THE INDONESIAN ENERGY TECHNOLOGY ASSESSMENT

(IETA) 2017

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ENERGY RESEARCH CLUSTER

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Glossary

Amortisation Period: the period over which a plant must achieve its economic returns.

Auxiliary Load: the internal or parasitic load from the electricity required to sustain the operation of a plant.

Battery Limit: the defined boundary for interfaces between the plant and the external infrastructure.

Capacity Factor: the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time.

Capital Cost: the cost of delivery of a plant, not including the cost of finance.

Cost Confidence Level: the P95 confidence interval for capital cost estimates.

Direct Cost: the cost associated with all major plant, materials, minor equipment and labour to develop a power plant to the stage of commercial operation.

Discount Rate: the rate at which future values are discounted or converted to a present value.

Dispatchable generation: sources of electricity that can be dispatched at the request of power grid operators.

First-of-a-Kind (FOAK) Plant cost: costs necessary to put a first commercial plant in place and that will not be incurred for subsequent plants. Design and certification costs are examples of such costs.

First Year Available for Construction: the year in which the technology will be available for commercial deployment globally.

Gross Capacity: maximum or rated generation from a power plant without losses and auxiliary loads taken into account.

Labour Cost: the component of the delivery cost for a plant associated with local

(Indonesian) labour.

Lead time for Development: the time taken from inception to financial close. This includes permitting, approvals, and engineering design.

Levelised Cost of Electricity (LCOE): the minimum cost of energy at which a generator must sell the produced electricity in order to achieve its desired economic returns.

Local Equipment Cost: the cost of locally sourced (Indonesia) plant and equipment for the project.

Ministry of Energy and Mineral Resources (MEMR): is the Indonesian ministry responsible for the country's energy and mineral resources.

Nameplate Capacity: the intended technical full–load sustained output of a power plant.

Net Capacity: the export capacity of a generation plant – i.e. the Gross Capacity less the losses and auxiliary loads of the plant.

Non-Dispatchable Power: Power that is not continuously available due to the availability of the resource, and cannot be dispatched to meet the demand of a power system.

Nth-of-a-kind (NOAK) plant cost: All engineering, equipment, construction, testing, tooling, project management, and other costs that are repetitive in nature and would be incurred if a plant identical to a FOAK plant were built. The NOAK plant is the nth-of-a-kind or equilibrium commercial plant of identical design to the FOAK plant.

Owner's Cost: the costs associated with the development of a project prior to the start of construction.

Sequestration: the process of transport and storage of Carbon Dioxide (CO2).

Thermal Efficiency: the ratio between the useful energy output of a generator and the input, in energy terms.

Executive summary

The Energy Cluster of the Australia-Indonesia Centre engaged Professor Kaliappa Kalirajan of the Crawford School of Public Policy at the Australian National University, and Dr Arif Syed, ex-Director at the Australian Department of Industry, Innovation and Science to develop cost estimates for 14 selected electricity generation technologies for the Indonesian Energy Technology Assessment (IETA) under the Jakarta regional conditions. The IETA cost estimates were developed with the active collaboration of the experts from the Australian National University, Monash University and experts from the Indonesian Ministry (MEMR) and other practitioners.

IETA cost estimates were developed to provide:

- Design framework and plant characteristics;
- Performance parameters;
- Capital cost estimates;
- Fuel cost estimates;
- Operational and Maintenance cost estimates; and
- Levelised Cost of Electricity (LCOE) estimates.

The cost estimates, available for each of the 14 selected technologies, were generated on a ‘bottom up’ approach that accounted for the component costs, which determine the overall long-run marginal cost of electricity generation from a utility-scale and an Nth-of-a-kind plant (NOAK). The methods used to build up the cost estimates were applied consistently across all technologies and all the key assumptions used to generate the costs are fully detailed in this report.

Electricity generation costs are changing fast. This change has serious repercussions on national energy policies. For efficient (least cost) and effective energy policy development, a good understanding of the electricity generation technology costs is very important. Policies cannot be developed in a country based on the electricity generation cost assumptions in other countries. Every country has its own set of labour market, technical and geographical conditions and many other domestic policy imperatives that affect performance parameters of individual technologies, and hence the final generation costs. Over the coming decades, the Indonesian electricity sector will need to adjust to unprecedented changes in the relative cost of electricity generation technologies from technological innovation, movements in fuel prices and climate change policies.

If planners and investors in the electricity sector are to effectively manage and adapt to this energy transformation, up-to-date and rigorous estimates of the cost of various electricity generation technologies will be required.

The *Indonesian Energy Technology Assessment* (IETA) 2017 provides the best available and most up-to-date cost estimates for 14 electricity generation technologies under Indonesian, specifically the Jakarta regional, conditions. These costs are provided by key cost-components and include a *Levelised Cost of Electricity* (LCOE) estimation that allows for cross-technology and over time comparisons in Indonesia. On the advice of the project sponsors, serious attempts have been made to develop the IETA on the lines of the *Australian Energy Technology Assessment* (AETA) report. Nonetheless, AETA was an expensive venture involving more than 50 Australian and foreign stakeholders and financial resources. Following AETA, all experts in the IETA Advisory Group were selected on the basis of their high-level of technical expertise. IETA also gained from valuable input by members of the Indonesian Ministry of Resources, MEMR, Indonesia. In addition, IETA consultation also included information from other Indonesian energy experts in the field.

The IETA provides a high level of transparency because it estimates technology costing by LCOE components. Comprehensive details of the underlying methodology, assumptions, parameter values and component costs are provided in the report. IETA parameters and costs will be invaluable to energy companies, regulators and operators who need detailed cost comparisons across energy technologies for planning purposes.

The IETA 2017 provides many important insights including the finding that Indonesia's electricity generation mix to 2050 is likely to be very different to its current state.

Key findings of the IETA 2017 include:
LCOE costs are provided for the years 2017, 2020, 2025, 2030, 2035, 2040, 2045 and 2050 (see table 5.10 in section 5).

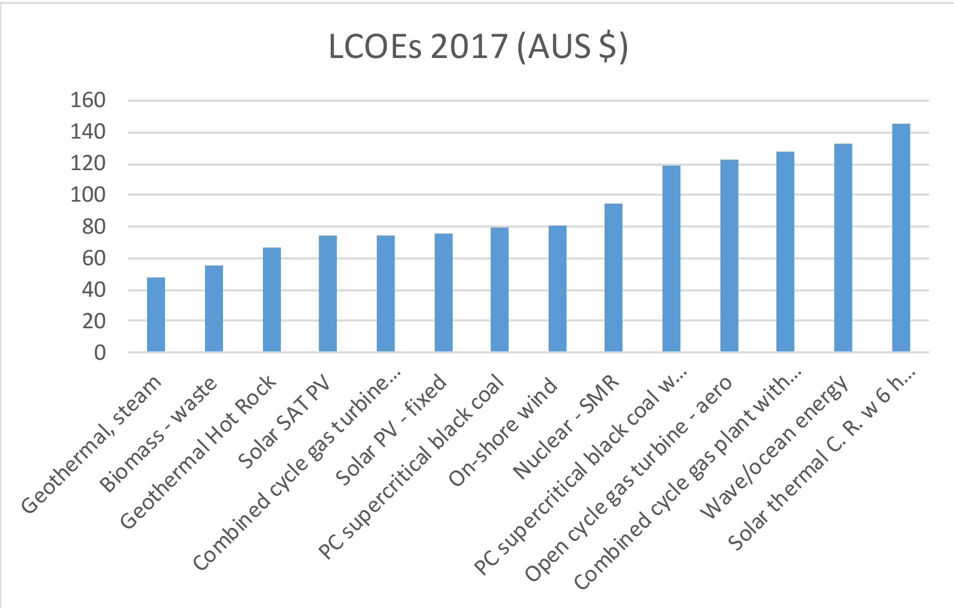
The projections of LCOEs in real Australian dollars from 2017 to 2050 for the Jakarta region are summarised in Table S-1.

Table S-1: LCOEs of IETA technologies to 2050, real AUS $/MWh

Year	2017	2020	2025	2030	2035	2040	2045	2050
PC supercritical black coal	79	79	75	68	65	65	64	63
PC supercritical black coal w CCS	119	118	113	104	102	99	98	98
Combined cycle gas turbine (CCGT)	75	75	75	74	74	74	74	74
Combined cycle gas plant with CCS	128	128	119	103	101	100	99	99
Open cycle gas turbine - aero	123	122	121	120	118	118	117	116
Solar thermal C. R. w 6 h storage	146	132	91	76	75	74	74	74
Solar PV - fixed	76	69	63	45	35	30	30	29
Solar SAT PV	74	67	61	44	34	30	29	29
On-shore wind	81	80	72	66	65	64	63	62
Wave/ocean energy	133	133	133	115	109	104	99	94
Biomass - waste	55	55	55	55	55	54	53	53
Geothermal, steam	48	48	48	47	47	47	47	47
Geothermal Hot Rock	67	67	67	66	65	65	65	65
Nuclear - SMR	95	95	95	94	94	94	93	92

As an example, Figure S-2 presents results for 2017. Such figures are presented in the report to 2050. The figures illustrate how the LCOE of various technologies change over time. Differences are explained by a multiplicity of factors mentioned in the report.

Figure S-2: LCOE for technologies, Jakarta, 2017



- LCOEs presented here represent the mid-point values of the LCOE ranges obtained in the model due to the ranges of fuel prices and other cost components.
- LCOE costs vary substantially across the technologies from AUS $48/MWh to AUS $146/MWh in 2017 and AUS $29/MWh to AUS $116/MWh in 2050.

- Estimated costs of solar photovoltaic technologies have declined dramatically in the past two to three years as a result of a rapid increase in global production of photovoltaic modules.
- Throughout the projection period to 2050, Geothermal Steam, Biomass, and some Solar electricity generation technologies remain the most cost competitive forms of electricity generation.
- Among the non-renewable technologies, PC supercritical black coal and combined cycle gas turbine offer the lowest LCOE over most of the projection period.

A key finding of the study is that the costs of renewable technologies would drop rapidly as a result of a rapid increase in global production and technological developments in these technologies. As a result of on-going cost reductions, differences in the cost of generating electricity, especially between fossil fuel based and renewable electricity generation technologies will diminish.

Chapter 1
Introduction

1.1 Preamble

The Indonesian Energy Technology Assessment (IETA) 2017 provides the best available and most recent cost estimates for generating electricity from a wide variety of technologies under (Jakarta) Indonesian conditions. It contains cost estimates for 14 utility-scale electricity generation technologies, which are presently commercially available or at an advanced stage of development internationally. These technologies encompass a diverse range of energy sources including renewable energy (such as wind, solar, geothermal, biomass and wave power), fossil fuels (such as coal and gas), and nuclear power.

The IETA report provides consistent and transparent cost estimates for the 14 chosen technologies. The costs are generated drawing on the methodology developed under the Australian Energy Technology Assessment (AETA) model under the leadership of Dr Arif Syed (AETA 2012 and 2013).

A key comparative cost across technologies is the Levelised Cost of Electricity (LCOE) that is expressed in real US dollars per Megawatt hour of electricity generation ($/MWh). The LCOE is the price at which electricity must be generated from a specific plant to break even, taking into account the costs incurred over the life of the plant (capital cost, cost of capital/financing, operations and maintenance costs, cost of fuel, and carbon price, if any). LCOE is equivalent to a long-run marginal cost of electricity generation.

While LCOE is an invaluable tool for comparing technology costs, the power generation companies and/or investors, who wish to choose a technology to deploy, would also need to consider other criteria such as site-specific costs, technology performance characteristics and experience with the technology prior to making any final investment decision. More on this issue is discussed in Chapter 2.

This IETA report has been developed in close consultation with an Advisory Group whose members include member from the Energy Change Institute, Australian National University (ANU), Professor Kalirajan of the ANU, and technology costing expert Dr Arif Syed, under whose Directorship the Australian Energy Technology Assessment (AETA) was developed at the Australian Government Department of Industry, Innovation and Science in 2012 and updated by Dr Syed in 2013.

Chapter 2 of the IETA report lists the 14 technologies and outlines the methods and also the macroeconomic and technical assumptions (many provided by the Indonesian team) used to generate cost estimates. Chapter 3 describes the working of the technologies including the core component costs by each technology in the following categories: coal-based; gas-based; solar-thermal; solar thermal-hybrid; photovoltaic; wind; wave; biomass; geothermal; and nuclear technologies. Chapter 4 reviews the Indonesian state-of-the-art in energy generation sphere. The projected LCOE by technology to 2050 are given in Chapter 5, including a relative ranking of the technologies. Chapter 6 offers concluding remarks.

1.2 Project Initiation and Purpose

This project is funded by the Energy Cluster of the Australia-Indonesia Centre. IETA will develop the foundation for energy technology assessment in Indonesia through the implementation of the best practice techniques developed in the Australian Energy Technology Assessment (AETA).

1.3 Project Objectives

The main objectives of IETA 2017 include the following:

- to provide the best available and most up-to-date estimates of current and future costs (component cost and levelised costs) of a set of technologies generated under Indonesian conditions. The list of these technologies was provided by the Indonesian Energy Ministry, MEMR.
- to pass on knowledge and skills concerning energy technology assessment from Australia to Indonesia, while working with the Indonesian MEMR team on IETA 2017 for the costing of the technologies.

1.4 Project Impact and benefits

Understanding the cost of generating technologies under domestic conditions is essential for the Government to develop effective electricity policy, as well as for private investors. By equipping policymakers, investors, researchers and developers with information necessary for practical technology selection, the project will direct the decision making process in energy markets towards the optimum mix of technologies capable of providing sustainable, reliable and affordable electricity to millions of Indonesian customers. It was stipulated that during the process of estimation, and working with the Indonesian team, the project will transfer the best practices and broad methodology developed in the Australian Energy Technology Assessment to Indonesia, and using Indonesian data the IETA will adapt technology costs to the (Jakarta) Indonesian economy.

The project will enhance links between Australia and Indonesia by developing and implementing an energy technology assessment system appropriate for comparison between the two economies. Future projections of costs of major electricity generation technologies will assist policy makers, and investors in selecting most appropriate technology-mix for providing affordable and sustainable electricity.

Further, the project encompasses the Australia-Indonesia Centre Energy Cluster's key activity that will support this strategic research project. Technology assessment in Indonesia is critical for modelling the Indonesian energy system. Hence, the collaboration with the Indonesian project team drawn from the Indonesian MEMR plays a vital role. It is expected that following the initial assessment scoped in this project, an ongoing IETA framework will be established in Indonesia. The Cluster team will be well positioned to play a key role in an ongoing assessment of continuously improving technologies in Indonesia that might be funded by the Government of Indonesia or major international donors and industrial partners investing in the electrification expansion in Indonesia.

Chapter 2
Methods and Assumptions

2.1 Project Method

Indonesian Energy Technology Assessment (IETA) was undertaken by drawing on Australian Energy Technology Assessment (AETA) 2012 and AETA 2013, as well as the Asia-Pacific Renewable Energy Assessment (APREA) studies of the Department of Industry, Innovation and Science, managed by Dr Arif Syed of the Department. AETA was managed by an external Project Steering Committee, including Professor Ken Baldwin (ANU, project Applicant), and internally by Dr Arif Syed (Department of Industry, Innovation and Science, Canberra, and a Visiting Fellow at ANU).

This work package includes estimates and future projections of component costs and levelised electricity costs.

IETA cost estimates were developed to provide:

- Design basis and plant characteristics in general;
- Performance parameters;
- Capital cost estimates;
- Fuel cost estimates;
- O&M cost estimates; and
- LCOE estimates.

Capital Cost Estimates

The IETA ensured that capital cost estimates are derived consistently for each electricity generation technology. Capital costs are provided on the basis of Nth-of-a-kind (NOAK) plant in Indonesia or Australia and, thus, will not attract the cost premiums of the delivery of a first-of-a-kind (FOAK) plant.

As in AETA, the capital costs to be considered in IETA as part of each generation project, includes plant and equipment costs, typical electrical and site preparation costs, and fuel and cooling costs inside the nominal ‘project fence’ that delineates the separation between the project and the grid. External factors such as electrical connection, fuel pipelines or delivery-handling systems, are excluded from capital costs.

All costs are developed at a 'high level', and not plant-by-plant.

2.2 List of technologies costed

The following 14 utility-scale electricity-generation technologies are assessed in this study:

Pulverised Coal (PC)

1. Pulverised coal supercritical based on black coal
2. Pulverised coal supercritical based on black coal with carbon capture and storage (CCS)

Combined Cycle Gas Turbine (CCGT)

3. Combined cycle gas turbine burning natural gas (CCGT)
4. Combined cycle gas turbine burning natural gas with post combustion CCS
5. Open Cycle Gas Turbine burning natural gas (OCGT)

Solar Thermal

6. Solar thermal using central receiver technology with 6 hours storage

Solar Photovoltaic (PV)

7. Solar photovoltaic, non-tracking
8. Solar photovoltaic, single axis tracking

Wind

9. On-shore wind plant

Ocean

10. Wave/ocean energy Conversion

Biomass

11. Biomass waste power plant

Nuclear

12. Nuclear, Generation

Geothermal

13. Geothermal steam
14. Fractured hot rocks

Time Series

The time series over which the LCOE values are estimated are chosen as 2017, 2020, 2025, 2030, 2035, 2040, 2045 and 2050.

The LCOEs for each technology are calculated for one location in Indonesia: Jakarta has been decided in consultation with the Indonesian Ministry.

As an established methodology, the LCOE approaches do not consider the cost of renewable electricity generation integration (into the grid), which may be significant for renewable generation higher than 30 per cent of total electricity generation. This is because the mix of fossil fuels and renewables in a country at a point in time determines what constitutes "higher generation" and when the integration costs will be higher. Integration costs if any, depend on the specific grid's operational conditions and the mix of technologies.

2.3 Project Method Justification

LCOE is the price at which electricity must be generated from a specific plant to break even, taking into consideration costs incurred over the life of the plant, from the starting of the plant in any given year to 2050. LCOE-based technology assessment and evaluation are approaches well established in Australia and internationally. Consequentially, the selected project method is based on the state-of the-art LCOE estimate developed in Australia.

2.4 Project team information

Project team expertise

- The project brings together experts in a range of energy generation technologies, their development, practical deployment and market integration, and economists with first-hand expertise in the development of technology assessment in Australia and other countries, especially in the Asia-Pacific region.

- The project was conducted by Professor Kaliappa Kalirajan and Dr Arif Syed. The project was managed by Professor Ken Baldwin, who was a member of the AETA Project Steering Committee and AIC Energy cluster chair, to ensure that the project aligns closely with the aims and objectives of the Energy Cluster. It also included Dr Ariel Liebman (Monash University) who has experience in energy markets from both an industry and academic perspectives. Dr Igor Skryabin (ANU), who has extensive expertise in industrial solar technologies, and who is the AIC Energy Cluster manager, coordinated the project.
- The project engaged Prof Kaliappa Kalirajan as a consultant, who has performed energy technology assessments for other countries in the Asia-Pacific region, particularly in India. Professor Kalirajan was advised and guided by Dr. Syed.
- The project team included Energy Cluster leads from Indonesia – Dr Retno Dewi and Dr Ucok Wrsiagian – with expertise on the Indonesian electricity sector, particularly, concerning the decarbonisation of electricity supply.

Project Team Diversity
The project brings together researchers with a diverse range of ages, ranging from mid-career to senior professors. The team includes a mix of Australian and Indonesian researchers. There is a highly differentiated range of fundamental disciplines represented on the project, including economics, policy, engineering, and physics.

2.5 Key points

2.5.1 Generation Technologies

Fourteen utility-scale generation technologies, including both fossil fuel based and renewables, are evaluated.

2.5.2 Macro assumptions

Key macroeconomic assumptions for Indonesia that affect the values of the technology cost estimates were obtained from the Ministry of Energy, MEMR Indonesia, and by the research team using an extensive web search.

2.5.3 Technical assumptions

- All technologies were costed on a consistent and transparent basis, with itemisation of component costs.
- Capital costs included direct (e.g. engineering, procurement and construction) and indirect (e.g. owners) costs, but excluded transmission and decommissioning costs.
- Future cost estimates included assumptions about the exchange rate, fuel costs, productivity variation, commodity variation and technology improvements.
- Fuel cost estimates were obtained from MEMR and by web search of the latest generation data.
- Projected growth rates for future operating and maintenance costs were provided.

2.6 Levelised cost of electricity (LCOE)

LCOE can be interpreted as the long-run marginal cost of electricity generation. Key factors used to calculate LCOE by technology include: amortisation period, discount rate, capacity factor, CO_2 emissions factor, CO_2 capture rate, CO_2 storage cost, fuel cost, variable and fixed O&M cost, and the capital cost.

The LCOEs were estimated for one region in Indonesia: Jakarta. Fuel costs and other economic and technical data were gathered for this region.

Details of the general assumptions used for calculating the LCOE are outlined below.

2.6.1 Macroeconomic assumptions

Information was requested on the following economic and technical variables from the Indonesian team and was supplemented using other sources (Table 2.1).

The input values presented in this table mainly provided the basis for calculating current LCOE estimates. Fuel prices are in the Australian dollars. Growth rates in the variables are not provided in the above table, but were separately estimated. Future increases (changes) in LCOE values (provided in real Australian dollar terms) were mainly based on the cost reduction estimates estimated by the Commonwealth Scientific and Industrial Research Organisation's (CSIRO) GALLM model (described in chapter 5). In brief, the LCOE values are influenced through both an increase in overall O&M costs, and technology developments.

Table 2.1 Macroeconomic assumptions

Factors	Variable used in this study
National economic growth	4 per cent (long term), current 5 per cent a year.
Global economic growth	2.5 per cent
Population growth	0.8 per cent (long term), Currently 1.3 per cent a year.
Carbon price, present or future year	0
Exchange rate	10,600 IR (AUD to IR)
Domestic gas price	$6.75/GJ
Domestic coal price	$3.5/GJ
Nuclear price	$1/GJ
Biomass Waste price	$0.75/GJ

The overall impact of the economic factors is a reduction of both the capital and operating cost for a plant over time due to the better experience with the technology and technical and production efficiencies achieved. The magnitude of this is dependent on the characteristics of the individual technologies.

The largest economy in Southeast Asia, Indonesia has achieved impressive economic growth since overcoming the Asian financial crisis of the late 1990s. The country's GDP per capita has steadily risen, from US$857 in the year 2000 to US$3,603 in 2017. Today, Indonesia is the world's fourth most populous nation, the world's 10th largest economy in terms of purchasing power parity, and a member of the G-20. An emerging middle-income country, Indonesia has made enormous gains in poverty reduction, cutting the poverty rate to more than half since 1999, to 10.9 per cent in 2017.

Indonesia's economic planning follows a 20-year development plan, spanning from 2005 to 2025. It is segmented into 5-year medium-term plans, called the RPJMN (Rencana Pembangunan Jangka Menengah Nasional) each with different development priorities. These plans also envisage emphasis on achieving persistent economic growth, more emphasis on research and development, and increased renewables in the energy generation mix.

2.6.2 Technical Assumptions

2.6.2.1 Capital Cost Estimates

Following AETA (2012 and 2013), for commercially established technologies and technologies that would be deployed in the near future, the cost of construction for a new generation technology has been developed, where possible, from a bottom-up approach.

For technologies that are earlier in the commercialisation cycle, information from industry sources, has been applied to establish plant costs and key operating parameters.

The information on future cost reductions for most technologies was based on CSIRO-developed learning rates (cost de-escalation) from 2017 to 2050. This data was also evaluated by the IETA stakeholder members. In general, data on future trends were verified against the Original Equipment Manufacturer (OEM) information, industry body and industry analysis papers.

All costs were developed at a 'high level' for Jakarta region in Indonesia. A breakdown of costs was provided for each technology.

(a) Direct and Indirect Costs

The following items were excluded from the direct and indirect capital costs:

- Escalation throughout the period-of-performance;
- All taxes;
- Site specific considerations including, but not limited to, such items as seismic zone, accessibility, local regulatory requirements, excessive rock, piles, and lay down space;
- For CCS cases, the cost associated with CO_2 injection wells, pipelines to deliver the CO_2 from the power plant to the storage facility and all administration supervision and control costs for the facility; and
- Import tariffs, if charged for importing equipment to Indonesia or shipping charges for this equipment.

Cost items such as IDC, were included as part of the total cost of generation, and were considered when estimating the LCOE.

(b) Decommissioning Costs

Costs associated with plant decommissioning have *not* been included in the calculation of LCOE. Decommissioning costs are discussed in individual technology sections where they may be significant.

(c) Contracting Strategy

Drawing on AETA (2012, 2013) the estimates were based on an Engineering/Procurement/Construction (EPC) approach that utilised a main contractor and multiple subcontracts. This approach provides the owner with greater certainty of costs associated with the facility, but attracts risk premiums that are typically included in an EPC contract price.

(d) Estimated Scope

The estimates related to a complete power plant on a generic site in Jakarta, Indonesia. Site-specific considerations such as soil conditions, seismic zone requirements, accessibility, and local regulatory requirements were *not* considered in the cost estimates.

Labour costs were based on 2017 Indonesian rates and productivities, in a competitive bidding environment. Estimates for labour productivity growth were included in future costs.

(e) Direct Cost Estimate

Each technology's direct cost estimate included costs associated with all major plant materials, minor equipment, and labour force used to develop the respective power plant to commercial operation.

(f) Owner's Cost Estimate

Development costs necessary to cover expenses prior to the start of construction and non-EPC costs were included. Specific development cost items that were included are listed below:

- Studies and project development;
- Site acquisition;
- Project support team;
- Development approvals;
- Duties and taxes;
- Operator training;
- Commissioning fuel; and
- Commissioning and testing.

(g) Productivity Rate Variation

Labour productivity growth (worker output per hour worked) was used to modify the labour component of the capital cost estimates for each technology. Following AETA and following discussions with the Indonesian team, a baseline of 0.8 per cent per annum improvement in output per hour was assumed.

(h) Commodity Variation

Commodity variation was assumed to fluctuate in line with the GDP growth rate over the period from 2017 to 2050.

(i) Technological Improvement or Learning Rates

Technological improvement and reductions in the cost of plant equipment and operation are likely to have the largest influence on pricing trends for generating technologies over the period 2017 to 2050. These learning rates incorporated into the IETA were primarily based on the Global Local Learning Model (GALLM) model developed by CSIRO's Energy Transformed Flagship Group and used in AETA 2012, AETA 2013 and CO2CRC 2015 in Australia).[1]

The GALLM model assesses a number of factors to establish the learning rate for each technology based on:

- technology maturity (i.e. its progression on the learning curve);
- expected rate of technology deployment; and
- rate of cost reduction (with deployment).

The consultants obtained the results from the GALLM model and, where relevant utilised their own assumptions, to estimate learning rates for technologies to 2050, consistent with the Indonesian conditions.

2.6.2.2 Fuel Cost Estimates

Domestic fuel cost estimates for each technology for each targeted year to 2050 for the Jakarta region were provided by MEMR, and by web searches.

Discrete fuel costs have been forecasted for each of the target years 2017, 2020, 2025, 2030,

[1] A paper outlining the GALLM model and its applications to energy cost projections is available at: http://www.csiro.au/Organisation-Structure/Divisions/Energy-Technology/GALLM-report.aspx

2040 and 2050. Costs for the intervening years have been linearly extrapolated. Fuel costs beyond 2050 were assumed to remain constant at real 2050 levels.

2.6.2.3 Operating and Maintenance Cost Estimates

Costs for fixed and variable operating and maintenance (O&M) expenses were provided as high-level estimates based on the consultant's experience, proximity to AETA values, and public domain information.

Operating costs excluded fuel costs, any carbon price, and carbon storage costs (the latter were separately included in the LCOE calculations).

The following costs were included in the fixed O&M (FO&M) cost estimates as an annual cost per MW capacity:

- Direct and home office labour and associated support costs;
- Fixed service provider costs;
- Minor spares and fixed operating consumables; and
- Fixed inspection, diagnostic and repair maintenance services.

The following costs were included in the Variable O&M (VO&M) costs as a cost rate per MWh of sent out energy:

- Chemicals and operating consumables that are generation dependent – e.g. raw water, and water treatment chemicals;
- Scheduled maintenance for entire plant including balance of plant; and
- Unplanned maintenance.

The escalation rates estimated in Table 2.2 represent the trend of increase at rates in excess of the consumer price index (CPI) of power station labour costs (both in-house and service provider). An escalation rate of 100 per cent implies costs increase at the *same* rate. Spare parts typically escalate at a mix of the metals index and labour rate increases. The escalation rate was assumed to be the same for all technologies.

