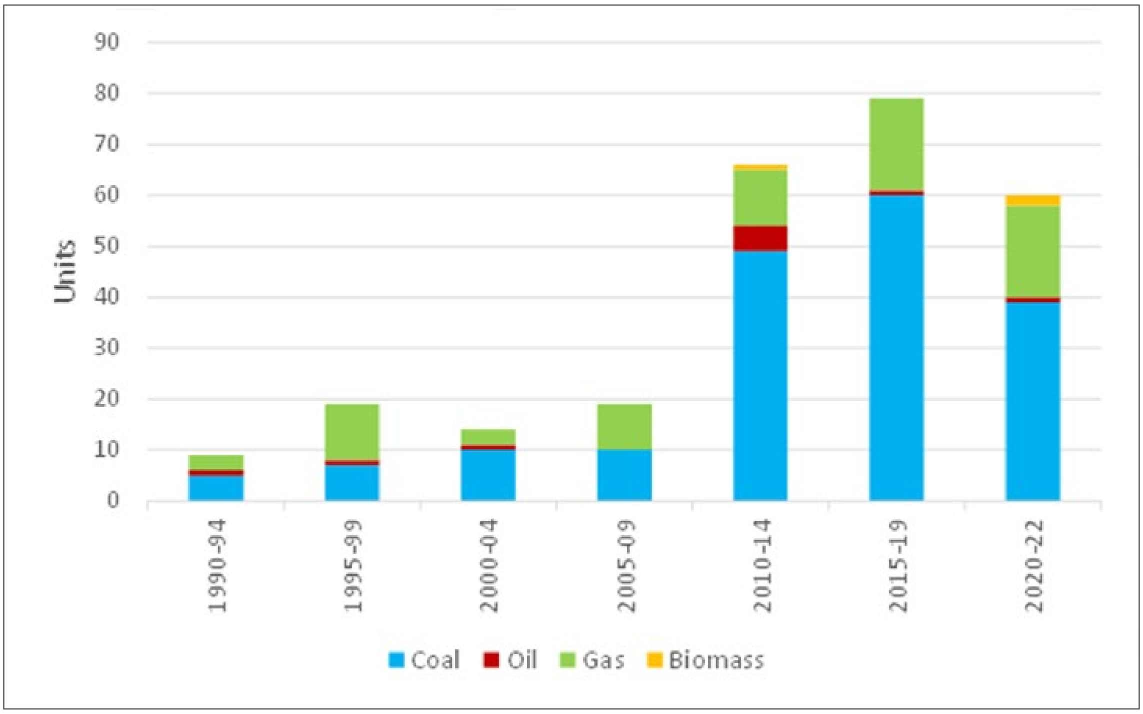
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.17. Additional Power Generation Capacity by Year and by Fuel (Indonesia)



Source: Authors, created from Enerdata, Power Plant Tracker database (https://www.enerdata.net/research/power-plant-database.html)

Figure 3.18. Additional Power Generation Unit by Year and by Fuel (Indonesia)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

4.3. Power Development Plan

Indonesia submitted its first NDC in November 2016 and an updated NDC in September 2022. In the updated NDC, the government set a target of reducing GHG emissions by 31.89% by 2030 and 43.20% with international support. Of the 43.20% reduction through international support, 25.4% will be cut in the forestry and other land use sectors, and 15.5% will be cut in the energy sector. A long-term strategy was submitted in July 2021, in which three scenarios were presented, including a low-carbon scenario compatible with the Paris Agreement target or LCCP. A carbon-neutral declaration was also submitted around the same time, aiming for net zero GHG emissions by 2060.

As for the power development plan, the government has formulated a comprehensive 20-year plan, the National Comprehensive Power Plan. Based on this plan, the state-owned electric power company PT Perusahaan Listrik Negara (PLN) has formulated a 10-year plan, the Power Supply Business Plan (RUPTL).

In May 2021, the Ministry of Energy and Mineral Resources announced that it would not build new coal-fired power plants. In June 2022, the state-owned electric power company PLN announced that it would halt its plans to develop coal-fired power plants. PLN also expects to phase out coal-fired power plants in 2040.

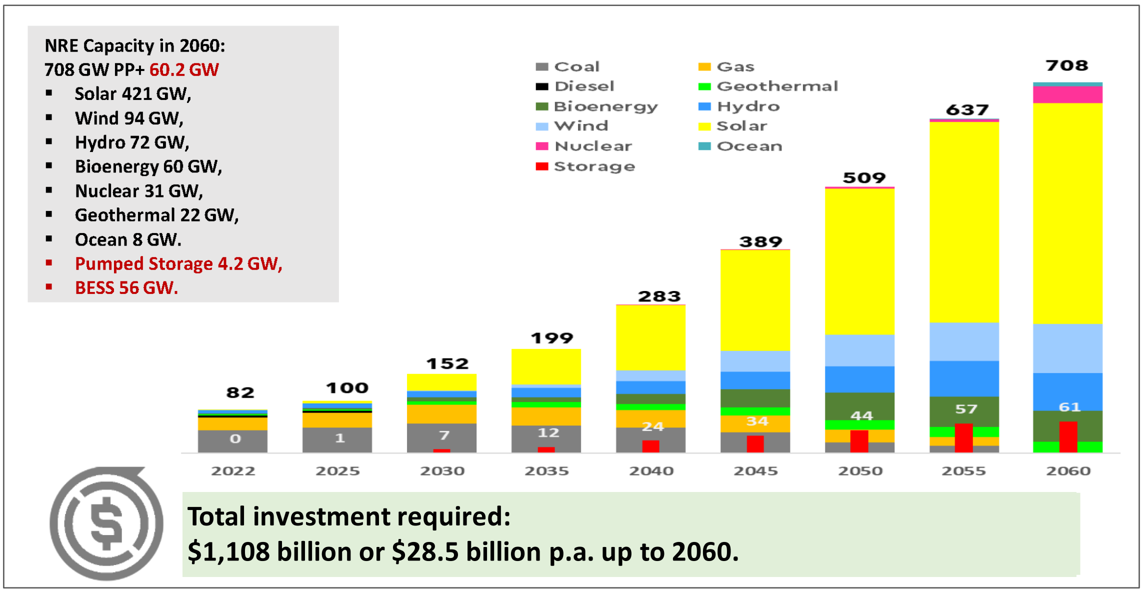
Indonesia positions coal-fired thermal power as a base power source but plans to generate about 25% of its electricity from renewable sources in 2030 (Table 3.1). The Indonesian government sets a target of increasing total generation capacity, including renewable energy, roughly twofold to 152 GW in 2030, about threefold to 283 GW in 2040, and about eightfold to 708 GW in 2060, the year of the NetZero target, compared to 82 GW in 2022 (Figure 3.19).

Table 3.1. Prospects of Power Generation Mix in RUPTL's 2021

Fuel Mix	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hydro	5.81	5.59	5.54	5.85	7.99	8.56	8.61	9.04	9.49	9.55
Geothermal	5.84	5.77	5.88	5.86	7.35	7.36	7.67	7.78	7.97	8.20
Other REs	0.95	1.48	2.00	2.69	7.66	6.98	6.36	6.04	5.96	6.15
Gas	16.58	18.01	18.10	17.37	15.64	14.85	14.89	15.74	15.54	15.44
Oil	3.52	3.04	1.52	0.51	0.41	0.41	0.41	0.41	0.40	0.40
Coal	66.98	66.12	66.95	67.71	60.95	61.70	61.58	60.34	59.83	59.37
Other RE potentials	0	0	0	0	0	0.16	0.47	0.66	0.81	0.89
Import	0.33	0	0	0	0	0	0	0	0	0
Total	100	100	100	100	100	100	100	100	100	100

RE = renewable energy.
Source: PLN (2021).

Figure 3.19. NRE Potential and NZE Power Plant Development Roadmap



Source: Government of Indonesia (2023).

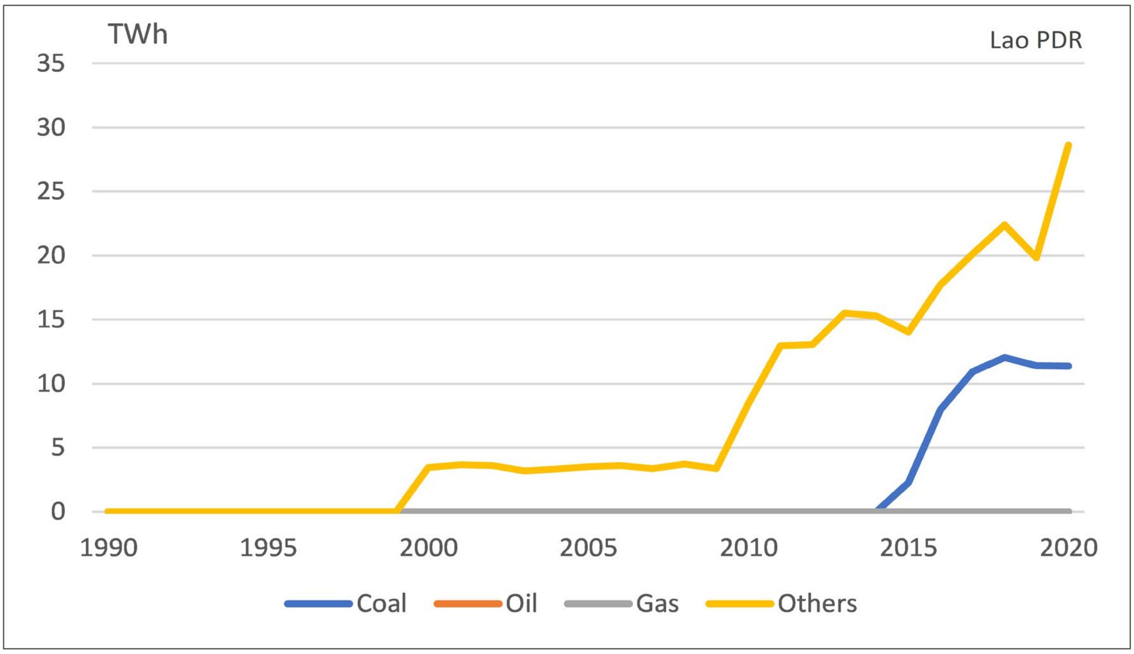
5. Lao PDR

5.1. History of Power Generation Mix

The Lao PDR is rich in hydropower resources, thanks to its rainy climate and the Mekong River, which runs north to south through the country. With its abundant hydropower resources, it exports electricity to neighbouring countries. Until 2015, domestic electricity generation was supplied by 100% hydroelectric power, but the government decided to develop coal-fired power generation due to the shortage of electricity during the dry season. Coal-fired power generation started in 2016 and has increased to account for 30% of total generation.

Since there is still room to develop hydropower resources, further development is expected. As for fossil fuels, domestic oil and natural gas reserves are not known. Coal is found to be distributed throughout the Lao PDR, with reserves of 540 million tonnes of lignite and 62.25 million tonnes of anthracite (JOGMEC, 2014).

Figure 3.20. Trajectory of Power Generation Mix in the Lao PDR



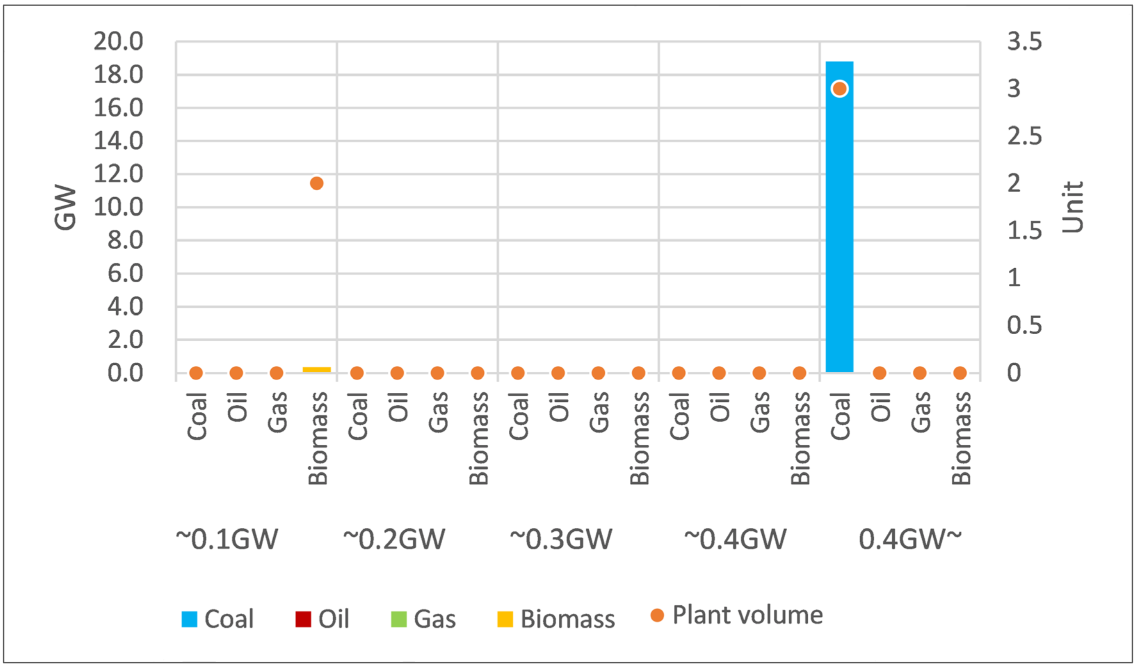
Source: IEA (2022).

5.2. Existing Fossil Power Plants

The Lao PDR has few thermal power generation plants, with only 1.9 GW (three units) of coal-fired power generation with a capacity of over 0.4 GW and two units of biomass power generation with a capacity of less than 0.1 GW. This is due to the country's abundant water resources; thermal power generation is positioned as a power source for the dry season when the amount of water decreases.

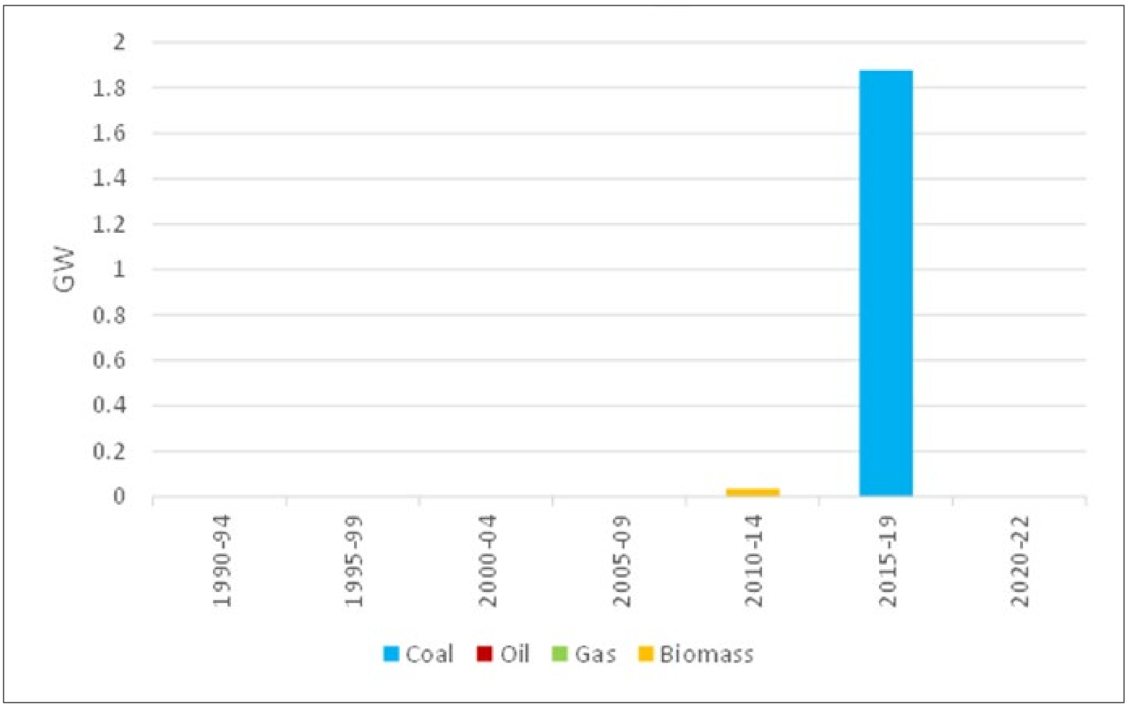
Looking at the history of thermal power generation, biomass power plants were built in 2013, and coal-fired power plants were built in 2015. Coal-fired power plants have been in operation for only 7 years.

Figure 3.21. Existing Power Generation Capacity by Size and Fuel (Lao PDR, 2022)



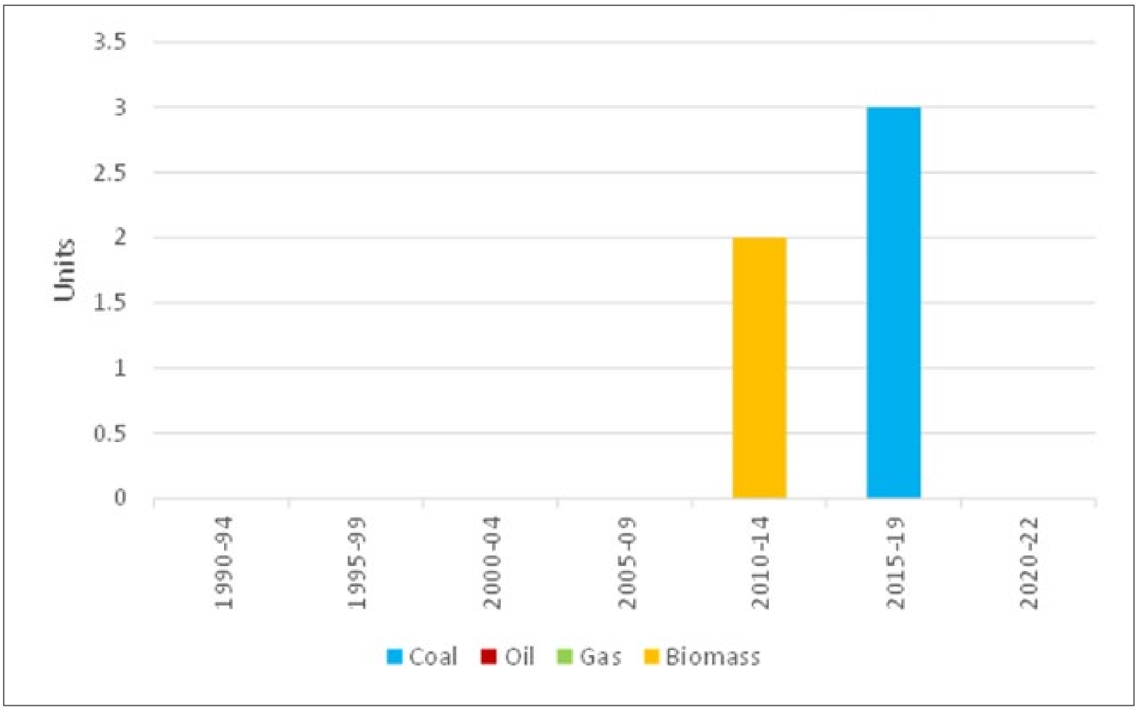
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.22. Additional Power Generation Capacity by Year and by Fuel (Lao PDR)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.23. Additional Power Generation Capacity by Year and by Fuel (Lao PDR)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

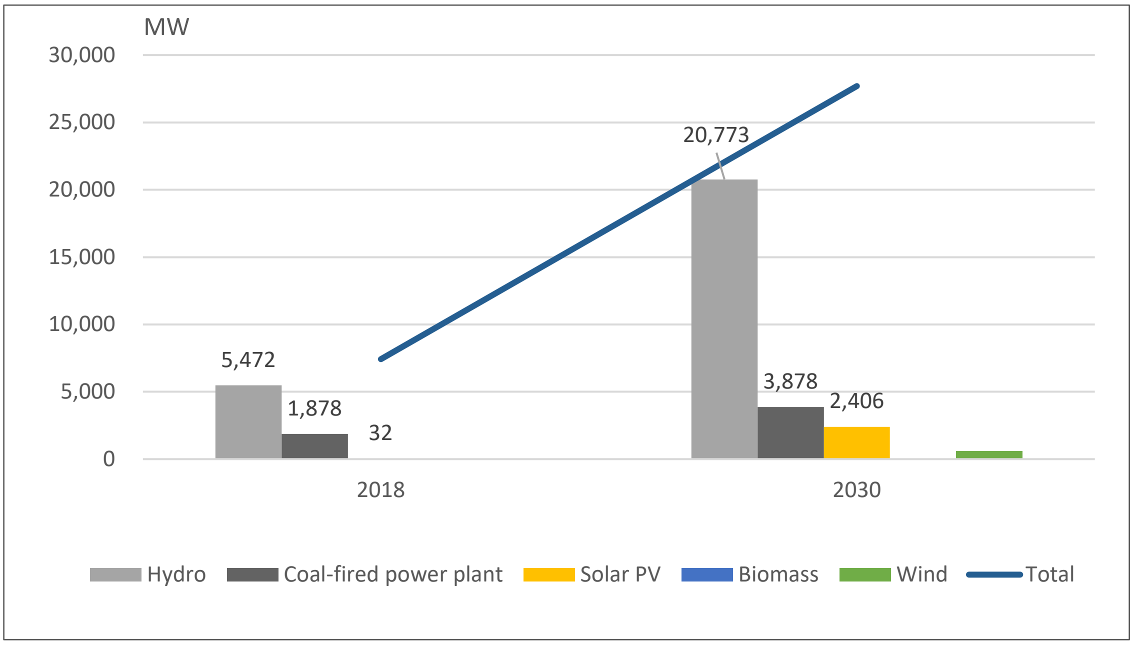
5.3. Power Development Plan

The Lao PDR submitted its NDC in October 2015 and an updated NDC in May 2021. The updated NDC indicates the unconditional target of reducing GHG emissions to 60% of BAU levels by 2030 and the conditional target of reducing GHG emissions to 63.5% of BAU levels. As of December 2022, no long-term strategy had been submitted, nor can the declaration of carbon neutrality confirmed.

The Lao PDR has focused on exporting electricity. As of 2018, it exported about 4,400 MW to neighbouring countries. The Lao PDR announced a plan to increase electricity exports by about three times to 14,600 MW in 2030.

The 2030 plan calls for installing about 20,770 MW of mainstay hydropower, an increase of nearly 280% over 2018, about 2,400 MW of solar power, an increase of about 7,400%, and 600 MW of wind power afresh, as well as bringing coal-fired thermal power to 3,880 MW and biomass power to 40 MW (Figure 3.24).