Table 2.2: Operations and maintenance escalation rates

FO&M Escalation Rate (% of CPI)	VO&M Escalation Rate (% of CPI)
150	150

2.6.3 Levelised Cost of Electricity (LCOE) Calculation

LCOE is the most commonly used tool for measuring and comparing electricity power generation costs. It reflects the minimum cost of energy at which a generator must sell the produced electricity in order to breakeven. It is equivalent to the long-run marginal cost of electricity at a given point in time because it measures the cost of producing one extra unit of electricity with a newly constructed electricity generation plant.

The calculation of LCOE requires a significant number of inputs and assumptions. AETA 2012 and AETA 2013 use the following formula for calculating LCOE and its component parts:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LCOE = Average lifetime levelised electricity generation cost

I_t = Investment expenditure in the year t

M_t = Operations and maintenance expenditure in the year t (in calculations, other costs such as a carbon price, if applicable, may be added into this variable or used separately)

F_t = Fuel expenditure in the year t

E_t = Electricity generation in the year t

r = Discount rate

n = Amortisation period

$$I_t = Capital\ Cost \times Net\ Plant\ Output \times 1000$$

$$M_t = Fixed\ O\ \&\ M \times Net\ Plant\ Output + Variable\ O\ \&\ M \times Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100} + Carbon\ Price \times \frac{Emissions}{1000} \times Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100} + Sequestration\ Costs \times \left(\frac{\frac{Emissions}{1000}}{\left(1 - \frac{Emissions\ Captured}{100}\right)} - \frac{Emissions}{1000} \right) \times Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$

$$F_t = Fuel\ Cost \times \frac{\frac{Net\ Plant\ Output}{Thermal\ Efficiency}}{100} \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$

$$E_t = Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$

2.6.4 LCOE Key Inputs

Key inputs and sensitivities affecting the LCOE calculation are:

(a) Amortisation period

(b) Discount rate

(c) Capacity factor

(d) Emissions factor

(e) CO_2 capture rate

(f) CO_2 emission cost (carbon price), if applicable

(g) CO_2 storage cost, if applicable

(h) Fuel cost

(i) VO&M

(j) FO&M

(k) Capital

(l) Exclusions

All components costs and factors were converted into common units to develop the LCOE in terms of real AUS $/MWh in 2017.

LCOE numbers were only generated for technologies where it was expected that the technology was commercially available. While LCOE estimates have been produced for technologies from 2017, it is possible that a technology may not be present in Indonesia for policy reasons, such as Nuclear; or large scale wave energy for technical reasons.

The key variables used to calculate LCOE are described below:

(a) Amortisation Period

The amortisation period defines the period of time over which the LCOE is calculated. This period can be determined by the life of the plant – an estimate of the operating life of a particular technology prior to repowering or decommissioning – or by the finance term the expected amortisation period for finance for a project.

For consistency, when in comparing technologies, and following AETA methodology, a uniform amortisation period of 30 years from the commencement of construction has been adopted.

(b) Discount Rate

To ensure consistency in the comparison between technologies, and as a result of consultations with the Stakeholder Reference Group, following AETA, a real discount rate of 8 per cent has been applied to all technologies for Jakarta.

(c) Capacity Factor

A generation plant's capacity factor is dependent on both the physical limitations of the plant to operate, and the market and operating regime it faces. To ensure consistency in the comparisons across technologies, the capacity factor applied in calculating the LCOE was based only on the physical operating constraints of the plant, consistent under Jakarta operating conditions.

The capacity factor was stated on a case-by-case basis and detailed in Chapters 3 and 5.

There are currently no commercial CO2 geo-sequestration operations in Indonesia, and much of the operation and costing information is at an early stage of development. The CO2CRC along with the University of NSW has carried out an assessment of the opportunities and costs associated with CO2 transport and storage for different regions in Australia (Allinson, Cinar, Hou, & Neal, 2009). For Jakarta, the following value has been used as the basis for storage and transport costs in this report, and is listed in Table 2.3.

Table 2.3: Adopted CO2 sequestration values

	Cost of Sequestration (AUS $/t CO2)
Jakarta	15

Currently, there is no carbon price policy in Indonesia; hence, carbon prices were assumed to be zero.

(d) Fuel cost

Previously outlined in fuel cost estimates in section 2.6.2.

(e) VO&M

Previously outlined in operating and maintenance cost estimates in section 2.6.2.

(f) FO&M

Previously outlined in operating and maintenance cost estimates in section 2.6.2.

(g) Capital

Previously outlined in capital cost estimates in section 2.6.2.

(h) Exclusions from LCOE

- The effects of taxation;
- Degradation effects for output from each technology;
- Plant decommissioning costs; and Plant residual cost.

2.6.5 Caveats on the use of LCOE

LCOE provides a generalised cost estimate and does not account for site specific factors that would be encountered when constructing an actual power plant. As a result, the costs associated with integrating a particular technology in a specific location to a specific electricity network are not considered.

Technologies with an established track record during the phases of both construction and operation, and with relatively stable costs during their lifetime may be regarded as less 'risky'. To the extent that a long term, stable income can be assured over a project's life, risk is further reduced. By contrast, technologies with historical cost overruns, costly delays during construction, and fuel cost volatility generate additional risks, real or perceived. Higher perceived risks will in turn demand higher rates of return on investment. Typically, the discount rate can be used to account for some of these differences in risk with a higher discount rate applied to the 'riskier' projects. For ease of comparison, however, a common discount rate of 8 per cent was applied for all technologies.

Projected LCOE does not necessarily provide a reliable indicator of the relative market value of generation technologies because of differences in the role of technologies in a wholesale electricity market. The value of variable (or intermittent) power plants (such as wind, and solar) will depend upon the extent to which such plants generate electricity during peak periods and the impact these plants have on the reliability of the electricity system. Unlike dispatchable power plants (such as coal, natural gas, biomass, and hydroelectric) – which are reliant on some form of stored energy (e.g. fuels, water storage) – wind and photovoltaic power plants do not, typically, include energy storage.

The IETA LCOEs are restricted to only utility-scale or large scale technologies. Consequently, small-scale technologies (e.g. non-tracking photovoltaics, fuel cells, co-generation, and trigeneration) that may be relevant to distributed generation are not included in the analysis. The LCOE cost estimates associated with distributed photovoltaics are likely to differ substantially from utility-scale photovoltaic systems as a result of differences in component costs (e.g. capital costs, operating and maintenance costs) and performance characteristics (e.g. capacity factor).

2.6.6 Future updates

To ensure the cost estimates are the most recent and account for the latest technological and commercial developments, cost estimates in the IETA report may be updated, as required, biannually or annually. This is because the costs of most technologies, and particularly that of renewable technologies have been changing fast over the past decade and this trend is likely to continue over the next decade before the technology costs are stabilised.

Chapter-3
Description of the Technologies

3.1 Prologue of this chapter

This study aims to assess the selected 14 utility-scale technologies that produce electricity from different fuel sources. From the list provided in Table 3.1, it is evident that some of these technologies are based on fossil-fuel while some of them are based on renewable energy sources.

Table 3.1: List of technologies assessed

Fuel	Technology
Pulverized Coal (PC)	1. PC supercritical based on black coal 2. PC supercritical based on black coal with carbon capture and storage (CCS)
Natural Gas	3. Combined cycle gas turbine burning natural gas (CCGT) 4. Combined cycle gas turbine burning natural gas with post-combustion CCS 5. Open Cycle Gas Turbine burning natural gas (OCGT)
Solar	6. Solar thermal using central receiver technology with 6 hours storage 7. Solar photovoltaic, non-tracking 8. Utility scale PV, single axis tracking
Wind	9. On-shore wind plant
Ocean/wave	10. Wave/ocean energy conversion
Biomass	11. Biomass waste power plant
Nuclear	12. Nuclear, Generation
Geothermal	13. Geothermal steam 14. Fractured hot rocks

This chapter will cover the following aspects of the technologies:

- a brief description of each technology design explaining its different components and how it works;
- technology's current development status; and

- future development directions or trends and expected advancements in the technology by 2030. Technology development predictions beyond 2030 will not be much reliable.

The design and performance estimations for each technology are of standard grade and can be used in any region of Indonesia, in general. However, site-specific and plant-specific settings can differ. Hence, caution will need to be taken when making actual investment decisions in generation technologies in Indonesia. The technology costs and performance parameters will differ by regional locations, and by specific plant locations within a single region. It should also be noted that cost estimates presented in this report are at the plant level, that is, at the plant gate. This is because no technology costing study can be undertaken for the region as whole, as the plant location and its distance from the electricity demand centres, and local conditions will determine the expenditure on poles and wires. That is why at the time of estimating electricity generation costs for technologies, Jakarta specific cost factor will be considered in the following chapters. Technology costs undertaken in one country, cannot be translated (using the exchange rates) for another country, since the local conditions, and other cost pressures affect performance of the technology, and cost conditions.

The costing undertaken in this study represents total cost of generating one megawatt hour (MWh) of electricity using a technology type, in Australian dollar terms (AUS$/MWh), but under Indonesian conditions. All costs will be estimated in the same way, and with similar parameters (discount rates, life of the plant, etc.). In this way, inter-technology costs can be compared with each other to draw policy conclusions regarding which technology to proceed with in a region.

It should also be noted that some renewable electricity generation technologies, mainly such as wind and solar, may also involve some additional cost to be able to integrate the electricity produced to the main electricity grid of the region. However, since the costing studies only estimate individual technology costs at the plant gate level, renewable integration costs are not discussed in the present report.

3.2 Technology Comparison features

Each electricity generation technology has some advantages as well as disadvantages. Renewable technologies such as solar, wind, and wave have no fuel costs and almost produce zero greenhouse gasses. However, these are mainly non-dispatchable in nature, hence are not always available. On the contrary, technologies such as coal and nuclear can produce electricity in large volume with a high level of reliability around the clock, but often result in significant greenhouse gas emissions (in the case of the coal) and long-term waste disposal challenges (in the case of the nuclear).

For comparative analysis among the technologies, first, we need to set some factors that may have a substantial impact on decision-making. Subsequently, we need to observe the probable impacts and variability of those factors on the technologies. The factors which may be considered are as follows:

i. *Geographical state:* This is a site-specific factor. The land is defined as the area needed to facilitate the fuel(s) supply, electricity generation process, and relevant activities. Whereas fuel supply affects fossil fuel technology choices; right type and duration of solar radiation, and sufficient flow and duration of wind affects performance of solar and wind renewable technologies, respectively.

ii. *Water requirements:* Water is a key requirement for most of the electricity generation technologies, especially for the cooling purpose. In the case of hydroelectric power generation, water requirements are also assessed on several factors that include evaporation from reservoirs.

iii. *Structural cost:* This is a technology-specific factor. The amount of expenditure required for designing, approving, and constructing the plant and related infrastructures are measured as structural or construction costs of specific technologies. Usually, structural cost is expressed in dollar per kilo watt ($/kW) terms.

iv. *Electricity generating cost:* total cost of electricity generation, called the levelised cost of electricity (LCOE) is the most important factor affecting the choice of a technology by the investor. The LCOE is expressed in dollar per megawatt hours ($/MWh).

v. *CO2 emissions:* The concept of CO2 emissions from the electricity generation has become a key issue under the low carbon sustainable growth frame. This factor compares CO2 emissions from different technologies in tons/MWh but does not include a life-cycle assessment of greenhouse gas emissions.

vi. *Waste products:* Electricity generation often produces wastes as a by-product from the operation. This factor thus compares the volumes, and toxicity of the wastes produced from electricity plant operations (such as nuclear waste, or simply the ash from a coal technology). The process of handling those wastes is also an important consideration in choosing the appropriate technology.

vii. *Accessibility:* Technically, this characteristic is called the 'capacity utilisation factor' or simply the capacity factor. The accessibility or the capacity utilisation factor determines the obtainability or availability of the technology during the year. It is important to know the fraction of time a particular technology would likely be available to operate over a year. Broadly, the availability factor reflects the nature of the fuel used for that technology. Fossil fuel-based technologies are found to have more availability than the renewables, such as wind and solar.

viii. *Flexibility:* This factor compares the tractability of electricity generating plants to increase or decrease its output within a short time to meet the varying demand of electricity. It also considers load-following, peaking, and ancillary services and quick start capability.

ix. *Adaptability*: The choice of technology also depends on the country's adaptability with the proposed technology. There are a few phases in any technological adaptation; such as innovators, early adopters, early majority, late majority, or laggards. A technology generally passes through many phases of development, such as research, development, demonstration, and commercial use. Investor should take their decisions based on the existing level of development of the particular technology as well as on the capability of the country to adapt the technology.

For each technology, some of the factors mentioned above may be found as more favorable or less favorable while comparing with the other technologies. For instance, coal and natural gas-fueled plants are considered to have more favorable advantages in terms of quick start and stable form of electricity, while may be considered to have lesser advantages in flexibility, and CO2 emissions factor. On the other hand, solar PV and wind are considered to have high favorable factors in terms of water requirements, CO2 emission, and waste products; while they are relatively less favorable in the case of stable nature of electricity, availability, and flexibility (EPRI, 2015).

3.3 Description of Technology designs

The following section describes the fuel used and design of the selected technologies. In the following, the fossil-fuel based technologies are considered first.

3.3.1 Pulverized Coal-based Technologies

The pulverized coal-fired plant dominates the electric power industry, producing about 50 per cent of the world's total electricity generation. A pulverized coal-fired electricity generation plant is the plant that generates thermal energy by burning pulverized coal (also known as *powdered coal* or *coal dust*) that is blown into the boiler.

3.3.1.1 Brief description of the technology

The basic structure of a pulverised coal (PC) electricity generation plant includes coal-handling equipment, boiler or steam generator island, turbine generator island and all balance of plant equipment, bottom and fly ash handling systems. In carbon capture updated plants, features for emissions control equipment is added. The various PC based electricity plants have an almost similar schematic structural setting. However, the main difference among these PC-based plants is marked with the respective boiler technology they use.

Conventional pulverized coal plants are broken into two categories: subcritical and supercritical. The difference between subcritical, supercritical and ultra-supercritical boiler technologies depends on the steam conditions (pressure and temperature) created in the boiler. Subcritical units generate steam at a minimum pressure of 19.0 Mega Pascals (MPa) and temperature ranging 535-560°C. On the other hand, a supercritical and ultra-supercritical unit can generate steam with a minimum pressure of 24.8 MPa and temperature ranging 565-593°C (BREE, 2012). Supercritical and ultra-supercritical technologies are also referred to as high-efficiency, low-emissions technologies.

Two PC-based technologies (as listed in Table 3.1) are described in more details in the following:

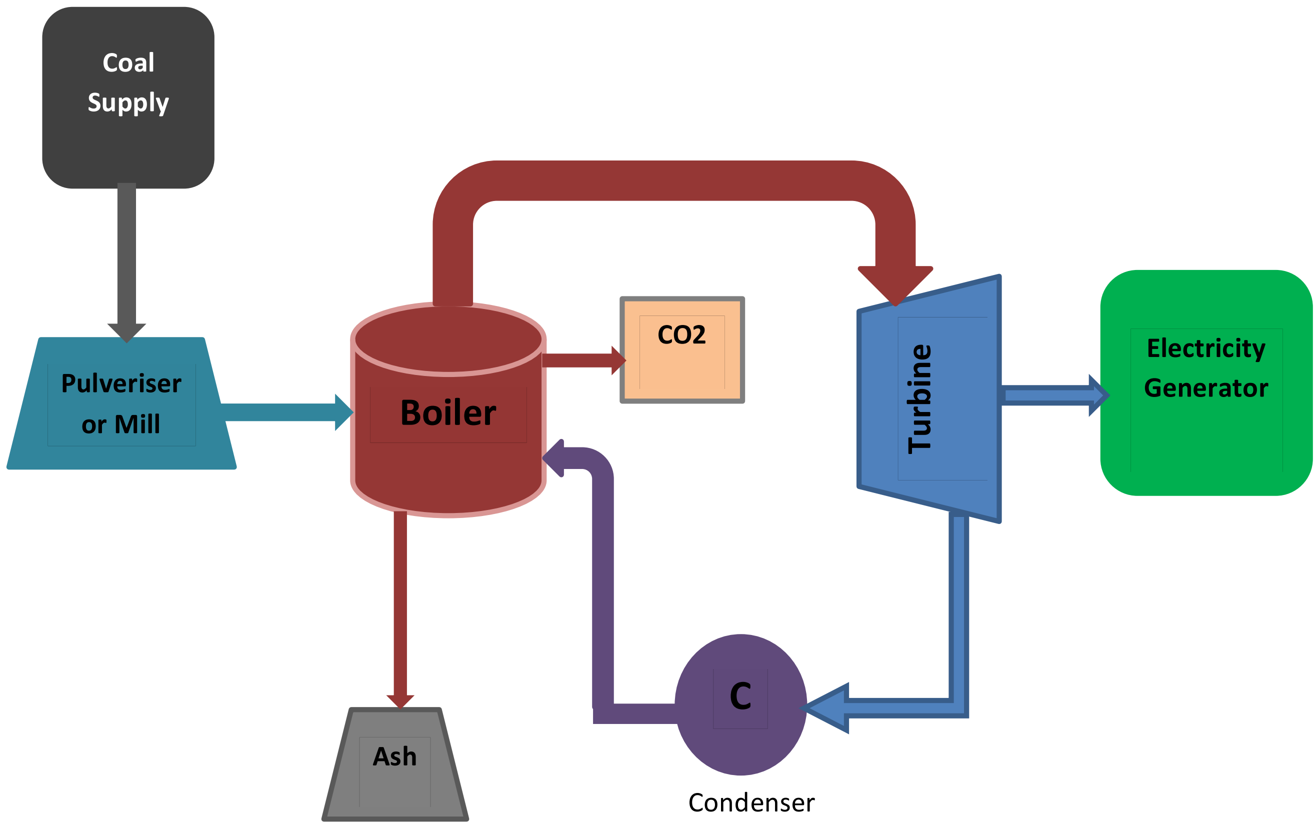
a) PC supercritical based on black coal plant

A simple schematic diagram for PC-based electricity generation technology is shown in Figure 3.1. Basically, it consists of two islands: steam generation Island, and turbine-generator island. The steam generator island comprises of coal pulverizers, burners, water wall lined furnaces, superheater, reheater and economizer heat transfer surfaces, soot blowers, air heaters, and forced-draft and induced-draft fans. The turbine-generator island consists of the steam turbine, the power generator, the main re-heater and extraction steam piping, feed-water heaters, boiler feed-water pumps, condensate pumps, and a system for condensing the low-pressure steam exiting the steam turbine.

Electricity generating process

Steam coal, also named as thermal coal, is used for generating electricity in these power plants. Coal is first pulverized, i.e. milled to a fine powder. Pulverization helps to increase the surface area of the coal and hence, allows it to burn more rapidly. The powdered coal is then blown into the combustion chamber consisting of a boiler where it is burnt at high temperature. The heat produced in the process is absorbed by the tubes set in the boiler walls. The hot gasses and heat energy thereby convert the water inside the tubes into steam. The high-pressure steam is then channelised towards a turbine which comprises a big number of propeller-like blades. The steam puts pressure on these blades to rotate at high speed. One end of the turbine shaft is connected to a generator. Electricity is thus generated when the high-speed rotation of the turbine shaft helps to vary the electromagnetic fields of the generator. After passing through the turbine, the steam is condensed and returned back to the boiler to be heated once again. Bottom ash and wastes are collected through the ash chamber.

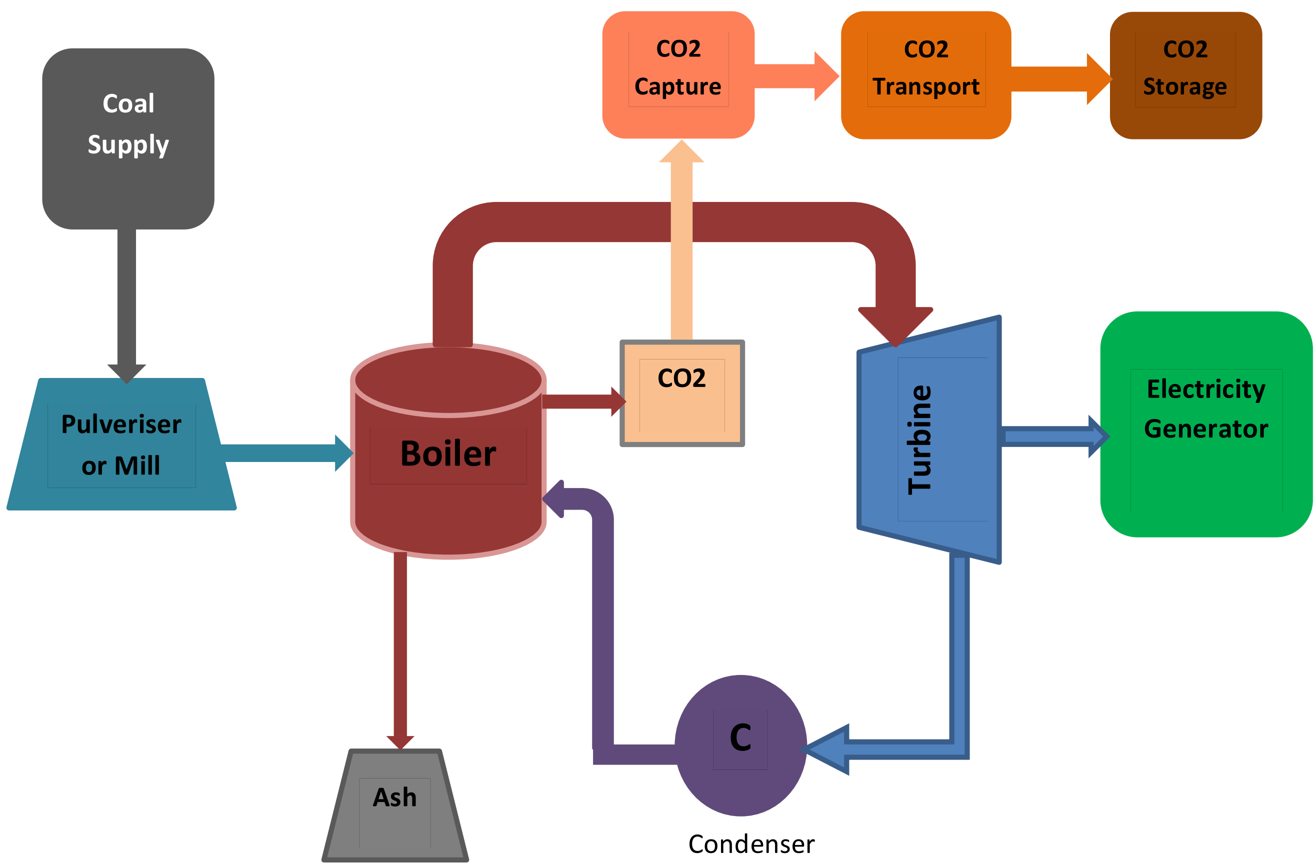
Figure 3.1: Simple Schematic diagram of a PC-based Electricity plant



b) PC supercritical technology–based on black coal plant with carbon capture and storage (CCS)

The PC-based electricity plant with a Carbon Capture and Storage (CCS) setting is shown in Figure 3.2. Electricity generation process in a PC-based electricity plant has already been discussed. The added feature, i.e. CCS is basically a technology which at first captures the CO2 emitted from the burning of coal during the electricity generation process. Captured CO2 is then transported either through the pipelines or by the ships. To prevent it from entering into the atmosphere and contributing to anthropogenic climate change, CO2 is then kept in the safe and permanent underground storage.

Figure 3.2: Simple Schematic diagram of a PC-based Electricity plant with CCS



There are three stages to CCS: capture, transport, and safe storage.

- Capture: At first, CO2 is removed, or separated, from the power plants. Broadly, there are three types of capture: post-combustion, pre-combustion and oxyfuel combustion. During this process, almost 90 per cent of the total CO_2 emission from the plants can be captured.

- Post-combustion capture: CO_2 is captured from the exhaust of a coal power plant, often referred to as the flue gas, by absorbing it in an appropriate solvent. The absorbed CO_2 is removed from the solvent, and then subsequently compressed for transport and storage. After capturing the CO_2, the solvent needs to recycle as part of an environmentally responsible process.
- Pre-combustion capture: In pre-combustion capture, also known as Integrated Gasification Combined Cycle (IGCC), the coal is pre-treated and the fuel is first gasified with oxygen to produce a synthesis gas. This gas is then chemically converted into separate streams of carbon dioxide and hydrogen in the so-called shift reaction ($CO+H_2O \leftrightarrow CO_2+H_2$). The hydrogen produced can then be used as a zero-carbon fuel.
- Oxyfuel combustion capture: In this oxyfuel capture system, the coal is combusted using oxygen instead of air, which then produces a more concentrated CO_2 stream which becomes easier to separate.

- Transport: CO_2 is then compressed and transported to an appropriate storage site. The transport is usually carried out through underground pipelines. For offshore CO_2 storage, ship transport is mostly considered.
- Storage: CO_2 is then injected into a suitable storage site, often into the underground. The geological formation of the site is so crucial to ensure safe and permanent storage. Depleted oil and gas fields or deep saline formations are often preferred for this.

Oxyfuel technology is one of the potential technologies applicable for CCS. An additional step is followed in this process. It involves turning air into oxygen before the pulverised coal combustion in the boiler. The oxygen stream is generally formed in an air separation unit (ASU), which also requires a considerable amount of electricity. This facilitates the removal of CO_2 from the boiler after combustion. Recycling is attained by looping the exhaust duct prior to the stack and redirecting the flue gas back to the boiler where it is mixed with a blend of oxygen and pulverized fuel.

3.3.1.2 Chronological progress in PC Supercritical technology

Modern pulverized coal supercritical technology is primarily invented in Japan and Western Europe, now being used by many countries. Supercritical technology has improved a lot since its first adaptation. The challenges accompanying with the first and second generation of the technology have been resolved through deploying better materials and designs. The purpose of this section is to identify common perceptions of supercritical technology and discuss how these issues have been addressed over the last two decades.

First and Second Generation Supercritical Units

Metallurgical advances did not occur early enough to impact the designs of units commissioned prior to 1985. Early problems with the first and second generation units have created a perception problem. Key issues regarding these early supercritical plants include reliability/availability, start-up, cycling, and part-load operation (Black & Veatch, 2000). Through experience over time, these early generation units have finally been able to overcome most of these issues.

Current Supercritical Designs

Since the early 1980s, following improvements have occurred with the supercritical technology:

- momentous improvements in material usage in the boiler and steam turbine,
- an improved understanding of water chemistry, and
- design advancement

All the above-mentioned factors have helped the current generation of supercritical units to be enormously robust and with a much-improved performance. The following subsections discuss issues that are important in explaining the supercritical technology.

Capital Cost

Nalbandian (2008) calculates that supercritical technology involves the plant capital cost which ranges between 950-1350 US$/kW as compared to the range of 1095-1150 US$/kW for the subcritical technology. It implies that the plant capital would cost 17 to 23 per cent higher if the technology is upgraded from the subcritical to the supercritical technology. The cost differences, however, have reduced in recent years owing to the use of better-quality materials, upgraded equipment designs, and amplified experience. The supercritical cycle has increased costs associated with the boiler, steam turbine, pumps, feedwater heaters, and piping. However, these cost increases are found to be offset by the cost savings in the balance of plant equipment such as coal handling, emissions control, and heat rejection, which is the outcome of increased cycle efficiency.

Efficiency

The efficiency of power plants with any particular technology may vary from country to country (Barnes, 2015). Nalbandian (2008) shows that the average efficiency of a supercritical PC-based plant is 45per cent, while it is around 36per cent for the subcritical technology. EPRI (2015) specifies that the efficiency of subcritical PC-based plants in Australia ranges between 34 per cent to 38 per cent, while it is in the range of 38 per cent to 41 per cent in case of supercritical technology based plants.

Reliability and Availability.

Several studies were performed by the North American Electric Reliability Council (NERC) using the Generating Availability Data System (GADS). The studies only consider first and second generation supercritical units and do not account for improvements in materials, equipment design, and experience from the early 1980s to the present (Paska, 2004). Those studies imply that during the first five years of operation, the first and second generation supercritical plants were evidently underachieved in terms of equivalent availability factor (EAF) and equivalent forced outage rate (EFOR) while comparing with their subcritical counterparts. The problems were more noticeable in the boiler than in the steam turbine. The data also reveals that the EAF and EFOR of second generation supercritical technology were far better than that of the first-generation technology.

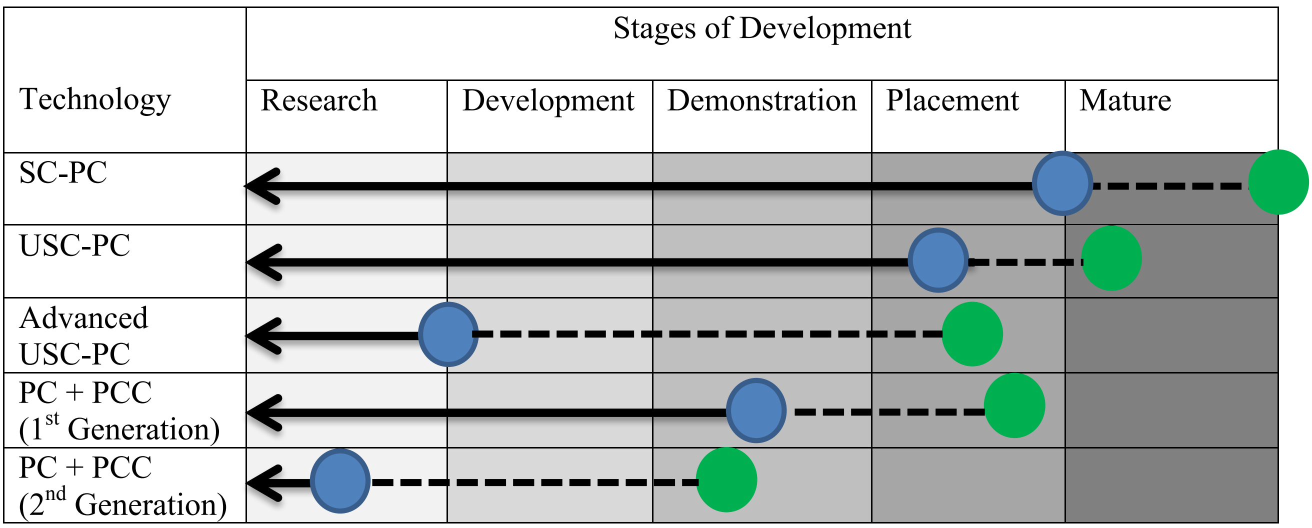
Almost all first-generation supercritical plants were constructed with *pressurized draft design*. The second-generation plants are, however, divided fairly evenly between *pressurized draft design* and *balanced draft design*. Between 1975 and 1980, nearly 90 percent of the units built in the US have been with the balanced draft design. In addition, 26 units originally constructed as pressurized draft had been converted to balanced draft prior 1985 (Black & Veatch, 2000).

There are two critical issues on reliability which are frequently experienced in the boiler: tube leaks and water-wall tube cracks. Few corrosion products are formed in the feedwater heater system. While flowing into the boiler, those corrosion products deposit on the channel. Eventually, it erodes the tube and results into the tube leaks. As a remedy, the conventional system is shifted towards the oxygenated water treatment system which significantly improved the tube leakage problem. The oxygenated treatment system also helped to reduce the water-wall tube cracks through forming ferric oxide hydrate. Ferric oxide hydrate has very low solubility. Hence, the amount of the oxide transported to the boiler is substantially reduced that subsequently helped to reduce the corrosive deposits on the water-walls. Since 1991, more than 60 supercritical units in the US have been switched to the oxygenated water treatment (Black & Veatch, 2000).

3.3.1.3 Development status of the coal-based technology

Table 3.2 shows the chronological development status of PC-based technologies. As already mentioned, advancement in technology for the PC-based electricity plants are categorized by the level of main steam temperature and pressure. Table 3.2 shows that supercritical plants are in the mature phase of technology development. Ultra-supercritical plants are considered to be in the deployment phase while the advanced ultra-supercritical plants are still in the early stage, i.e. in the development phase.

Table 3.2: Technology development curve for pulverized coal-based plant



Note1: Blue circle represents the current state of development, while green circle refers to the probable development state in 2030
2. SC stands for Super-critical pulverized coal (PC). USC stands for Ultra Supercritical PC. PCC stands for Post-Combustion Capture
Source: (EPRI, 2015)

3.3.1.4 Future potential developments of PC-based technologies

The key technical factors for the further advancement of the PC technology are mainly related with new metal alloys along with its operating flexibility. For further improvements in this technology, newer materials will be required to sustain higher temperature and pressures. For e.g. with such advancement, high-quality chrome, and nickel alloy would be required which can be steadfastly operated under higher pressure and at temperatures over 700 degrees Celsius (ºC).

a) PC supercritical

Global trends in technology reveal that there are plans to initiate commercial-scale supercritical PC facility with a main steam temperature of 700ºC by 2016 (BREE, 2012). Besides, efforts are also going on to develop, design and test the materials needed to sustain at steam conditions of 760ºC and 34.5 MPa in boilers and steam turbines. It is expected that plant with those conditions will be marketable for commercial-scale plants by 2030. It is also estimated that scaling up to 760ºC and 34.5 MPa will improve the thermal efficiency by at least six percentage points as compared to the current technology.

For attaining the advancement in technologies for the PC-based supercritical plant, following key technical issues are needed to be taken into account:

- The process of code qualification should be tough as well as costly for the *Original Equipment Manufacturer* (OEM) and fabricators.
- Since the newer (or reengineered) materials would be needed for the advancement of technology, manufacturers need to invent the more sophisticated fabrication techniques along with the welding procedures.

Several R&D experiments have been conducting in several countries. The US plays the pioneering role in this regard. The US Department of Energy’s (DoE) National Renewable Energy Laboratory (NREL) – in collaboration with the Ohio Coal Development Office, major boiler- and turbine-equipment manufacturers and other key stakeholders, including EPRI – initiated a project in 2001 to develop and certify nickel alloys to improve the boiler and turbine steam settings towards 760°C/35 MPa (EPRI, 2015). Europe, Japan, China, and India are also working to attain this advancement. As an outcome, momentous wide-reaching progress has been achieved to date in the areas of detecting, assessing and qualifying the alloys. Hence, construction of the critical apparatuses of coal-fired boilers and steam turbines has been easier than before. This also enhances the capability of the system to operate with improved efficiencies than the ultra-supercritical plants. Future plant system will probably entail an additional reheat to the steam cycle, along with sliding pressure design. Such features are now in the process of experimenting in Japan and Europe.

b) PC with post-combustion carbon capture

Improvement in efficiency may not have a direct impact on the post-combustion capture (PCC) processes but expected to have an indirect advantageous impact. The higher the efficiency of a power plant, the lesser will be CO2 produced per MWh electricity generated. Therefore, with a given output capacity, the plant with higher thermal efficiency will require a smaller CO2 capture system. It will help reduce the capital cost of the CO2 capture process. It will also reduce the required auxiliary power load of the capture system.

CO2 compression technology is also expected to advance by 2030 along with the improvement in the solvents. Such advancements may comprise more efficient compressors and intercooler designs to capture the heat of compression. The additional heat captured will then improve the system into two ways:

a) by returning to the steam cycle, and
b) Using the heat for solvent regeneration.

Altogether, it is expected that the aggregated advancements in solvents and compression systems would noticeably decrease the total loss in electricity production ascribed to the PCC. With further advancement towards the learning curve more advantageous features are expected to be deployed. It would, therefore, result into some additional capital cost savings in the PCC technology. With all these potential developments, significant changes are expected in lowering cost and with higher efficiency for other CCS systems under development.

3.3.2 Gas-based Technologies

3.3.2.1 Brief description of the technology

A gas turbine, often known as the combustion turbine, has three main units: air compressor, combustion chamber, and an expansion turbine.

- Compressor: It draws air into the engine, pressurises it, and feeds it to the combustion chamber at speeds of hundreds of miles per hour.

- Combustion chamber: Usually a ring of fuel injectors injects a steady stream of gas into combustion chambers where it mixes with the air. The mixture is burned at temperatures of more than 2000°F. The combustion results in a high temperature, a high-pressure gas stream that enters and swells through the turbine section.
- Turbine: It is a complex setting of alternate stationary and rotating aerofoil section blades. While the hot combustion gas is expanding through the turbine, it compels the rotating blades to spin. The rotating blades, with one hand, drive the compressor to draw more pressurized air into the combustion section, and with the other hand, spin a generator to produce electricity.

In addition to this system, a heat recovery steam generator (HRSG) may also be linked with the gas turbine to produce steam for electricity generation. Generally, this HRSG is run with a natural gas turbine, hence, termed as natural gas combined cycle turbine.

Two combined cycle gas turbine electricity generation technologies (as listed in Table 3.1) are described in more details in the following:

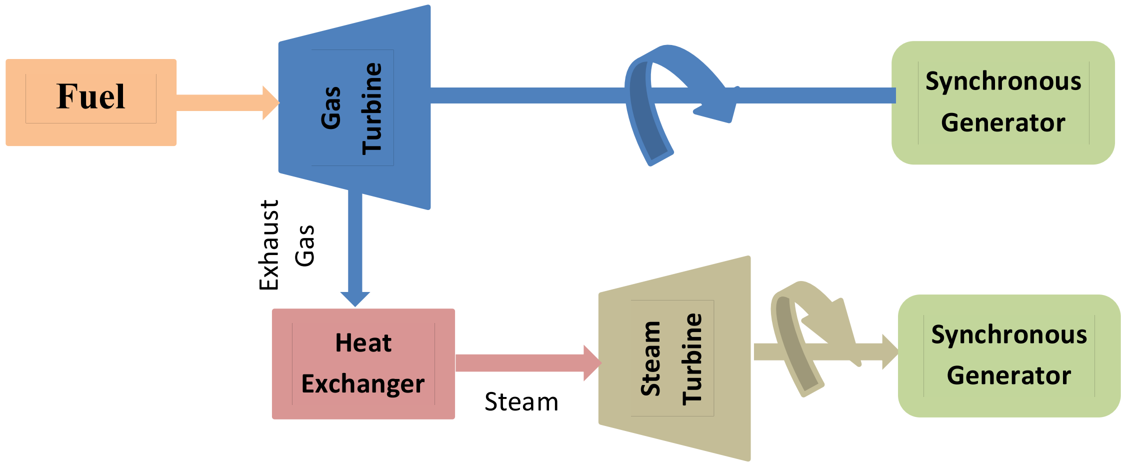
a. Combined cycle gas turbine burning natural gas (CCGT)

b. Combined cycle gas turbine burning natural gas (CCGT) with post-combustion CCS

Combined cycle gas turbine (CCGT) is the arrangement where a gas turbine is coupled with a Rankine steam cycle to attain significant improvements in efficiency and electricity output. Figure 3.3 shows a schematic diagram of a CCGT plant. In a natural gas CCGT, the hot exhaust gas coming from the turbine is passed through a heat exchanger, also known as HRSG. Here heat is exchanged with water. Subsequently, steam is produced while gas is cooled at a temperature range of 110°- 135°C. The overall generation maximum efficiency of a combined-cycle power system may be up to in the range of 43-49.5 per cent which is considered as a substantial improvement over the efficiency of a simple, open-cycle application of less than 35 per cent (BREE, 2012).

The inclusion of CCS module will follow the same process as described in the PC-based electricity plant with CCS in section 3.2.1.1. Such added feature with the CCGT will affect plant performance and cost. However, CO2 concentration in a combined cycle gas plant's flue gas is only 4 per cent, while it is around 12 to 15 per cent for a coal-fired plant (EPRI, 2015). Moreover, as the ambient air is used as the compressible medium by the gas turbine, the flue gas flow in a natural gas-fired plant is about 50 per cent higher as compared to a coal-fired plant per MW of capacity. Owing to the higher flue gas flow and lower CO2 concentration in exhaust gas, carbon capturing cost might increase by 100 per cent per ton.

Figure 3.3: Schematic setting of a Combined Cycle Gas Turbine base electricity generating system



Operational mechanism

1. *Gas turbine combusts fuel.*

   First, the air is compressed and mixed with fuel which is heated to a very high temperature. The hot air-fuel mixture is channelised through the gas turbine blades, making them rotate. The fast-spinning turbine drives a generator that converts the spinning mechanical energy into electricity.

2. *Heat recovery system captures the exhaust gas.*

   The HRSG captures the exhaust heat coming out of the gas turbine that would otherwise discharge through the exhaust load. The HRSG produces steam at a higher pressure and temperature from the exhaust heat and delivers it to the steam turbine. Initially, the steam coming from the steam turbine is condensed which is then returned to the HRSG through the condensate pumps. The condensate generated through the condenser is then pumped to the drum of the HRSG at low pressure. Feed-water propelled by the feed-water pumps is then carried to the steam drum (also known as an evaporator) circuit through high-pressure economisers. The steam generated in the steam drum is heated at a high temperature at the front part of the HRSG and channelised to the inlet of the steam turbine.

3. *The steam turbine generates additional electricity.*

   The steam turbine sends its energy to the generator drive shaft, where it is converted into additional electricity. On average, about two-thirds of the total electricity is generated by the gas turbines and rest one-third is generated from the steam cycle (Ramireddy, 2012).

Categories of CCGT

CCGT may differ in terms of the steam cycle, HRSG pressure level, and the number of shafts. Depending on these features, CCGT plants can be categorized in followings:

- steam cycle: reheat or non-reheat
- HRSG pressure levels: single-pressure, two-pressure, three-pressure
- number of turbine-generator shafts and their arrangement: single-shaft or multi-shaft.

Advantages of Combined Cycle Electricity Plant

- Since in a CCGT system both plants are used, the electricity generated by this plant is more than the electricity generated by a single steam or gas generator power plant.
- The thermal efficiency and mechanical efficiency of the CCGT plant is usually higher, even higher than the hydro-electric plant.
- Gas availability is ample in nature, and generates lower level of emissions than coal plants.
- The fuel cost of this CCGT plant is usually very inexpensive.
- CCGT plant is suitable for relatively quick starting and stopping compared to a coal plant, even in the times of extreme temperatures, i.e. at very hot or cold situations.
- Flexibility is an advantageous feature of the CCGT plant. It can accept varying loads and, therefore, can be used as both *base load* and *peak load* plant.
- The operational cost is usually lower for CCGT plant.

Disadvantages of Combined Cycle Electricity Plant

- Maintenance cost of the CCGT plant is often very high.
- As compared to single cycle gas electricity plants, the initial installation cost of the CCGT plant is very high.
- Interconnectivity sometimes results into a contagion kind of problem. Trouble or mishandling in the first plant often causes the second plant malfunctioning. In a severe case, trouble in the first plant might compel the entire plant to shut down.

Areas of improvement in CCGT technology

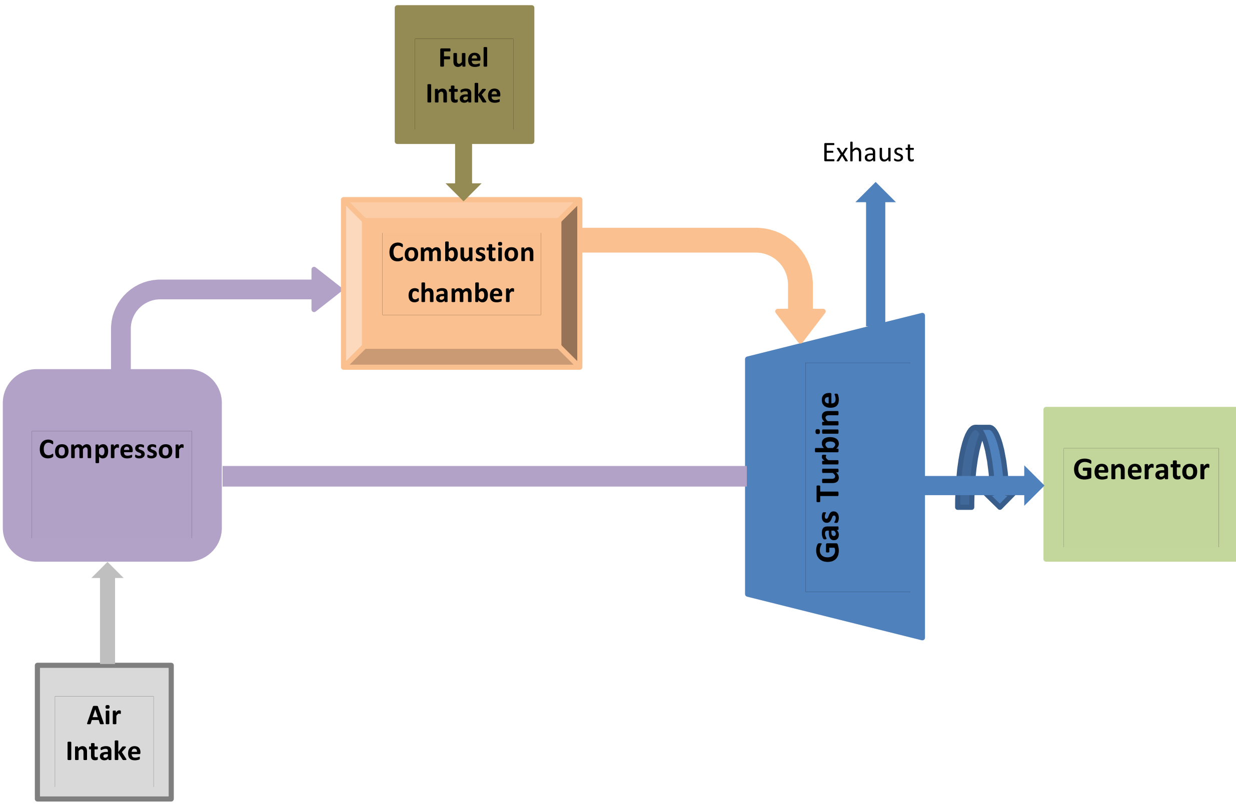
To improve the performance, this core design of a combined cycle plant may need to incorporate few additional settings depending on the gas turbine class, scale of the plant, flexibility requirements in operations, requirements for emissions control etc. Additional features may be in form of supplementary firing in the HRSGs, which lets the plant to raise its output at a little cost of cycle efficiency. Sometimes, a natural gas combined cycle electricity plant experiences certain restrictions on the level of water consumption and discharge. In such case, the plant needs to install an air cooling system with it. An air cooling condenser is added into the system. Combined cycle plants with air-cooled condensers necessitate a steam turbine that can be operated under high-backpressure. It, however, typically declines plant output and efficiency as compared to the orthodox steam turbine design.

The open cycle gas turbine electricity generation technology can be described as follows.

c. Open cycle gas turbine (OCGT)

In this technology, most of the gas turbines operate on an open cycle in which air is extracted from the atmosphere, compressed in a centrifugal or axial-flow compressor, and then fed into a combustion chamber.

Figure 3.4: Schematic setting of an Open Cycle Gas Turbine base electricity generating system



There are three key components in an OCGT: an air compressor, a combustor, and an expansion turbine. A simple schematic diagram is illustrated in Figure 3.4. The compressor sucks air in from the atmosphere and compresses it through a number of compression stages. Fuel (natural gas) is pumped into a combustion chamber and mixed with the compressed air under certain pressure. The fuel/air mixture is then ignited to form hot, high-velocity gas. This gas is passed through turbine blades. The shaft of the gas turbine is connected to both the air compressor as well as to the shaft of the generator. The shaft rotates and the mechanical spinning energy converts into electricity. This electricity is then distributed via the high voltage network to where it is needed.

Advantages of the OCGT plant

- Once the turbine is geared up to the rated speed (by the starting motor) and the fuel is ignited, the warm-up time required for the OCGT plant from cold start to full load is usually very quick. It is especially advantageous when the plant is used as a peak load plant.
- The thermal efficiency of an OCGT plant can be improved by component or auxiliary refinements in the system. Once such improvement is attained, an OCGT plant can be very cost effective in terms of plant's load factors and other operating conditions. At the moment it is very expensive to run the OCGT plant though.
- The weight of a typical OCGT plant, expressed in kg per kW, is very low. It also requires lesser space as compared to the close cycle plants.
- There are many options available for the fuel in OCGT plant. Nearly any hydrocarbon fuel from high-octane gasoline to heavy diesel oils can be used in its combustion chamber. Generally, it uses the natural gas.
- A typical OCGT plant does not require cooling water which gives the benefit of being independent of a cooling system and thus, becomes self-contained[2].

[2] In open cycle system, controlling the emissions remains a big challenge. The key pollutant emitted from open cycle combustion turbines are nitrogen oxides (NOX) and carbon monoxide. In the earlier configurations of the technology, for controlling the NOX emissions, water or steam was needed to inject into a conventional combustor. However, designs keep improving and nowadays, dry low-NOX or dry low-emissions combustors are available in the market, which do not need any water or steam to inject for removing NOX pollutants.

Disadvantages of the OCGT plant

- Since a considerable portion of the electricity generated by the turbine is required for driving the compressor, the load efficiency of the OCGT plant is comparatively lower than the CCGT or any closed cycle plant.
- The OCGT plant is usually sensitive to the changes in the atmospheric air temperature, pressure, and humidity. The efficiency of the plant varies according to these factors.
- Since the air rate of an OCGT plant is higher than a closed-cycle plant, the amount of heat loss in the exhaust gasses is also high for an OCGT plant.
- In an OCGT plant, there is a higher risk of dust entering into the compressor that may increase the erosion and depositions on the blades and channels of the compressor and turbine. This could easily reduce the overall efficiency of an OCGT plant. The deposition of the carbon and ash content on the turbine blades is also a big concern for an OCGT plant.

3.3.2.2 Performance factors of Gas turbine technology

Following factors influence the performance of a gas turbine:

- Inlet mass flow
- Ambient temperature
- Relative humidity
- Fuel type
- Inlet pressure drop
- Outlet pressure drop
- Compression ratio
- Site elevation.

Most of these factors are location and plant specific. However, some additional measures may be incorporated to extract enhanced performance. These include,

- *Inlet cooling:* By installation of an evaporative cooler or inlet air chiller in the inlet ducting downstream of the inlet filters, compressor inlet temperature can be lowered.
- *Steam or water injection:* Injection of steam or water would enhance the power along with the control over the oxides of nitrogen (NO_X).

- *Increase in firing temperature:* Increased firing temperature may require to aid peak operation. Consequently, with lesser operating hours, it is possible to generate more output with this additional feature. Operating a gas turbine at peak firing temperature is considered as a cost-effective way to obtain more electricity without the need for additional settings.

3.3.2.3 Future potential improvement in Gas-based technologies

CCGT technology is at its matured stage. The advancements and improvements in existing technology are enduring over time. There are two key considerations in this development process:

1) attaining minimum load while being within the emissions limits and
2) maximum power output with minimum start-up time.

In meeting these considerations, gas turbine manufacturers are now focusing on improving the overall cycling capability of the entire plant, rather focusing on individual components. Improvement in cycling capability needs the ideal setting and optimal interactions between the main elements (e.g. gas turbine, steam turbine, generator), auxiliary plant equipment (e.g. HRSG, water and steam systems) and the control system.

Further improvement in technology would enable the system to operate at much higher firing temperatures and higher pressure ratios than the current plants. Currently, an F-class heavy-duty gas turbine with advanced bucket cooling technology and improved coating is able to operate at the firing temperature exceeding 1,315°C. Siemens & MHI (H and J class technologies) claim that their latest machine with advanced air cooling and steam cooling can operate at over 1,650°C turbine inlet temperature (EPRI, 2015). There seems to be a potential improvement in designing the future CCGT plants based on advanced heavy-duty gas turbines. This development is expected to continue even further. Along with the further improvement in the cooling system, bucket quality and durability are also projected to advance significantly in future (BREE, 2012). Not only the features of the gas turbine but also the efficiency of the steam turbine are expected to improve. Advancement in the reheat steam turbine cycle would lead to higher efficiency for the bottoming cycle of a CCGT plant. Such advancements in technology would help to increase the overall plant efficiency and lower capital cost. Following the trend of development, it is projected to be the cheapest of all fossil-fuel conventional baseload technologies (EPRI, 2015).

Combined cycles natural gas-fired plant based on the advanced machines and technologies have already been on the verge of breaking the 60 per cent combined cycle lower heating value efficiency barrier. It is, therefore, expected that by 2020–2030 all these technologies will be at their mature stage (EPRI, 2015).

CCGT with CCS technology is still at its early stage of development. But it is getting momentum in recent times. CO2 absorption process requires amines, especially mono-ethanol amine (MEA), that helps to optimize energy consumption and improve the absorption efficiency (Luis, 2016). Significant improvement in the existing MEA-based amine solvent system is expected over the next few years (BREE, 2012). Development in CO2 compressor technology and inter-cooling systems will lead to decline the capital cost along with the auxiliary loads require for running the CCS plant. According to the EPRI (2015) study, through advancement in technology, capital costs for CCS plant are likely to reduce by 30–50 per cent, which would lead to a reduction in the levelised cost of 10–25 per cent. The thermal efficiency of a CCGT plant with CCS is also expected to increase further by at least eight percentage points by 2030.

Open cycle gas turbine plants are, on the other hand, already at a mature generation stage. There are many types of gas turbines available in the market today, such as the state-of-the-art heavy-duty F, G, and H-class turbine models and aero-derivative gas turbines. The performance of an open cycle gas turbine is intensely influenced by several factors, such as inlet mass flow, compression ratio, and expansion turbine inlet temperature. In terms of maximum turbine inlet temperatures, it has improved from the early heavy-duty gas turbines with 800–1,100ºC to a more recent one with 1,300–1,375ºC. Innovative designs, improved materials, and additional sealing and coatings, and advanced secondary air cooling system also are helping to improve the efficiency and electricity output. By 2030, the overall thermal efficiency of the OCGT plan is expected to increase by at least 6 percentage points, though the capital cost also might increase up to 10 per cent (EPRI, 2015).

3.3.3 Solar-based Technologies

Three solar-based technologies are discussed in this section:

3.3.3.1 Brief description of the technologies

a. Solar Thermal Technology

Concentrating solar thermal technologies generally refer to four kinds of different solar thermal power systems, which are listed here:

- central receivers
- parabolic troughs
- linear Fresnel reflectors
- dish or dish Stirling engines

All four systems follow the same principles here: direct normal solar radiation (direct normal irradiation or DNI) is collected by the mirrors (heliostats) to produce steam which is then used in a steam turbine generator to generate electricity. This report is primarily concerned with Central Receivers System, also known as the Power Tower System.

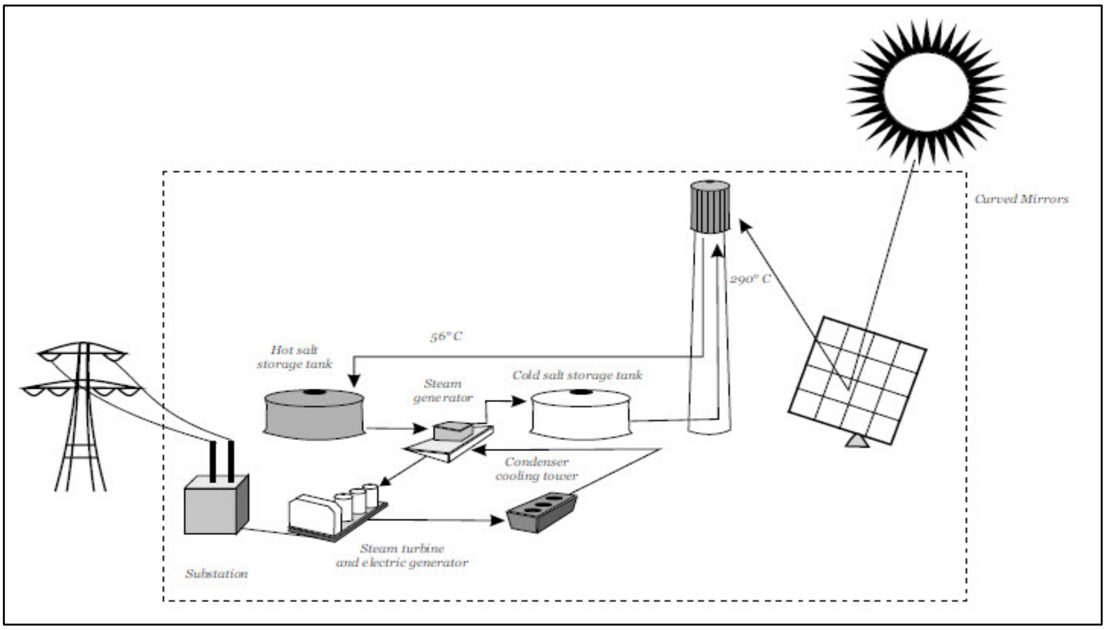
The central receiver system uses heliostats (two-axis tracking mirrors which can continuously track the sun's position) to reflect and concentrate DNI onto a receiver installed at the top of a tower. Figure 3.5, the photograph of Ivanpah project – the world's largest operational solar thermal power plant – shows the typical structure of a central receiver system.