Figure 3.24. Power Generation Capacities in 2018 and 2030



Source: United Nations (2022).

6. Malaysia

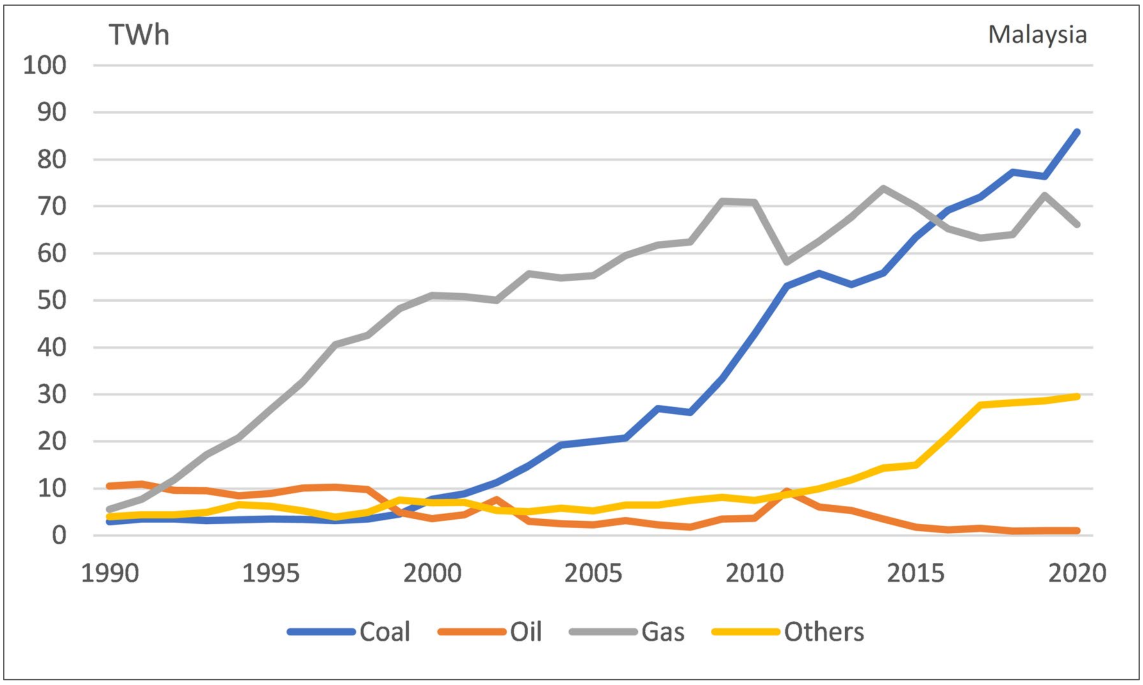
6.1. History of Power Generation Mix

Malaysia has oil and natural gas resources offshore and coal resources inland. The reserves-to-production ratio is 12.5 years for oil and 12.4 years for natural gas. Electricity demand has continued to expand on the back of solid economic growth since the 1990s. Under these circumstances, oil-fired and gas-fired power plants, especially those using domestically produced oil and natural gas, have become the primary power supply source. From 2000 onwards, the government has promoted strengthening coal-fired power generation from the perspective of the best energy mix strategy. Since 2005, gas-fired and coal-fired power has continued to increase, while oil-fired power has been reduced to a trickle. Coal-fired thermal power generation has outpaced gas-fired thermal power generation since 2015. Currently, coal-fired thermal power generation leads the market.

Natural gas used to rely on domestic production. But as domestic demand in the Malay Peninsula increased, imports from neighbouring countries have covered the shortage since 2013.

Regarding renewable energy, the increase in hydropower generation has been significant since 2010, with solar, wind, and biomass power also increasing steadily.

Figure 3.25. Trajectory of Power Generation Mix in Malaysia



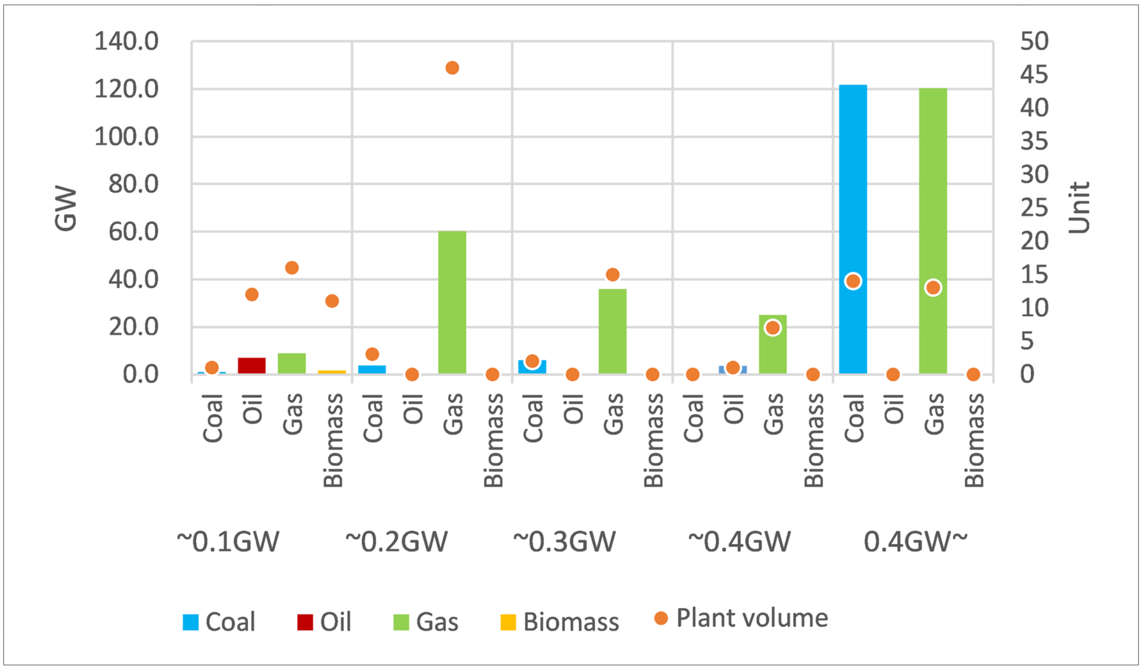
Source: IEA (2022).

6.2. Existing Fossil Power Plants

The largest share of Malaysia's thermal power is 25.1 GW (97 units) from gas, followed by 13.3 GW (20 units) from coal and 1.1 GW (13 units) from oil. Biomass power generation is small at 0.2 GW (11 units) with a capacity of less than 0.1 GW. The number of gas-fired plants is very large. There are 16 units with a capacity of under 0.1 GW and 81 units with a capacity of over 0.1 GW, accounting for 0.9 GW and 24.2 GW of the share, respectively. Coal-fired power plants, with a capacity of over 0.4 GW, account for a large share at 12.2 GW (14 units).

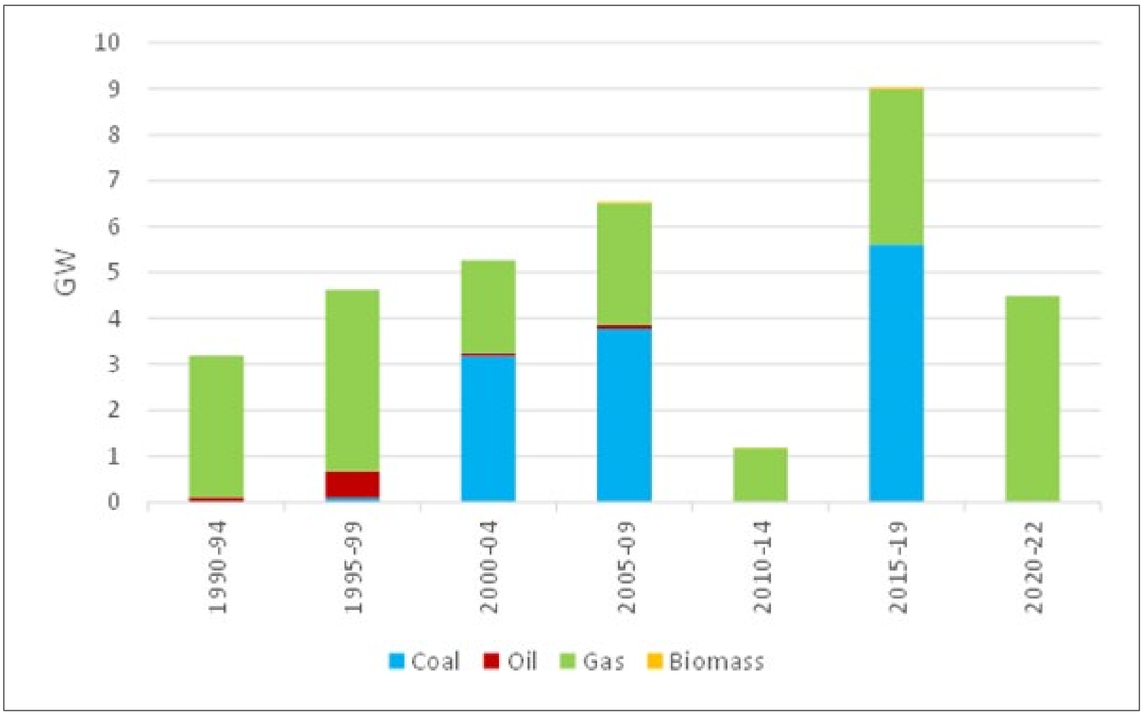
Looking at the history of thermal power generation, gas-fired power generation has increased since the 1990s, and coal-fired power generation has increased since 2000. As a result, there are a relatively large number of young gas-fired and coal-fired plants. Oil-fired power plants had been built sporadically since the 1990s but not since 2007. Biomass power plants have been built since 2005.

Figure 3.26. Existing Power Generation Capacity by Size and Fuel (Malaysia, 2022)



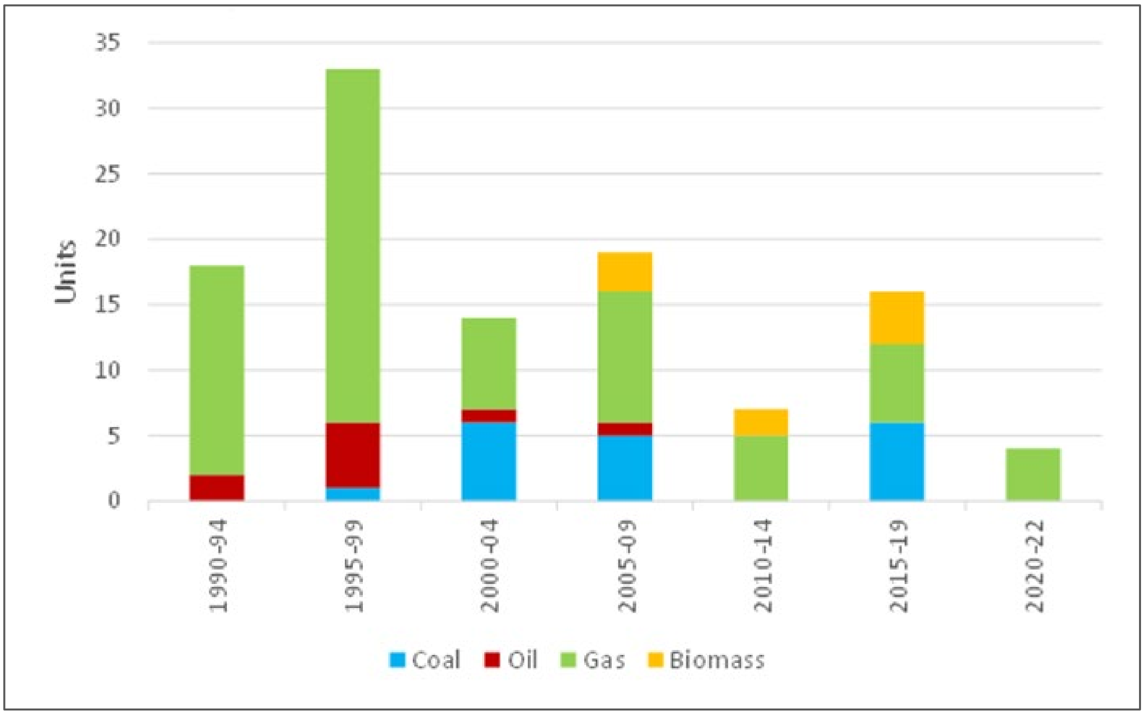
Source: Authos, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.27. Additional Power Generation Capacity by Year and by Fuel (Malaysia)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.28. Additional Power Generation Unit by Year and by Fuel (Malaysia)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

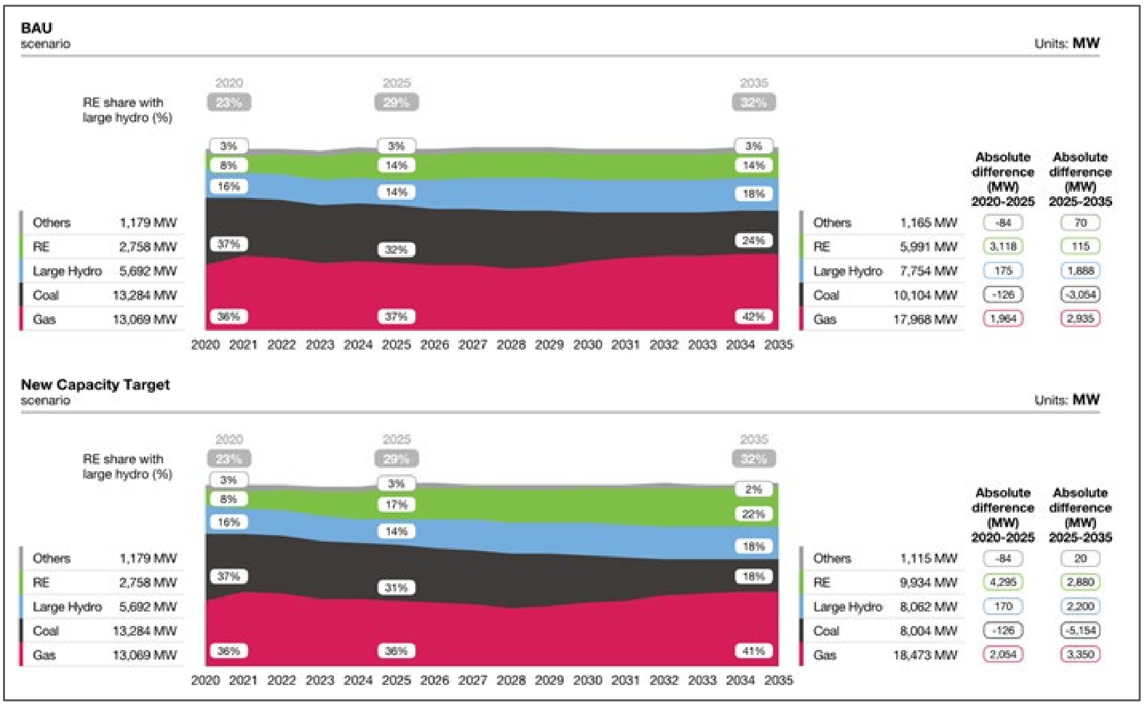
6.3. Power Development Plan

Malaysia submitted its first NDC in November 2016 and its update in July 2021. The updated NDC shows the target to reduce GHG emissions by 45% from the 2005 levels by 2030. As of December 2021, no long-term strategy had been submitted. In September 2021, Malaysia set a goal of achieving carbon neutrality by 2050 and announced a halt to the construction of coal-fired power plants.

Malaysia also set a target to reach 31% of renewable energy share in the national installed capacity by 2025.

The power development plan calls for a power generation capacity of about 42,980 MW in 2035, up about 20% from approximately 35,980 MW in 2020 under the BAU scenario. of which renewable energy, excluding large-scale hydropower, is expected to increase by almost 117% to around 5,990 MW and large-scale hydropower generation is expected to increase by about 36% to approximately 7,750 MW. The conditional scenario assumes an increase of about 27% to around 45,590 MW in 2035 compared to about 35,980 MW in 2020, of which renewable energy, excluding large-scale hydropower, is expected to increase by about 260% to approximately 9,930 MW and large-scale hydropower generation is expected to increase by about 42% to approximately 8,062 MW (Figure 3.29).

Figure 3.29. Capacity Mix for Malaysia for BAU and New Capacity Target Scenario, 2020–2035



Source: Government of Malaysia (2021).

7. Myanmar

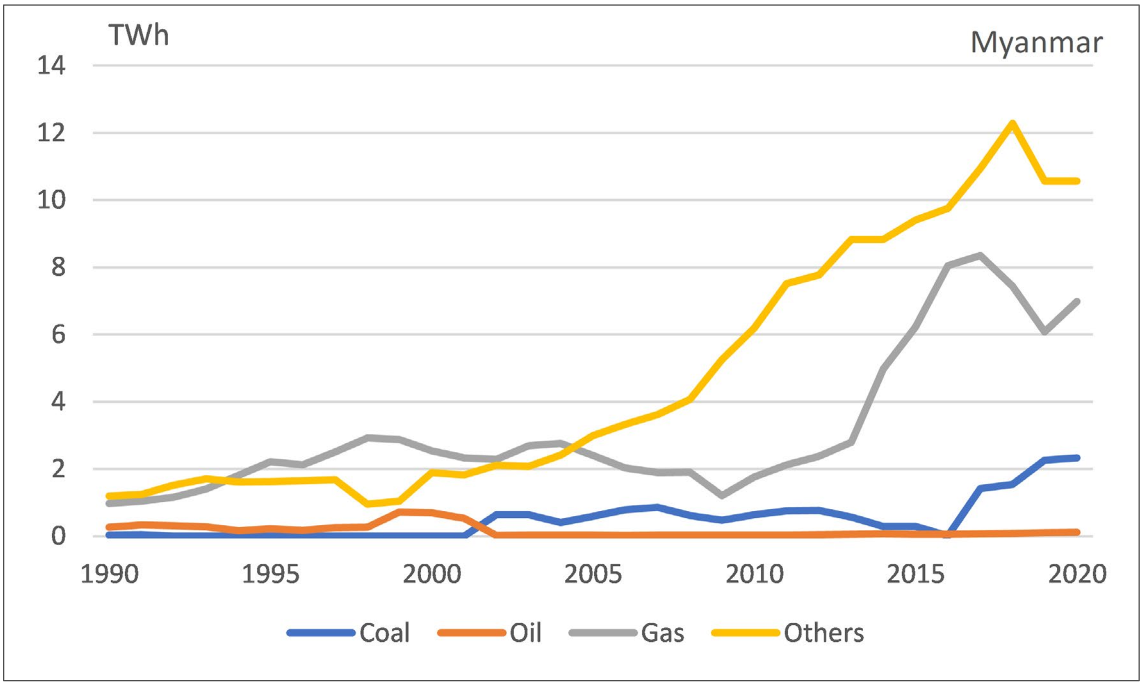
7.1. History of Power Generation Mix

Myanmar utilises its rivers with abundant water flow, climate with relatively high rainfall, and mountainous systems to have a sizeable hydroelectric power supply. It also has natural gas resources offshore and oil and coal resources inland. In terms of the reserve–production ratio, natural gas is listed as having 24.4 years, but there is no data to confirm for oil and coal. Crude oil has been produced since the latter half of the 19th century; since peaking in 1985, production has been declining. Natural gas, which has been under development since the 1980s, has become a major export item for Myanmar as exports through pipelines to neighbouring countries have increased.

Against this background, hydropower has consistently been the dominant source of electricity, except for the 10 years between 1995 and 2005. Next in line is gas-fired thermal power using domestic natural gas. Coal-fired thermal power plants began to be used in 2002 but were temporarily suspended in 2016 due to environmental concerns. The operator has changed since then, and the plants resumed operation in 2017 due to compliance with environmental regulations and have been used stably in recent years. Oil-fired thermal power was used briefly around 2000, but only a fraction has been utilised.

Following a political upheaval by the military in February 2021, companies involved in natural gas production, mostly from Europe and the United States, have withdrawn from Myanmar operations successively. Companies in Myanmar, Thailand, and elsewhere have taken over businesses, and production continues. In addition, the military attaches importance to ties with Russia and moves towards introducing nuclear power have been confirmed.

Figure 3.30. Trajectory of Power Generation Mix in Myanmar



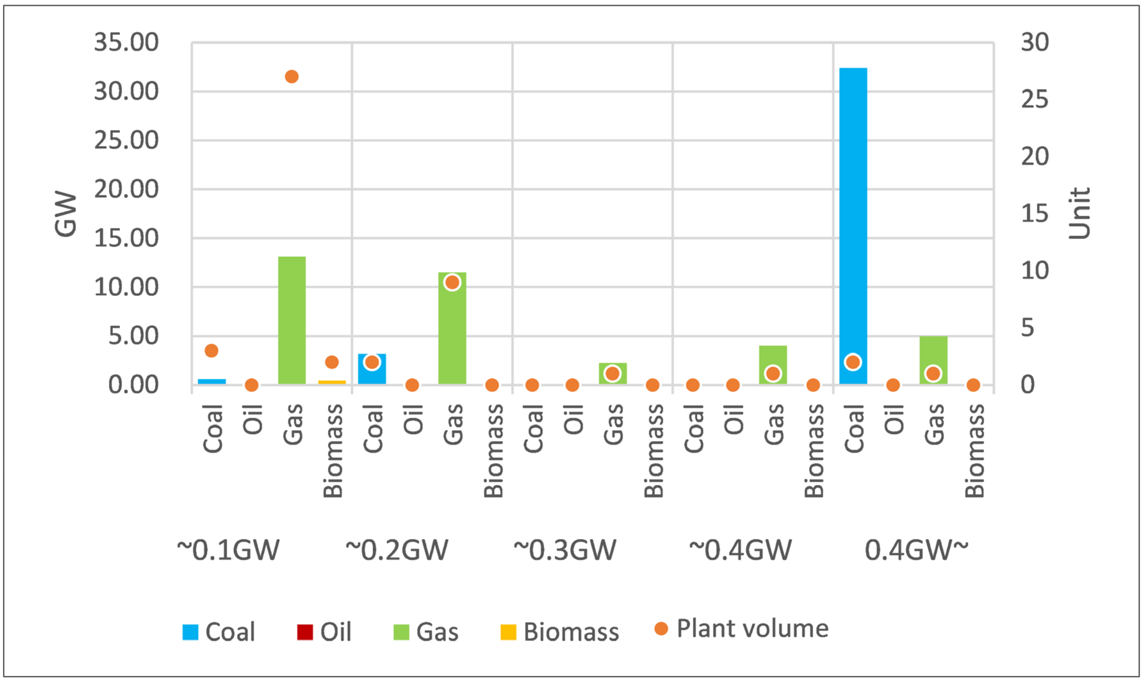
Source: IEA (2022).