Figure 3.5: Ivanpah Solar thermal based electricity generation Project

Source: http://www.energy.ca.gov/tour/ivanpah/

Theoretically, the concentrated solar energy can be both directly or indirectly transferred to produce stream, while the existing central receiver system applies indirect method. The indirect method relies on a fluid or solid medium which will firstly be heated by concentrated radiation energy to transfer the heat to water then to produce stream, indirectly. Typically, central receiver system adopts a kind of a molten nitrate salt as the heat transfer medium. Figure 3.6 describes how a central receiver power plant uses solar radiation to generate electricity. Initially, the molten nitrate salt is heated to around 290ºC (degrees Celsius) in a relatively colder tank. After that, it will be piped into another relatively hotter tank via the solar receiver, in which it will absorb the concentrated solar energy and be heated up to 565ºC. The last step is to transfer the 565ºC molten nitrate salt onto the steam generator to produce steam that will be further used by conventional steam turbine for electricity generation.

Figure 3.6: Central Receiver System of a Solar-based technology



Source: http://www.solarpaces.org/

Characteristics and Assessment of the technology

Since the molten nitrate salt can be heated up to 565ºC, after transferring the solar energy to produce steam, it can still remain at pretty high degree (around 540ºC), which promotes the efficiency in terms of the procedure of energy transfer cycle (compared with the parabolic trough system). In addition, the price of molten nitrate salt is considerably cheaper than other kinds of heat transfer medium. Moreover, if the energy storage sector is considered to be integrated within the system, the molten nitrate salt can also play a role in thermal energy storage itself, which leads to a significant cost reduction of central receiver system. Generally, the storage capability is more or less required by solar power plants, since it allows those plants to store energy during the most intensive period of sunshine and continue to generate electricity during sunless period. As mentioned above, the two-tank system is adopted in central receiver technology while it can play the role of storage of energy at the same time as long as the hot tank is large enough and possesses excellent thermal insulation performance. If so, the heated molten nitrate salt can be preserved in the hot tank at a high temperature and then be used to generate steam after sun set.

One issue associated with storage system, however, is the trade-off between the power output level and storage capacity. It is the size of the steam turbine that actually determines the outcome. Typically, a larger turbine could produce higher power output during the solar irradiation peak time while less energy would be left for storing. Similarly, a smaller turbine could produce lower peak time output but more energy would be stored. Theoretically, this balance can be improved by installing more mirrors in a central receiver system so that more DNI can be collected and stored during sunshine intensive period while keeping the power output unreduced. Nevertheless, this method is highly restricted by the installation and maintenance cost, as well as the available land usage which will be mentioned later in section

3.3.3.2.

The structure of central receivers also has some site requirements such as having a level land area and a continuous parcel of land which is able to accommodate an oval-shaped footprint, however, those requirements are relatively less strict because of the tracking mirrors. Also because of the tracking system, the footprint of a tower system is relatively larger than that of a parabolic trough system.

One disadvantage of central receiver technology, however, is that as the freezing point of nitrate salt is 220ºC (APGTR 2015), in order to maintain its melting state, a freeze protection system or natural gas auxiliary boiler must be used, which obviously brings about an additional cost. Furthermore, under this technology, each heliostat must be controlled by an independent dual-axis tracking controller, which requires a more complex controlling system and causes extra cost and workloads.

b. Solar Photovoltaic Technologies (non-tracking)

c. Solar Photovoltaic Technologies (Single-axis tracking)

Solar photovoltaic (PV) technologies can directly use sunlight to generate electricity via exposing PV cells to light, which is the basic power generating component in solar PV technologies. Typically, PV cells are composed of semiconductor material that mixes silicon with other elements which 'have either one more or one less valence electrons to alter the conductivity of the silicon', which could produce an extra electron or electron vacancy for conduction respectively (AETA 2012, p. 42). Therefore, when exposed to light, the solar PV cell will generate an electron flow, or electric current, between different semiconductors mentioned above, which means electricity. There exist four common types of semiconductor materials, which are listed below:

- crystalline silicon cell
- thin film (of amorphous silicon)
- multi-junction cell
- single-junction cell.

Crystalline silicon and thin film are more widely used materials than the other two.

The size of a typical silicon solar PV cell is about 100 cm^2 and it can produce about 3 amps at 0.5 volts. To generate higher voltage and current magnitude, PV cells are combined in series and parallel as a module, and modules will be further combined as an array.

Based on different installation methods of arrays, solar PV technologies can be categorized as:

- flat plate
- fixed tilt
- single-axis tracking (SAT)
- dual-axis tracking (DAT)

This report only provides focus on flat plate and fixed tilt system, also called the non-tracking system together, as well as the SAT system.

Apparently, non-tracking system refers to the arrays that are installed as fixed tilt on roofs or on a large field, which are unable to move with the sunlight position. Figure 3.7 illustrates a typical non-tracking Solar Photovoltaic arrays.

On the contrary, SAT system mounts arrays on the tracking devices. Generally, SAT will turn arrays from east to west to follow the sunlight movement every day. However, some SAT systems adjust arrays from south to north to track sun's position on a seasonal basis, which may be more useful according to the location of plants.

Figure 3.7: Non-tracking Solar Photovoltaic Arrays

Source: https://evergreensolar.com/how/how-does-solar-photovoltaic-energy-work/

Characteristics and assessment of the technologies

Obviously, adding tracking devices to a PV system increases the energy production by allowing the arrays to dynamically follow the sunlight position. Typically, it is expected that single axis trackers will increase annual electricity output of solar PV arrays by 27 per cent to 32 per cent compared with non-tracking arrays (AETA 2012). In addition, SAT system needs a relatively smaller plant area, compared with fixed system. The APGTR (2015) suggests that commonly the SAT system requires 2.8 hectares/MW in terms of land use while the non-tracking system often requires 5 hectares/MW (p. 41).

Nevertheless, adding a tracking system also significantly increases capital cost as well as operating and maintenance cost, which will offset the production premium. According to the US Electric Power Research Institute (EPRI), for a C-Si based panel system, the cost of single axis tracking would add \$0.48/W compared to a fixed tilt system (Black and Veatch, 2010). Also, the concern that the increased electricity production cannot cover the increase in cost, results in a cost-prohibitive situation of SAT system.

The choice of semiconductor materials also has a crucial impact on the technology performance. As mentioned above, currently crystalline silicon and thin film are the two main types, which represents first-generation and second-generation technology respectively. Previous literature reveals that the production efficiency of wafer-based crystalline silicon technology is approximately between 14 per cent to 21 per cent, which is higher than second-generation technology. However, this technology also generates higher cost since its production procedure requires relatively better processing control and larger energy consumption. Conversely, the second-generation technology, thin film technology is less expensive because its module only contains at most 5 per cent semiconductor materials of what is used in previous technology while the production efficiency is only around 7 per cent to 14 per cent.

Another vital performance factor is the Direct Current (DC) to Alternating Current (AC) converter. Commonly named DC/AC inverter, influences the output of solar PV arrays for both SAT system and non-tracking system, because solar PV systems produces DC while current transfer system changes it to AC. The ratio between the maximum DC input which is the arrays rated capacity and the inverter's maximum AC output is called Inverter Load Ratio (ILR), also named as array-to-inverter ratio. For example, a 6 kW PV array combined with a 5 kW AC rated inverter has a 1.2 ILR while a 6 kW PV array with a 6 kW AC inverter has a 1.0 ILR. If the ILR of a solar PV plant is larger than 1.0, it means that arrays could reach its production limitation. The plant can only produce AC at the inverter's maximum capacity, which means the plant would lose produced power during normal operation, known as 'clipping loss'.

Conventionally, the optimal ILR of a solar PV plant is between 1.1 and 1.25 (Jon Fiorelli, Michael Zuercher-Martinson 2013). Firstly, one important reason is that PV arrays cannot always reach the designed power, as the working condition in reality usually has higher temperature and cannot enjoy full sunlight because of the weather issues, compared with 'Standard Test Condition' (STC). Moreover, designers always want to achieve the highest efficiency from arrays' production, that is, reducing 'clipping loss' as much as possible, which implies that inverters with relatively larger capacity are employed in solar PV system. Indeed, the above idea leads to an intensely high efficiency of total AC production, but a larger inverter always means higher capital cost.

Recently, a new practise is to oversize the ILR to 1.5, or even larger (Jon Fiorelli, Michael Zuercher-Martinson 2013). The basic driving force of this trend is the dramatic decrease in the cost of solar PV arrays' installation, which results from the impressive development of utility scale PV technology. This cost decrease allows plant owners to adopt inverters with relatively smaller maximum AC output while combining them with a larger number of DC generators to cover the ‘clipping loss’, which reduces the production efficiency but can bring about monetary profits. Recent literature demonstrates that the ‘clipping loss’ is not as much as the ILR shows, if we take time-of-use factor into account. Therefore, the optimal ILR for a specific solar PV plant really depends on designer’s desire, project goal, and other physical conditions, such as project location.

3.3.3.2 Challenges and future development of solar-based technologies

a. Solar thermal technology

The central receiver technology is at an early stage of its development. In 2014, only 1,066 MW of concentrating solar power was installed around the world, which was less than 1 per cent of globally installed renewable generation power capacity (Market Size Power Generation Database 2015). Even within solar thermal technologies, it only occupies 41 per cent of total power capacities, less than parabolic troughs (46 per cent) in 2014.

Massive researches are underway to facilitate central receiver technology in terms of promoting generation efficiency and reducing costs. The energy storage capacity of the system has been of a particular interest of such studies. Although the current two-tank molten nitrate salt system partly solves the storage problem, it is still in the early stage and heavily need development to make the production process ‘smoother’. Many advanced thermal energy storage technologies, such as thermoclines, concrete or graphite storage, phase change materials, and thermochemical storage are currently under the research and development stage (R&D), and some of those technologies, including two-tank molten salt technology, are expected to be mature and come into effect by 2030.

Another crucial factor that matters the development of this technology is the usage of land and water. As mentioned above, the construction of a central receiver plant claims a relatively larger land area (compared with other solar thermal technologies). If a storage sector is required to be built within the system, the land demand, in terms of per peak capacity, could be increased significantly. For example, the land usage of a central receiver plant with 6 hours storage capacity can be at most 10 times as much as one without storage sector. Therefore, a more rational and efficient land use plan needs to be developed to improve the total generation capacity.

Because the central receiver technology is under sustainable developing, and commercial-sized plants are expected to mature by 2030, which will bring about excellent samples and experiences, it is reasonable to predict that the construction cost, including the expenses of basic solar thermal power production equipment, will significantly decline. Moreover, following the technology development, a cheaper and stronger heat transfer medium is expected to be adopted to enhance the heat transfer efficiency and reduce operation and maintenance cost. In addition, the expected improvement in storage system, receiver tube and steam turbine will effectively promote the electricity generation capacity of the central receiver technology. Overall, all those factors will generate a lower levelised cost of electricity in the future. More specific models, such as GALLM model, AETA 2012 & 2013 model, and review of relevant literature applicable to Indonesia will be used to estimate the capital, operational and total costs of the central receiver technology in 2030 in later chapters.

b. Solar PV technologies (non-tracking and Single-axis tracking)

Clearly, solar PV technology is still in the early developing stage, except the crystalline silicon technology. During recent decades, there have been significant increases in solar PV installations, especially for large utility scale manufactured plants, which also significantly reduce production cost as well as electricity price. In 2014, the capacity of newly installed solar PV facilities was 45 GW in the world, but has increased the worldwide solar PV capacity to 186 GW by 2015 (APGTR 2015). Meanwhile, taking US solar market as an example, the capital cost of solar PV plants decreased by 23 per cent from 2010 to 2011 (Solar Energy Industries Association 2012) and more so in recent years. It is acceptable to predict that the power generation capacity and efficiency will keep growing with the levelised cost of electricity decreasing.

One technical issue which is associated with the thin film system's development is the production efficiency of semiconductor materials used in this technology. As mentioned above, currently the efficiency of thin film's array is significantly lower than crystalline silicon's. However, theoretically speaking, thin film technologies should have the same efficiency frontier (known as the Shockley–Queisser limit) with crystalline silicon technologies, which means the current efficiency gap between two technologies is caused by drawbacks of the manufacturing process. Therefore, this problem is expected to be effectively improved in the future.

Another trend is to reduce the cost of installing tracking system in SAT technology. As previous section indicated, compared with non-tracking PV technology, the SAT could increase the energy yield, while generating a non-negligible cost increase which may cancel out the premium of improved production efficiency. Fortunately, the recently built SAT PV plants clearly show a positive total effect on power generation (Klise et al. 2014), which means the economic benefit of energy yield increase is generally larger than the cost increase, though this premium may be smaller for utility scale PV systems. Moreover, according to GTM Research, the cost of adding tracking system is projected to reduce from $0.48/W to at least $0.20/W in the future. In addition, the operation and maintenance cost of SAT system is also expected to decrease as experience in managing SAT system increases with more installed SAT facilities.

The advances in DC/AC inverter should not be ignored. Inverter reliability requires more promotion in all PV systems since the cost of repairing and replacing inverters occupies the largest proportion of operation and maintenance cost (Flicker 2014).

Overall, Crystalline silicon PV is expected to be a mature technology while thin-film PV technology will be in late deployment or early mature phase by 2030. The solar PV array cost and PV cell efficiency is predicted to rapidly increase and decrease respectively over time, the balance of ILR choice and inverter costs are also expected to be promoted, all of which leads to an optimization in manufacturing capacity and process. Besides, many researches are underway to develop new PV configurations, such as multi-junction concentrators, which will further increase PV cells and systems efficiency. Overall, the levelised cost of electricity of solar PV technologies is expected to decrease in the future. More specific models, such as GALLM model and Road Map estimation methodology, will be used to estimate the capital cost and thermal efficiency of the central receiver technology in 2030 in later chapters.

3.3.4 Wind-based Technologies

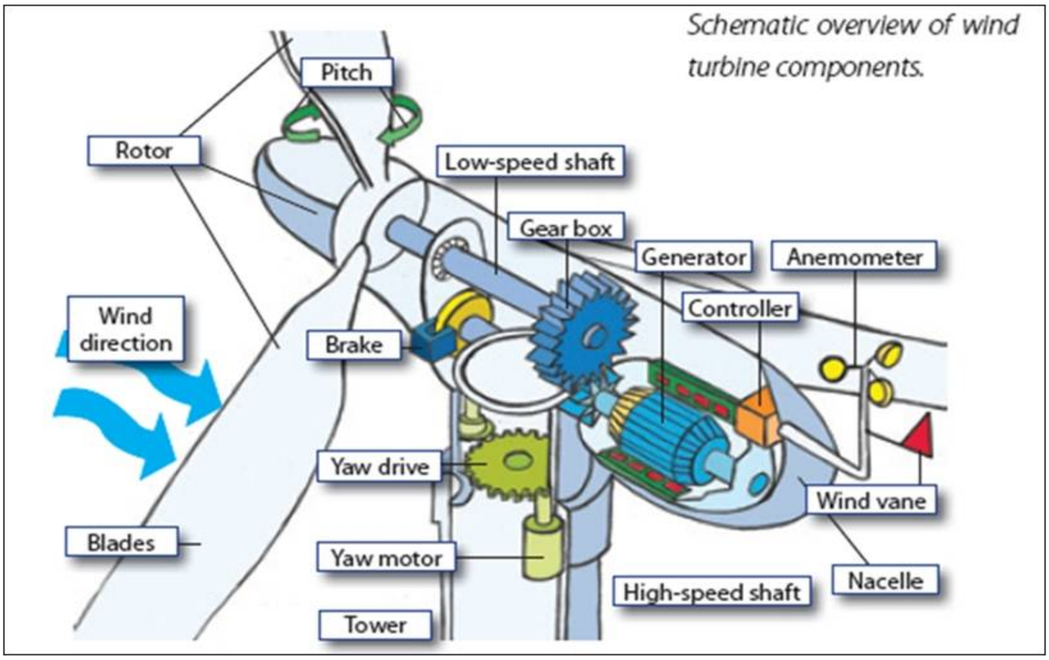
3.3.4.1 Brief description of the technology

The basic principle of wind energy is to use wind power to rotate the wind turbine rotor to spin a generator to generate electricity. Wind technologies generally contain two categories, onshore wind technology and offshore wind technology, while this report only concentrates on onshore wind energy.

Generally, an onshore wind turbine plant is composed of the foundation, tower, rotor and nacelle which contains gearbox, and generator as well as the electrical controllers. The tower is the main body which holds the nacelle and the rotor, and is commonly made from steel. Similarly, to support the tower and the dynamic structural loads created by the rotating turbine solidly, the foundation is usually made up by steel-reinforced concrete and occupies a relative large area.

The core part of wind turbine plants, the rotor and nacelle, is located at the top of the tower. As shown in Figure 3.8, the most common design of modern wind turbines contains a rotor with three wind blades and a nacelle which includes a three-speed gearbox, a variable-speed generator and power electronic controllers.

Figure 3.8: Schematic diagram of the parts of a Wind Turbine



Source: http://www.luminosityengtech.com/joomla/index.php/applications/wind-turbines

The electronic controller monitors the wind speed and automatically signals the system to start working when the speed of wind reaches the 'cut- in' level, or the minimum speed required for the system to work. The controller would also signal the system to shut down if the speed of wind exceeds the upper bond or the 'cut-out' speed.

The electronic controller also controls the facing direction of the rotor and blades under different weather conditions to maximize wind power. Right after the wind speed reaches its cut-in speed, the electronic controller will rotate the rotor and blades via the yaw mechanism to optimize wind power and increase power yield even at a relatively low wind rate. At high wind speeds, the controller is able to take a converse function to reduce the wind power so that turbines can remain producing at its maximum capacity until the natural wind speed reaches the upper bond or cut-out speed. An electronic controller will also automatically shut down the wind turbine plants if a mechanical fault is detected.

3.3.4.2 Characteristics and assessment of onshore wind technology

The height of wind towers has an important influence on onshore wind systems' performance, since higher tower can obviously capture greater wind speed and more stable wind condition, which result in a larger output capacity and a smaller operation and maintenance cost for wind turbine plants.

In addition, as it is rotor blades that capture the wind kinetic energy in the first place, the size of blades also heavily affects wind turbines' production. Typically, a longer blade or a larger wind wheel is preferred to capture low speed wind more efficiently, which will enhance turbines' productivity at low speed as well as lower the cut-in speed limit. However, this will sacrifice the production efficiency, when the speed is higher than rated capacity speed, under which the efficiency is not that important.

In terms of large scale wind electricity system which contains several independent wind turbine facilities at the same site, the position of each tower must be carefully arranged to reduce the impact of wake turbulence on other downwind turbines as far as possible and maximize the total output capacity. Typically, wind towers are set up in single or multiple rows and separated by 5–15 rotor diameters downwind and 3–5 rotor diameters in the direction perpendicular to the wind (APGTR 2015).

3.3.4.3 Challenges and future development of wind-based technologies

Onshore wind turbines are considered to be a mature technology. According to Bloomberg New Energy Finance (Q3 2015), in 2014, over 350 GW onshore wind energy capacity is installed globally, and the average size continues to increase. However, advances are still being made and will continue to be made in turbine components to help improve turbine equipment, reduce plant cost and enhance energy generation.

A trend of taller towers has been clearly shown in the world market. For example, in Germany, the average height of turbine tower was lower than 100 meters while this number significant increased to 116 meters in 2014. A report by the United States Department of Energy suggests that the number or area of available project sites for onshore wind technology will increase by 54 per cent if the height of turbine towers increase from 80 meters to 110 meters.

Another major trend is the deployment of longer rotor blades. The average rotor diameter in the U.S. almost doubled from 50 m in 1998 to 97 m in 2014. The change from fiberglass composite rotor blades to carbon composite is also a tendency. Besides, the advances in longer blades generate the idea of establishing longer blade onshore wind turbine at low-speed sites, which is under deployment. Theoretically, compared shorter blades, longer blades are relatively easier to be pushed and can capture the kinetic energy contained in wind more efficiently. This characteristic significantly lowers the cut-in speed for wind turbines, which makes it possible to build wind energy plants at low-speed wind sites. All of these factors reveal that 'the global wind industry is trending towards larger turbines to achieve greater economies of scale' (APGTR 2015, p. 50).

The biggest problem of wind technology is the intermittency (weather dependence). The drawbacks of unstable production of wind plants will be more serious and significant as the integration of wind generation with the existing electricity grid systems keeps growing.

One effective solution for this issue so far is to improve the forecasting system. A more accurate forecasting system will allow the electricity network operator (management) to better schedule an output plan, which will partly avoid the reliability problems.

In conclusion, advances in taller towers, longer blades and blade material will increase the power output for onshore wind plants. In addition, improvements in manufacturing process of power electronics and drive systems will also facilitate the wind turbines' maximum capacity. In terms of large scale wind power systems, more advanced design concepts and richer design experiences will generate better structured plants, which will raise the electricity production efficiency for the whole system.

On the other hand, the cost of wind technologies is expected to decrease in the future, since the developments in operation, such as optimized wind turbine control system, and production efficiency can significantly reduce it. Moreover, the life expectancy of wind turbines is predicted to increase from current 20 years to 30 years by 2030 due to the optimization in manufacturing process, which makes the key components of wind turbines more reliable. This expected life extension can effectively reduce the levelised cost of electricity for wind technology. Following the brief description of technologies, this report will examine the levelised cost of wind generation, and its cost parameters.

3.3.5 Ocean Technologies

3.3.5.1 Brief description of the technologies

The two main categories of ocean technologies are wave energy conversion system and tidal conversion system while the ocean technology also contain ocean currents, ocean thermal energy conversion, ocean winds and salinity gradients technologies. This report only assesses the performance of wave energy conversion technology.

Ocean waves is originally generated from wind power. When the wind blows to the ocean surface, it will engender many ripples. As wind keeps blowing, more and more ripples will finally concentrate together into waves and spread over the sea. The potential energy carried by ocean waves is called wave energy. Wave energy conversion technology is used to capture wave energy to produce electricity. Theoretically, the conversion process can be summarized as (Hosna Titah-Benbouzid & Mohamed Benbouzid 2015, p. 55):

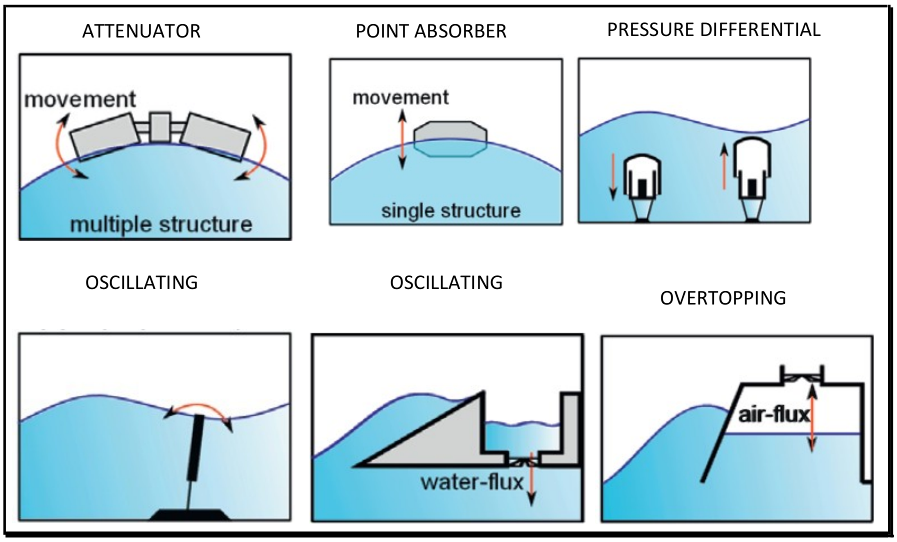
The PTO (Power Take-Off system) extracts the mechanical power due to incoming waves by a system made up of a cylindrical buoy sliding along a partially submerged structure. This structure is made up of a vertical cylinder, referenced in the following as spar, with a damping plate attached at its keel. Energy resulting from the relative motion between the two concentric bodies is harnessed by rack-and-pinion, which drives a permanent magnet synchronous generator through a gearbox.

Wave energy technologies consist of four major sectors:

- The structure and the prime mover collect the wave energy;
- The foundation or mooring anchors the structure and prime mover;
- The power take-off system transforms mechanical energy into electrical energy;
- The control system protects and enhances the operations.

The most important part of wave conversion technology is the wave energy collection device, which is also the most complex sector. These devices are adopted to capture wave motion (wave energy) and transform it to slow-speed rotational or reciprocating motion. This slow-speed motion will be in future converted into high-speed rotational motion which is required by conventional rotatory electrical generator by PTO. Figure 3.9 presents six most popular design ideas of energy collection device.

Figure 3.9: Schematics of various wave energy conversion configurations



Source: https://hal.archives-ouvertes.fr/hal-01153767/document

3.3.5.2 Challenges and future development of Ocean-based technologies

Although it is one of the most developed ocean technologies, wave energy conversion technology is still under development. The transition from the concept to commercial scale plant of wave energy conversion system needs plenty of time and finance.

For wave energy conversion to evolve into a mature technology, a large amount of work needs to be undertaken which focuses on:

- creating offshore generators that can better tolerate rough seas;
- improving mooring designs to withstand waves, currents and winds;
- overcoming structural fatigue;
- reducing operation and maintenance costs;
- dealing with marine growth and corrosion problems.

3.3.6 Biomass Technologies

3.3.6.1 Brief description of the technology

The basic principle of biomass energy technology is to produce steam or heat via burning biomass fuels, then to generate electricity. One competitive advantage of biomass technology is that, unlike other renewable energy technologies which could only be used to generate electricity, the biomass fuels produced within biomass system can substitute the position of fossil fuels in manufacture production and people's daily life.

Biomass fuels are the outcomes of biological activity, which can transfer biomass, wood, plant residues, and other inorganic matter into combustible gases, such as methane and hydrogen, or flammable liquids, such as alcohol and oil. The most common biomass fuels used in biomass technology are landfill gas (LFG) and sugar cane waste. LFG is primarily a mixture of methane and carbon dioxide, which is produced by chemical reactions between microbes and organic wastes in landfill deposits. The sugar cane waste is simply the fibrous residue of the sugar cane milling process, which is also called the bagasse.

3.3.6.2 Characteristics and assessment of biomass technologies

The biomass electricity generation plant which uses LFG as the fuel needs to integrate a gas collection system into the project. The typical working principle is to extract LFG by a series of wells using a blower or vacuum system from the landfill, then deliver the gas to the central generator where it can be further processed via an array of pipes. When firstly extracted, since the gas contains a considerable number of contaminants which will seriously reduce the production efficiency, a vital process for filtering the gas is also needed within the system. Apparently, the production rate of LFG can fundamentally influence the power yield of a LFG biomass plant, and is determined by a number of factors such as waste composition, landfill geometry, and chemical make-up. Currently, some landfills employ bioreactor technology to promote the LFG output.

The sugar cane waste energy plant is normally integrated with sugar mill industry, in which bagasse is fired to generate steam. Typically, some of the steam is used as part of the sugar production process while the rest is delivered to steam turbine generators for electricity generation. Because different design features are employed by individual sugar cane waste electricity generation plants to fit for the specific sugar mills, it is not possible to specify a typical sugar cane waste plant model. However, sugarcane plants are faced with the problem that the harvest of local cane is fixed in specific season, which leads to a seasonally fluctuated power output. Moreover, since sugar mills always try to achieve an energy balance between the amount of bagasse fuel produced by milling operations and the electricity generation requirement of the mill, the excess energy exported to exterior electricity grim is relatively low, which causes a lower production efficiency of sugar cane waste power plants (much lower than the coal or gas plants).

Another conception of biomass technology is to mix biomass fuels with other fossil fuels used to generate electricity, which is called biomass co-firing technology. In current demonstrations of co-firing system, biomass fuels are treated as a supplement to coal in a pulverized coal electricity generation plant, which brings about one advantage of biomass co-firing technology that it can utilize infrastructure already developed for generating electricity from coal and can normally be developed at a relatively low cost. Besides, solid biomass such as wood can also be co-fired with coal in existing power generation plants.

3.3.6.3 Challenges and future development of Biomass-based technologies

One limitation of biomass technology comes from typical biomass fuel characteristics: 240–320 kg/m3 bulk density; 40–50 per cent moisture; and 8–10 GJ/tone as received. It significantly limits the boiler and generating capacity and causes a relatively larger storage and fuel transport cost. One effective solution is to increase the energy density at the source by palletization or pyrolysis. Take sugar cane waste plants as an example, one technology development that has been trialed is drying or pelletizing of bagasse. The advantage of this is that the fuel is much easier to transport and, because of its reduced water content, can be fired more efficiently in a boiler.

Another problem is biomass fuels always tend to contain trace minerals, which can cause material corrosion under high firing temperatures. Therefore, advances in pre-treatment technology, such as filtering system, need to be developed which can significantly reduce replacement and maintenance costs.

A recent development in biomass technology known as integrated gasification combined cycle (IGCC) has attracted many researchers' attention as it is deemed to be a practical and economic system of biomass production. It is estimated that the rate of conversion (from biomass to energy) with such technology is 55 per cent or twice the currently available plants. There are still major challenges facing the full scale development of IGCC and no significant progress is anticipated in Australia (so that it can be passed on to Indonesia) in the foreseeable future.

3.3.7 Nuclear Technologies

3.3.7.1 Brief description of nuclear technology

The operating principle of a typical nuclear power plant is that it extracts the energy from the nuclear fission reaction and transfers the heat to produce stream which will be further used to generate electricity via steam turbines. Nowadays, nuclear plants can be roughly divided into two categories by their output capacity: Large-scale Nuclear Power Generation and Small Modular Reactors (SMR) with generator capacity ranging from 1000-1600 MW and 25-1200 MW, respectively (AETA 2012).

Initially launched at Soviet Union in 1954, the large-scale nuclear technology has been developed into Generation III, which has more optimized plant design benchmark than Generation II, such as AP1000 and EPR1600, and satisfies the safety indicator of Utility Requirement Document (URD) which consists of a comprehensive set of design requirements for future Light Water Reactors (LWRs). The most common types of Generation III generators are:

- Pressurized Water Reactors (PWRs), accounting for approximate 60 per cent of all nuclear reactors;
- Boiling Water Reactors (BWRs), around 20 per cent;
- Pressurized Heavy Water Reactors (PHWRs), also named as CANDU, around 10 per cent.

Source: https://www.clpgroup.com/NuclearEnergy/Sch/power/power4_1_1.aspx

Figure 3.10(i) to 3.10 (iii) show the structures of each kind of reactors.

Figure 3.10 (i): Schematic diagram of a PWR

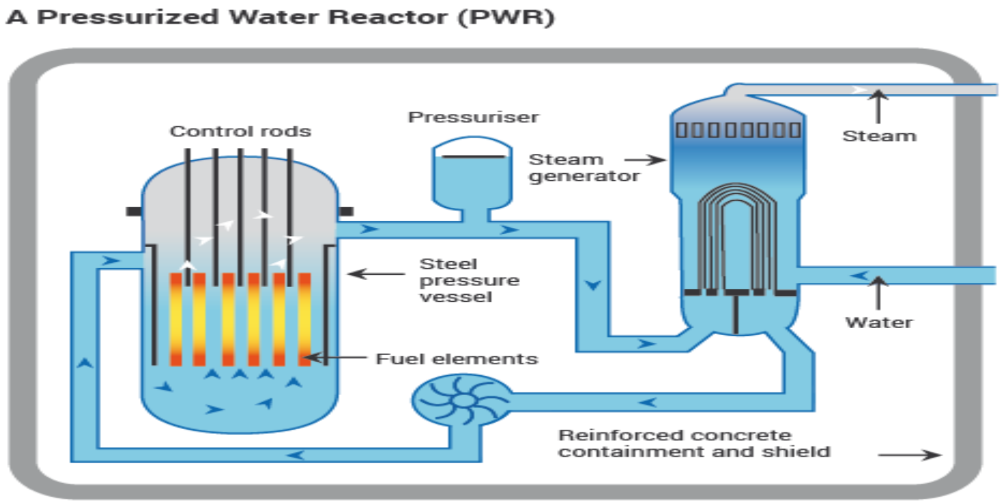


Figure 3.10 (ii): Schematic diagram of a BWR

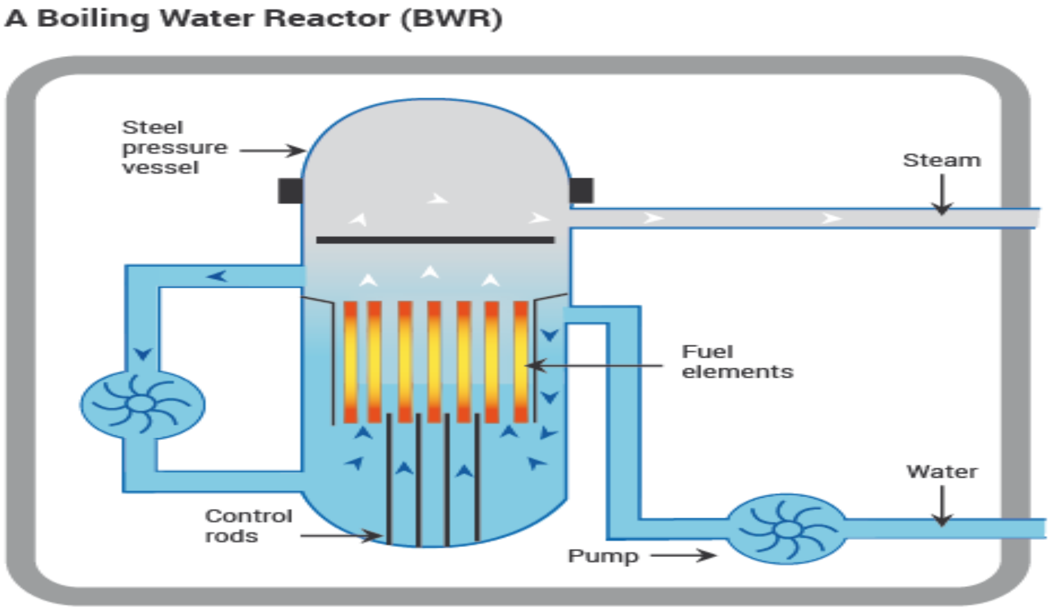
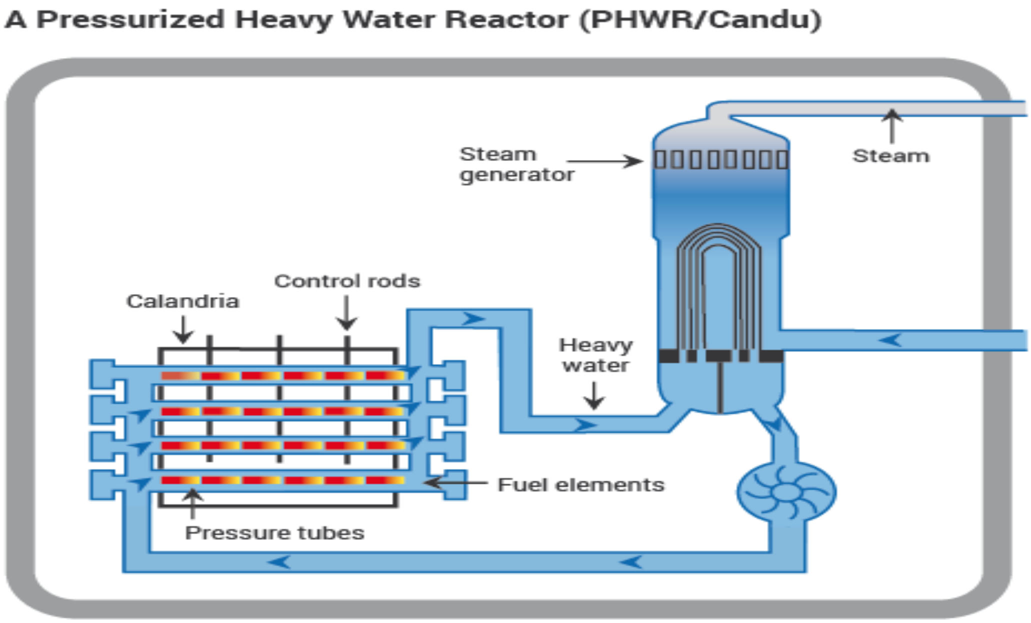


Figure 3.10 (iii): Schematic diagram of a PHWR



Source: http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/nuclear-power-reactors.aspx

This classification is based on the different types of moderators, coolants and control rods used in the fission reaction. For example, PWRs and BWRs use light water (common water) as the moderator while PHWRs use heavy water. Moderators and control rods are vital components of a reactor. Theoretically, a nuclear fission is induced by neutrons. When a heavy fissile atomic nucleus, such as uranium-235 or plutonium-239, absorbs a neutron, it can split into two or more lighter nuclei, releasing kinetic energy and free neutrons. If the newly generated neutrons are absorbed by other heavy nuclei, the fission reaction will continue to occur and become sustainable, which is known as nuclear chain reactions. However, one problem is that these fissile nuclei could only effectively absorb slow neutrons while the neutrons released from fission reactions are fast neutrons. In order to maintain the nuclear chain reaction, nuclear moderators are employed to slow down the fast neutrons. Nevertheless, if too many neutrons are introduced in reactions at the same time, the fission reaction will be out of control and a nuclear reactor will become a 'nuclear bomb'. Hence control rods are built inside a reactor to absorb neutrons so as to reduce the reaction rate.

SMR is an emerging nuclear technology which basically shares the same principle and similar technology categories with large-scale nuclear technology while has relatively smaller output capacity. As SMR is modular technology, it has shorter constructing time since modules are designed to be prefabricated in factories, which separates the production from the installation process. Besides, SMR could also start to generate electricity after the first module is installed while the rest parts can be set up over time, which significantly reduces the time of financial returns compared with Generation III technology. According to AETA (2012), ‘Current projections are that the lead time for SMR will be 2–3 years compared to 4–5 years for Gen III’ (p. 55).

3.3.7.2 Characteristics and assessment of the Nuclear technology

Generation III nuclear technology plants are very sensitive to financial conditions because they are highly capital intensive technology and typically require long construction period. Minor changes of international and domestic macroeconomic environment as well as the delays in construction schedule could have a significant impact on the cost of electricity generation. However, according to available data such as that of WorleyParsons, nuclear technology plants enjoy competitive advantage in operations and maintenance cost compared with conventional power plants.

Water usage is another problem that nuclear plants need to solve. As most nuclear power plants use ordinary water as the coolant in reactions, massively abundant water must be used in the cooling system. If no major technical progress occurs to improve existing cooling system, the access to water will remain to be a restriction in terms of project site selection and unanticipated water shortage will heavily reduce the power output.

Last but not the least, although may not considered into the levelised cost of electricity generation, the disposal of nuclear waste is a tough issue which seriously hinders the development of nuclear energy technology. The Generation IV technology which is under development could partly relieve this problem since it can improve the coefficient of fission fuel utilization (Generation IV technology will be discussed in next section). However, nuclear waste still remains to be radically solved.

3.3.7.3 Challenges and future development of the Nuclear technologies

Currently Generation III is considered to be a mature technology while Generation III+ (advanced Generation III) is heading into the late deployment phase. SMR technology is still at the early stage, but it is expected that SMR technology could potentially be commercially available in the next 5–10 years.

One technological development trend is to deploy High Temperature Gas and Liquid Metal reactors which are currently at the concept proofing stage. One advantage of this technology is that it could operate at a relatively higher temperature which can improve the thermal efficiency. More importantly, higher operating temperature will increase the burn-up rate of nuclear fuels which can considerably reduce the production of nuclear waste. In addition, since this kind of reactors adopt gas and liquid metal as the coolants and moderators, it alleviates the restriction of access to water, which indirectly promotes the output efficiency.

Fast Neutron Reactor is another technological advance which is related to Generation IV reactors. As mentioned above, under Generation III technology, only slow neutrons can be absorbed to maintain nuclear chain reactions. As distinguished with it, fast neutron reactors can make use of fast neutrons to convert non-fissile atomic nuclei to fissile ones, such as uranium-238 to plutonium-239. Because in the nature more than 99 per cent of uranium is in the form of uranium-238 rather than uranium-235, fast neutron reactor technology remarkably increases the nuclear fuels reserve. Furthermore, a more advanced concept is to build fast neutron reactors which are able to consume the used fuel, such as long lived actinides, from Generation III reactors, which provides an alternative way to handle the nuclear waste. Fast neutron reactors are expected to be commercial scaled by 2030 while plenty of research has been undertaken and one demonstration is now operating in Russia.

One relatively new concept in the future nuclear energy technology is to apply fusion reactions into electricity generation as currently all nuclear power plants are based on fission reactions. Although it is now even not under research phase, AETA report (2012) predicts that 'it is possible that commercial fusion technology could become a reality by 2050'.

Overall, cost reductions in nuclear power technology are likely to occur by 2030, following the deployment of increasingly more Generation III/III+ and SMR reactors. Meanwhile, due to the development of Generation IV technology, thermal efficiency, output capacity, the security and reliability of nuclear power plants will increase evidently.

3.3.8 Geothermal-based Technologies

3.3.8.1 Geothermal energy: basic concept

Geothermal energy is the form of heat from the Earth. It is considered as a clean and sustainable source of energy. As the underneath heat moves from centre of the earth to its outer surface, the temperature gradually rises with depth throughout the planet. However, it is evident that at some locations temperature is found higher than the average of that depth temperature. It may because of following reasons:

- The presence of molten rock (also named as magma) in the closer surface. Molten rock is generally sited deep within the mantle of the earth which occasionally comes towards the surface through cracks in the mantles or owing to the eruption of volcanoes. In this process, the internal heat also comes out of the surface.
- Rocks buried at shallow depths normally contain higher concentrations of radiogenic elements that emit heat as they endure radioactive decay.

3.3.8.2 Basic descriptions of Geothermal-based electricity generation technologies

This report describes two types of geothermal-based electricity generation technologies:

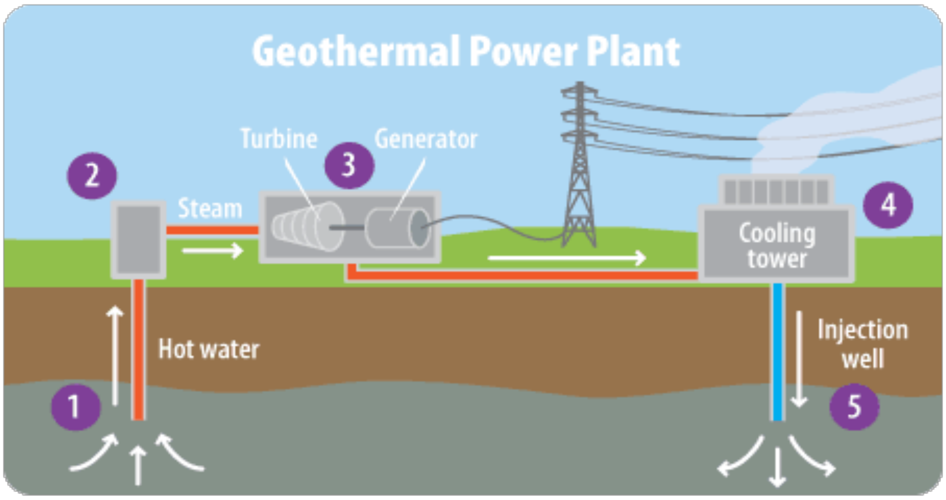
a) Geothermal steam-based electricity generation

b) Fractured hot rocks-based electricity generation

a) Geothermal steam-based electricity generation

Geothermal steam-based electricity plants are the conventional electricity plants that use the steam produced from the reservoirs of hot water located at different layers of the earth. The flow of steam helps to rotate the turbine that triggers a generator and produces electricity. Figure 3.11 illustrates the electricity generating stages of a steam-based geothermal electricity plant.

Figure 3.11: Electricity generating stages for a steam-based geothermal electricity plant



Source: US Environmental Protection Agency (2016)

Generation process follows the following steps:

1. Hot water is pumped through a well from deep underneath the ground at high pressure.
2. As the water comes close to the surface, it turns the water into steam.
3. The steam is channelised through a series of blades of a turbine. Another end of the turbine is connected to a rotor of the generator. Spinning of the turbine creates the rotation into the rotor, and in the process, electricity is generated.
4. The exhausted steam is passed to a cooling tower where it gets condensed and back to the form of water.
5. The cooled water is then pumped back into the underground to continue the process.

Depending on the steam conversion, there are three types of geothermal steam-based electricity plants:

i. Dry steam plant,
ii. Hydrothermal flash steam conversion plant, and
iii. binary cycle conversion plant

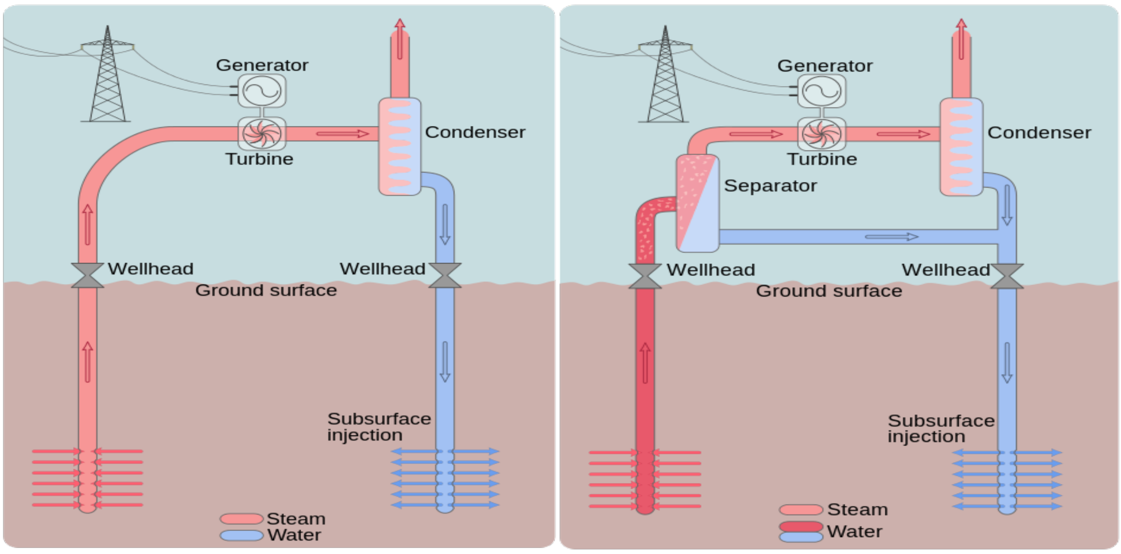
i. **Dry steam plant**

The dry steam geothermal electricity plant, also known as back-pressure plant draws from underground resources of steam. The steam is piped directly from underground wells to the electricity plant, where it is directed into a turbine and generator unit. A schematic illustration of such plant is shown in Figure 3.12. It is the simplest and cheapest among the geothermal technologies. However, it has the lowest thermal efficiency as compared to the other geothermal electricity plants. The addition of a condenser into the system might help to double the conversion of the steam energy into electricity.

ii. Hydrothermal flash steam conversion plant

Flash steam electricity plant is the most common of all geothermal based plants. It normally uses the geothermal reservoirs of water with the temperatures above 360°F (182°C) (Renewable Energy World, 2016). This very hot water flows up through wells in the ground under its own pressure. As it flows upward, the drop-in pressure causes part of the water to turn to steam. The steam is then separated from the water and used to power a turbine or generator as shown in Figure 3.12.

Figure 3.12: Schematic diagram of Dry steam plant and Flash steam geothermal plant



Dry Steam Plant **Flash Steam plant**

Source: Tek-en (2014)

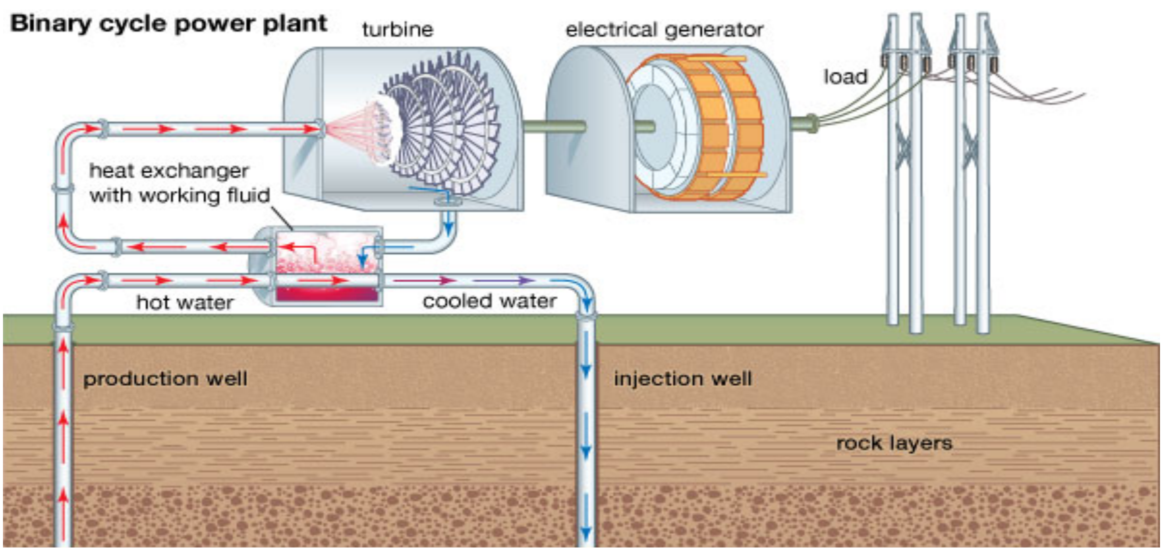
Any leftover water and condensed steam are injected back into the reservoir, making this a sustainable resource. Liquid from the first flash is sometimes sent to a second-stage separator ('dual flash') to produce lower pressure steam.

The flashed steam flow is naturally 15 to 25 per cent of the mass of the fluid. In the case of multiple flashes, it is sent to the subsequent high-pressure and low-pressure inlets of a steam turbine generator. The steam is then channelized through the generator while the separated water (termed as brine) is reinjected into the hydrothermal reservoir. The steam is condensed after it passes through the turbine. Finally, it is returned to the reservoir to be reheated.

iii. Binary Steam conversion plant

Binary cycle plants use the heat from the hot water to boil a working fluid, usually an organic compound with a low boiling point. They are normally operated on the water with a lower temperature range of 225°–360°F (107°–182°C). Binary cycle hydrothermal plants are mostly appropriate to moderate-to-low-enthalpy geothermal resources. For moderate-enthalpy systems, brine is removed from the production well and passed through a heat exchanger, where it transfers heat to a second (binary) liquid – the working fluid. This working fluid is then boiled to vapour. It is, therefore, expanded through a turbine and electricity is generated. Figure 3.13 shows a schematic diagram of a binary steam conversion geothermal plant.

Figure 3.13: Schematic diagram of a Binary steam conversion geothermal plant



Source: Lund (2015)

The working fluid is then condensed to a liquid to restart the cycle again, while the geothermal water is returned to the reservoir via a reinjection well to be reheated. The water and the working fluid are kept separated during the whole process, so there are little or no air emissions. In the case of a low-enthalpy geothermal resource, a cycle based on reverse cycle air-conditioning components is used. The cycle needs a single-stage centrifugal compressor to run in reverse as a radial inflow turbine, and a heat exchanger to transfer the heat from the geothermal resource to the working fluid. This technology can operate at reduced temperature to produce electricity from shallow, lower temperature hot spring systems from around 80°-105°C (EPRI, 2015).

b) Fractured hot rocks-based electricity generation

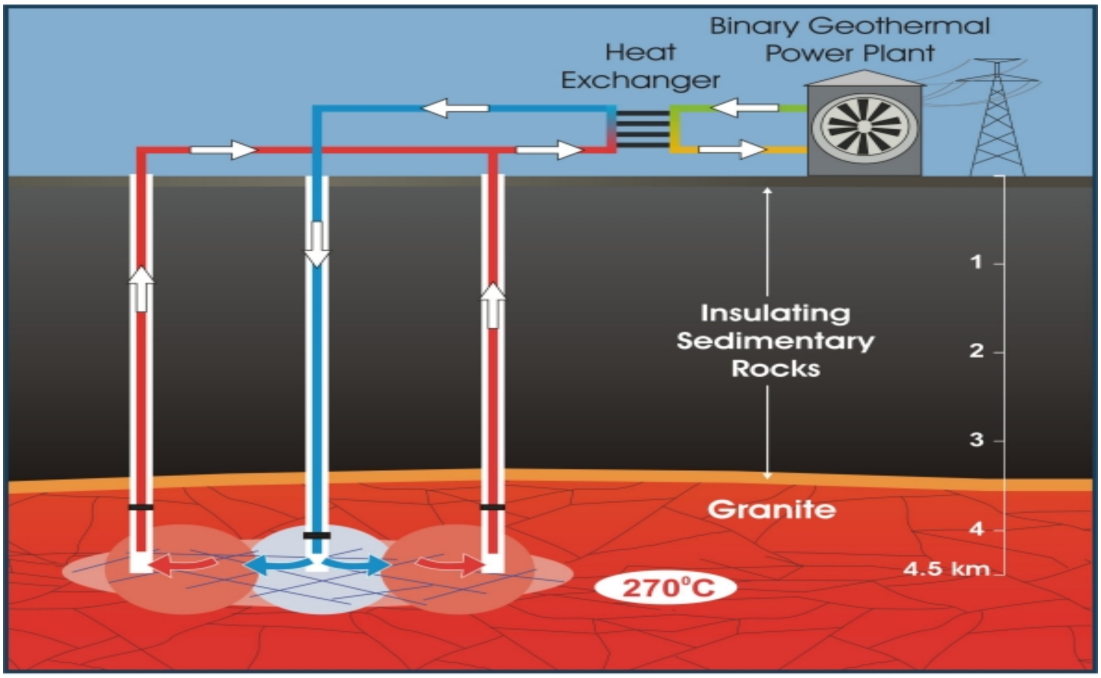
Fractured hot rocks-based electricity generation is basically the enhanced geothermal system with hot rock resources. This system describes the process of extracting heat from deep crystalline rock heated by the decay of radioactive elements including uranium, thorium, and potassium isotopes in effect. In practice, this resource is also known as Hot Rock Energy.

Potential hot rock energies are originated from fairly deep masses of rock that contain little or no steam or water and are not very permeable. It is implied that this sort of enhanced geothermal technology can be constructed in any place on earth. However, to make the extraction economically viable, cost-effectiveness and existing demand factors must be analysed. While a conventional steam-based geothermal system can be operated with a drilling closer to underneath the surface, this fractured hot rocks-based geothermal system requires going much deeper in most cases. At the initial stage, an exploratory well is drilled to get an idea about the geological state and features of the resource. Following the early stimulation and relevant mapping of the fractures, a subsequent well is set to drill in such a way that a permeable reservoir exists between the first and second drill.

Many wells can be drilled and found unproductive, but this is true with all types of geothermal electricity generation technologies, unless working in an appropriate location. Indonesia may have enormous geothermal electricity generation potential.

When the drilling is properly made, operational phase starts. Geothermal brine is taken from the reservoir to the surface. The water is then flashed to steam at a high temperature. Consequently, the electricity is generated. Sometimes, the brine is maintained in liquid form by holding at high enough pressure. It is then used in a binary, or a flash i.e. binary hybrid cycle. Finally, the brine is reinjected to be reheated. Figure 3.14 illustrates the process of electricity generation by the fractured hot-rocks based geothermal power plant.

Figure 3.14: Schematic diagram of Fractured hot rock-based geothermal power generation



Source: Needham (2009)

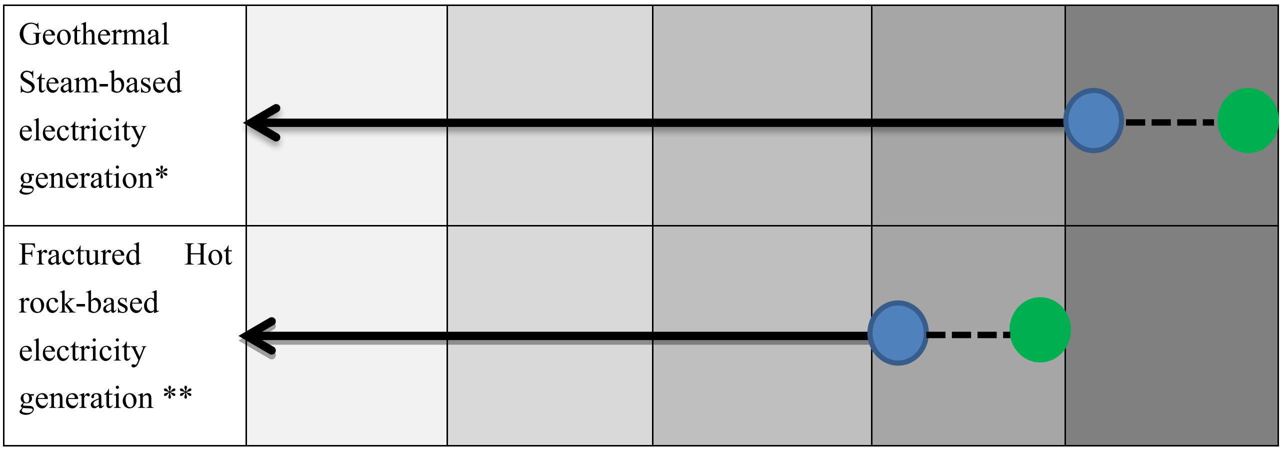
3.3.8.3 Chronological development in Geothermal-based technologies

Technology development status, major technical issues, and future development trends of the geothermal-based electricity generation technologies are illustrated in Table 3.3.