7.2. Existing Fossil Power Plants

As for thermal power generation in Myanmar, coal-fired power generation has the largest capacity at 3.6 GW (7 units), followed by gas-fired power generation at 3.6 GW (39 units). Biomass power generation is small, at 0.0 GW (two units) from facilities with a capacity under 0.1 GW. Oil-fired power is not confirmed. Coal-fired thermal power generation is low; 3.2 GW (two units) from facilities with a capacity larger than 0.4 GW and 0.4 GW (five units) from those with a capacity smaller than 0.2 GW. Similarly, gas-fired thermal power is only 2.5 GW (36 units) from those under 0.2 GW, and 1.1 GW (3 units) from those over 0.2 GW.

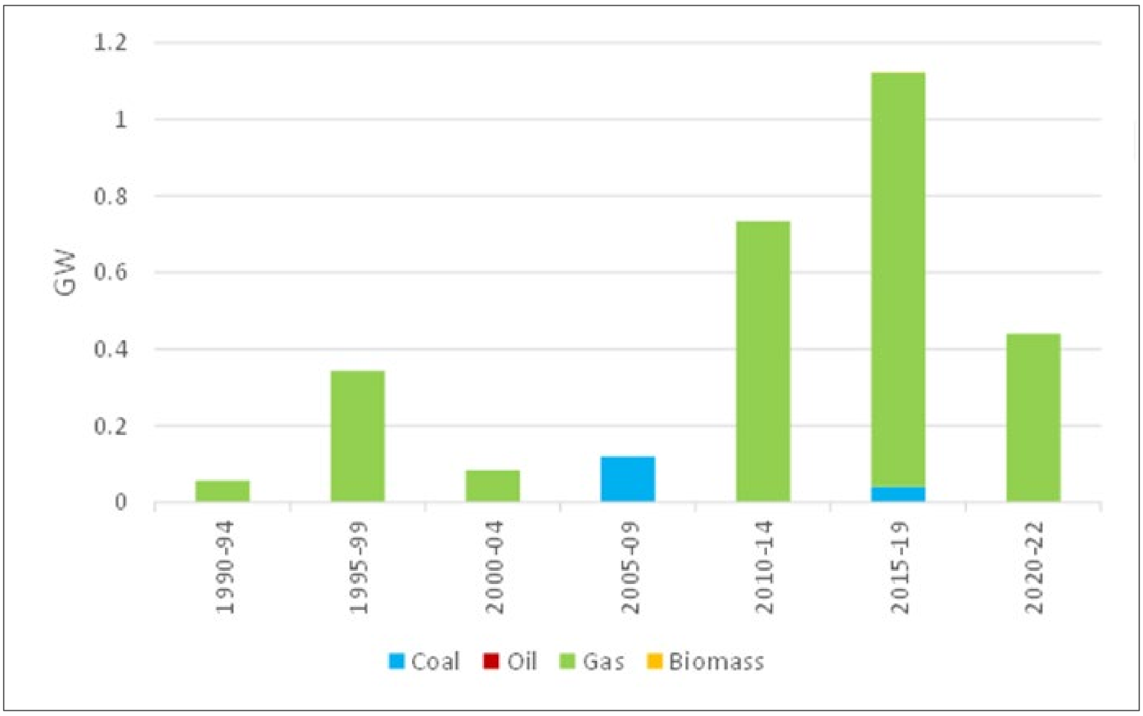
The history of thermal power generation shows that gas-fired power plants have been under construction since the 1990s and on the rise since the 2010s. In other words, young gas-fired thermal power plants, which have operated for less than 10 years, are the main power source. Coal-fired power plants were built in 2005 and 2017. Biomass power plants were also built in 2017.

Figure 3.31. Existing Power Generation Capacity by Size and Fuel (Myanmar, 2022)



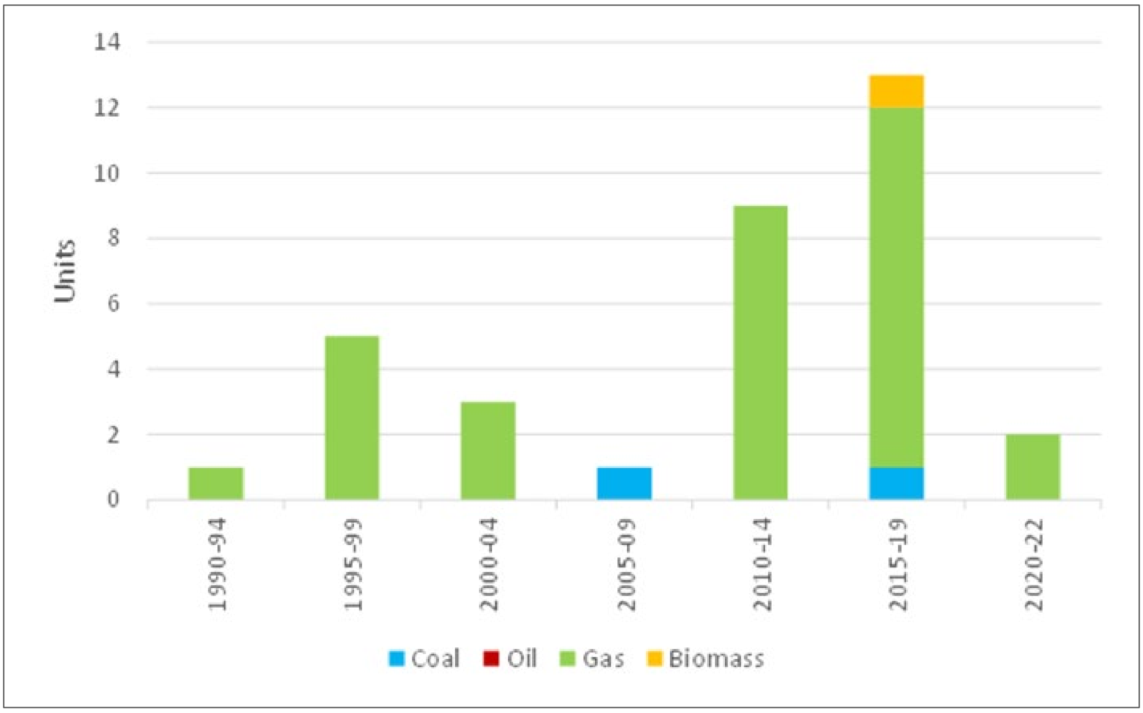
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.32. Additional Power Generation Capacity by Year and by Fuel (Myanmar)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.33. Additional Power Generation Unit by Year and by Fuel (Myanmar)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

7.3. Power Development Plan

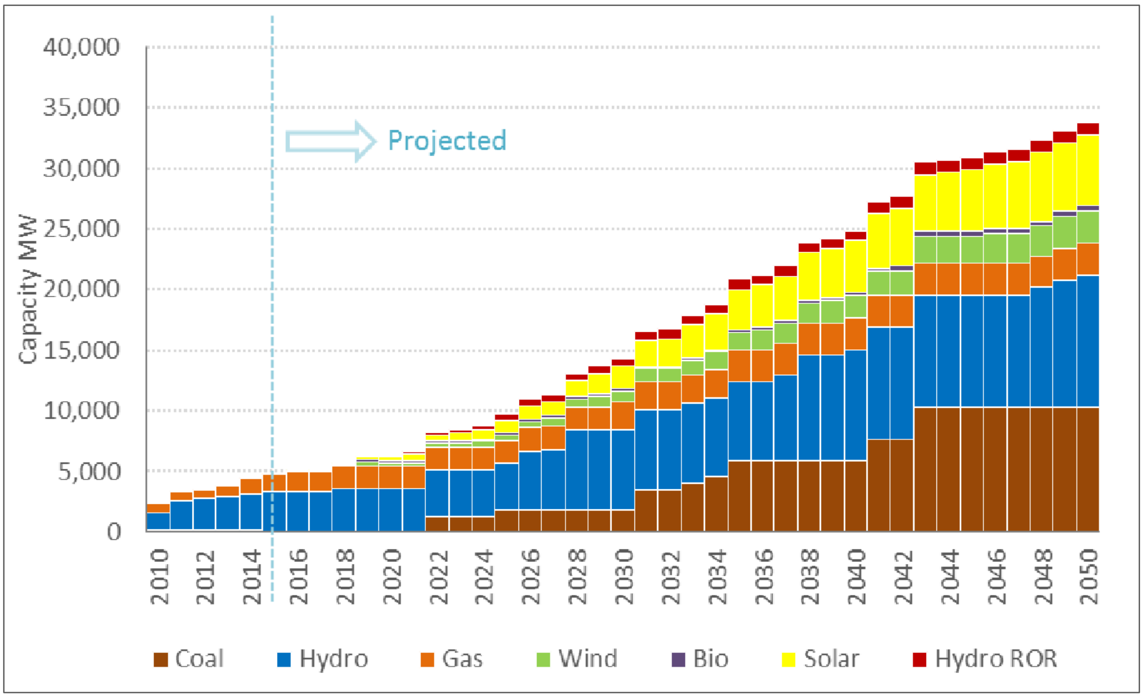
Myanmar submitted its NDC in September 2017 and an updated one in August 2021. The updated NDC presents an unconditional target to reduce GHG (and CO_2) emissions by 244.52 million tonne-CO_2e and a conditional target to reduce GHG (and CO_2) emissions by 414.76 million tonne-CO_2e by 2030.

As of December 2021, Myanmar had not submitted its long-term strategy. The declaration of carbon neutrality could not also be confirmed.

The military-led government is promoting the installation of solar power by Chinese companies. It is also strengthening ties with Russia in anticipation of the introduction of nuclear power.

A report released in 2016, before the political change, indicated plans to install 1,830 MW of coal-fired power in 2030 and 10,300 MW in 2050, about a 5.6-fold increase. In addition, 10,882 MW of hydropower, up about 3.1 times from 3,508 MW in 2020, 2,648 MW of wind power, and 5,911 MW of solar power will be installed by 2050 (Figure 3.34).

Figure 3.34. Prospect of Installed Capacity in Myanmar (BAU)



Source: WWF (2016).

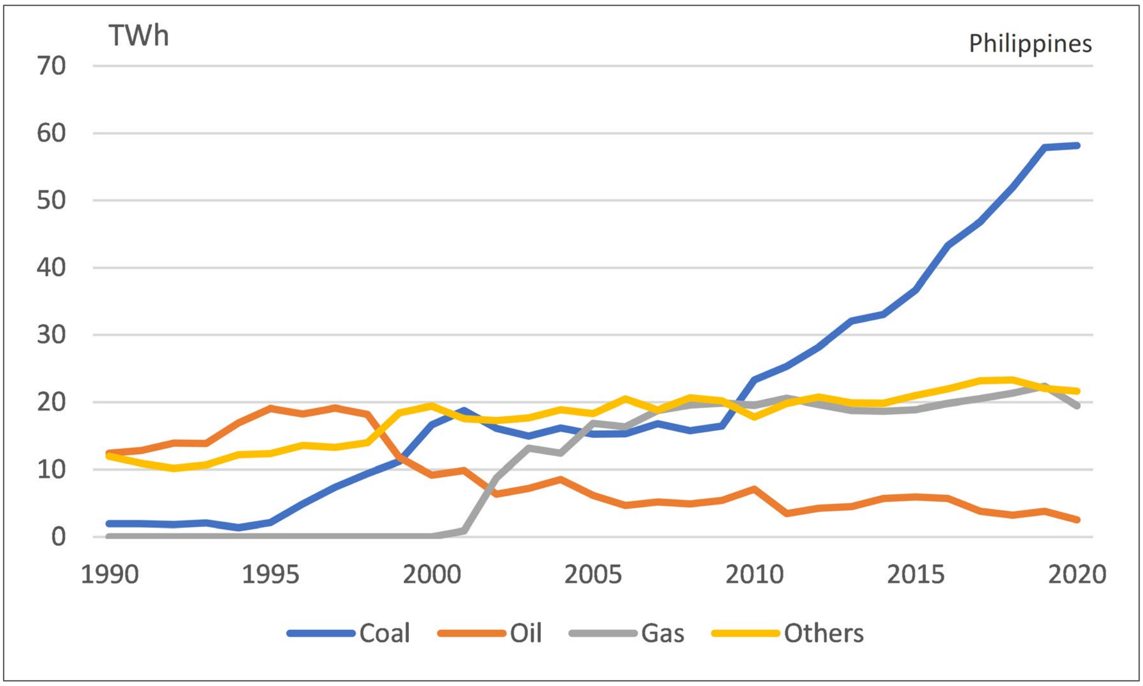
8. Philippines

8.1. History of Power Generation Mix

The Philippines has natural gas resources offshore and geothermal and hydropower resources inland. The reserve–production ratio of fossil fuels was 10.3 years for oil as of 2019, 28.2 years for natural gas as of 2018, and 57.5 years for coal at the end of 2015. Until 2000, the Philippines depended on oil and coal imports, but gas-fired power has increased since natural gas was developed in 2002. While domestic coal production has increased since the 2000s, its imports from neighbouring countries have also increased, resulting in imports exceeding domestic production.

As hydropower resources are abundant and many undeveloped sites remain, new hydropower development is expected. Geothermal power generation is the second-largest in the world. It is valued as a base power source because of its relatively low generation cost and high capacity factor.

Figure 3.35. Trajectory of Power Generation Mix in the Philippines



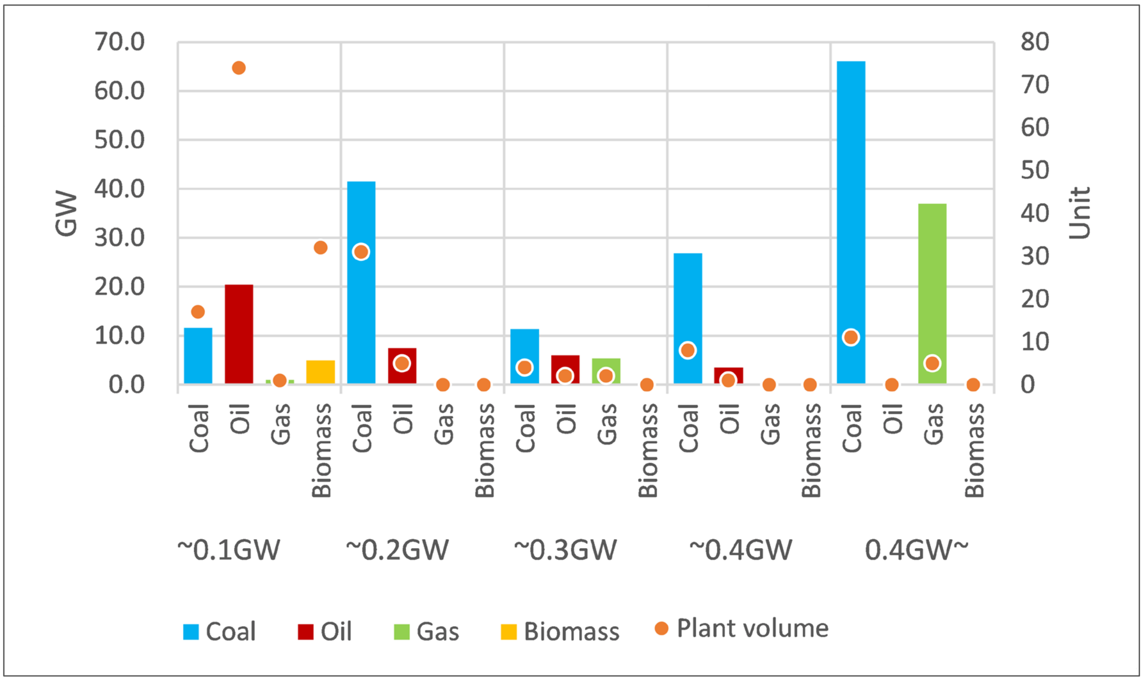
Source: IEA (2022).

8.2. Existing fossil power plants

Coal-fired thermal power generation accounts for the largest share in the Philippines, at 15.7 GW (71 units), followed by gas-fired thermal power at 4.3 GW (8 units), oil-fired thermal power at 3.7 GW (82 units), and biomass power at 0.5 GW (10 units). Coal-fired power generation is ubiquitous on all scales. Gas-fired power generation plants with a capacity of 0.4 GW or more account for the majority at 3.7 GW (five units). There are 2.0 GW (79 units) and 0.5 GW (32 units) of oil-fired and biomass power generation for facilities with a capacity under 0.2 GW.

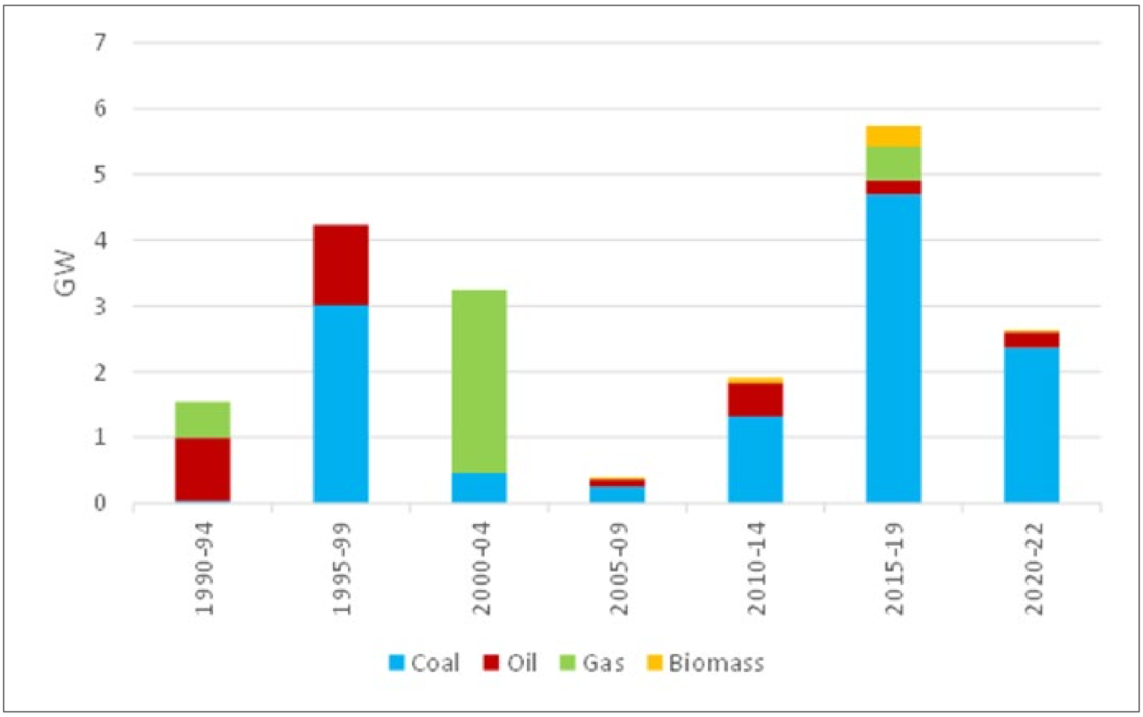
The history of thermal power generation shows that oil-fired power was dominant from 1990 to 1994, and coal-fired power was dominant from 1995 to 2000. Gas-fired power generation increased rapidly in 2000 and 2002. Construction between 2003 and 2009 was slow and has increased since 2010, especially for coal-fired power plants. In other words, many young coal-fired plants have operated for less than 10 years.

Figure 3.36. Existing Power Generation Capacity by Size and Fuel (Philippines, 2022)



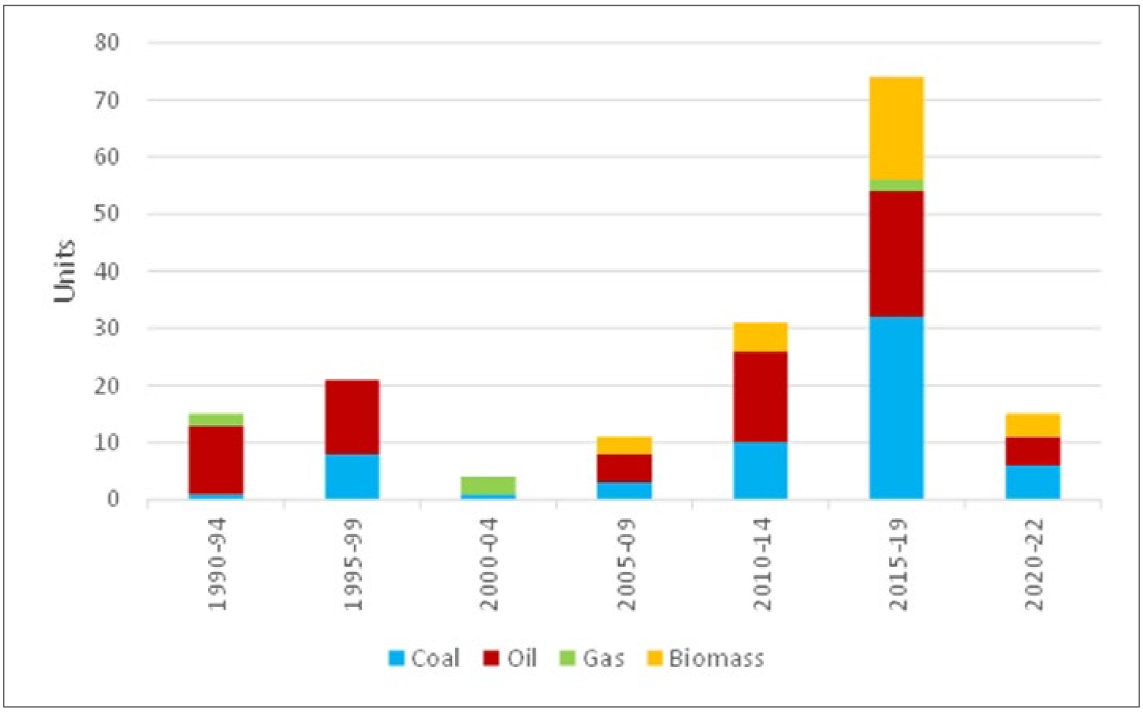
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.37. Additional Power Generation Capacity by Year and by Fuel (Philippines)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.38. Additional Power Generation Capacity by Year and by Fuel (Philippines)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

8.3. Power Development Plan

The Philippines submitted its NDC in April 2021, setting a GHG target reduction of 75% compared to BAU levels by 2030. (No conditions: 2.71%, conditional with international support: 72.29%) As of December 2022, a long-term strategy has not been submitted, nor a carbon neutrality declaration confirmed.