Geothermal steam-based power generation technologies are at the more mature stage of development as compared to the fractured hot rocks-based electricity generation technologies. This is because electricity generation equipment is readily available for hydrothermal plants, and the drilling technology is now well established. Advancements in the scale inhibitor chemicals help to deal with the problems of wellbore and equipment scale. It also helps to reduce the operations and maintenance (O&M) costs. Further efforts are going on to improve the reservoir management in terms of increasing project lifespans and reducing long-term resource risks. Few of the risk areas require much attention in this regard. The risks comprise higher exploration and drilling costs, cooling the reservoir, and managing the reservoir to uphold its output.

Table 3.3: Technology development curve for Geothermal steam-based plant

Technology	Stages of Development				
	Research	Development	Demonstration	Placement	Mature



Note: Blue circle represents the current state of development, while green circle refers to the probable development state in 2030

Source: * EPRI (2015) and **IEA (2011)

The fractured hot rock-based geothermal technology is quite new and yet to be adopted on a large-scale commercial basis. Few small-scale systems are tested in few countries. Cost is a big challenge for this technology as the expense in drilling the well increases exponentially with the depth. As mentioned earlier, enhanced geothermal system requires deeper exploration, hence it is much more expensive to develop. While the technical viability of making enhanced reservoirs has been verified, each project is highly site-specific and demands extensive development. IEA (2011) projects that through substantial research, development, and demonstration (RD&D), this technology will be commercially viable by 2030.

3.3.8.4 Future potential improvements in Geothermal based technologies

In general, the geothermal technology for power generation is experiencing continuous advancement and progress in many aspects. Especially, the experiences of R&D and innovation in the extraction of oil and shale gas are expected to be adopted in the future development of the geothermal based technologies for power generation (EPRI, 2015). Innovation in well design, drilling techniques, and hydraulic stimulation have been advancing at a rapid pace, particularly in Europe and the US.

It is to be noted that potential of a geothermal-based electricity project depends on some factors, such as geographic location, local geology comprising rock types, depth, size, fluid characteristics, permeability and enthalpy, reservoir characteristics, geothermal temperature, plant size, and technology type. No doubt, a substantial investment is required in this geothermal technology for both the exploration process as well as the adaptation process. Exploration comprises initial reconnaissance and drilling while the adaptation refers to reviewing the local project-scale geological states before going for the implementation. It is vital that local Indonesian expertise is maintained while the evolving experiences of Europe and the United States are tailored to support the future application in the Indonesian context.

Ongoing trends in fracturing technology indicate the potential for step-change reductions in the major capital cost of wells, and hence, in the electricity generation costs. Fracturing technologies are expected to be benefited from the significant R&D expenditures in the development of the large US and Canadian shale gas resources. Advances in resource exploration and evaluation techniques will also help to reduce the cost (BREE, 2012).

The cost of wells is so vital in a geothermal based technology. The total cost of the technology is influenced mainly by two main factors:

i. Cost of drilling wells, and
ii. The average productivity of the wells.

As mentioned earlier, determinant factors of all cost component have wide and significant variance from well to well, it is very hard to predict the well completion cost.

Location of exploration also has immense influence in determining future potential of using certain technologies. The vicinity areas around volcanoes or geysers usually conceal high thermal condition which is conducive to developing the conventional geothermal steam-based electricity generation technology at lower cost. Hence, countries like Indonesia, Philippines, and New Zealand have great potential to improve and adopt this technology. On the other hand, if the location has no volcano or geyser, then it has to drill deeper to reach to the granite to use fractured hot rock-based electricity generation approach. Since success rate of this approach is relatively uncertain and the technology is complex in nature, its cost, in average, is usually higher. Therefore, the countries like the US, Canada, and Australia which are using this technology find it bit expensive as well as unproductive.

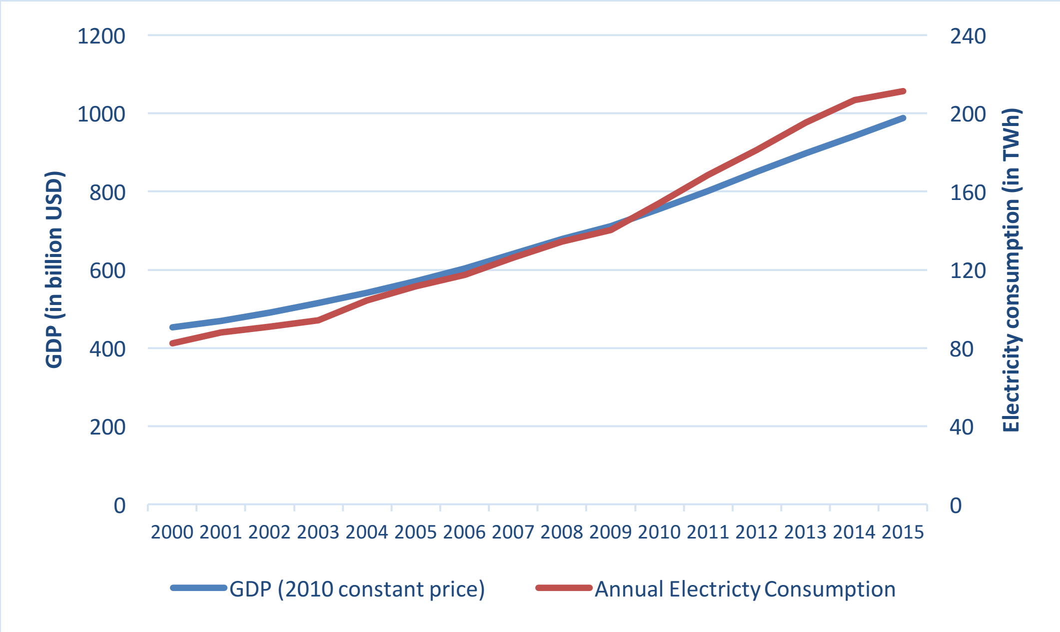
Chapter-4
Overview of the Indonesian electricity generation - state of the art

4.1 Introduction

Indonesia has an excellent success story in the process of its economic and political development since the Asian financial crisis of the late 90s (IEA, 2015a). Since then, the country has consistently attained high growth rates, steadied its fledgling democracy, and successfully adopted the decentralization of decision making and budgetary power to the root level. Indonesia is the fourth-most populous country in the world with a population of 257.56 million and with an annual growth rate of 1.4 per cent during 2000-2015 (UNDESA, 2015). It is the largest economy in Southeast Asia. According to the World Economic Outlook 2016, it ranks as the 16th largest economy in the world having the nominal GDP amounting 940.95 billion USD (IMF, 2016). The economy grew at an average growth rate of 5.4 per cent a year during 2000-2016. In terms of GDP measured in Purchasing Power Parity (PPP), Indonesia ranks 7th in the world with 3.256 trillion of International dollar (IMF, 2016). Per capita income has also increased by 3.92 per cent during this period. The upward momentum of the economy, growing population with rising living standards, and rapid urbanization has led to a sharp increase in its electricity demand. Ministry of Energy & Mineral Resources of Indonesia (2016) reveals that the consumption of electricity has increased from 82.51 Terawatt hours (TWh) in 2000 to 233 TWh in 2015, i.e. at an average annual growth rate of 10.41 per cent during this period. Figure 4.1 shows the trends in real GDP and electricity consumption of Indonesia during the 2000-2015 period.

Despite a 100 per cent increase in its electricity generation capacity over the last decade, Indonesia still lags behind in the electrification rate as compared to the countries with similar income levels. According to the World Energy Outlook 2015, electrification rate of Indonesia was 81 per cent in 2013, i.e. 81 per cent of Indonesia's total population had access to electricity in 2013 (IEA, 2015b). The rate, however, is still lower than its neighbouring countries like Malaysia (100 per cent), Brunei (100 per cent), Singapore (100 per cent), Thailand (99 per cent), Vietnam (97 per cent), and even Lao (87 per cent). Rural-urban parity in electricity access is also very high in Indonesia. While 94 per cent of the urban population has got the access to electricity, the rate is only 66 per cent among the rural population.

Figure 4.1: Gross Domestic Product (in billion USD) and Annual Power Consumption (TWh) in Indonesia, 2000–2015



Source: World Bank (2017) and Ministry of Energy & Mineral Resources of Indonesia (2016)

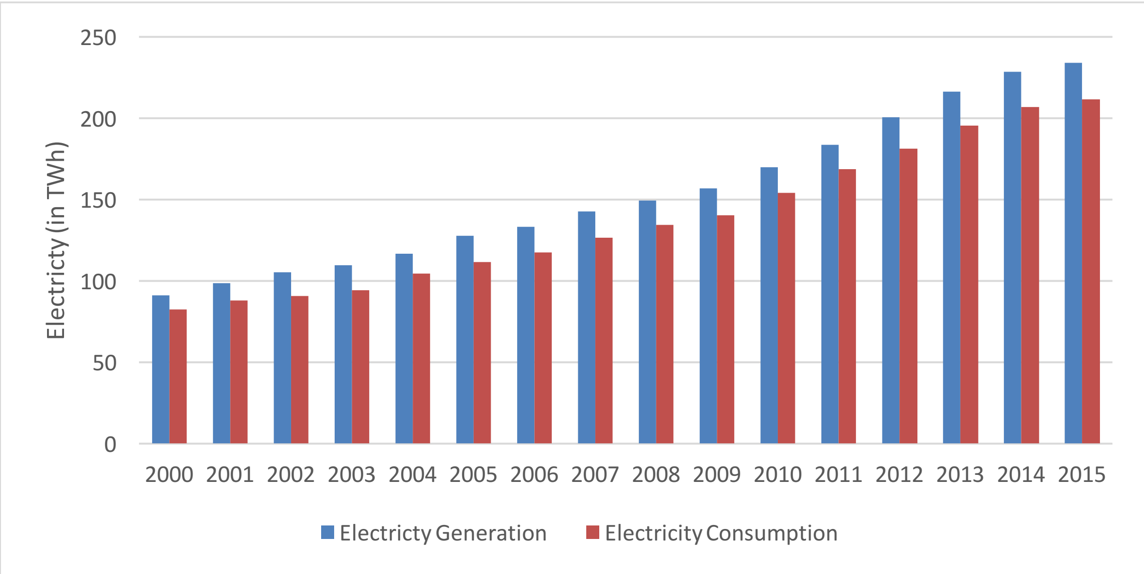
Total electricity generation of Indonesia amounts 233.98 TWh in 2015 which comes from a total installed capacity of 55.53 GW (Ministry of Energy & Mineral Resources of Indonesia, 2016). To strengthening the enduring economic growth and meeting the challenges of lifting the standards of living of its people, President Joko Widodo has set a target of additional 35 GW electricity generation capacity by 2019 (PwC Indonesia, 2016). The target also aimed to increase the electrification rate to 97.35 per cent at the end of 2019 (Ministry of Energy & Mineral Resources of Indonesia, 2015). On boosting the electricity sector, current government and policymakers are demanding policy reforms which urge more investments from the private sector in forms of Independent Power Producers (IPPs) and Public-Private Partnership (PPP) to achieve the target. At the same time, there is an agreement for the concurrent transition towards the clean, renewable, or low carbon electricity generation system. A holistic approach is already underway to develop the electricity sector. However, there are still some areas of concern in achieving the huge target set by the government. Especially following the slow progress in recent time regarding power purchase agreement and engagement with the private sector, the challenges have been increasing in this regard (Wilda Asmarini, 2015).

This chapter will focus on these issues relating to the electricity generation in Indonesia. Following section will discuss on the demand and supply scenario of electricity market- its current state and future projection. Next section will figure out the present challenges in electricity generation, followed by a section with detail policy issues. Subsequent sections will highlight on Indonesia's new focus on renewables, and the potential of each renewable source of electricity generation.

4.2 Demand and Supply of Electricity Generation

Following the growing demand for the electricity, its generation has also been increased at an average growth rate of 10.45 per cent a year, i.e. from 91.1 Terawatt hours (TWh) to 233.98 TWh during 2000-2015. Figure 4.2 illustrates the ongoing trend of electricity generation and consumption during the 2000-2015 period.

Figure 4.2: Annual Electricity Generation and Consumption (in TWh) in Indonesia, 2000–2015



Source: Ministry of Energy & Mineral Resources of Indonesia (2016)

Future projection estimated by the GlobalData (2015) shows that consumption demand for electricity may increase further by an average rate of 9.92 per cent a year over the 2016-2025 period. As shown in Table 4.1, the consumption may reach at 426.9 TWh in 2025. During the same forecasting period, electricity generation is anticipated to increase by 9.07 per cent a year, on average which is forecasted to reach at 462.3 TWh in 2025.

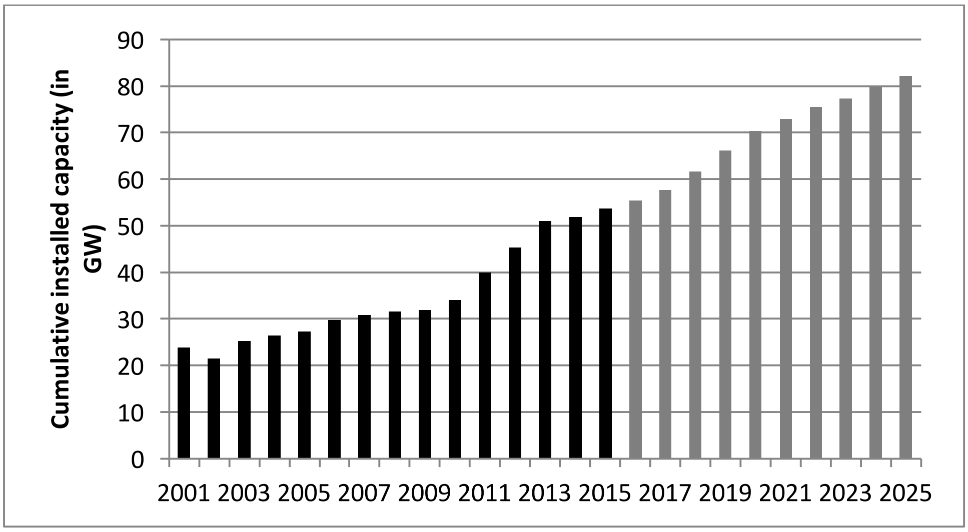
Table 4.1: Projection of electricity demand and supply in Indonesia, 2016-2025

Year	Total consumption (in TWh)	Total generation (in TWh)
2016	225.9	254.5
2017	242.7	272.9
2018	260.6	295.5
2019	279.8	318.1
2020	300.3	340.4
2021	322.3	361.5
2022	345.8	386.1
2023	371.0	413.1
2024	398.0	439.9
2025	426.9	462.3

Source: GlobalData (2015)

Figure 4.3 shows the current and future (projected) trend in cumulative installed capacities of the electricity generation plants over the 2001-2025 period. It reveals that installed capacity may be increased by 49 per cent over the current capacity of 55 GW in 2016 to 82 GW by 2025.

Figure 4.3: Current and future (projected) trend in cumulative installed capacities, 2001-2025



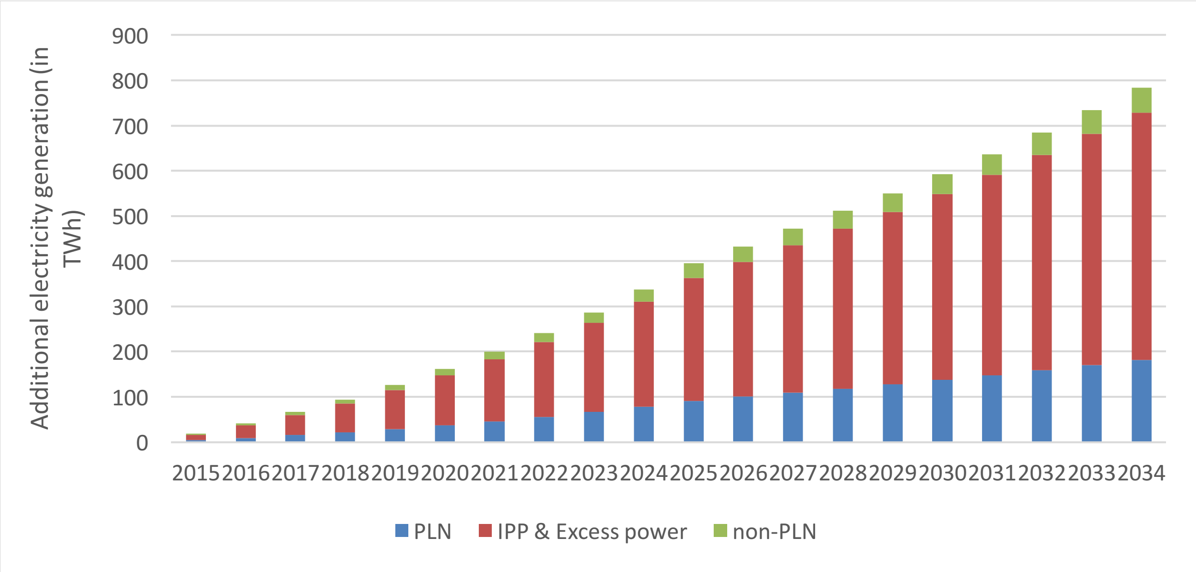
Source: GlobalData (2015)

4.3 Government policy for future generation

Ministry of Energy & Mineral Resources of Indonesia has set up its plan for the future electricity generation in Indonesia. In existing system, Perusahaan Listrik Negara (PLN), an

Indonesian government-owned corporation, has the monopoly on electricity production and distribution in the country. Government policy on future electricity generation (between 2015-2034) aims to achieve around 23 per cent contribution of the additional electricity generation from the PLN. As revealed in Figure 4.4, around 70 per cent of the generation is expected from the Independent Power Producers (IPPs). This aggregate generation by the PLN and IPPs will be distributed through the PLN networks (referred as *'PLN business area'* in the plan). Rest of the electricity generation is expected to be produced and distributed by the non-PLN system.

Figure 4.4: Future additional electricity generation in Indonesia (based on 2014), by the groups of electricity generation companies



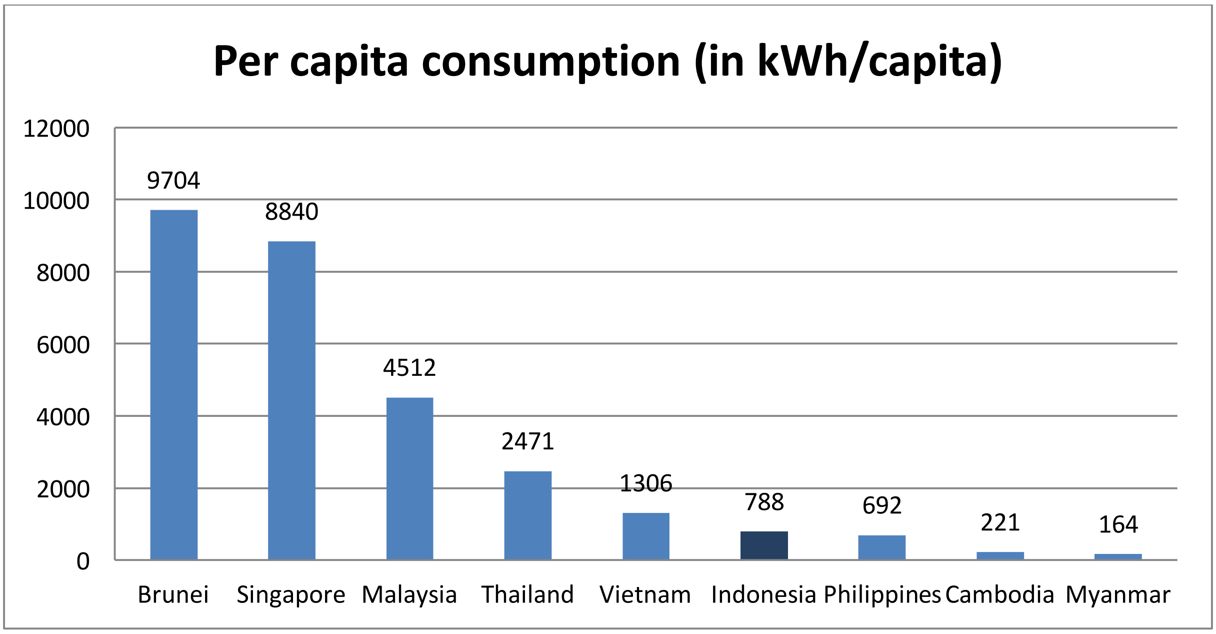
Source: Ministry of Energy & Mineral Resources of Indonesia (2015)

4.4 Challenges in electricity generation

As mentioned earlier, successful economic progress, rising living standards, increasing population, and hasty urbanisation: all led to a sharp rise in electricty demand in Indonesia. According to the prediction of the International Energy Agency (IEA), such increasing trend would continue further. Therefore, to meet the challenges in energy availability and energy security should be among the top priorities for Indonesia's energy policy in coming days. As rightly pointed out by the IEA (2015a), *"The continuation of Indonesia's economic, political and social success story depends on its ability to deliver sustainable and sufficient energy supply to markets and ultimately to consumers"*.

Along with the lower electrification rate the per capita consumption of electricity in Indonesia is also a big concern in its development path. As shown in Figure 4.5, Indonesia lags much behind in per capita electricity consumption among the ASEAN countries. In 2013, its consumption was lower at 788 KWh per capita as compared to Brunei (with 9,704 KWh/capita), Singapore (with 8,840 KWh/capita), Malaysia (with 4,512 KWh/capita), Thailand (with 2,471 KWh/capita), and Vietnam (with 1,306 KWh/capita).

Figure 4.5: Electricity consumption per capita in major ASEAN countries in 2013



Source: IEA (2017)

To improve the electricity generation, Indonesian Government is undertaking many reforms and policy adjustments in recent time. According to the strategies as revealed by Ministry of Energy & Mineral Resources of Indonesia (2015), a significant part of the future electricity generation will come from the IPPs. However, to encourage the IPPs, government needs to introduce adequate incentives to make the electricity market conducive to the private sector's participation.

Another strategic challenge is to properly addressing the future energy composition for electricity generation. Use of clean and renewable energy is a globally adopted phenomenon nowadays. At present, Indonesia has huge dependency on fossil fuels for its electricity generation. Potential of the renewables in the form of geothermal and hydro seems trendy, though the production cost would be a factor to deal with for these energies. To accommodate the rising demand while ensuring the environmental sustainability in electricity generation, energy supplies and costs will play the most important roles in its economic and investment policies and strategies.

To cope up with the challenges of Indonesian electricty market, (IEA, 2015a) identifies five key areas as follow:

- Improvements to institutional set-up,
- Stronger policy reforms and implementation,
- Adequate investment in critical energy infrastructure,
- Transition towards a market-oriented regulation for the energy markets, and
- Adopting the cost-reflective pricing.

4.5 State of electricity generation composition

Energy composition is a very crucial decision-making element in electricity generation. In general, the choice of energy in producing electricity depends on following three factors:

a. Cost aspect: decision may be influenced by the cost of energy as well as the cost of technology used in electricity generation.

b. Environment issue: transition towards the low carbon economy would insist the application of clean and renewable energy in electricity generation.

c. Adaptability aspect: Technological advancement and the country's adaptibility may also affect the decision of energy composition in electricity generation.

In aggregate, the contribution of fossil fuels in electricity generation in Indonesia ranges from 88 to 89 per cent during the 2009-2015Q2, while the contribution of renewables ranges between 11 to 12 per cent during this period as shown in Table 4.2.

Table 4.2: Share of fossil fuels and renewables in electricity generation

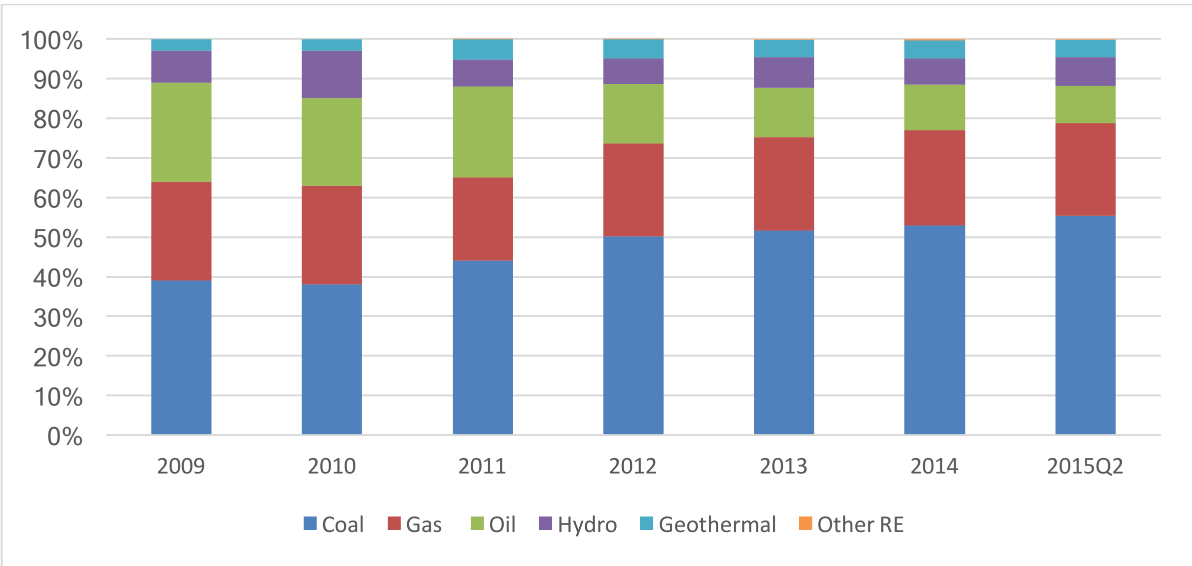
	Share in electricity generation	
	Fossil total	Renewables
2009	89.0	11.0
2010	85.0	15.0
2011	88.0	12.0

2012	88.7	11.4
2013	87.7	12.3
2014	88.4	11.6
2015Q2	88.1	11.9

Source: Ministry of Energy & Mineral Resources of Indonesia (2015)

Figure 4.6 presents the energy-mix trend in electricity generation in Indonesia since 2009 to the 2nd quarter of 2015. Since Indonesia is one of the leading countries in terms of coal and natural gas reserves, it has endured dominance in using the fossil fuels in electricity generation. Coal has been the most dominating energy source for generating electricity in Indonesian over the years. Latest electricity fuel mix data for 2015Q2 reveals that coal has a share of 55.3 per cent of the total installed capacity, followed by the natural gas with 23.5 per cent, oil with 9.3 per cent, and hydropower with 7.4 per cent. Geothermal power is the leading renewable source of energy in the country and contributed around 4.4 per cent of the total generation capacity. Other renewable sources, which include onshore wind, solar Photovoltaic (PV), biomass and biogas make up the rest 0.19 per cent.

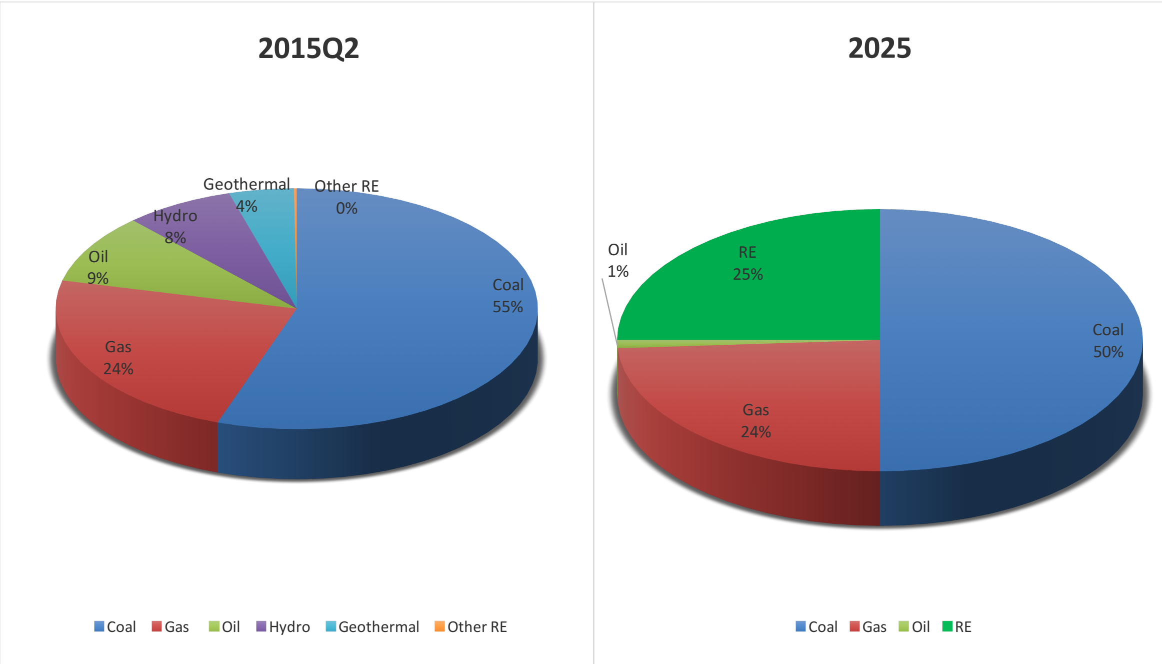
Figure 4.6: Trends in energy composition of electricity generation in Indonesia (2009-2015)



Source: Ministry of Energy & Mineral Resources of Indonesia (2015)

Projections of the Ministry of Energy & Mineral Resources of Indonesia reveal that government has a policy to increase the contribution of renewable energies in electricity generation. Figure 4.7 illustrates the comparative energy composition in electricity generation in Indonesia in 2015 and 2025. Dominance of coal is expected to drop from 55 per cent to 50 per cent during this time. Share of natural gas would be almost the same, however, a sharp decline of oil use is predicted from 9 per cent to 1 per cent over this time. Consequently, the share of renewables is expected to rise from 12 per cent to 25 per cent during this period.

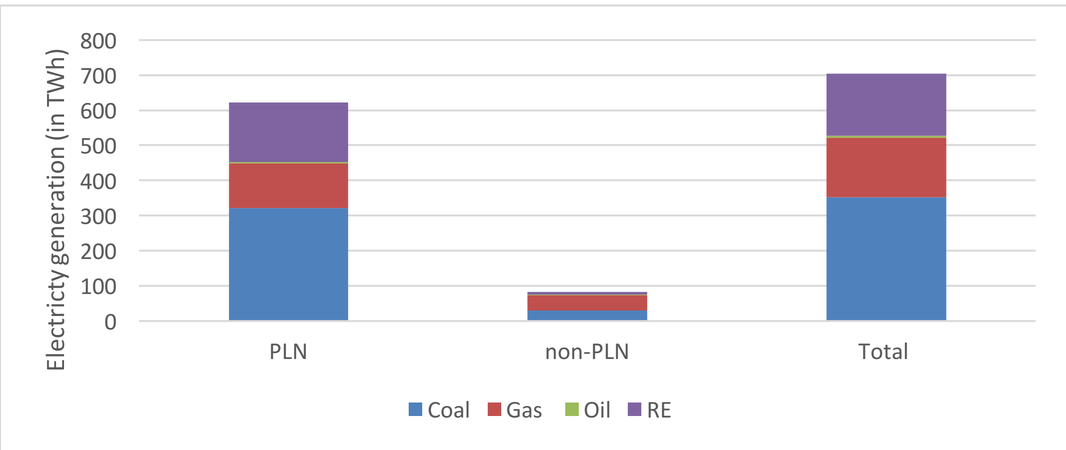
Figure 4.7: Comparison of energy composition in electricity generation in Indonesia (2015 and 2025)



Source: Ministry of Energy & Mineral Resources of Indonesia (2015)

According to the government's future policy, the PLN system will be mostly responsible for adopting the renewable energy in electricity generation (Figure 4.8).

Figure 4.8: Projected energy composition in 2034, by the electricity producer groups



Source: Ministry of Energy & Mineral Resources of Indonesia (2015) (based on General planning of National Electricity, RUKN draft 2015-2034)

4.6 Policy and Regulatory Issues

The Ministry of Energy and Mineral Resources *(Kementerian Energi dan Sumber daya Mineral)*, is the chief regulatory authority in the electricity sector in Indonesia. It is primarily responsible for the the legislation, implementation, co-ordination, enforcement and compliance of this sector. The current regulatory framework is adopted by the *2009 Electricity Law* along with the regulations of GR No. 14/2012 on *Electricity Business Provision* (as amended by GR No. 23/2014), GR No. 42/2012 on *Cross-Border Sale and Purchase* and GR No. 62/2012 on *Electricity Support Business*. There are also relevant regulations issued by the Ministry of Energy and Mineral Resources (MoEMR), the Minister of Industry, the Minister of Finance, the Minister of Forestry and other Ministers with responsibilites relating to the electricity sector (PwC Indonesia, 2016).

There are also several laws and regulations that affect the generation, transmission, and distributional operations of this sector: e.g. Law No. 2/2012 on *Land Procurement for Public Interest Development* (the 2012 *Land Acquisition Law*) and regulation PR No. 71/2012 on the *Implementation of Land Procurement for Public Interest Development* (as amended by PR Nos. 40/2014, 99/2014 and 30/2015), which provide the framework for acquiring land for infrastructure projects. Moreover, there are few laws and regulations adopted for specific subsectors of electricity such as Law No. 21/2014 on Geothermal (the 2014 *Geothermal Law*).

The *2009 Electricity Law* adopts the policy that electricity tariffs may vary according to operating areas and, therefore, no longer need to be uniform throughout the country. Tariffs may be differentiated according to the end user groups. The law assumes that electricity tariffs are set by considering the ability of customers to pay, as well as the installed power capacity of each customer group. In general, the higher the installed capacity, the higher the tariff would impose. Tariffs are also subjected to the different subsidy arrangements. Normally the small household tariffs are heavily subsidised. For instance, in 2015, a small household tariff is subsidised with 319 IDR /kWh, which is less than one-fourth of the average generation cost of 1,350 IDR / kWh (PwC Indonesia, 2016).

Before 2013, the electricity price in Indonesia was mostly regulated by the government. Tariff was set by the Central Government and ultimately approved by the Parliament, except for electricity prices in Kota Tarakan and Batam. If the generation cost exceeded the regulatory price, there was a provision to compensate the PLN through subsidies (PwC Indonesia, 2016). Since 2013, *automatic adjustment mechanism* is adopted via MoEMR Regulation No. 31/2014. With this mechanism, price is adjusted automatically given the rate of inflation, the price of oil and the USD/IDR exchange rate. The Public Service Obligation (PSO) margin was introduced in 2009 as part of the subsidy. It was initially set at 5 per cent above the cost of electricity supplied. The margin was increased to 8 per cent for 2010 and 2011 and then reduced to 7 per cent since 2012. However, a new regulation from January 2017 (which has been postponed until 1 January 2018) implies that PLN will no longer automatically receive its PSO margin. Rather, to receive the subsidy, it is now required to attain certain performance targets set in each year (Ministry of Finance Regulation No. 195/2015).

4.7 A new focus on Renewables

A new focus in using renewables for electricity generation is evident in government policy and regulations. Government Regulation no. 79/2014 on National Energy Policy (the *2014 NEP*) emphasises on the adoption of more renewable resources. This is not only to support the pro-environmental policies, but also to ensure energy security in a more decentralized way (PwC Indonesia, 2016). Policymakers advocate to expand the renewables base in Indonesia because certain renewable technologies have become more attractive owing to their falling costs in recent times. Such policy transition is based on the fact that Indonesia has huge untapped potential of renewable resources for its electricity generation. As shown in Table 4.3, unused potential for hydropower is 94 per cent, for geothermal is 96 per cent, for biomass is 99 per cent, and for wind is 99 per cent (Global Business Guide Indonesia, 2012). Ocean current is yet to be tapped in Indonesia as outlined in Table 4.3.

Table 4.3: Potential of different energy sources in electricity generation

	Resource potential*	Unused potential (in %)
Hydropower	75.7 GW	94
Geothermal	27.5 GW	96
Small hydropower	0.5 GW	83
Biomass	49.8 GW	99
Solar	4.8kWh/m^3/day	-
Wind	9.2 GW	99
Ocean current	0.035 GW	100

Source: Global Business Guide Indonesia (2012)

* Calculation of resource potential is based on technical analysis only. Financial or economic viability are not considered in calculation.

Ability of the renewables to support the off-grid electricity supply to the tens of millions of Indonesians living in different remote islands can be of significant advantage. At this moment, most of these people rely on costly electricity from diesel generators (Global Business Guide Indonesia, 2014a).

Government is also keen to replace the expensive imported oil with renewables. Hence, it plans to provide adequate financial incentives to promote the development of renewable sources of energy in electricity generation. Soft loans from development banks and multilateral investment funds such as the Clean Technology Fund are offered to the investors. Process of tender has been simplified in recent time. Infrastructure and connectivity is improving that would encourage setting up of renewable projects in remote regions (Global Business Guide Indonesia, 2014a). Relevant legal reforms are also adopted in recent times. Government also established the *Indonesia Infrastructure Guarantee Fund* to provide guarantees for the construction and operation of electricity generating plants in public-private partnerships (PPPs) (Global Business Guide Indonesia, 2014b). The Geothermal Fund Facility (GFF) provides support for the investors in data acquisition and exploration activities. There are also few incentives provided in the form of tax holidays, income tax reductions, and certain exemptions on Value Added Tax (VAT) and duties levied on the import of capital goods for renewable energy projects.

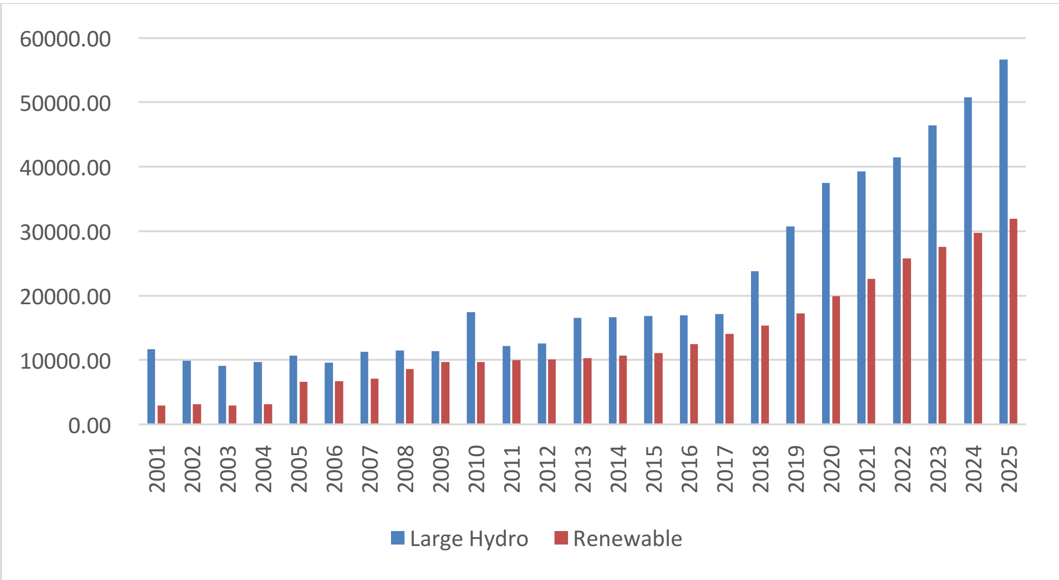
4.8 Potentials of Renewable Sourced Energy

Indonesia has abundant renewable energy resources, such as the largest geothermal resources reserve and seventh largest biomass (including biogas) resources reserve in the world. However, the production of renewable energy is still far away from efficient. In year 2014, according to GlobalData (2015), the renewable energy (exclude large hydro power) production capacity and large hydro and pumped storage power capacity in Indonesia are around 1,691 MW and 5,059 MW, but only account for 3 per cent and 10 per cent of total current generation capacity respectively. Similarly, the power generation from renewable energy and large hydro and pumped storage in 2014 were 10,726 GWh and 16,654 GWh respectively while the national electricity generation is 225,270 GWh. Currently, within non-hydro renewable energy resources, geothermal takes the lead position, which occupies more than 82 per cent of all installed renewable energy capacity and 91 per cent of renewable energy generation, followed by biomass, small hydro, solar PV and onshore wind.

One thing to be mentioned is that the huge gap between renewable energy generation and renewable resources reserve strongly indicates a large potential of renewable energy in future development. GlobalData (2015) expects that the cumulative installed generation capacity of renewable energy will achieve 5,784 MW in 2025 (accounting for 7 per cent of total output capacity), with a 11.8 per cent compound annual growth rate (CAGR). At the same time, total renewable energy generation is predicted to increase at a CAGR of 10 per cent, finally reaching 31,899 GWh in 2025. This development will particularly occur, in geothermal, hydropower, solar PV, onshore wind and biomass.

Figure 4.9 represent the (expected) power generation by renewable and large hydro and pumped storage energy resources in Indonesia for the period from 2001 to 2025 respectively.

Figure 4.9: Power generation by renewable and large hydro energy resources in Indonesia for the period from 2001 to 2025, GWh



Source: GlobalData Power Database

The following sections provide a brief description of the existing renewable energy resource potential in Indonesia.

4.8.1 Geothermal resource

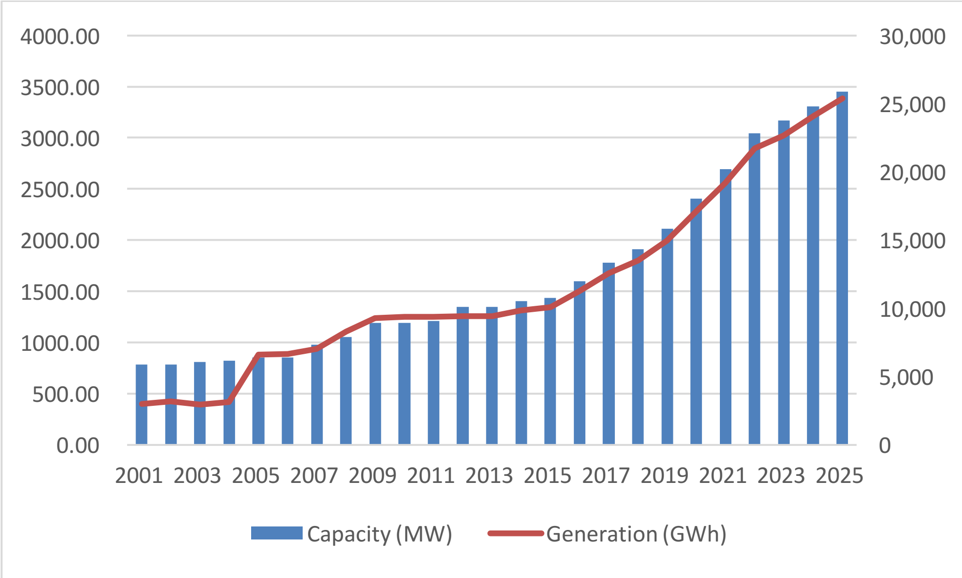
Although Indonesia is the third largest country in the world in terms of geothermal energy generation, following U.S. and Philippines, the geothermal energy generation capacity remains greatly inefficient compared with its geothermal energy reserve. Located in the pacific ring of fire, Indonesia enjoys about 40 per cent of the world's geothermal energy reserve, approximately 27 GW, which is located below its surface while only 4 to 5 per cent of it (about 1,400 MW) is being currently developed. Many reasons contribute to this situation, the most direct one of which is that the cost of establishing a geothermal energy plant is relatively higher compared with a coal or gas plant. Moreover, before 2014, activities of exploring geothermal energy were defined as mining activities by Indonesian law while mining is extremely prohibited to be implemented in natural reserve area in Indonesia, which apparently impeded the development of geothermal projects. Besides, plenty of geothermal sources are located at remote areas, which lack the necessary infrastructure for building geothermal power plants.

The government of Indonesia has recently undertaken a number of encouraging steps aimed at attracting geothermal energy investment, and further moves are being prepared. The Geothermal Fund Facility (GFF) provides support for data acquisition and exploration activities, which is seen as crucial to mitigate risks and justify the high upfront costs for project development. In addition, in August 2014, Indonesian government revised the government is revising the Geothermal Law (Law No. 27/2003), which separates geothermal activities from mining.

Despite all the existing problems, as mentioned above, currently geothermal energy takes the leadership in Indonesian renewable energy market. The market forecasts that the cumulative installed capacity and power generation of geothermal energy will increase from 1,450 MW to 3,448 MW and 9,820 GWh to 25,372 GWh respectively from 2015 to 2025. Although the market share of geothermal energy in terms of installed capacity will decrease from more than 80 per cent currently to around 60 per cent in 2025, it remains the largest proportion in renewable energy.

Figure 4.10 shows the (expected) cumulative installed capacity and power generation of geothermal energy during the period from 2001 to 2025.

Figure 4.10: Cumulative installed capacity and power generation of geothermal energy during the period from 2001 to 2025



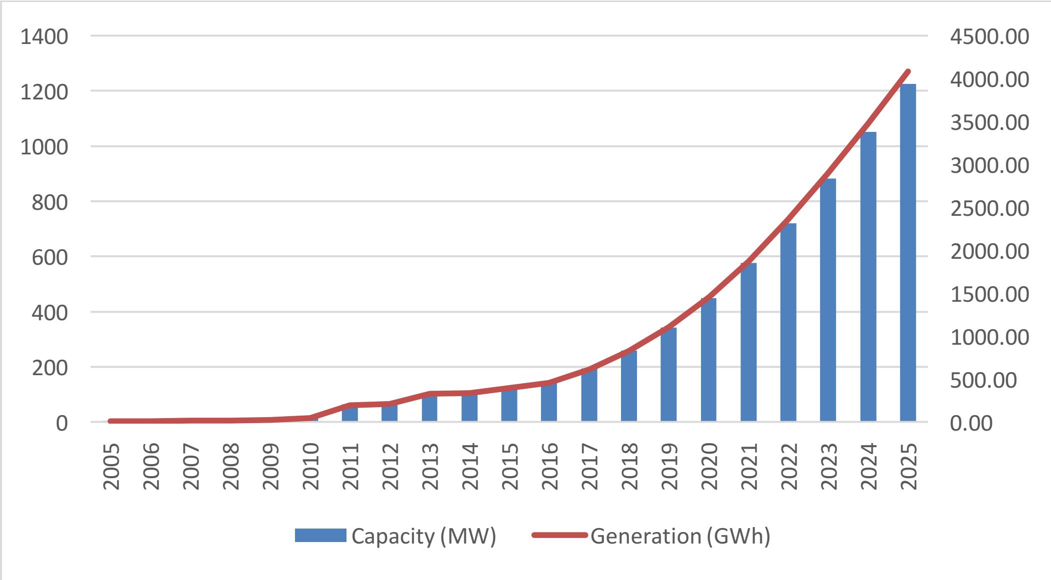
Source: GlobalData Power Database, 2015

4.8.2 Hydro power (large scale and small scale)

It is estimated that hydroelectric power boasts even more than geothermal energy, with an approximately 75,000 MW power potential. With the installed capacity of nearly 6,000 MW, hydropower is currently regarded as most utilised source of renewable energy. Multiple hydropower sites are across the nation and under way, among which several major plants have been projected around the underserved eastern regions of the country like Maluku and Papua. The locations of intended large-scale hydropower projects are mostly isolated or forested regions with little or no infrastructure, which presents a major geographical challenge to developers and architectures.

For relatively small projects with less than 10 MW power generation, they are faced with little financial options and require more technical assistance. The transportation costs of equipment, whether interstate or international are high considering the limited capacity of such projects. However, micro and mini hydropower projects are often supported by the local government and development organisations and in some cases microfinance credit. Hydropower projects also bring about business opportunities for suppliers and consultants with public sectors. Therefore, the cumulative installed capacity of small hydro power is projected to increase from 125 MW in 2015 to 1,226.4 MW in 2025, and power generation from 393.6 GWh to 4,082.4 GWh. Figure 4.11 shows the cumulative installed capacity and power generation of small hydro power during the period from 2005 to 2025.

Figure 4.11: Cumulative installed capacity and power generation of small hydro power energy during the period from 2005 to 2025



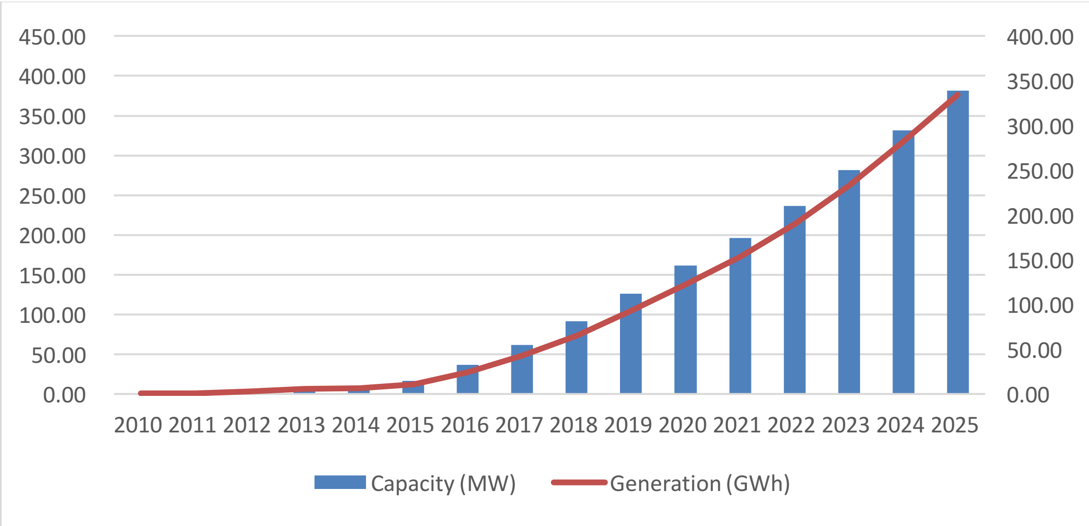
Source: GlobalData Power Database, 2015

4.8.3 Solar PV energy

While photovoltaic solar energy has long been neglected in Indonesia as a form of renewable energy, it is believed that Solar PV could contribute immensely to filling the electricity gap throughout the nation. Indonesia is blessed with strong solar radiation thanks to its location along the equator. Eastern and Southern regions like East Java are especially abundant in solar energy, which is fit for electrifying rural regions. The major challenge with PV projects in remote areas is that they are commercially unfeasible and lacking funding from government subsidy programs. Meanwhile, the commercialising of PV electricity to PLN remain largely untested in Indonesia despite a growing interest. In November 2013 80 new plants were launched with a total capacity of 140 MW, many of which are joint programs of foreign companies and local entities. Indonesian government is currently encouraging the localisation of PV generation. Use of more than 40 percent locally produced equipment are rewarded by higher feed-in tariffs.

Currently, the development of solar PV energy is still relatively low in Indonesia, with a 16.5 MW of cumulative installed capacity and a 10.8 GWh power generation in 2015. However, it is reasonable to predict that significant growth will occur in Indonesia's solar PV energy, of which the cumulative installed capacity and power generation are expected to increase by 365 MW and 323 GWh respectively during a 10 years period. Figure 4.12 shows the cumulative installed capacity and power generation of solar PV energy during the period from 2010 to 2025.

Figure 4.12: Cumulative installed capacity and power generation of solar PV energy during the period from 2010 to 2025



Source: GlobalData Power Database, 2015

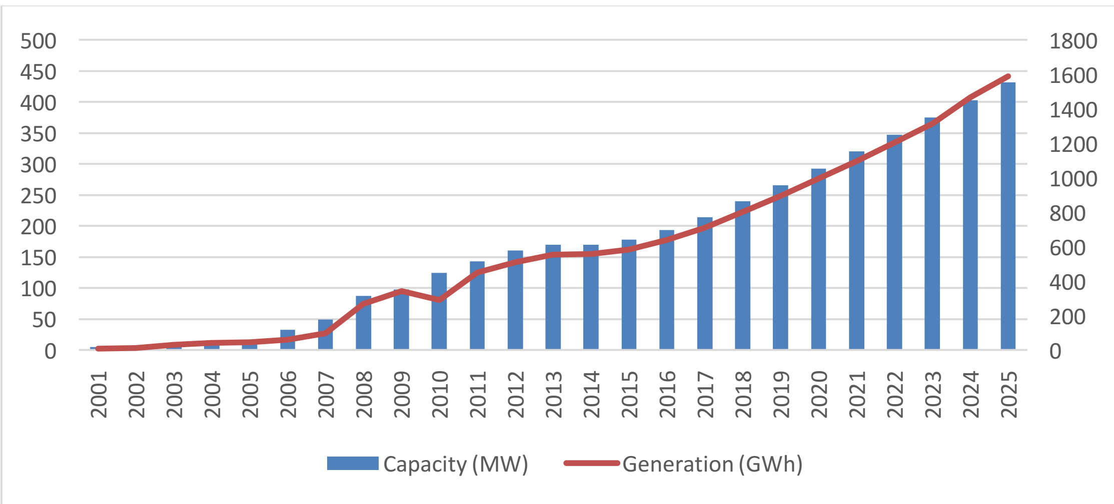
4.8.4 Biomass energy (including biogas)

Biomass is an underexploited renewable energy that has the potential to provide Indonesian population with 49,500 MW of electricity according to Frost and Sullivan (2013) while the current installed capacity is 1,600 MW. Rice husk, coconut husk and empty fruit bunches from CPO (Crude Palm Oil) are just a few examples of the promising sources of biomass energy. State-owned enterprises of Indonesia have only recently entered partnerships with international supporting organisations with the likes of NEDO, Japan who undertook several projects with PTPN III and PTPN X for biomass production from CPO production and sugarcane processing waste. Local agribusiness is also looking at biomass production as remedies for the rocketing electricity tariffs and constant electricity cut-down as such process turns bio-based waste into energy, a truly win-win for them. Utilisation of biomass production has been put on the agenda of more and more not only state-owned enterprise but also an increasing number of private firms, which indicated a potentially huge demand for the supply of relevant technology involved in the biomass production. Agricultural cooperatives for crops such as tea and cocoa as they strive to move up the value chain also offer potential provided expertise can also be provided in supporting logistics for centralising waste material collection across numerous small holdings.

Biofuels energy is a relatively new component in terms of Indonesia's electricity supply system, and is getting more and more attention by the Indonesian government as it seeks to be less oil dependent (on import) and to improve ecological credentials without harming the country's future development of transportation system. Initially introducing biogas energy in 2010, Indonesia is now a major producer of ethanol and biodiesel in the global market. In 2015, Indonesian biogas energy sector owns a 3.56 MW cumulative installed capacity and a 28.4 GWh power generation. Crude palm oil is abundant in feedstock but is vulnerable to global price shocks. There has been a growing demand for biofuels in response to the increase in social infrastructure as well as private vehicle users under the tightened blending requirement. Biofuel is not a perfect solution to the imbalance of electricity supply and demand but according to the Indonesian Biofuel Producers Association (APROBI) in 2015, the sales of biodiesel is almost tripled in the domestic market. The export of biodiesel is expected to rise by more than 20 percent due to rising demand from Asia Pacific countries, such as from China, India, Australia, PaulusTjakrawan, APROBI chairman shared with Reuters News in March 2014. Exports to Euro are cut back by anti-dumping duties exposed by the European Union, who believe the biofuels are being illegally subsidised. Should the two parties come to a mutual understanding, Indonesia will see a boost in its biofuel export. Overall, it is expected that the cumulative installed capacity of biogas energy in Indonesia will increase consistently over the years.

Figure 4.13 shows the cumulative installed capacity and power generation of biomass (including biogas) energy during the period from 2001 to 2025.

Figure 4.13: Cumulative installed capacity and power generation of biomass energy during the period from 2001 to 2025



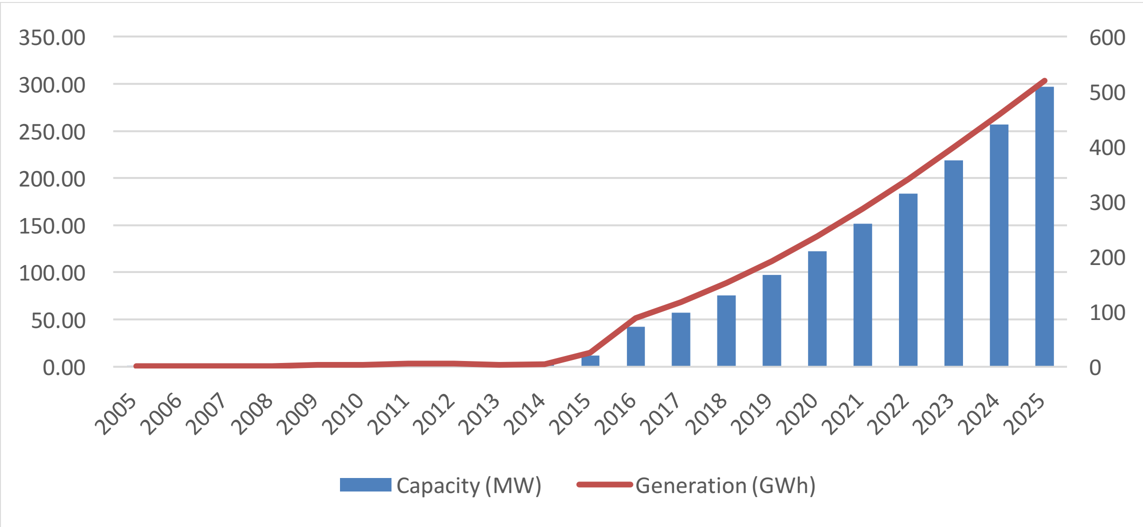
Source: GlobalData Power Database, 2015

4.8.5 Onshore wind energy

The development of onshore wind energy currently remains relatively low even compared with other kinds of renewable energy sources in Indonesia. Cumulative installed onshore wind capacity only stood at 11.87 MW in 2015 and generation was 23.35 GWh. Fortunately, Indonesian government is now importing advanced onshore wind technology from Denmark. In 2016, an agreement to build the Tolo Wind Farm project in South Sulawesi, which will be the first large-scale onshore wind energy project in Indonesia, is signed by Indonesia's national electricity company PT PLN and Equis Asia Fund II. This project consists of 21 wind turbines which will be supplied by Vestas, and is expected to provide 60 MW capacity after being finished in late 2017 or early 2018 (Embassy of Denmark in Jakarta, 2016). With abundant wind resources across the country, the cumulative installed onshore wind capacity is expected to increase to 297 MW and the power generation is predicted to achieve 520 GWh in 2025 with an approximate compound annual growth rate of 92 per cent and 88 per cent respectively.