The *Philippine Energy Plan: PEP 2020–2040* states that domestic electricity demand will increase from 91,369 GWh in 2020 to 335,691 GWh in 2040. To deal with this situation, the Philippines plans to build new plants, mainly gas-fired, hydroelectric, and solar power plants, and increase the total capacity from 102 GW (101,969 MW) in 2020 to 364 GW (364,396 MW) in 2040. For 2040, the government has prepared two scenarios depending on the demand. In the R35-High Demand Scenario, the shortfall in renewable power generation will be covered by natural gas–fired power. In the R50-High Demand Scenario, the increase in natural gas will be limited, and renewable power generation will cover the limited amount. For renewable power generation, efforts will be made to promote solar power generation (Table 3-2).

Table 3.2. The Philippines's Power Demand and Supply Outlook

(MW)

	Actual	R35-High Demand Scenario	R50-High Demand Scenario	R35/ 2020 (%)	R50/ 2020 (%)	R35/ R50 (%)
	2020	**2040**	**2040**			
Coal	57,040	89,717	84,348	157	148	106
Oil	69	281	549	407	796	51
Natural gas	20,291	146,858	97,301	724	480	151
Renewables	24,569	127,540	182,198	519	742	70
Geothermal	12,821	16,184	15,962	126	124	101
Hydropower	8,623	51,550	65,885	598	764	78
Solar PV	988	53,062	75,148	5,373	7,610	71
Wind	1,360	5,121	22,723	377	1671	23
Biomass	778	1,623	2,480	209	319	65
Total	**101,969**	**364,396**	**364,396**	**357**	**357**	**100**

Source: Government of the Philippines (2021).

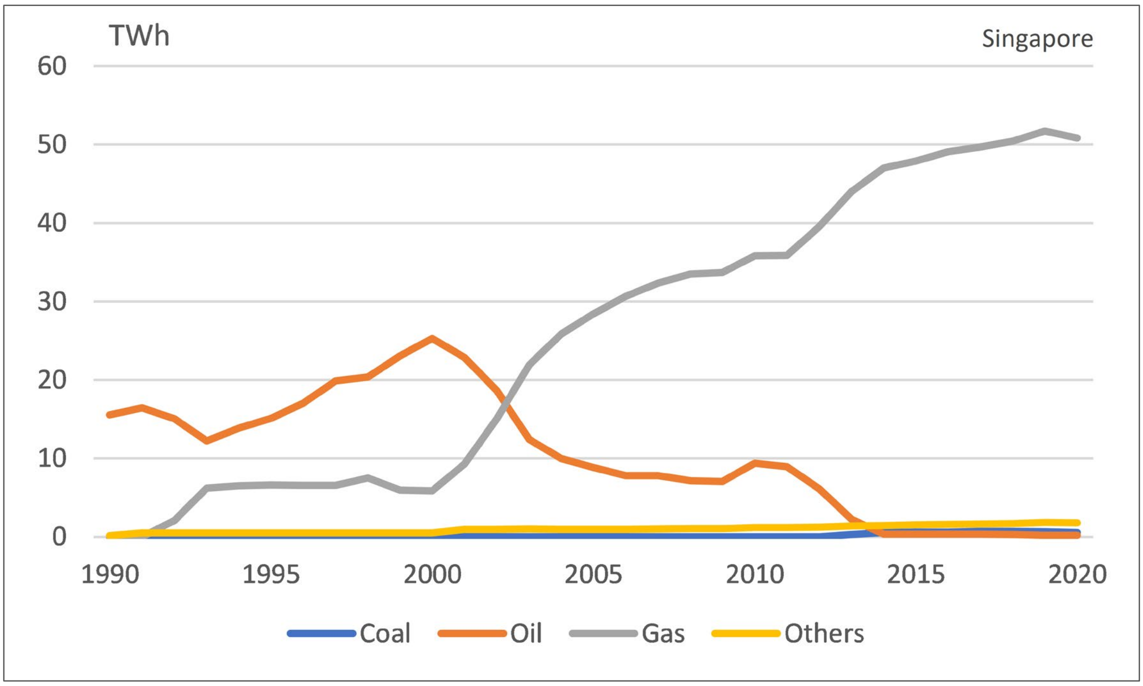
9. Singapore

9.1. History of Power Generation Mix

Singapore meets almost 100% of its energy needs through imports, as it has few energy resources. Oil-fired thermal power used to be the main source of electricity supply, but it peaked in 2000 and continued to decline, falling below gas-fired thermal power in 2002. Since 2014, only a tiny amount has remained. Gas-fired thermal power began in the 1990s and has expanded even after surpassing oil-fired thermal power in 2002. Natural gas is stably imported through LNG and pipelines from neighbouring countries.

Singapore emphasises environmental policies and promotes increased biomass and solar power due to its location near the equator.

Figure 3.39. Trajectory of Power Generation Mix in Singapore



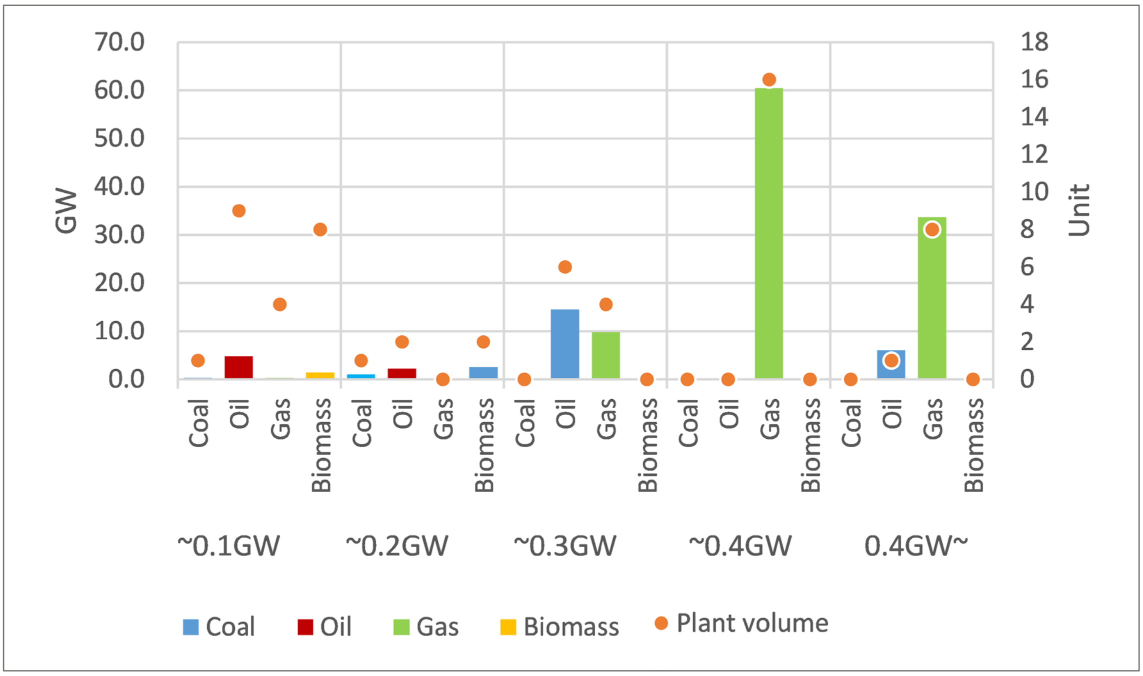
Source: IEA (2022).

9.2. Existing Fossil Power Plants

Singapore's largest thermal power generation capacity is 10.4 GW (32 units) from gas, followed by 2.7 GW (18 units) from oil and 0.4 GW (10 units) from biomass. Coal-fired power also has 0.1 GW (two units) but is small in scale. There are 10.4 GW (28 units) of gas-fired thermal power from facilities with a capacity over 0.2 GW and 2.2 GW (9 units) of oil-fired thermal power from those over 0.2 GW. There are 0.1 GW (2 units) and 0.4 GW (10 units) of coal-fired and biomass power generation, respectively, for facilities with less than 0.2 GW capacity.

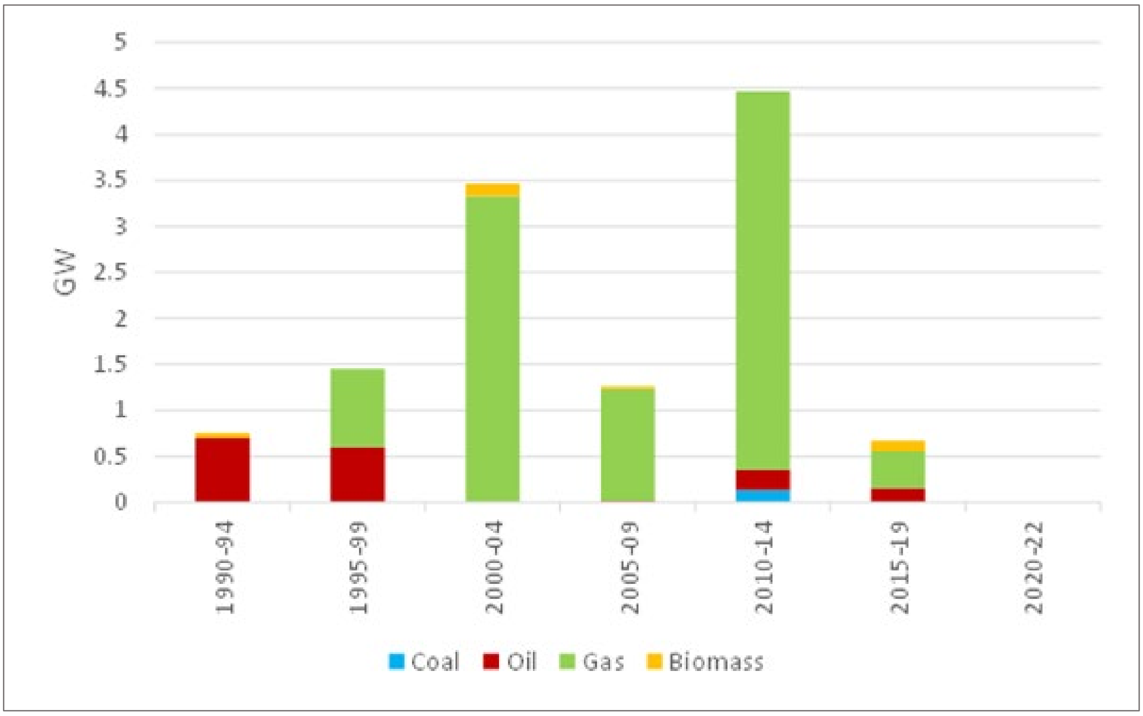
Oil-fired thermal power generation has increased since the 1990s and gas-fired thermal power generation has increased intensively since the 2000s. For this reason, a certain number of relatively young gas-fired power plants are around 10 years old. Coal-fired power plants were built in 2013 and 2014. Biomass power plants have been constructed sporadically since 1993. Thermal power generation has not increased since 2019.

Figure 3.40. Existing Power Generation Capacity by Size and Fuel (Singapore, 2022)



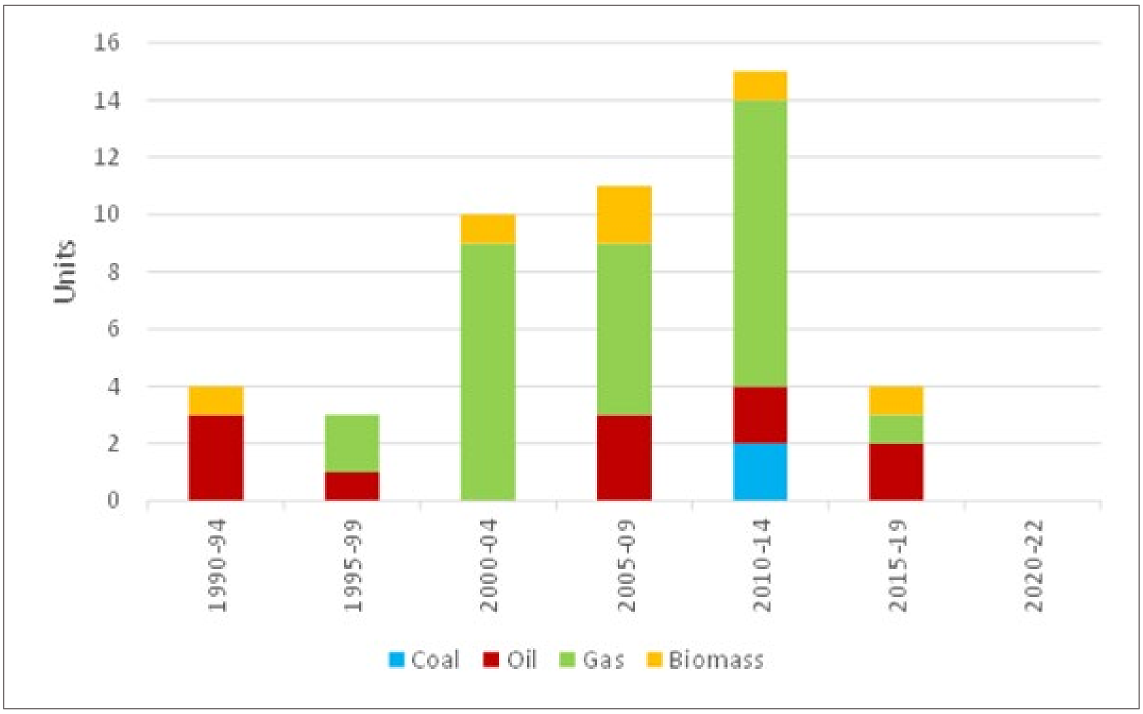
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.41. Additional Power Generation Capacity by Year and by Fuel (Singapore)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.42. Additional Power Generation Unit by Year and by Fuel (Singapore)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

9.3. Power Development Plan

Singapore submitted its first NDC in September 2016, followed by an update in March 2020, and the latest NDC in November 2022. The latest NDC stated the target to reduce GHG emissions is less than 65 million tonnes-CO_2e by around 2030. In March 2020, Singapore submitted its long-term strategy, which includes a target to halve CO_2 emissions from the peak by 2050, as well as initiatives to expand the use of renewable energy; introduce advanced technologies such as carbon capture, utilisation, and storage; and increase electricity imports. It also includes creating business opportunities such as green finance.

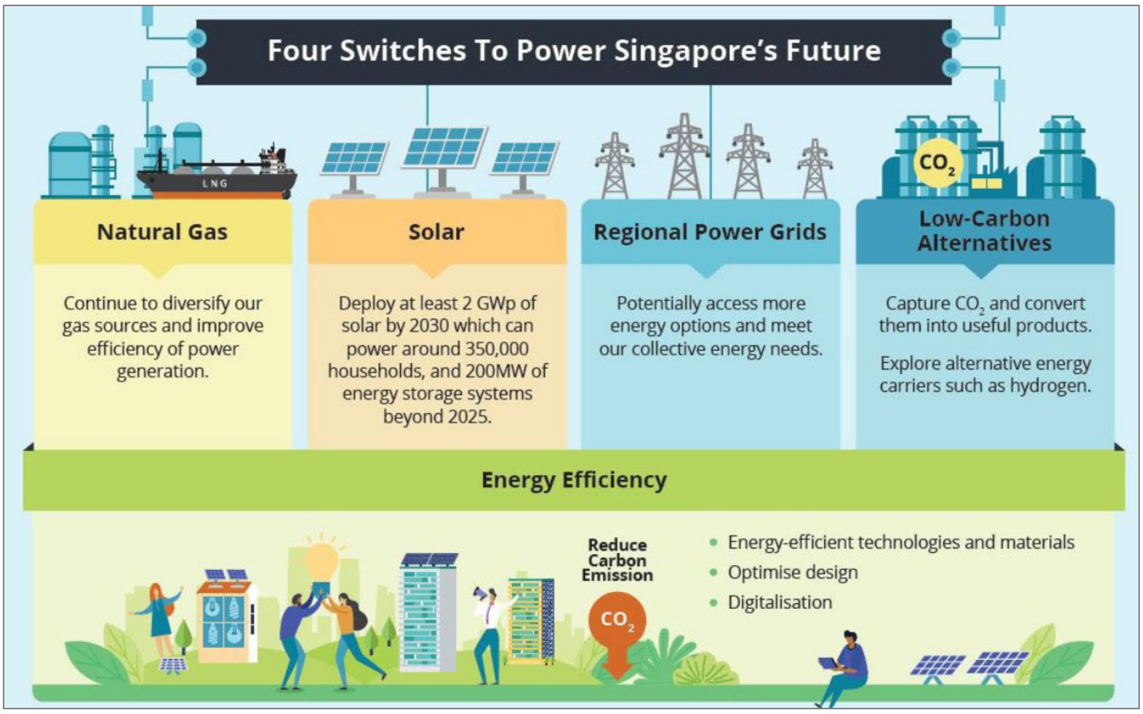
Singapore has set targets to peak out GHG emissions in 2030, halving them from peak emissions by 2050 and aiming to achieve zero emissions by the second half of the 21st century. However, it has not explicitly declared carbon neutrality due to geographical, economic, and industrial structural limitations.

The National Energy Strategy 'Energy for Growth'[3] calls for a shift from oil-fired thermal power to gas-fired thermal power, and a shift to gas-combined-cycle power generation in response to increased electricity demand due to economic growth.

[3] Ministry of Trade and Industry Singapore, https://www.mti.gov.sg/Resources/publications/National-Energy-Policy-Report

The power sector set the expanded weight on natural gas, the increase in solar power generation, regional electricity grid creation, and the expansion of low-carbon alternative solutions as the future value in the medium to long term, and promotes them (Figure 3.43).

Figure 3.43. Singapore's Future Electricity Grid



Source: Government of Singapore (2020).

10. Thailand

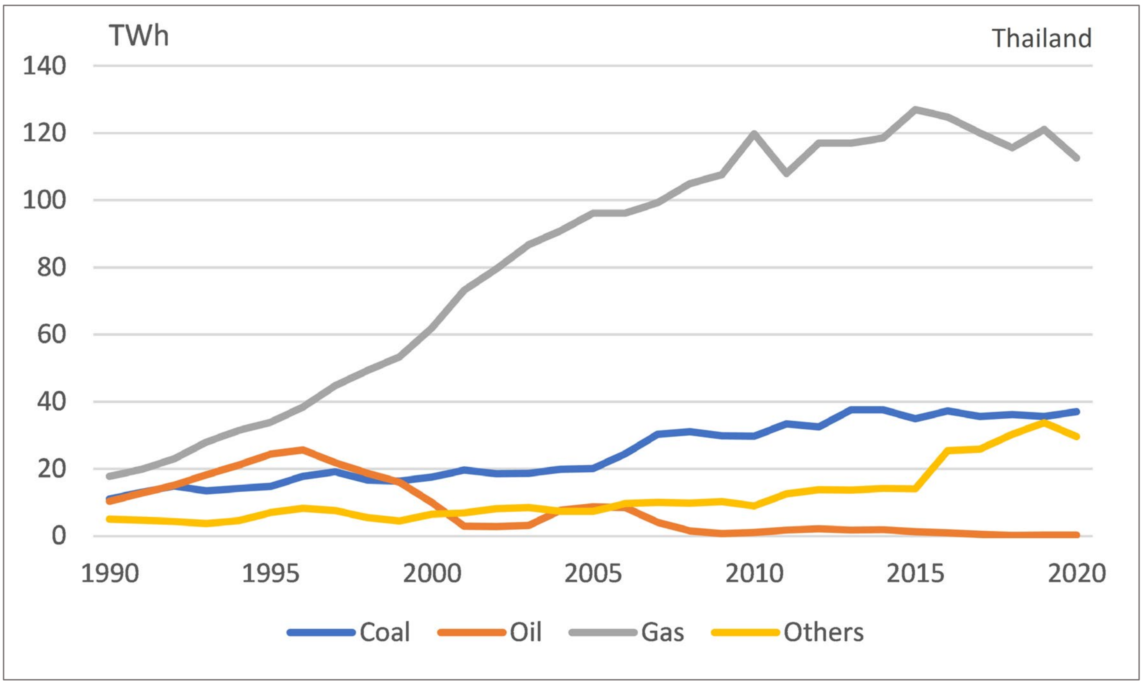
10.1. History of Power Generation Mix

Thailand has natural gas resources offshore and coal resources inland. The reserves-to-production ratio is 1.7 years for oil, 4.4 years for natural gas, and 80 years for coal. Electricity demand has expanded due to solid economic growth since the 1990s. Under these circumstances, gas-fired power plants, especially those using domestic natural gas, have become the main power supply source. Initially, Thailand strengthened its oil-fired thermal power to meet growing demand. However, as the expansion of gas-fired thermal power got on track, oil-fired thermal power has gradually declined, with only a small amount now available.

In terms of natural gas supply, the decline of domestic gas began around 2014. In response, Thailand started importing LNG, but the challenges were that LNG is more expensive than domestic natural gas and that it carries energy security risks. As a result, the Thai government turned to coal to diversify its power mix. Thailand's coal-fired thermal power plant, Mae Mo, is near the mid-north Mae Mo coal field. Thailand has pursued this expansion and other development plans at different locations by IPPs. However, the Mae Mo coal field and coal-fired thermal power plants have had significant environmental pollution problems, and there is strong public opposition. That has stalled progress on many of the planned coal-fired power plant projects.

Renewable energy has expanded remarkably in recent years. Solar and onshore wind power has been growing since the Adder scheme started in 2007 to support introducing renewable energy power. The decline in the use of gas-fired thermal power in recent years is thought to be the remarkably low marginal cost of renewable energy power.

Figure 3.44. Trajectory of Power Generation Mix in Thailand



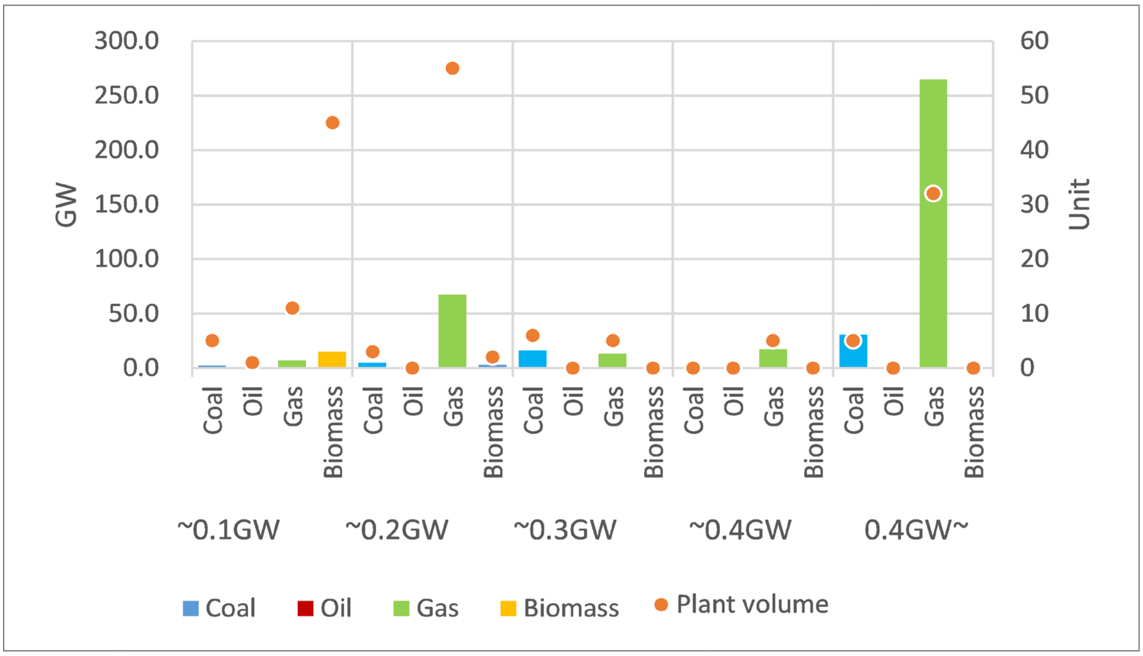
Source: IEA (2022).

10.2. Existing Fossil Power Plants

Thailand's largest thermal power generation capacity is 36.9 GW (108 units) from gas, followed by 5.4 GW (19 units) from coal. There is only one oil-fired power unit. There are 1.8 GW (47 units) of biomass power generation from facilities with under 0.2 GW capacity. There are 7.4 GW (66 units) of gas-fired thermal power plants with under 0.2 GW capacity and 26.5 GW (32 units) of those with over 0.4 GW capacity. There are 2.3 GW (14 units) of coal-fired power generation from facilities with less than 0.3 GW capacity, while there are 3.0 GW (5 units) of coal-fired power from those with more than 0.4 GW.

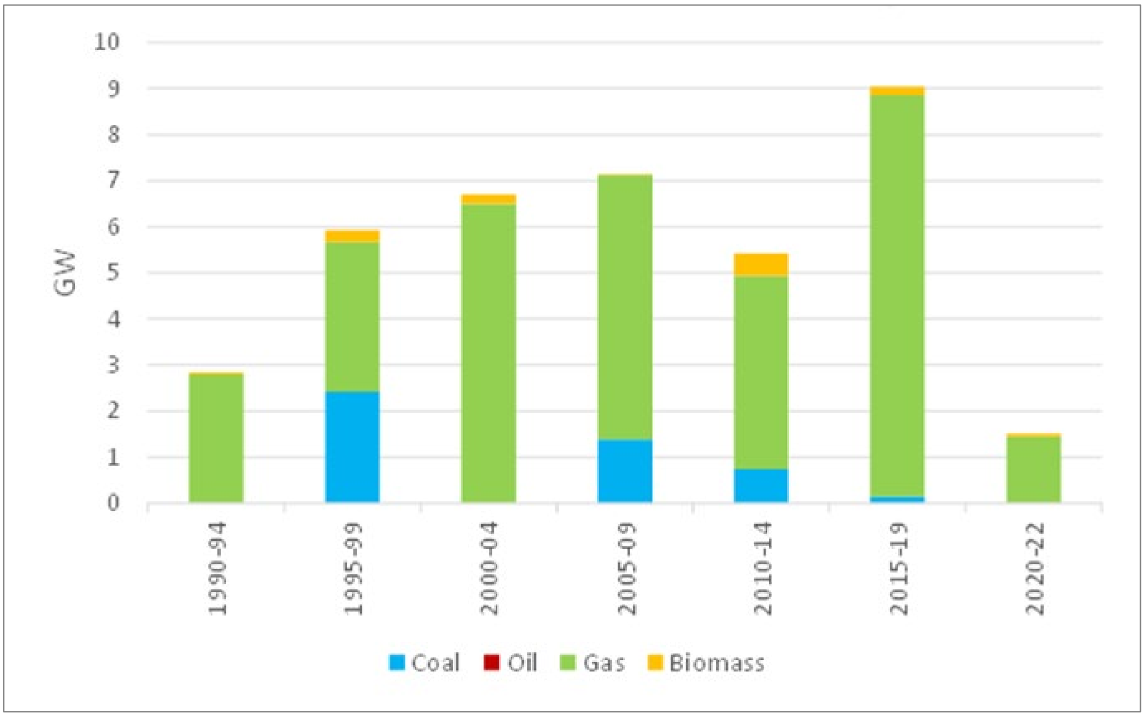
The history of thermal power generation shows that gas-fired power generation has been increasing since the 1990s, especially in 2000 and 2008. Many young gas-fired power plants have operated for less than 10 years. In Put Into Operation, coal-fired and biomass power generation has increased steadily since the 1990s. Oil-fired thermal power has not increased since 1990.

Figure 3.45. Existing Power Generation Capacity by Size and Fuel (Thailand, 2022)



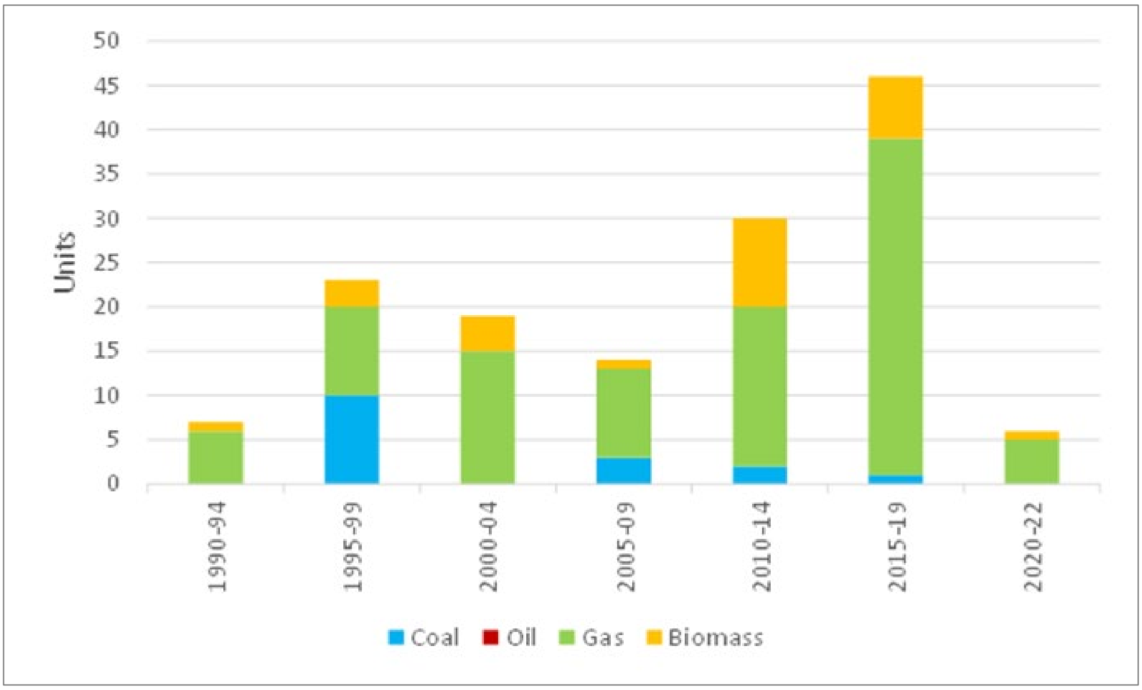
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.46. Additional Power Generation Capacity by Year and by Fuel (Thailand)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.47. Additional Power Generation Unit by Year and by Fuel (Thailand)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

10.3. Power Development Plan

Thailand submitted its NDC in October 2015, which set a target of reducing GHG emissions by 20% relative to the 2005-based BAU levels by 2030. It maintained this target in the October 2020 update (BAU 2030: about 555 Mt CO_2).

In November 2021, Thailand's Prime Minister Prayuth announced new targets at COP26 to achieve net-zero CO_2 emissions by 2050 and net-zero GHG emissions by 2065.

According to the Power Development Plan 2018, a revision 1 of the Power Development Plan 2018–2037, Thailand's three power generation corporations will have a combined generation capacity of 77,211 MW by the end of 2037. At the end of 2017, the generation capacity was 46,090 MW and 56,431 MW will be added from 2018 to 2037. With 25,310 MW of power generation facilities to be decommissioned during the same period, the capacity will be 77,211 MW at the end of 2037 (Table 3.3).

Thailand also plans to increase the share of renewable energy in the power generation mix to 36% by 2037 (Figure 3.48).

Table 3.3. Prospect of Change in Power Generating Capacity in 2018–2037 in Thailand, MW

As of December 2017	46,090
Put into Operation in 2018–2037	56,431
Retirement in 2018–2037	-25,310
Remaining by the end of 2037	77,211

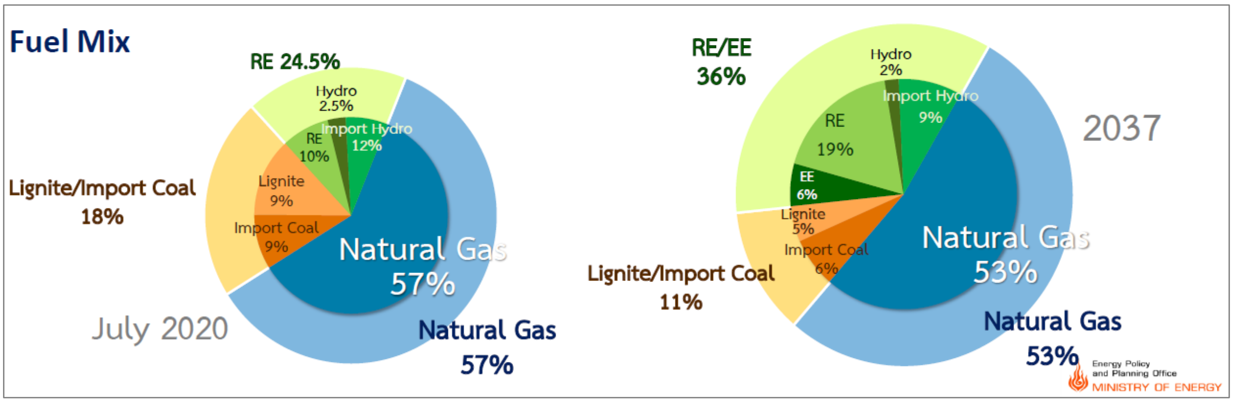
Source: Government of Thailand (2020).

Table 3.4. Prospect of Additional Capacity in 2018–2037 in Thailand

Renewables	18,833 MW
Community	1,933 MW
Pumped storage hydropower	500 MW
Combined heat and power	2,112 MW
Combined cycle gas turbine	15,096 MW
Coal/lignite	1,200 MW
Import	5,857 MW
New/replacement power plants	6,900 MW
Efficiency improvement	4,000 MW
Total	56,431 MW

Source: Thailand Government (2020).

Figure 3.48. Prospect of Power Generation Mix in Thailand



Source: Government of Thailand (2020).

11. Viet Nam

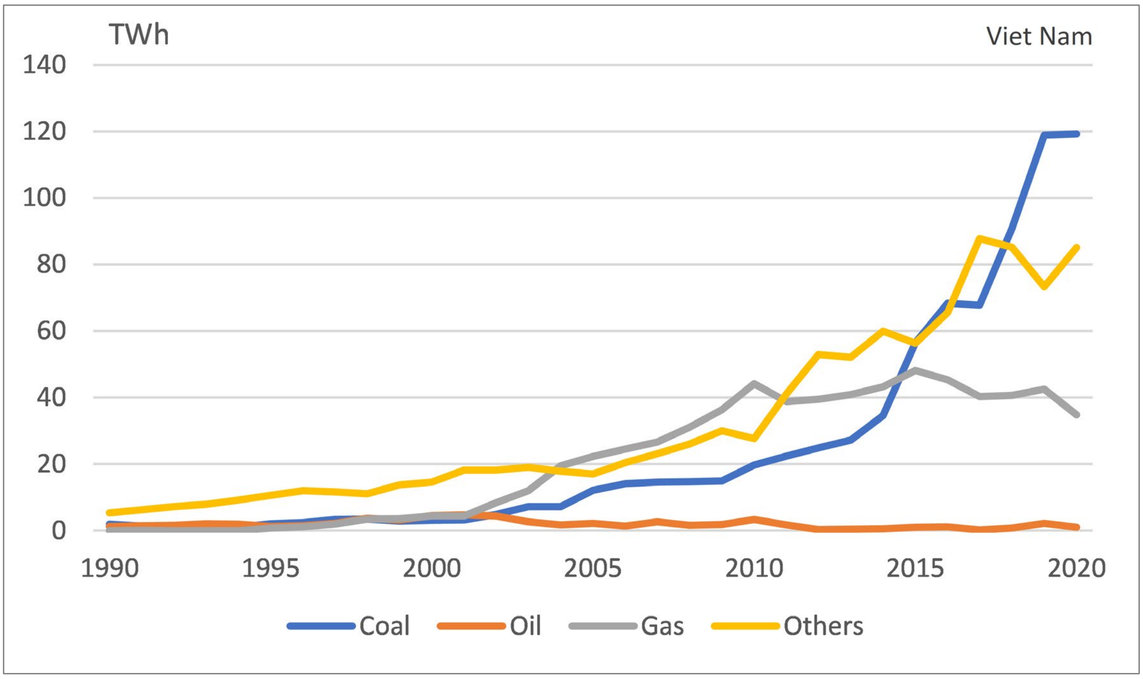
11.1. History of Power Generation Mix

Viet Nam has oil and natural gas resources offshore in the south and coal resources inland in the north. The reserves-to-production ratio of fossil fuels is 58.1 years for oil, 74.1 years for natural gas, and 69 years for coal. It also has rivers in the north and the south and is rich in hydropower resources. With a long north–south coastline, wind power generation by seasonal winds is also expected. Regarding the development of resources in the south, conflicts with neighbouring countries over territorial rights of the sea area have become a major development issue.

Viet Nam focuses on coal-fired and hydroelectric power generation. Although oil-fired thermal power was used in 1980, it peaked in 2001 and then declined, with only a fraction left now. The use of gas-fired thermal power began in the 1980s and has continued to increase as domestic production of natural gas has taken off. In addition to domestically produced coal, imported coal is used to generate coal-fired power.

Hydropower generation has increased its production through development using abundant river water. However, due to environmental policies, development sites have decreased in recent years. Renewable energy sources other than hydropower, such as wind, solar, geothermal, and biomass power, are also rich and are expected to be developed.

Figure 3.49. Trajectory of Power Generation Mix in Viet Nam



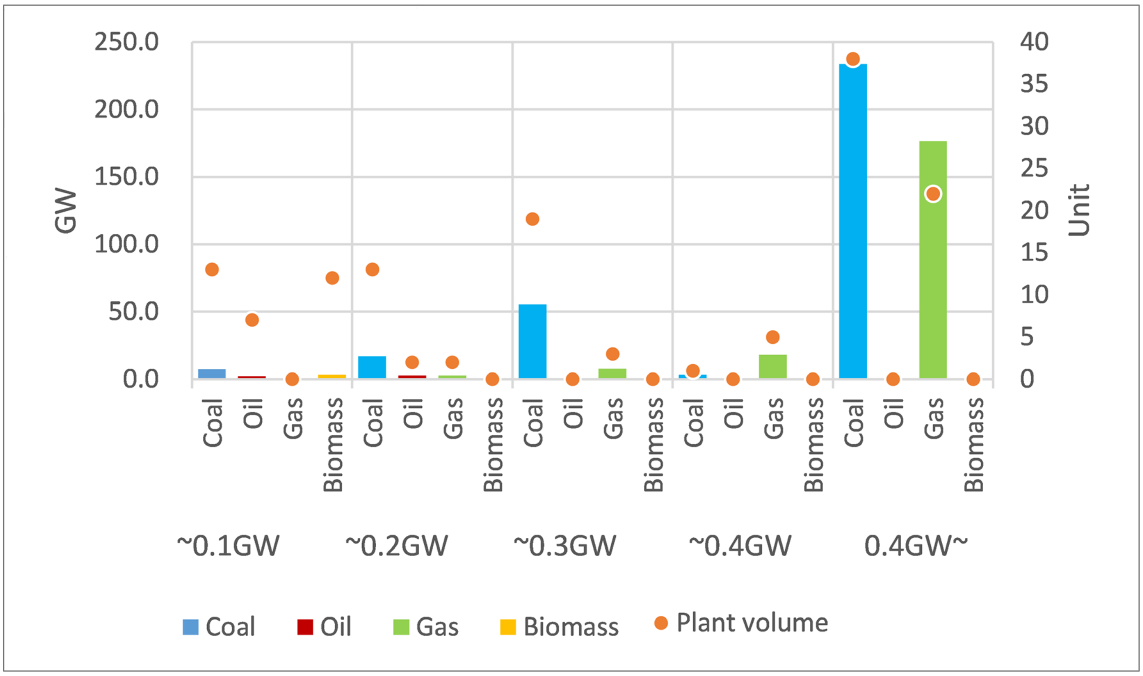
Source: IEA (2022).

11.2. Existing Fossil Power Plants

The largest thermal power in Viet Nam is coal-fired, at 31.7 GW (84 units), followed by gas-fired power, at 20.5 GW (32 units). There are 0.5 GW (9 units) of oil-fired thermal power from facilities with a capacity of under 0.2 GW, and 0.3 GW (12 units) of biomass power from those with less than 0.1 GW capacity. There are 8.0 GW (45 units) of coal-fired thermal power generated from plants with under 0.3 GW capacity and 23.4 GW (38 units) from those with over 0.4 GW capacity. While there are 17.7 GW (22 units) of gas-fired power generation from plants with a capacity of over 0.4 GW, there are 2.9 GW (10 units) from those with a capacity of under 0.3 GW.

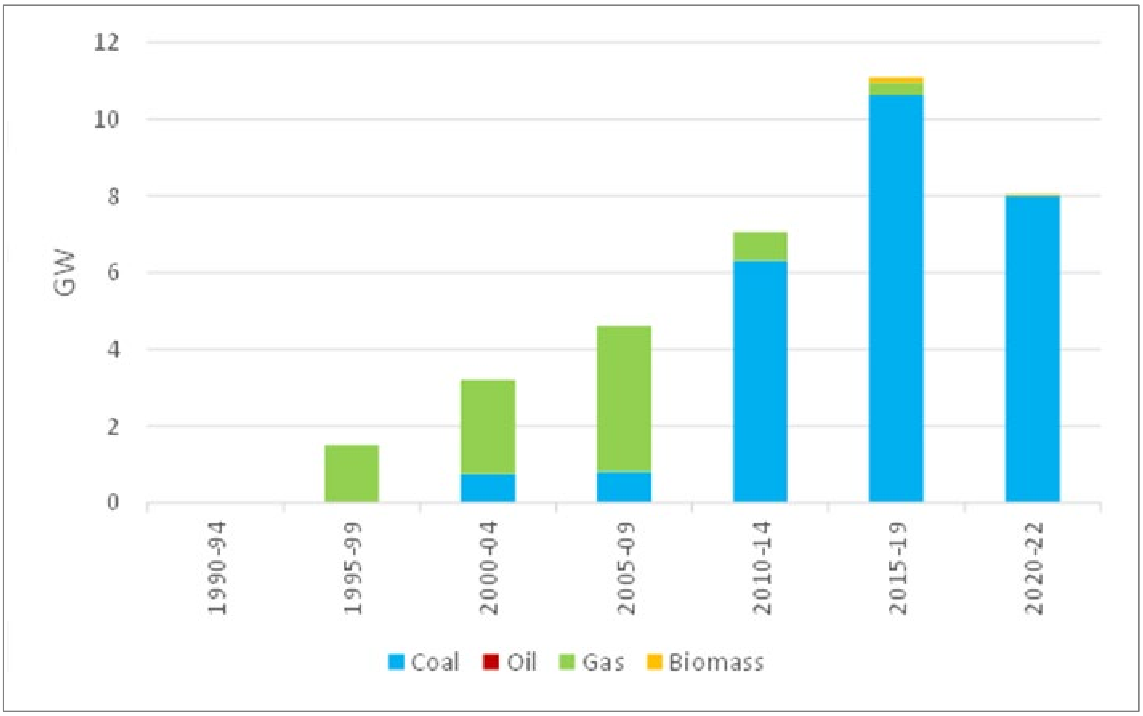
The history of thermal power generation shows that gas-fired power started to increase in 1995, both gas-fired and coal-fired power began to grow in 2000, and coal-fired power has increased since 2012. For this reason, coal-fired power generation, which has operated for 10 years or less, has become the mainstay. Biomass power generation has increased since 2016.

Figure 3.50. Existing Power Generation Capacity by Size and by Fuel (Viet Nam, 2022)



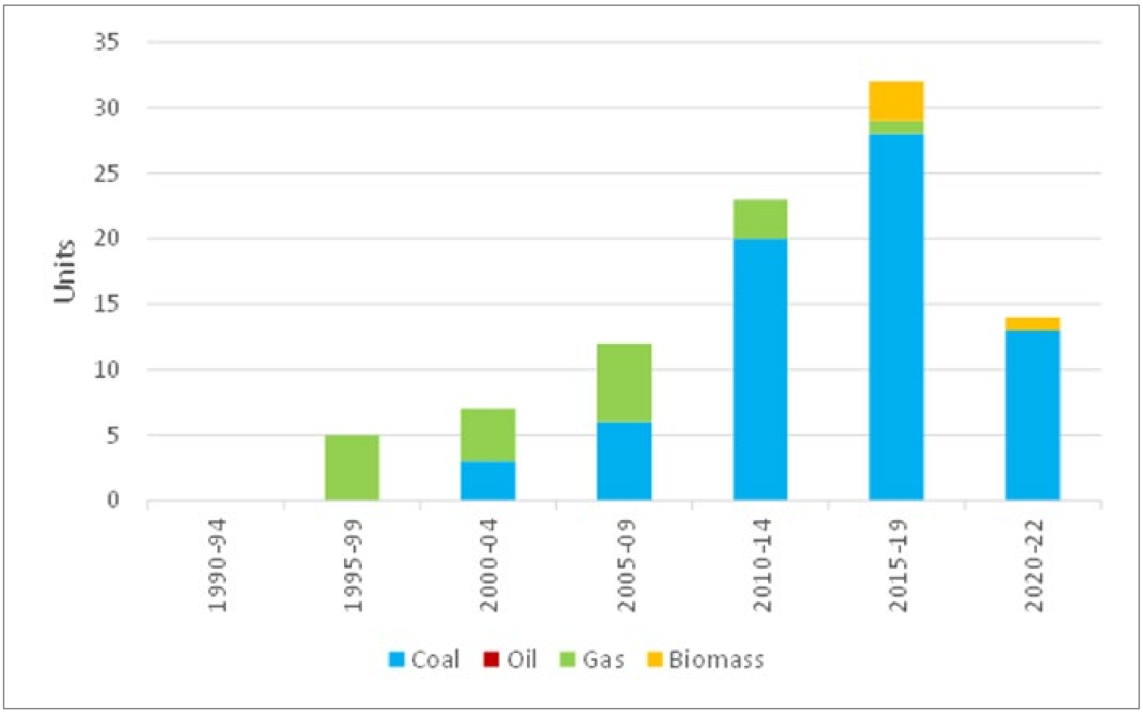
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.51. Additional Power Generation Capacity by Year and by Fuel (Viet Nam)



Source: Authors, created from Enerdata, Power Plant Tracker, database, https://www.enerdata.net/research/power-plant-database.html.

Figure 3.52. Additional Power Generation Unit by Year and by Fuel (Viet Nam)



Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

11.3. Power Development Plan

Viet Nam submitted its first NDC in November 2016 and its second update in November 2022. In the NDC, the government set the target to reduce GHG emissions by 9% by 2030 through domestic self-help efforts and by 27% through international assistance. As of September 2022, no long-term strategy had been submitted. In January 2021, Viet Nam declared it would aim for carbon neutrality by 2050. In Put Into Operation, the government has formulated the 'Green Growth Strategy', which balances environmental protection with economic growth, and an action plan to reduce methane emissions by 2030 to combat global warming.

The National Strategy on Green Growth for 2021–2030, with a vision to 2050[4] formulated in February 2020, aims to maintain coal-fired thermal power as a base power source while raising the ratio of renewable energy sources to 15%–20% by 2030 and 25%–30% by 2045 to meet rising demand.

The Vietnamese government released a draft of the 8th Power Development Plan (PDP8 Draft) in 2021 but has not received approval from the prime minister. However, the government intends to significantly reduce the amount of coal-fired power generation in the future and increase the ratio of new and renewable energy generation, which can be grasped even through the PDP8 Draft (Table 3-5).

The most recent revised version of the PDP (November 2022) states that Viet Nam plans to stop building new coal-fired power plants after 2030 and to have no coal-fired power plants on the grid by 2050.[5]

[4] http://vanban.chinhphu.vn/portal/page/portal/chinhphu/hethongvanban?class_id=2&_page=1&mode=detail&document_id=204226

[5] Appendix: Key Highlights of the New Draft of the National Power Development Plan (Draft PDP8) (2021).

Table 3.5. PDP8 (February 2021) and the Amended PDP7

(MW)

Source	2020	Draft PDP8		Amended PDP7	
		2025	2030	2025	2030
Coal-fired thermal power	20,431	29,523	37,323	47,877	55,477
Gas-to-power and oil/diesel-fired thermal power	9,030	14,055	28,871	15,016	19,016
Hydropower + pumped-storage hydropower (including small-scale hydropower)	20,685	24,497	25,992	24,611	27,871
Wind power	630	11,320	18,010	2,030	5,990
Solar power	16,640	17,240	18,640	3,935	11,765
Biomass and other renewable power	570	2,050	3,150	1,844	3,444
Power import	1,272	3,508	5,677	1,436	1,508
Nuclear power					4,600
Total capacity	69,258	102,193	139,693	96,749	129,671
Pmax (MW)	38,706	59,389	86,493	63,471	90,651

Source: Appendix: Key Highlights of the New Draft of National Power Development Plan (Draft PDP8).

Table 3.6. PDP8 (February 2021) and the Amended PDP7

(%)

Source	2020	Draft PDP8		Amended PDP7	
		2025	2030	2025	2030
Coal-fired thermal power	29.5%	28.9%	26.7%	49.5%	42.8%
Gas-to-power and oil/diesel-fired thermal power	13.0%	13.8%	20.7%	15.5%	14.7%
Hydropower + pumped-storage hydropower (including small-scale hydropower)	29.9%	24.0%	18.6%	25.4%	21.5%
Wind power	0.9%	11.1%	12.9%	2.1%	4.6%
Solar power	24.0%	16.9%	13.3%	4.1%	9.1%
Biomass and other renewable power	0.8%	2.0%	2.3%	1.9%	2.7%
Power import	1.8%	3.4%	4.1%	1.5%	1.2%
Nuclear power	0.0%	0.0%	0.0%	0.0%	3.5%
Total capacity	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Appendix: Key Highlights of the New Draft of the National Power Development Plan (Draft PDP8).

Chapter 4

Economic Impact Analysis

This section compares the costs and benefits of decommissioning thermal power plants earlier than the normally assumed operating years. Specifically, first assuming a model plant, the impact of shortening its operating period is analysed. Next, the impact of each country is analysed based on the current status of thermal power generation owned by a country.

The impact analysis assumes the cash flow of the model plant and calculates its net present value (NPV). The cash flow and its NPV change depend on the operating scenario (shutdown timing). Therefore, we define the economic impact as the difference between the case where the operation period is shortened and the case where the model plant operates as initially planned.

Cash flow estimates consider the following costs and benefits. The costs consist of the plant's construction, operating, and fuel costs. The benefits assume the cost of avoiding CO_2 emissions and electricity sales revenue.

Table 4.1. Item of Costs and Benefits

	Costs	**Benefits**
Internal	Construction costs	Electricity sales
	Fixed operating expenses	
	Variable operating expenses	
	Fuel costs	
External	-	Avoided CO_2 costs

Source: Authors.

1. Conditions of Analysis

In this section, cases of analysis and various assumptions are organised.

1.1. Case settings

There are two ways to speed up the decommissioning of thermal power plants. The first way is to set a uniform time limit for retirement, for example, the year 2030, regardless of operating years, which vary from plant to plant. The second is to request retirement when a plant has been in operation for a prescribed number of years (for example, 15 years after starting operation).

The former means that thermal power generation will be discontinued after a set year. To achieve this, the capacity of clean power sources to meet all electricity needs and corresponding transmission and distribution networks must be in place before retirement. In addition, the operation of the electricity supply system will change significantly after a particular day. In reality, such a method cannot be adopted, and therefore, this analysis assumes the latter scenario (Method B: discontinued after a given number of operating years).

Figure 4.1. Methods to Set Operation Termination Year

Source: Authors.

Next, there are two ways to consider using sites where thermal power plants were discontinued. The first case is that the site of a decommissioned thermal power plant shall be used for purposes other than power generation. The second case is installing a decarbonised power source on the site, such as solar PV power.

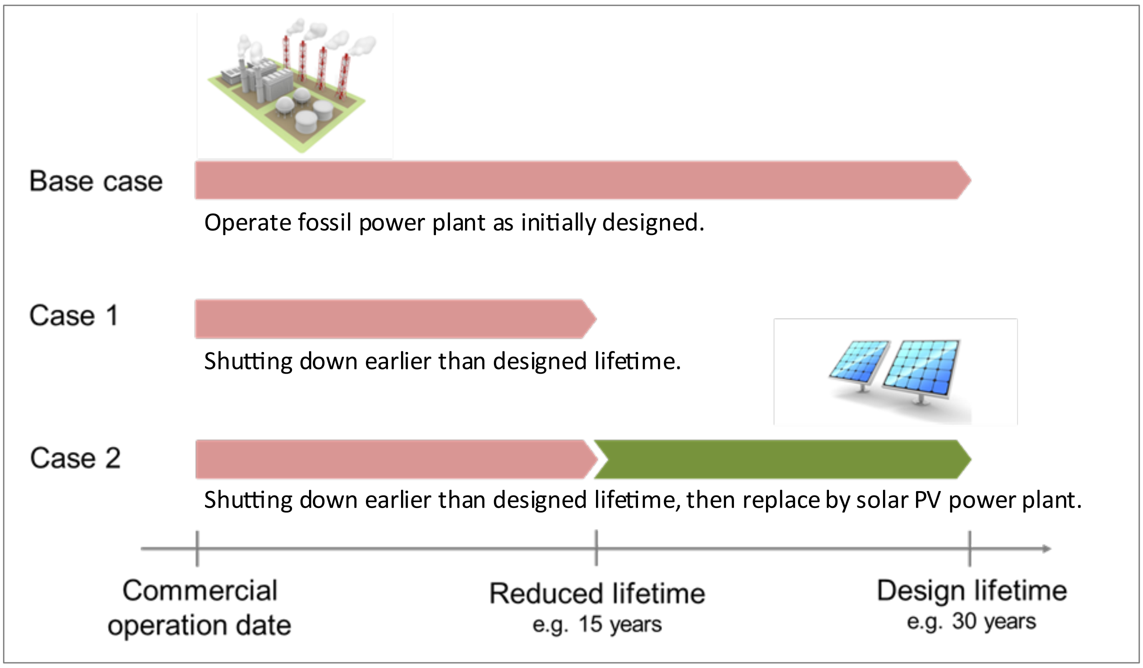
In the former case, the power generation business is terminated when the thermal power plant is decommissioned, after which no additional costs and benefits associated with electricity generation arise. In the latter case, costs and benefits from the plant after replacement are incurred and can be added to the evaluation.

Based on the above, the cost–benefit analysis cases can be broadly classified into two. In the case of replacement, we assume solar PV generation, which is considered more applicable in Southeast Asia. Wind power is possible, but wind conditions vary widely from place to place, making it not a universal option.

Case 1: A thermal power plant is decommissioned after several operating years. (No power generation business after that.)

Case 2: A thermal power plant is decommissioned after several operating years, and solar PV generation is installed.

Figure 4.2. Concept of the Cases



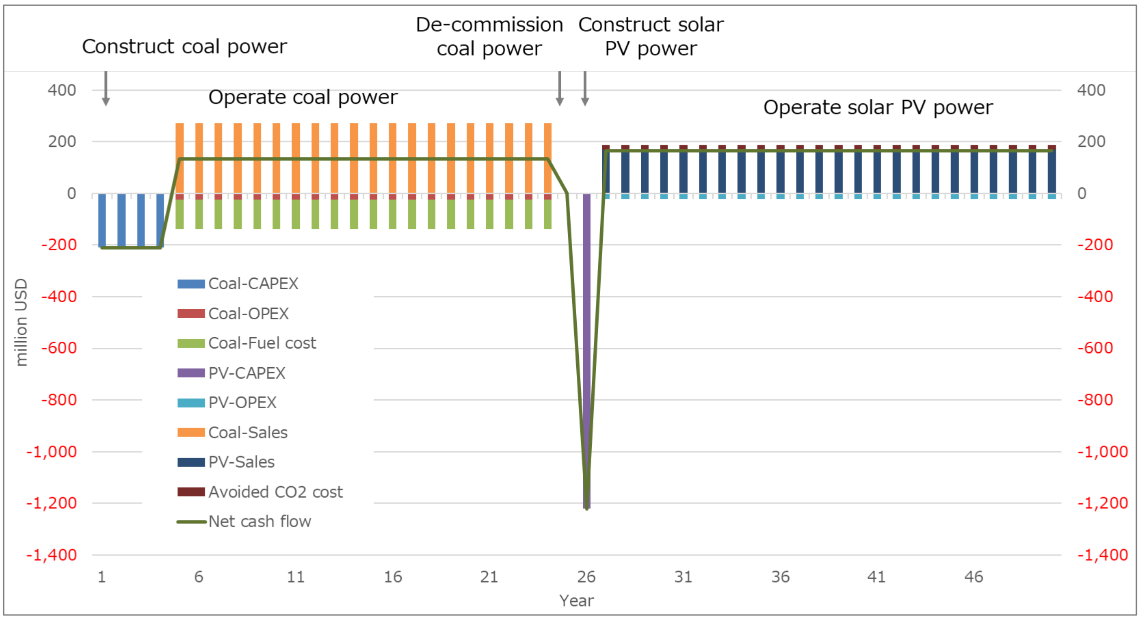
Source: Authors.

1.2. Cash Flow

Figure 4.3 shows an image of cash flow over the evaluation period.

After starting the business, the first thing that happens is a cash outflow for constructing the thermal power plant. Once commercial operations begin, there is a cash outflow for operating and fuel costs, while there is cash inflow through the sale of electricity. A thermal power plant is shut down after a certain number of years and is replaced by solar PV power. In the first year of replacement, there will be a major cash outflow of solar PV power plant construction costs, followed by a small operating expense. On the other hand, there will be a cash inflow through the sale of electricity by solar PV and the cost of avoiding CO_2 emissions.

Figure 4.3. Example of Project Cash Flow



Source: Authors.

1.3. Model Plant

In setting a model plan, reference was made to the 'Technology Data for the Indonesian Power Sector' (ESDM et al. 2021). This is rare literature analysing the costs of various power generation technologies for Indonesia.

The target thermal power generation technology was represented by the one with the largest installed capacity among the thermal power plants owned by each ASEAN member country. For coal-fired power generation, subcritical coal power generation (hereinafter referred to as 'sub-C') and supercritical (SC) coal power generation (hereinafter referred to as 'SC') were chosen; for gas-fired power generation, the combined cycle gas turbine generation (hereinafter referred to as 'CCGT') was chosen. For example, in the case of coal-fired thermal power plants, many countries have plants with sub-C technology; therefore, we used this as a representative technology. However, for Cambodia and Viet Nam, where plants with SC technology account for the majority, SC was chosen as the representative technology.

The representative year for costs was set at 2020 for existing thermal power and 2030 for solar PV after replacement.

Table 4.2. Existing Fossil Power Generation Capacity by Technologies

Coal MW

	Cambodia	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam
Subcritical	507	**22,082**	**1,878**	**6,050**	**160**	**8,670**	0	**3,116**	5,880
Supercritical	**700**	3,665	0	0	0	1,520	0	660	**14,051**
USC	150	4,827	0	5,010	0	0	0	0	600
Un-specified	50	8,811	0	1,600	0	689	134	926	5,975
Total	1,407	39,384	1,878	12,660	160	10,879	134	4,702	26,506

Gas MW

	Cambodia	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam
Steam	0	572	0	0	40	0	0	2,173	705
GT	0	1,520	0	0	956	97	0	733	1,119
CCGT	0	**6,097**	0	**14,362**	**1,288**	**3,194**	**7,185**	**25,148**	**5,568**
Un-specified	0	594	0	310	165	0	0	1,360	473
Total	0	8,783	0	14,672	2,449	3,291	7,185	29,414	7,865

CCGT = combined cycle gas turbine, GT = gas turbine, USC = ultra supercritical.
Source: Authors, created from Enerdata, Power Plant Tracker database, https://www.enerdata.net/research/power-plant-database.html.

The key characteristics of thermal power generation technology are as follows. The capacity factor was set at 0.8, assuming a baseload power supply.

Table 4.3. Key Characteristics of Model Plants

	Coal/Sub-C	Coal/SC	Gas/CCGT
Capacity (MW)	150	600	600
Thermal efficiency (%)	34	37	56
Construction period (year)	3	4	2.5 (roundup to 3)
Design lifetime (year)	30	30	25
Decommissioning period (year)	1	1	1
Capital expenditure (million $/MW)	1.65	1.4	0.69
Fixed operating expenses ($/MW/year)	45,300	41,200	23,500
Variable operating expenses ($/MWh)	0.13	0.12	2.3

CCGT = combined cycle gas turbine, sub-C = subcritical, SC = supercritical.
Notes: Employed data for the year 2020. Variable operating expenses do not include fuel costs.
Source: Authors, created from ESDM et al. (2021).

The key characteristics of solar PV facilities assumed in Case 2 are as follows. The installed capacity was calculated from the capacity needed to generate the same electricity amount as the thermal power plant before replacement. At that time, the capacity factor of solar PV was set at 0.22 (ESDM et al. 2021).

Table 4.4. Key Characteristics of Solar PV

	Solar PV to Replace Coal/Sub-C	Solar PV to Replace Coal/SC	Solar PV to Replace Gas/CCGT
Capacity (MW)	545	2,182	2,182
Capacity factor		0.22	
Construction period (year)		0.5 (roundup to 1)	
Design lifetime (year)		40	
Capital expenditure (million $/MW)		0.56	
Fixed operating expenses ($/MW/year)		10,000	
Variable operating expenses ($/MWh)		-	

CCGT = combined cycle gas turbine. sub-C = subcritical, SC = supercritical.
Source: Authors, created ESDM et al. (2021).

1.4. Fuel supply

The net calorific value, carbon intensity, and fuel price for thermal power generation were set as follows. Coal was priced at the upper limit of $70/tonne, which is set under Indonesia's Domestic Market Obligation (Reuters, 2022). The price of natural gas was set at $6/MMBtu, the upper limit price of natural gas for power generation (NNA Asia, 2020).

Table 4.5. Key Characteristics of Fuel for Power Generation

	Coal	Natural Gas
Net calorific value (kcal/kg)	6,000	12,000
Carbon intensity (kg-C/GJ)	25.8	15.3
Fuel price	70	6

Source: IEA (2020), Reuters (2022), NNA Asia (2020).

1.5. Unit Electricity Sales Price

The sales price of generated electricity was assumed to be determined based on bilateral contracts, such as PPAs, rather than through the wholesale market. In other words, thermal and solar power sales prices were assumed. Specifically, based on an example of a PPA concluded in Indonesia (ESDM et al. 2021) and the levelized cost of electricity (LCOE) for a model plant, the wholesale price of electricity generated by thermal power was set at $65/MWh and the wholesale price of electricity generated by solar PV at $40/MWh.

1.6. Unit Carbon Price

The carbon price was assumed to be $5/tonne-$CO_2$ based on the 'Trends of Çarbon pricing in Asia' (JRI, 2022). We chose such a small value because many ASEAN member countries do not have an explicit carbon price. However, carbon prices may rise as decarbonisation policies are strengthened. Carbon prices also have a greater impact on solar PV installations after the closure of thermal power plants. Therefore, a sensitivity analysis was conducted using the carbon price as a variable.

1.7. Evaluation Period

The period for calculating NPV was defined as the construction period of a thermal power plant plus the normal number of operating years (ESDM et al. 2021).

Table 4.6. Evaluation Period of Net Present Value of Cash Flow

	Coal Sub-C	**Coal SC**	**Gas CCGT**
Construction period (year)	3	4	2.5 (roundup to 3)
Design lifetime (year)	30	30	25
Evaluation period (year)	33	34	28

CCGT = combined cycle gas turbine, sub-C = subcritical, SC = supercritical.
Source: Authors, created from ESDM et al. (2021).

1.8. Discount Rate

The discount rate was assumed to be 10% based on the *Levelized Cost of Electricity (LCOE) for Selected Renewable Energy Technologies in the ASEAN Member States II* (ACE 2019). While the discount rate makes a big difference in the absolute value of NPV, the appropriate value varies from project to project and from country to country. Therefore, a sensitivity analysis was conducted using the discount rate as a variable.

2. Economic Impact Analysis of the Model Plant

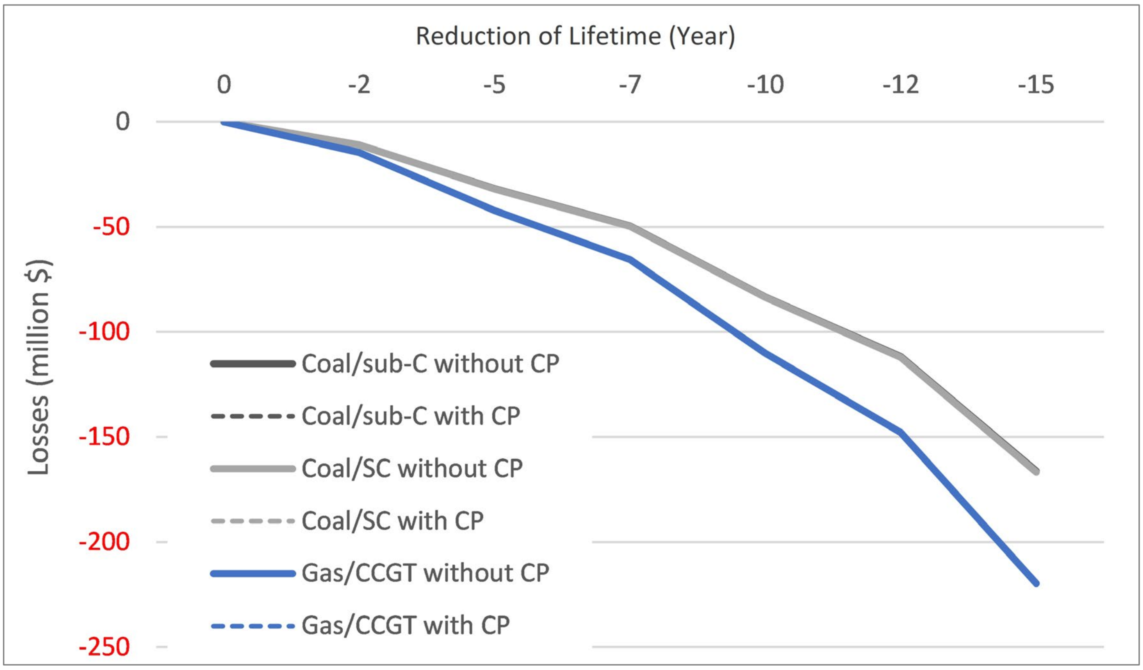
The results of an impact analysis of shortening the operating period on the economics of a model plant are shown below.

2.1. Case 1 (WITHOUT replacement to solar PV)

The greater the reduction in the operating period, the greater the losses. The loss of electricity prices due to power plant shutdowns is a natural consequence. When coal-fired and gas-fired thermal power plants are compared, if the number of years to be shortened is the same, the impact is greater for gas-fired thermal power plants with shorter planned operation periods.

As Case 1 does not assume replacing with solar PV after shutting down a thermal power plant, the presence or absence of a carbon price does not affect the losses.

Figure 4.4. Losses Resulting from Reduced Operating Lifetime (Case 1)



CCGT = combined cycle gas turbine, CP = carbon price, sub-C = subcritical, SC = supercritical.
Note: Losses per 600 MW capacity.
Source: Authors.

Table 4.7. Losses Resulting from Reduced Operating Lifetime (Case 1)

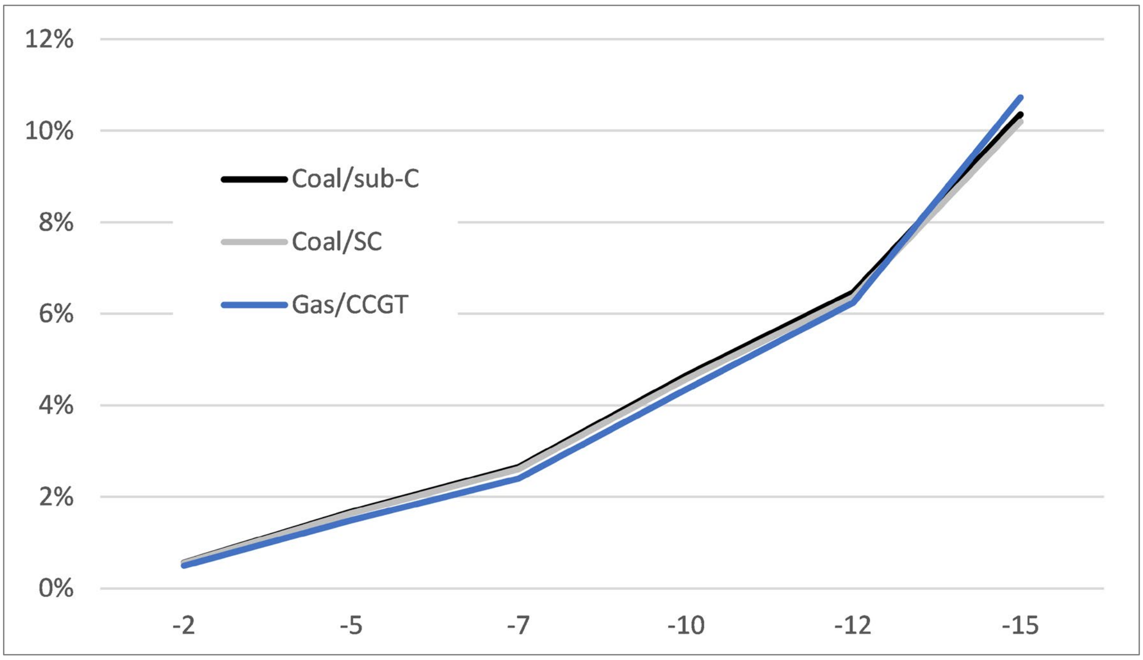
million $

Reduction of Lifetime (Year)	Coal/sub-C		Coal/SC		Gas/CCGT	
	without CP	with CP	without CP	with CP	without CP	with CP
0	0	0	0	0	0	0
-2	-11	-11	-11	-11	-15	-15
-5	-32	-32	-32	-32	-42	-42
-7	-50	-50	-50	-50	-66	-66
-10	-83	-83	-84	-84	-110	-110
-12	-112	-112	-112	-112	-148	-148
-15	-166	-166	-167	-167	-220	-220

CCGT = combined cycle gas turbine, CP = carbon price, sub-C = subcritical, SC = supercritical.
Note: Losses per 600 MW capacity.
Source: Authors.

The impact of a reduced operating year on the LCOE is estimated, indicating that LCOE will rise about 10%, which has no significant difference between the technologies.

Figure 4.5. Estimated Increase of LCOE (Case 1)



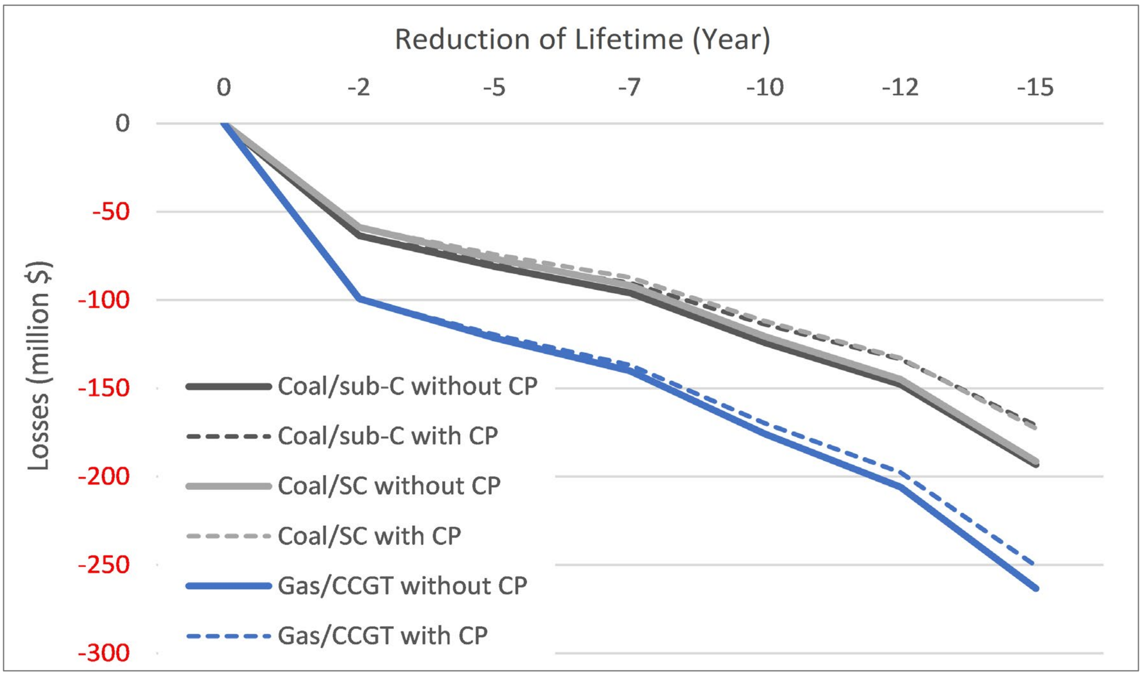
Source: Authors.

2.2. Case 2 (WITH replacement to solar PV)

As in Case 1, the greater the reduced operating period, the greater the losses. However, compared with Case 1, the losses are greater regardless of a reduced lifetime. This is because of the assumption that solar PV will replace a thermal power plant after it is decommissioned. The burden of Put Into Operational investment for solar PV cannot be recovered within the evaluation period.

When carbon price is considered, replacing it with solar PV can mitigate the burden compared to a case without a carbon price. However, because the assumed carbon price ($5/tonne-$CO_2$) is low, the effect of improving economics is small.

Figure 4.6. Losses Resulting from Reduced Operating Lifetime (Case 2)



CCGT = combined cycle gas turbine, CP = carbon price, sub-C = subcritical, SC = supercritical.
Note: Losses per 600 MW capacity.
Source: Authors.

Table 4.8. Losses Resulting from Reduced Operating Lifetime (Case 2)

million $

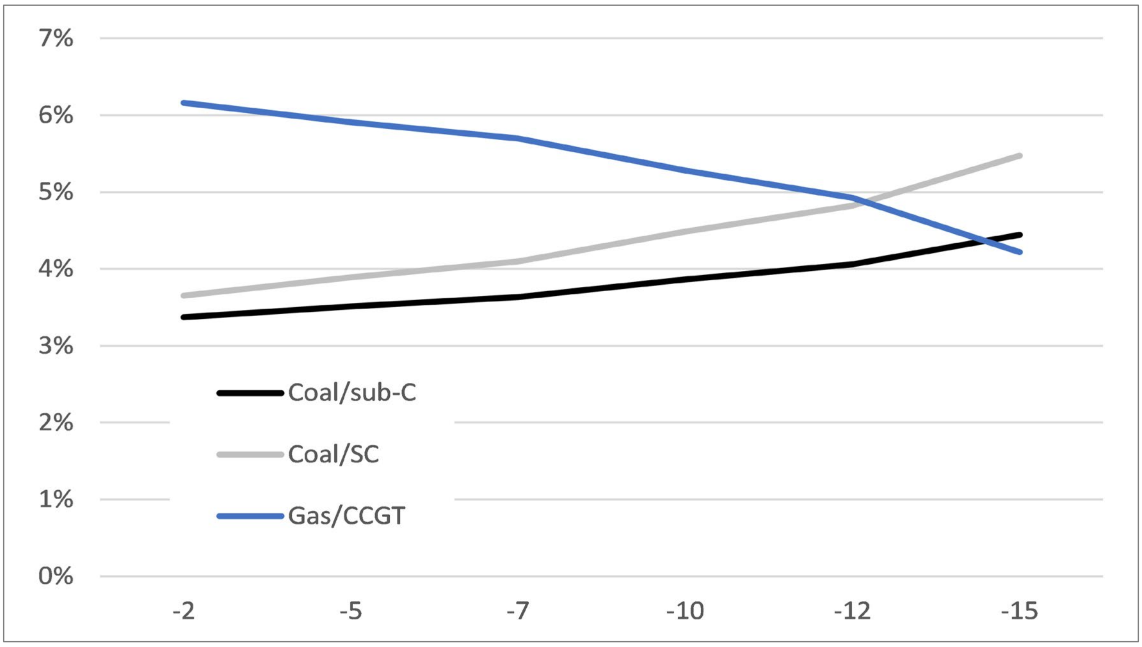
Reduction of Lifetime (Year)	Coal/sub-C		Coal/SC		Gas/CCGT	
	without CP	with CP	without CP	with CP	without CP	with CP
0	0	0	0	0	0	0
-2	-64	-64	-59	-59	-99	-99
-5	-81	-78	-77	-74	-121	-120
-7	-96	-90	-92	-87	-140	-137
-10	-124	-114	-121	-112	-176	-170
-12	-148	-133	-145	-133	-206	-197
-15	-193	-171	-191	-173	-263	-250

*****Note: Losses per 600 MW capacity.
CCGT = combined cycle gas turbine, CP = carbon price, sub-C = subcritical, SC = supercritical.
Source: Authors.

The impact of reduced operating year on LCOE presents a different shape from Case 1. Because of the added cost of PV investment, reducing lifetime operation by even fewer years would have a larger impact than in Case 1. On the other hand, future costs are discounted by the discount rate in the LCOE calculation. Therefore, future cost increases due to the installation of PV power generation are evaluated as relatively small. Therefore, the impact on LCOE is moderate compared to Case 1.

Gas-fired power plants have a heavier operating cost burden than coal-fired power plants. Therefore, the reduction in the NPV of thermal power costs due to shorter operating periods is larger. This outweighs the increase in the NPV of PV costs, resulting in decreased LCOE with greater operating period reduction.

Figure 4.7. Estimated Increase of LCOE (Case 2)



Source: Authors.

2.3. Sensitivity against Discount Rate

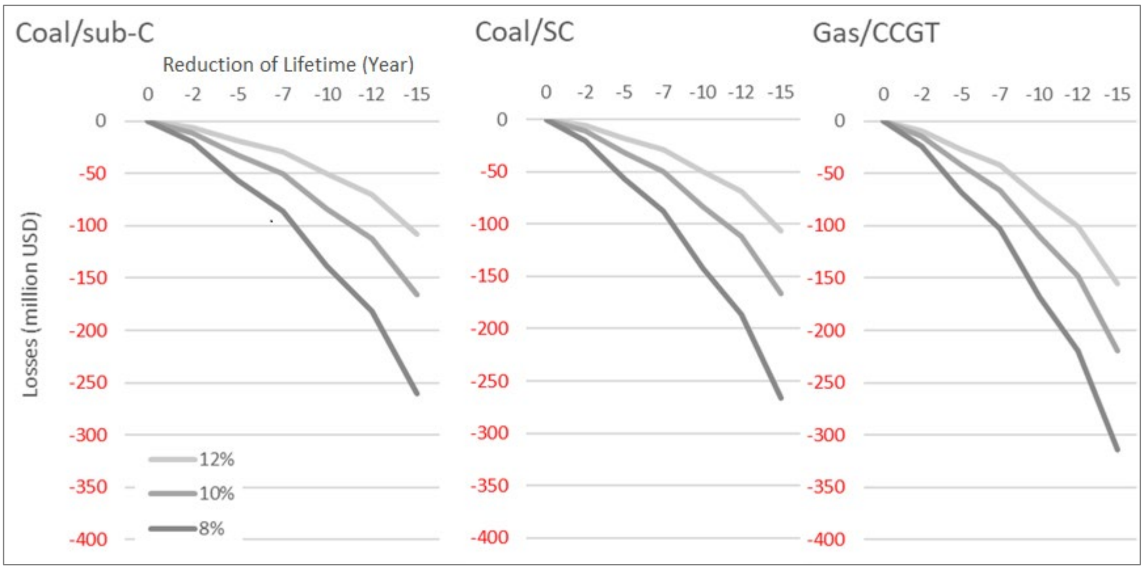
A sensitivity analysis was conducted to determine how much the discount rate would affect losses. When the discount rate is small, future cash flows affect the NPV more. Conversely, when the discount rate is large, the effect of future cash flows on NPV is small.

The discount rate would be 2% less than the standard 10% to 8%, would result in greater losses due to a larger estimation of future lost profits (electricity bill revenues expected to be received in the future). The losses would increase by $900 million to $1,000 million (per 600 MW) for Case 1 with a 15-year reduction in operation period. This is roughly 1.5 times the losses when the discount rate is 10%.

If the discount rate is set at 12%, 2% higher than the standard 10%, the loss is smaller because the impact of future lost earnings is estimated to be smaller. A 15-year reduction in the operating period in Case 1 will reduce losses by about $600 million. This is roughly 0.6 times the losses when the discount rate is 10%.

The above analysis shows that the discount rate significantly impacts the losses incurred by shortening the operating period.

Figure 4.8. Sensitivity of Losses against Discount Rate (Case 1)



Note: Losses per 600 MW capacity.
CCGT = combined cycle gas turbine, CP = carbon price, sub-C = subcritical, SC = supercritical.
Source: Authors.

Table 4.9. Sensitivity of Losses against Discount Rate (Case 1)

million $

Reduction of Lifetime (Year)	Coal/sub-C			Coal/SC			Gas/CCGT		
	8%	10%	12%	8%	10%	12%	8%	10%	12%
0	0	0	0	0	0	0	0	0	0
-2	-20	-11	-6	-20	-11	-6	-24	-15	-9
-5	-56	-32	-18	-57	-32	-18	-68	-42	-27
-7	-86	-50	-29	-87	-50	-29	-103	-66	-42
-10	-139	-83	-51	-142	-84	-50	-167	-110	-73
-12	-182	-112	-70	-186	-112	-69	-219	-148	-101
-15	-260	-166	-108	-266	-167	-106	-314	-220	-156

Note: Losses per 600 MW capacity.
CCGT = combined cycle gas turbine, CP = carbon price, sub-C = subcritical, SC = supercritical.
Source: Authors.

2.4. Sensitivity against Carbon Price

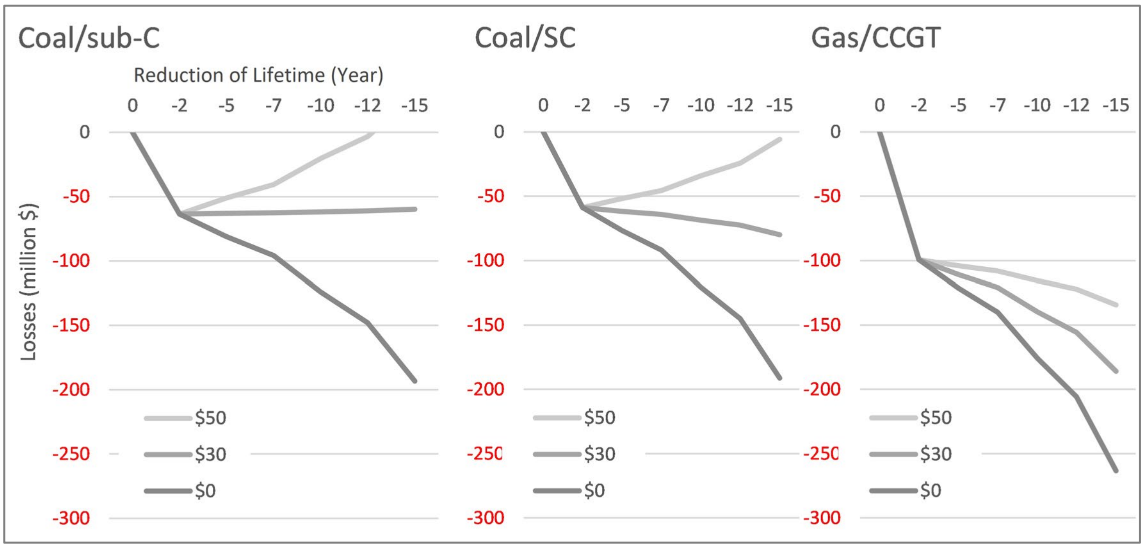
A sensitivity analysis was conducted to determine how much the carbon price would affect losses. Lower carbon prices reduce the economic benefit of reducing CO_2 emissions by replacement with solar PV, while higher carbon prices increase the economic benefit.

The loss-reducing effect of increased carbon prices is equally apparent in all thermal power plants. However, the effect is very different between coal-fired and gas-fired power plants. While a significant effect can be obtained for coal-fired thermal power plants with high CO_2 emissions, the impact of increasing carbon prices is smaller for gas-fired thermal power plants with inherently low CO_2 emissions.

Here, we estimated the carbon prices required to reduce the loss to 0 for sub-C coal-fired power generation, supercritical coal-fired power generation, and CCGT generation when the operation period is shortened by 15 years. As a result, the required carbon prices (\$/tonne-CO_2) were \$43, \$52, and \$102, respectively. This indicates that the early retirement of thermal power plants and the replacement with solar PV could be an economically rational choice by raising the carbon price. In other words, under the current carbon price range in ASEAN member countries, an early retirement of thermal power plants and the replacement with solar PV will not be economically rational.

It is also important to note the price level required. The European Union Emissions Trading System (EU-ETS) is well-known worldwide, and European Union Allowance spot prices in 2022 were traded in the range of approximately €60–100/tonne-CO_2 (\$66– 110/tonne-CO_2)[6], [7]. Achieving a similar carbon price in ASEAN would incentivise the early shutdown of coal-fired power plants.

Figure 4.9. Sensitivity of Losses against Carbon Price (Case 2)



Source: Authors.

[6] Assuming €1 = \$1.1

[7] Ember, Carbon Price tracker. The price of emission allowances in the EU and the United Kingdom, access on May 2023 (https://ember-climate.org/data/data-tools/carbon-price-viewer/)

Table 4.10. Sensitivity of Losses against Carbon Price (Case 2)

million $

Reduction of Lifetime (Year)	Coal/sub-C			Coal/SC			Gas/CCGT		
	$0	$30	$50	$0	$30	$50	$0	$30	$50
0	0	0	0	0	0	0	0	0	0
-2	-64	-64	-64	-59	-59	-59	-99	-99	-99
-5	-81	-63	-51	-77	-62	-52	-121	-111	-104
-7	-96	-63	-41	-92	-64	-46	-140	-121	-108
-10	-124	-62	-20	-121	-69	-34	-176	-140	-116
-12	-148	-61	-3	-145	-73	-24	-206	-156	-122
-15	-193	-60	29	-191	-80	-6	-263	-186	-134

Source: Authors.

3. Impact Analysis of Each Country

This section, based on the results of analysis of the model plant, evaluated the impact of shorter operating periods for each country. Brunei was excluded from the analysis because no data in the power plant database was used.

❖ Method

The analysis was carried out by the following procedure.

1) Calculate the total installed capacity of thermal power plants affected by the shortened operating period.

2) Calculate the factor of impact by dividing the model plant's installed capacity of 600 MW.

3) Multiply the amount of impact determined by the model plant by the factor obtained in 2).

$$\begin{aligned} &Economic\ impact_{country} \\ &\quad = Economic\ impact_{600MW\ model\ plant} \\ &\quad \times \frac{Affected\ capacity_{country,technology}}{600MW} \end{aligned}$$

Here, if the operation period is shortened by 5 years, for example, there will be plants with remaining operational life of 1 to 4 years. For those plants, 2 years, the average of the remaining operating years, is set to be the representative value of the shortened period. Then, the impact amount of shortened operating period of the model plant by 2 years was applied. Likewise, the representative values of the shortened operating period are set at 5 years for the plants with a remaining operational life of 1–9 years when the operation period is shortened by 10 years, and 7 years for those with a remaining operational life of 1–14 years when the operation period is shortened by 15 years.

❖ **Existing Fossil Power Plants**

For existing thermal power plants, the installed capacities that would be affected if the operation period was shortened by 5, 10, or 15 years were calculated. At this time, facilities that had reached the planned life of 30 years for coal-fired power plants and 25 years for gas-fired power plants as of 2022 were excluded.

By country, Indonesia, Malaysia, Thailand, and Viet Nam show the largest amounts of thermal power affected. However, a different picture emerges if coal-fired power and gas-fired power are separate. More coal-fired power plants are affected in the Philippines than in Thailand. As for gas-fired thermal power, Thailand and Malaysia are particularly affected.

Table 4.11. Affected Power Plant Capacity

MW

Scenarios		5 yr earlier retirement		10 yr earlier retirement		15 yr earlier retirement	
		1-4 yr earlier	5 yr earlyier	1-9 yr earlier	10 yr earlyier	1-14 yr earlier	15 yr earlyier
Cambodia	Coal	0	1,407	0	1,407	0	1,407
	Gas	0	0	0	0	0	0
	Total	0	1,407	0	1,407	0	1,407
Indonesia	Coal	3,441	35,943	6,598	32,786	8,748	30,636
	Gas	345	8,438	2,619	6,164	3,157	5,626
	Total	3,786	44,381	9,217	38,950	11,905	36,262
Lao PDR	Coal	0	1,878	0	1,878	0	1,878
	Gas	0	0	0	0	0	0
	Total	0	1,878	0	1,878	0	1,878
Malaysia	Coal	100	12,560	3,170	9,490	5,380	7,280
	Gas	1,978	12,694	3,412	11,260	6,140	8,532
	Total	2,078	25,254	6,582	20,750	11,520	15,812
Myanmar	Coal	0	160	0	160	120	40
	Gas	160	2,290	193	2,256	193	2,256
	Total	160	2,450	193	2,416	313	2,296
Philippines	Coal	2,405	8,474	5,895	4,984	6,912	3,967
	Gas	2,780	511	3,291	0	3,291	0
	Total	5,185	8,985	9,186	4,984	10,203	3,967
Singapore	Coal	0	134	0	134	0	134
	Gas	725	6,460	2,665	4,520	4,340	2,845
	Total	725	6,594	2,665	4,654	4,340	2,979
Thailand	Coal	1,654	3,048	2,425	2,277	3,771	931
	Gas	8,176	21,238	10,004	19,410	16,501	12,913
	Total	9,830	24,286	12,429	21,687	20,272	13,844
Viet Nam	Coal	0	26,506	600	25,906	1,265	25,241
	Gas	2,505	5,360	4,448	3,417	7,535	330
	Total	2,505	31,866	5,048	29,323	8,800	25,571

Source: Enerdata, Power Plant tracker database. (https://www.enerdata.net/research/power-plant-database.html)

3.1. Cambodia

Cambodia has young coal-fired power plants, and shortening their operating years will result in losses. The greater the number of years to be shortened, the greater the impact; a 15-year reduction would cost about $400 million without solar PV replacement. This is equivalent to 1.7% of GDP in 2020, or a burden of $23 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.12. Economic Impact of Early Retirement of Fossil Power (Cambodia)

Cambodia

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person
Case 1	Coal	-75	0.3%	4	-196	0.9%	12	-391	1.7%	23
	Gas	0	0.0%	0	0	0.0%	0	0	0.0%	0
	Total	-75	0.3%	4	-196	0.9%	12	-391	1.7%	23
Case 2	Coal	-186	0.8%	11	-305	1.3%	18	-496	2.2%	30
w/o CP	Gas	0	0.0%	0	0	0.0%	0	0	0.0%	0
	Total	-186	0.8%	11	-305	1.3%	18	-496	2.2%	30
Case 2	Coal	-180	0.8%	11	-285	1.2%	17	-452	2.0%	27
w/ CP	Gas	0	0.0%	0	0	0.0%	0	0	0.0%	0
	Total	-180	0.8%	11	-285	1.2%	17	-452	2.0%	27

CP = carbon price ($5/tonne-$CO_2$)
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.2. Indonesia

Reducing the operating period by 15 years without solar PV replacement would cost about $11.6 billion. This is equivalent to 1.1% of GDP in 2020, or a burden of $42 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.13. Economic Impact of Early Retirement of Fossil Power (Indonesia)

Indonesia

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person
Case 1	Coal	-1,976	0.2%	7	-4,907	0.5%	18	-9,211	0.9%	34
	Gas	-602	0.1%	2	-1,316	0.1%	5	-2,405	0.2%	9
	Total	-2,578	0.3%	9	-6,224	0.6%	23	-11,616	1.1%	42
Case 2	Coal	-5,402	0.5%	20	-8,270	0.8%	30	-12,481	1.2%	46
w/o CP	Gas	-1,832	0.2%	7	-2,528	0.2%	9	-3,588	0.3%	13
	Total	-7,234	0.7%	26	-10,798	1.1%	39	-16,069	1.6%	59
Case 2	Coal	-5,223	0.5%	19	-7,671	0.7%	28	-11,265	1.1%	41
w/ CP	Gas	-1,808	0.2%	7	-2,458	0.2%	9	-3,450	0.3%	13
	Total	-7,030	0.7%	26	-10,129	1.0%	37	-14,715	1.4%	54

CP = carbon price ($5/tonne-$CO_2$)
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.3. Lao PDR

Reducing the operating period by 15 years without solar PV replacement would cost about $500 million. This is equivalent to 2.9% of GDP in 2020, or a burden of $71 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.14. Economic Impact of Early Retirement of Fossil Power (Lao PDR)

Lao PDR

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person
Case 1	Coal	-100	0.5%	14	-261	1.4%	36	-520	2.9%	71
	Gas	0	0.0%	0	0	0.0%	0	0	0.0%	0
	Total	-100	0.5%	14	-261	1.4%	36	-520	2.9%	71
Case 2	Coal	-263	1.4%	36	-421	2.3%	58	-674	3.7%	93
w/o CP	Gas	0	0.0%	0	0	0.0%	0	0	0.0%	0
	Total	-263	1.4%	36	-421	2.3%	58	-674	3.7%	93
Case 2	Coal	-254	1.4%	35	-388	2.1%	53	-605	3.3%	83
w/ CP	Gas	0	0.0%	0	0	0.0%	0	0	0.0%	0
	Total	-254	1.4%	35	-388	2.1%	53	-605	3.3%	83

CP = carbon price ($5/tonne-$CO_2$).
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.4. Malaysia

Reducing the operating period by 15 years without solar PV replacement would cost about $6.3 billion. This is equivalent to 1.8% of GDP in 2020, or a burden of $193 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.15. Economic Impact of Early Retirement of Fossil Power (Malaysia)

Malaysia

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person
Case 1	Coal	-670	0.2%	21	-1,487	0.4%	46	-2,462	0.7%	76
	Gas	-941	0.3%	29	-2,308	0.7%	71	-3,795	1.1%	117
	Total	-1,611	0.5%	50	-3,796	1.1%	117	-6,257	1.8%	193
Case 2	Coal	-1,771	0.5%	55	-2,570	0.7%	79	-3,524	1.0%	109
w/o CP	Gas	-2,997	0.9%	93	-4,328	1.3%	134	-5,777	1.7%	178
	Total	-4,768	1.4%	147	-6,899	2.0%	213	-9,300	2.7%	287
Case 2	Coal	-1,708	0.5%	53	-2,391	0.7%	74	-3,204	0.9%	99
w/ CP	Gas	-2,960	0.9%	91	-4,206	1.2%	130	-5,560	1.6%	172
	Total	-4,669	1.4%	144	-6,596	1.9%	204	-8,765	2.5%	271

CP = carbon price ($5/tonne-$CO_2$).
GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.5. Myanmar

Reducing the operating period by 15 years without solar PV replacement would cost about $900 million. This is equivalent to 1.1% of GDP in 2020, or a burden of $16 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.16. Economic Impact of Early Retirement of Fossil Power (Myanmar)

Myanmar

Scenarios		5 yr earlier Losses mil. $	5 yr earlier Share to GDP	5 yr earlier $/person	10 yr earlier Losses mil. $	10 yr earlier Share to GDP	10 yr earlier $/person	15 yr earlier Losses mil. $	15 yr earlier Share to GDP	15 yr earlier $/person
Case 1	Coal	-9	0.0%	0	-22	0.0%	0	-21	0.0%	0
	Gas	-165	0.2%	3	-428	0.5%	8	-847	1.1%	16
	Total	-173	0.2%	3	-450	0.6%	8	-868	1.1%	16
Case 2	Coal	-22	0.0%	0	-36	0.0%	1	-35	0.0%	1
w/o CP	Gas	-508	0.6%	9	-764	1.0%	14	-1,172	1.5%	22
	Total	-530	0.7%	10	-800	1.0%	15	-1,207	1.5%	22
Case 2	Coal	-22	0.0%	0	-33	0.0%	1	-32	0.0%	1
w/ CP	Gas	-501	0.6%	9	-741	0.9%	14	-1,123	1.4%	21
	Total	-523	0.7%	10	-774	1.0%	14	-1,155	1.5%	21

CP = carbon price ($5/tonne-$CO_2$).
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.6. Philippines

Reducing the operating period by 15 years without solar PV replacement would cost about $2 billion. This is equivalent to 0.6% of GDP in 2020, or a burden of $19 per capita.

The assumed conditions for solar PV replacement and carbon prices were insufficient, and the replacement resulted in an increased burden.

Table 4.17. Economic Impact of Early Retirement of Fossil Power (Philippines)

Philippines

Scenarios		5 yr earlier Losses mil. $	5 yr earlier Share to GDP	5 yr earlier $/person	10 yr earlier Losses mil. $	10 yr earlier Share to GDP	10 yr earlier $/person	15 yr earlier Losses mil. $	15 yr earlier Share to GDP	15 yr earlier $/person
Case 1	Coal	-495	0.1%	5	-1,006	0.3%	9	-1,671	0.5%	15
	Gas	-103	0.0%	1	-232	0.1%	2	-360	0.1%	3
	Total	-598	0.2%	5	-1,238	0.3%	11	-2,031	0.6%	19
Case 2	Coal	-1,443	0.4%	13	-1,943	0.5%	18	-2,593	0.7%	24
w/o CP	Gas	-567	0.2%	5	-692	0.2%	6	-817	0.2%	7
	Total	-2,010	0.6%	18	-2,635	0.7%	24	-3,410	1.0%	31
Case 2	Coal	-1,400	0.4%	13	-1,827	0.5%	17	-2,382	0.7%	22
w/ CP	Gas	-566	0.2%	5	-683	0.2%	6	-800	0.2%	7
	Total	-1,966	0.5%	18	-2,510	0.7%	23	-3,182	0.9%	29

CP = carbon price ($5/tonne-$CO_2$).
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.7. Singapore

Reducing the operating period by 15 years would cost about \$1.6 billion without solar PV replacement. This is equivalent to 0.5% of GDP in 2020, or a burden of \$273 per capita.

The assumed conditions for solar PV replacement and carbon prices were insufficient, and the replacement resulted in an increased burden.

Table 4.18. Economic Impact of Early Retirement of Fossil Power (Singapore)

Singapore

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. \$	Share to GDP	\$/person	Losses mil. \$	Share to GDP	\$/person	Losses mil. \$	Share to GDP	\$/person
Case 1	Coal	-7	0.0%	1	-19	0.0%	3	-37	0.0%	6
	Gas	-472	0.1%	83	-1,018	0.3%	179	-1,516	0.5%	266
	Total	-479	0.1%	84	-1,036	0.3%	182	-1,553	0.5%	273
Case 2	Coal	-19	0.0%	3	-30	0.0%	5	-48	0.0%	8
w/o CP	Gas	-1,479	0.4%	260	-2,010	0.6%	353	-2,496	0.7%	439
	Total	-1,498	0.4%	263	-2,040	0.6%	359	-2,544	0.8%	447
Case 2	Coal	-18	0.0%	3	-28	0.0%	5	-43	0.0%	8
w/ CP	Gas	-1,460	0.4%	257	-1,957	0.6%	344	-2,411	0.7%	424
	Total	-1,478	0.4%	260	-1,985	0.6%	349	-2,454	0.7%	431

CP = carbon price (\$5/tonne-CO_2).
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.8. Thailand

Reducing the operating period by 15 years without solar PV replacement would cost about \$7.1 billion. This is equivalent to 1.6% of GDP in 2020, or a burden of \$102 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.19. Economic Impact of Early Retirement of Fossil Power (Thailand)

Thailand

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person
Case 1	Coal	-193	0.0%	3	-446	0.1%	6	-570	0.1%	8
	Gas	-1,692	0.4%	24	-4,269	1.0%	61	-6,532	1.5%	94
	Total	-1,885	0.4%	27	-4,714	1.1%	68	-7,102	1.6%	102
Case 2	Coal	-603	0.1%	9	-850	0.2%	12	-972	0.2%	14
w/o CP	Gas	-5,820	1.3%	83	-8,329	1.9%	119	-10,533	2.4%	151
	Total	-6,422	1.5%	92	-9,179	2.1%	132	-11,505	2.7%	165
Case 2	Coal	-587	0.1%	8	-799	0.2%	11	-902	0.2%	13
w/ CP	Gas	-5,758	1.3%	82	-8,105	1.9%	116	-10,167	2.4%	146
	Total	-6,346	1.5%	91	-8,904	2.1%	128	-11,070	2.6%	159

CP = carbon price ($5/tonne-$CO_2$).
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

3.9. Viet Nam

Reducing the operating period by 15 years without solar PV replacement would cost about $8 billion. This is equivalent to 2.5% of GDP in 2020, or a burden of $83 per capita.

The assumed conditions for solar PV replacement and carbon prices were not sufficient, and the replacement resulted in an increased burden.

Table 4.20. Economic Impact of Early Retirement of Fossil Power (Viet Nam)

Viet Nam

Scenarios		5 yr earlier			10 yr earlier			15 yr earlier		
		Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person	Losses mil. $	Share to GDP	$/person
Case 1	Coal	-1,415	0.4%	15	-3,643	1.1%	37	-7,119	2.2%	73
	Gas	-438	0.1%	4	-941	0.3%	10	-945	0.3%	10
	Total	-1,853	0.6%	19	-4,584	1.4%	47	-8,064	2.5%	83
Case 2	Coal	-3,510	1.1%	36	-5,694	1.8%	58	-9,102	2.8%	94
w/o CP	Gas	-1,542	0.5%	16	-2,031	0.6%	21	-2,035	0.6%	21
	Total	-5,052	1.6%	52	-7,726	2.4%	79	-11,138	3.5%	114
Case 2	Coal	-3,399	1.1%	35	-5,318	1.6%	55	-8,311	2.6%	85
w/ CP	Gas	-1,526	0.5%	16	-1,984	0.6%	20	-1,988	0.6%	20
	Total	-4,925	1.5%	51	-7,302	2.3%	75	-10,299	3.2%	106

CP = carbon price ($5/tonne-$CO_2$).
Note: GDP and population are 2020 data from IEA (2022).
Source: Authors.

4. Summary of Analysis

The analysis revealed that the early retirement of existing thermal power plants has no small impact. Under the conditions of the estimation, a significant operation period reduction of 15 years would result in losses equivalent to a few percent of GDP.

Under the assumed conditions, losses will not be mitigated even if a coal-fired power plant is decommissioned and then replaced by solar PV. In theory, losses could be compensated by making carbon prices even higher. However, in such a case, the carbon price should be about \$50–\$60/tonne-CO_2 for coal-fired thermal power and about \$100/tonne-CO_2 for gas-fired thermal power.

It should be noted that this analysis does not include commercial losses such as the cancellation of existing PPAs and associated compensation.

Chapter 5

Policy Implications

This section examines policy recommendations based on the current status of electricity systems in ASEAN member countries (Chapters 2 and 3) and the results of economic impact analysis of the early retirement of thermal power plants (Chapter 4). Policy recommendations are presented from the following three perspectives:

- Requires careful consideration before being acted upon
- Design carbon pricing as a compensation mechanism
- Prevent reducing the resilience of the energy system due to loss of diversity

1. Requires Careful Consideration before Acting

The analysis shows that under the business environment normally assumed, early retirement of thermal power plants would only result in economic loss. The aim of shutting down thermal power plants is to reduce GHG emissions as early as possible, which is feasible. However, the economic side effects of early retirement are not small. Therefore, it needs to be carefully weighed against the benefits of reducing GHG emissions. Possible economic side effects include the following in addition to the loss amounts listed in Chapter 4:

- If a plant is operated for too short a period (e.g., less than 10 years), even the money invested cannot be recovered.
- Early retirement means shutting down plants with lower generation costs, for which initial investments have been written off. This could lead increased average power generation costs.
- If early retirement results in an extraordinary loss to the state-owned power company or increases the average power generation cost, all of these will be borne by consumers. Therefore, this could be a factor that depresses people's lives and the economy.
- If an IPP is subject to early retirement, it may incur payment obligations (take or pay) until the concluded PPA expires, even though no power is generated. There may be a risk of administrative litigation in some cases.
- If banks and other private investors incur losses, they could bring turmoil to the management of individual investors and the financial market, depending on the amount and scope of losses.
- Drastic policy changes with economic losses could undermine investor confidence and negatively affect future private financing.

2. Design Carbon Pricing as a Compensation Mechanism

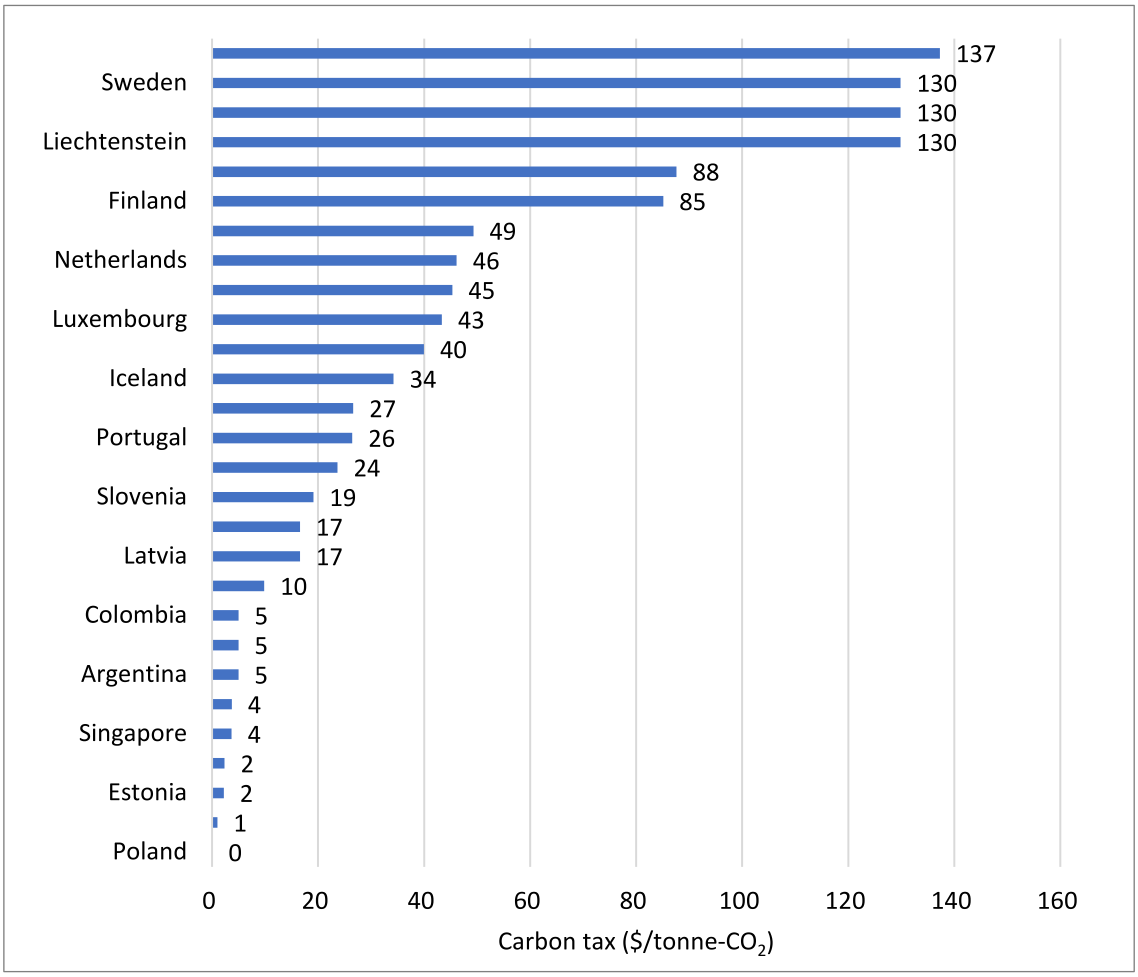
Early retirement of thermal power plants can cause economic losses, but the losses can be compensated by carbon pricing. In the analysis in Chapter 4, solar PV was assumed to replace the thermal power plant after shutdown. With carbon pricing, CO_2 emissions reduction through replacement would be an economic value of reducing the cost of carbon emissions. If carbon prices are high enough, the savings in CO_2 costs could outweigh the economic losses associated with early retirement of thermal power plants. In this case, power producers would benefit more from shutting down thermal power plants and replacing them with non-CO_2-emitting solar PV and other sources rather than continuing to run thermal power plants at the cost of CO_2.

Then, what carbon price level would incentivise thermal power plants' early retirement? The results of this analysis indicate that a carbon price of \$43/tonne-CO_2 is required for a model plant of sub-C coal-fired power, \$52/tonne-CO_2 for supercritical coal-fired power, and \$102/tonne-CO_2 for CCGT generation. In contrast, many of the current ASEAN member countries have not introduced carbon pricing, and even when they do, it is around \$5/tonne-CO_2. Therefore, in the current environment, the early retirement of thermal power plants will only result in economic losses.

Conversely, the introduction of carbon pricing and a gradual increase in the price level as ASEAN member countries step up their efforts to combat climate change can create an environment that encourages the early retirement of thermal power plants. Some countries have introduced carbon prices that exceed \$100/tonne-CO_2. Moreover, the trading price of emission allowances (European Union allowance) in the EU-ETS is around \$60–\$100/tonne-CO_2. While carbon prices are unfamiliar to current ASEAN member countries, such global examples show that a future in which carbon prices influence technology choices is possible enough.

In this way, the institutionalisation of carbon pricing is essential to facilitate the early retirement of thermal power plants. Therefore, the early retirement of thermal power plants should be considered in tandem with the institutional design of carbon pricing. However, introducing carbon pricing itself poses a challenge. There are two types of carbon pricing: carbon taxes and emissions trading. In the case of a carbon tax, the public and industries will widely bear the costs; therefore, setting and raising the tax amount must be done carefully while assessing the impact on the economy. In the case of emissions trading, it is very difficult to set allowances. As is evident from the history of the EU-ETS, it takes much trial and error to make trading markets functional.

Figure 5.1. Carbon Tax in the World (as of April 2022)



Source: World Bank, Carbon Pricing Dashboard, https://carbonpricingdashboard.worldbank.org/map_data.

3. Prevent Reducing the Resilience of the Energy System due to Loss of Diversity

Another important consideration in the early retirement of thermal power plants is the risk of reducing the resilience of the energy system due to loss of diversity in the power mix.

With the Russian invasion of Ukraine, Europe is facing a crisis of energy supply stability. Imports of natural gas from Russia, which is heavily used for power generation, industries, and heating, have plummeted, and Europe is struggling to find alternatives. Before the invasion, Europe had aggressively taken action against climate change. One was the suspension of thermal power generation plants, mainly coal-based. If Europe had retained sufficient coal-fired power, it could have operated coal-fired power plants as an alternative to gas-fired power, thus alleviating the gas shortage to a certain extent.

The European case shows that diversity in energy systems can be a powerful tool to ensure a stable supply in a crisis. Decarbonisation is not the only goal of energy policy; rather, clean energy should be promoted based on stable supply and economic rationality. This is because people's lives and economic activities are not sustainable if the energy supply is unstable, such as frequent power outages, or if energy prices are extremely high.

Climate change is a common global challenge, and all countries are expected to contribute to this issue. Actual measures, however, need to consider the availability and cost of technologies to support a stable energy supply. Solar and wind power are clean, but the world does not have a stable, cheap way to use the electricity it generates (which is technically feasible using batteries and the like, but less economical). Promoting the early retirement of thermal power plants in haste is dangerous because it could increase the vulnerability of the energy system. The transition should be carried out in stages while keeping an eye on the progress of clean energy technologies. Electricity is energy that can be generated from various fuels, and it is desirable to maintain diversity as a key to a stable energy supply.

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