Figure 4.14 shows the cumulative installed capacity and power generation of onshore wind energy during the period from 2005 to 2025.

Figure 4.14: Cumulative installed capacity and power generation of onshore wind energy during the period from 2005 to 2025



Source: GlobalData Power Database

4.8.6 Nuclear energy

Indonesia is widely considered to be the first country to establish commercial-scale nuclear power plants as it has a relatively richer experience and better infrastructure in nuclear technology than any other countries in Southeast Asia area (except Australia). Currently, three experimental nuclear reactors have been built in Indonesia for research purpose and are operated by BATAN (the Indonesia's National Nuclear Power Agency) with an approximate 32 MW capacity in total. Moreover, as early as 2009, the International Atomic Energy Agency (IAEA) assessed that Indonesia is ready to develop scaled nuclear energy based on its human resources, stakeholders, industry and regulations. However, until now, Indonesia does not possess any nuclear power output capacity, which also indicates the huge potential of nuclear energy's development in the future.

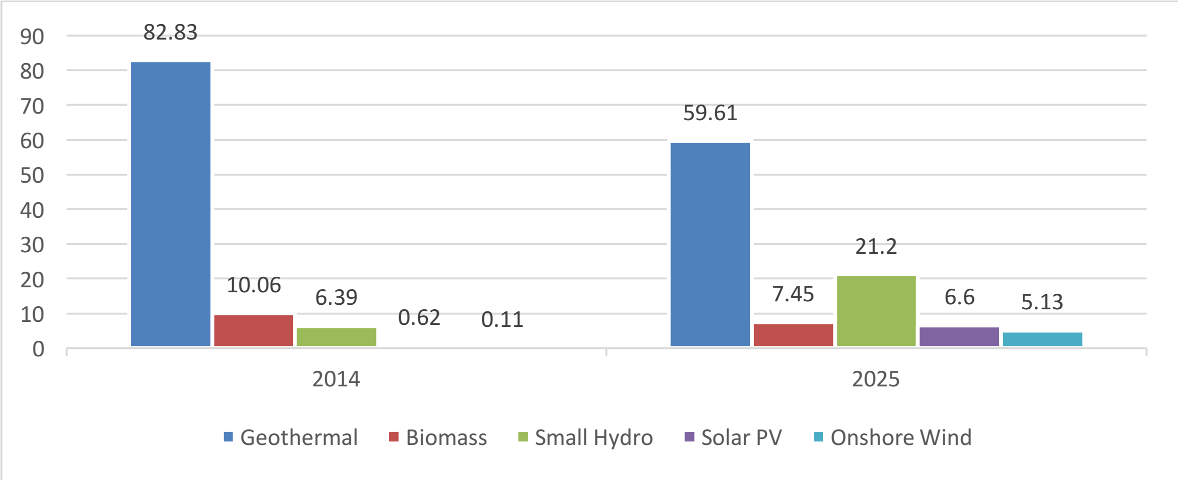
Indonesia's government firstly began its research on nuclear energy in 1956, and BATAN carries on the research since 1980s. BATAN proposed many plans and conducted several feasibility studies to practice nuclear energy plants while none of them is eventually implemented. Its focus about possible construction sites also shifts between Muria, Banten, Bangka Island and Jepara. One of the most recent proposals is the agreement, which is signed by Russia's state owned Rosatom and BATAN in 2015, on the construction of Indonesia's first large scale nuclear energy plant with 30 MW capacity. Besides, in 2016, BATAN also signed an agreement with China Nuclear Engineering Corporation (CNEC) to cooperate on a high-temperature gas-cooled reactor (HTGR) project in Indonesia from 2027 onward. This agreement does not only refer to establishing conventional large Light Water Reactors, but also plans for small HTGRs (up to 100 MW) to supply electricity and heat for industry purpose.

One policy imperative that should be highlighted is that the National Energy Plan (2015) states that 'Indonesia will not resort to nuclear energy to meet its target of 136.7 GW of power capacity by 2025 and 430 GW by 2050'. It is further explained by the Energy and Mineral Resources Minister Sudirman Said that a previous 8-billion-dollars plan, last revised in 2006, which operates four nuclear plants with a total capacity of 6 GW by 2025 will be cancelled. This represents that plans for large-scale nuclear energy plants will be delayed further.

4.8.7 Summing up

Geothermal currently enjoys the maximum share in the total renewable power installed capacity of Indonesia. Although the market share of geothermal energy will decrease, it will retain its leadership role in the year 2025. 'Small hydropower' market is expected to develop considerably during the period 2016-2025, with the increasing share of small hydro market from 6.4 per cent of the cumulative renewable power capacity in the year 2014 to 21.2 per cent in the year 2025. The share of biomass is predicted to decrease by 2025 while the share of solar PV and onshore wind will increase to 6.6 per cent and 5.1 per cent per cent respectively.

Figure 4.15: Cumulative installed capacity in the year 2014 and 2025, percentage



Source: Global Data Power Database.

Figure 4.15 shows the comparison among various renewable sources in terms of cumulative installed capacity by the year end 2014 and 2025 (excluding large-scale hydro power).

4.9. The Jakarta region: An Overview

Jakarta, the capital of Indonesia, is located on the northwest coast of the world's most populous island of Java. Being the centre of economy, culture and politics of the country, it is officially known as the *Special Capital Region of Jakarta*. Greater Jakarta metropolitan area, which is known as Jabodetabek is the second largest urban agglomeration in the world. Total area of Jakarta is 661.5 square km.

Figure 4.16: The Location of Jakarta in the map

Source: Businessinsider.com

4.9.1 Population

Jakarta metropolitan has a total population over 10.4 million. According to 2016 data, it is the second most populous city in the South-east Asian countries after Manila[3] (UNDESA, 2016). Jakarta's business and employment potential along with the opportunities to offer higher standard of living, attract migrants from all over the Indonesian archipelago, making it a fusion of many communities and cultures. A historic mix of cultures – Javanese, Malay, Chinese, Arab, Indian and European – has influenced its architecture, language and cuisine.

Table 4.4 shows the trend of increasing population at different major cities and municipalities of Jakarta. Demographic growth pattern projections show that population of Indonesia may grow at an annual average (compound) rate of 0.65 per cent a year over the 2015-2025 time period. During this time, the urbanization rate may increase from 55 to 75 per cent. Hence, there could be immense pressure of the increasing population in the major cities like Jakarta. According to the UNDESA (2016) Report, the population of Jakarta metropolitan in 2030 would be 13.8 million, 32 per cent higher as compared to 2016.

Table 4.4: Population density and Human Development Index in different parts of Jakarta

[3] This comparison is for only the metropolis cities. If the whole area of the cities are considered, Jakarta ranks first among the South-east Asian countries (Wikipedia, 2017a).

City/Regency	Area (km^2)	Total population (2010)	Total population (2014)	Population Density (per km^2) in 2010	Population Density (per km^2) in 2014	HDI 2015 Estimates
South Jakarta (*Jakarta Selatan*)	141.27	2,057,080	2,164,070	14,561	15,319	0.833
East Jakarta (*Jakarta Timur*)	188.03	2,687,027	2,817,994	14,290	14,987	0.807
Central Jakarta (*Jakarta Pusat*)	48.13	898,883	910,381	18,676	18,915	0.796
West Jakarta (*Jakarta Barat*)	129.54	2,278,825	2,430,410	17,592	18,762	0.797
North Jakarta (*Jakarta Utara*)	146.66	1,645,312	1,729,444	11,219	11,792	0.796
Thousand Islands (*Kepulauan Seribu*)	8.7	21,071	23,011	2,422	2,645	0.688

Source: aseanup.com (2017)

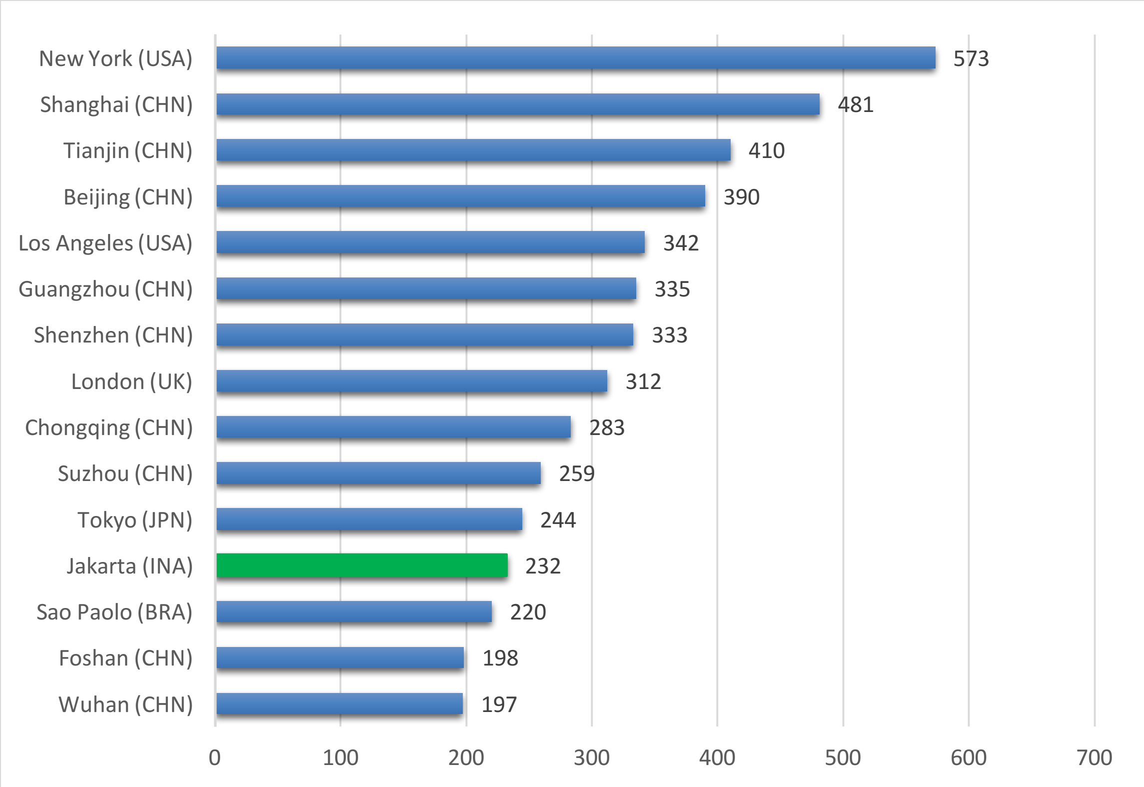
4.9.2. Economy

Jakarta is the economic nerve centre of Indonesia- the largest economy of ASEAN. Nominal GDP of DKI Jakarta[4] was US$143.8 billion in 2015, which is about 17.5 per cent of the nominal GDP of Indonesia (Statistik Indonesia, 2016). Economy of Jakarta grew at a rate above 6 per cent per year since 2009. In 2014, per capita GDP of DKI Jakarta inhabitants was USD 14,426.

According to the Brookings Institution (2014), Jakarta ranked 34 among the world's largest metropolitan cities in terms of economic performance of 2014. Oxford Economics predicts that Jakarta will be the 12th richest city in the world in 2030 with its GDP of 232 billion GBP. Figure 4.17 shows world's top 15 Cities in terms of GDP in 2030 (McCarthy, 2015). It can give some indication about the pace at which the Jakarta's economy is expected to grow in next 15 years.

Figure 4.17: World's top 15 Cities, by GDP in 2030 (in billion GBP)

[4] Jakarta is also known as Daerah Khusus Ibukota (DKI) Jakarta (literally means the special area of the capital city of Jakarta).



Source: Oxford Economics (cited from McCarthy, 2015)

Economic structure, as shows in Table 4.5 implies that Jakarta's economy is heavily relied on tertiary sector, i.e. the service industries. Almost 72 per cent of its GDP comes from this sector. Secondary sector comprising Manufacturing, electricity, gas, and water, and construction industries share about 27 per cent while the primary sectors (agriculture and mining) constitutes less than one per cent of total GDP. Most of industries in Jakarta include electronics, automotive, chemicals, mechanical engineering and biomedical sciences manufacturing.

Table 4.5: Value addition of the sectors of Jakarta's economy

Sectors of economy	Industries	Value added (in trillion IDR)
Primary sector	Agriculture	1.7
	Mining	4.5
Secondary sector	Manufacture	239.6
	Electricity, Gas, and water	6.3
	Construction	234.2
Tertiary sector	Trade	304.7

	Finance, and insurance	179
	ICT	128
	Real estate	111.7
	Others	551.4

Source: BPS-DKI, Statistics Indonesia- Jakarta Provincial Office. (2017)

Household consumption constitutes around 60 per cent of total income in Jakarta. Among this, about 36 per cent is consumed in food and the rest are in non-food items. The cost of living in the city continues to rise. Both land price and rents has become expensive. Mercer's *(2017)* ranked Jakarta as 88th expensive city in the world for expatriate employees living. Most of the industrial and manufacturing settings and the construction of new housing are usually undertaken at the border areas in Jakarta, while commerce and banking remain concentrated in centre of the city. Jakarta has a vibrant property market. Because of the supply shortage in real estate along with the depreciation of currency results into a higher return on the property investment.

In order to achieve higher GDP growth, Indonesia should focus on attracting more investment into the country, Sampoerna University economist Wahyu Soedarmono said. "*If the government wants to achieve GDP growth of 7 percent in 2019, then the country should increase productivity*," he said, adding that high productivity would bolster investment and spur economic growth. Being the centre of the development and planning process of the country, Jakarta should also adapt the policies to increase economic productivity (The Jakarta Post, 2016).

4.9.3. Electricity

Electricity can play a key role in attaining the goals of higher economic growth. It can facilitate increased production in manufacturing and industrial sectors. Simultaneously, it can help to provide better standards of living for the people. Therefore, the cost of electricity is an important issue for the economy. Indonesian Electricity charges have increased noticeably over the past few years. Substantial reforms have been made to progressively eliminate the subsidies, the removal of the abandonment (a fixed charge before one used any electricity) and the stamp duty (Wilson, 2016). In last few years, the government removed the fixed price charged imposed by *Pertamina* (an Indonesian state-owned oil and natural gas corporation based in Jakarta) for petrol and diesel usage. It now allows the price of oil and gas to fluctuate according to the international price. PLN (*Perusahaan Listrik Negara*), an Indonesian government-owned corporation having a monopoly on electricity distribution in Indonesia and generates the majority of the country's electricity, has been now following the Pertamina's ways and has linked the price of electricity to the floating price of oil and, as a result, the price of electricity is changing on a regular basis.

In July 2017, the Energy and Mineral Resources Minister Ignasius Jonan mentioned, "*The President has stated that electricity will serve as the foundation to boost Indonesia's economic competitiveness*". He also opined that if electricity prices are more affordable, industries will be more efficient. Though, PLN's spokesman Mr Suprateka said the government's decision to maintain current electricity prices would pose a significant challenge for the company, which is expected to book revenues alongside a mandate to develop electricity infrastructures nationwide. He also stated, "*PLN needs to develop electricity infrastructure across the country within the next three years*" (The Jakarta Post, 2017).

4.10. Electricity - Climatic conditions Nexus

Choice of electricity generation depends on the climatic condition of the location. Jakarta has a tropical monsoon climate according to the "Köppen climate classification system". The wet (rainy) season in Jakarta covers the maximum time of the year, i.e., from October to May. The four months of June to September are considered as the drier season. On average, each of these four months experience the rainfall of less than 100 mm or 3.9 inch. Being located in the western part of Java, Jakarta experiences the maximum (peak) monthly rainfall in January and February with the average monthly rainfall of 299.7 mm or 11.80 inch, and its dry season low point is in August with a monthly average of 43.2 mm or 1.70 inch (Wikipedia, 2017b).

Chapter 5
Technology Cost Assessments

5.1 Introduction

This chapter evaluates technology costs for the 14 selected technologies. A list of these 14 technologies along with their design framework and a complete description of their working – starting from the input movement to the electricity generation – were mentioned in chapters 3 and 4. In the following sections, only clarifying comments are made briefly, where they add to the previous description about the technology design and development. The main emphasis of this chapter is to populate the technology performance parameters, which were subsequently used to estimate individual technology LCOEs, or the cost of electricity generation in terms of dollar per megawatt hour (AUS $/MWh). The LCOE formula *per se* was described in chapter 2.

Cost and performance parameters have been obtained by drawing on the review of Indonesian, Australian and other literature, as well as liaising and obtaining information from Indonesian energy experts (IRENA 2017, REN21 2016, Energy Outlook Indonesia 2015, CO2CRC 2015, IER 2015, BNEF 2014, AETA 2013 and AETA 2012). The LCOE cost and performance parameters were converted to the Jakarta, Indonesia conditions, when international studies were used.

5.1.1 Capital Cost Estimates

The total owner's capital cost for most technologies includes:

- specialized equipment (international equipment)
- auxiliary equipment (local equipment) such as, where applicable, pumps, tanks, heat exchangers, air compressors, medium and low voltage equipment, coal/ash handling equipment, etc.
- labour
- buildings
- engineering and plant start-up support, and
- soft costs including contingency, management fees and permits and licenses fees, legal and financial costs, administration and developer costs, etc.

5.1.2 Operations and Maintenance Cost Estimates

The operations and maintenance cost for most technologies include the following:

Fixed O&M costs include estimates as an annual cost per MW capacity for:

- direct and home office labour and associated support costs
- fixed service provider costs
- minor spares and fixed operating consumables
- fixed inspection, diagnostic and repair maintenance services.
- the discount rate used is 8 percent.

Variable operating costs are estimated excluding the cost of fuel, where applicable. The following elements are included in the Variable O & M costs as a cost rate per MWh of sent out energy:

- Chemicals and operating consumables that are generation dependent – e.g. raw water, water treatment chemicals
- Auxiliary power
- Scheduled maintenance for entire plant including balance of plant, and
- Unplanned maintenance.

5.2 Supercritical PC black coal with and without CCS

Subcritical pressure units generate steam at pressures of at least 19.0 MegaPascals (MPa) with steam temperatures of 535–560°C. Subcritical coal fired power plants are common in Indonesia at present. However, because of the need to reduce carbon emissions, supercritical plants will increase in the future. In addition, in many cases existing subcritical plants can be retrofitted with carbon capture equipment to reduce CO_2 emissions. Supercritical plants generate steam at pressures of at least 24.8 MPa with steam temperatures of 565-600°C, and achieve higher thermal efficiency than subcritical units.

The supercritical pulverised coal (PC) plant with Carbon Capture and Storage (CCS) includes a post-combustion carbon capture technology, where carbon is absorbed using chemical solvents such as amines. This process is able to capture up to 90 per cent of the generated CO2, which is subsequently condensed and sent for sequestration (storage).

5.2.1 Supercritical Pulverised Black Coal

In the LCOE cost estimation (Table 5.1), the supercritical pulverised black coal plant has been based on a 375 MW sized unit in the Jakarta region with black coal being used for the pulverised fuel. The supercritical pulverised black coal with CCS plant has been based on a 270 MW sized unit with black coal being used for the pulverised fuel.

Performance

The performance parameters have been obtained from the review of literature as mentioned above, including from the AETA 2012 and AETA2013 models, which were developed under the management of one of the authors of the present study, as well as drafted by the present author (Syed, 2013). The performance mentioned in the following table should be considered as typical for a plant.

Expected Technological Improvement

It is expected that there will be ongoing improvements in new metal alloys as well as in operating flexibility. New materials such as high chrome and nickel alloy pressure parts are likely to develop that will allow higher temperature and pressures. They will be able to operate in excess of 700ºC. It is expected that those conditions will be available in commercial-scale plants by 2025-30, and will increase thermal efficiency by at least six percentage points compared to today's technology. It will also mean a more efficient power plant which produces less CO_2 per MWh.

This will require smaller CO_2 capture systems due to the higher thermal efficiency. This will ultimately result in a decrease in the capital cost of CO_2 capture on a $/kW basis. It is expected that the post-combustion CO_2 capture technology itself will improve significantly by 2025-30. For example, the current Mono Ethanol Amine MEA based system is expected to improve significantly over the next several years and there are likely to be step changes in lower cost and higher efficiency processes for other CCS systems under development. Advancement in CO_2 compressor technology, with inter-cooling systems, will also lower the overall $/kW cost.

The key performance parameters obtained from the above mentioned review of literature are summarized in Table 5.1.

Table 5.1: Key performance parameters and cost estimates for Supercritical pulverised black coal technology options - with and without CCS

Technology description	Units	PC supercritical black coal	PC supercritical black coal w CCS
Construction period	y	4	4
New entrant plant capacity	MW	375	270
Capital cost	$/kW	2870	4100
CO2 Transport & Storage	$/t	0	15
Thermal efficiency (sent out - HHV)	%	40	33
Average capacity factor	%	85	85
Fuel price	$/GJ	3.5	3.5
Fixed O&M	$/kW-y	45	51
Variable O&M	$/MWh	3.5	7
Emissions captured	%	0	90
Emissions rate	kg CO2e/MWh	792	96
LCOE			
Capital cost	$/MWh	38	54
Fixed O&M	$/MWh	6	7
Variable O&M	$/MWh	4	7
Fuel costs	$/MWh	32	38
Cost of CO2 T&S	$/MWh	0	13
LCOE	$/MWh	79	119

It should be noted that if the carbon price is higher than $15/t as assumed in the table, the LCOE of the PC supercritical black coal with CCS will increase. For example, for a carbon price of $30/t, the LCOE will be $132/MWh (and not $119/MWh as in the table).

5.3 Combined cycle gas technology with and without CCS

Natural gas based electricity generation technologies provide a via media between the coal technologies that emit substantial amounts of carbon emissions and renewable technologies that emit nil or negligible emissions. Gas based technologies are established technologies as well. Therefore, gas based technologies are expected to increase in Indonesia in the near future due to the imperative of carbon reductions, especially in the aftermath of the Paris climate agreement. There are various types and categories of gas turbines available in the market today that are suitable to the power generation industry. These include the earlier designed E class and the state-of-the-art heavy-duty F, G and H class turbine models; all of which are suitable for CCGT applications.

Their efficiencies depend on several factors such as inlet mass flow, compression ratio and expansion turbine inlet temperature. Recent state-of-the-art heavy-duty gas turbine designs have advanced hot gas path materials and coatings, advanced secondary air cooling systems, and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures that reach over 1,371°C.

A CCGT plant based on natural gas uses a combination of a natural gas fired turbo-generator system, a HRSG, and a steam turbo-generator system to provide power. Combined cycle plants can operate with both the lower class of gas turbines and the advanced class gas turbines. The combined cycle gas turbine facility can be built up from the discrete size gas turbine(s). The HRSG and steam turbine are sized to utilise the exhaust energy available from the gas turbine(s) in order to maximise the recoverable energy from the gas turbine exhaust. It is expected that the new generating plants based on CCGT technology will be medium sized CCGT (300-500 MW) plants.

A CCGT plant with Carbon Capture and Storage (CCS) is based on the same technology as a CCGT plant with the addition of a system after combustion to capture carbon dioxide to prevent its release to the atmosphere.

The addition of a CCS system on a CCGT, however, is not very common as the flue gas from a CCGT contains less CO_2 than coal fired supercritical plants (CO_2 concentration in a combined cycle plant's flue gas is only around four per cent compared to 12 to 15 per cent for coal plant). This lower CO_2 concentration increases the cost per tonne of capturing carbon comparable to a similar sized coal fired station. On the other hand, the increase in capture costs is offset due to the higher efficiency of a CCGT plant.

Performance

A review of the literature along with the reliance upon the AETA (2012, and 2013) was used to judge and derive the performance parameters for CCGT technologies in Jakarta. In a CCGT plant with CCS, an amine based carbon capture plant with a capture efficiency of 80 per cent was used. Details of the performance parameters for each CCGT plant configurations are detailed in Table 5.2 below.

Though CCGT plants with CCS are a relatively mature technology, the lead time for development (construction period) in Jakarta, Indonesia is three years given that there is currently no such plant there and a new plant will take more time than two years' lead time. The technology itself may be available after 2017 in Indonesia. The lead time for a CCGT plant without CCS is two years.

Expected Technological Improvement

CCGT without CCS technology is a matured generating technology, with a number of plants installed in Indonesia. Improvements in efficiency and reductions in capital costs are not likely to be as extreme as an emerging technology. Future combined cycle plants will be based on advanced heavy-duty gas turbines, which are expected to operate at higher firing temperatures and higher pressure ratios than the current ones. With these newer machines and upgraded materials, combined cycle efficiencies can approach 60 percent.

CCGT with CCS is still an emerging technology. The current MEA based amine system is expected to improve significantly over the next several years and there are likely to be step changes in lower cost and higher efficiency processes for other CCS systems that are under development. Advancement in CO_2 compressor technology, with inter-cooling systems, will also work towards reducing the overall $/kW capital cost of the CCS plant. The percentage of emissions captured is generally claimed by the manufacturers of the technology to be as high as 98 percent for laboratory conditions (AETA 2012); however, in practice a capture rate of 80-90 per cent is a more realistic number for the Jakarta region.

5.4 Open Cycle Gas Turbine

Technology Description

Along with CCGT plants, it is expected that Open Cycle Gas Turbine (OCGT) power plants fired on natural gas will be the basis for the majority of Jakarta's and Indonesia's new power generation facilities in the near future. Because of their ability to start in a short period of time, OCGT's are well suited for peaking applications, and also to provide a supporting role for the integration of renewable electricity generation. With the introduction of state of the art units, such as the F class turbine, fewer units need to be installed on site to achieve a larger power output at a higher efficiency.

Performance

Aeroderivative Intercooler Gas Turbines: Intercooler systems work to increase efficiency by allowing for higher pressure ratios in the combustion zone. This is achieved by splitting the compression unit into two sections: the low pressure compressor (LPC) and the high pressure compressor (HPC). By cooling the air part way through but not losing any of the pressure gain, the intercooler allows for a second compression to occur, allowing air in the combustor to be within the temperature limits but with a much higher pressure ratio. The higher ratio causes the turbine to generate more power with the same fuel input, increasing the overall efficiency of the turbine.

To derive the performance characteristics of a typical OCGT utility plant, the literature based on a 100 MW OCGT Aeroderivative plant was chosen. The average capacity factor for this plant is assumed to be 25 percent. The lead time for the plant development is minimum one year for Jakarta.

Expected Technological Improvement

Open cycle technology is a matured generating technology, with a number of plants installed in Australia.

Improvements in efficiency and reductions in capital costs are not likely to be as extreme as an emerging technology. Future OCGT plants will be based on advanced heavy-duty gas turbines, which are expected to operate at higher firing temperatures and higher pressure ratios than the current ones and thus operate at greater efficiencies (AETA 2012, CO2CRC 2015).

The key performance parameters are summarized in the following table.

Table 5.2: Key performance parameters and cost estimates for gas technology options

Technology description	**Units**	**Combined cycle gas turbine (CCGT)**	**Combined cycle gas plant with CCS**	**Open cycle gas turbine - aero**
Construction period	y	2	3	1
New entrant plant capacity	MW	440	375	100
Capital cost	$/kW	1300	2800	1000
CO2 Transport & Storage	$/t	0	15	0
Thermal efficiency (sent out - HHV)	%	50	42	39
Average capacity factor	%	65	65	25
Fuel price	$/GJ	6.75	6.75	6.75
Fixed O&M	$/kW-y	20	35	10
Variable O&M	$/MWh	1.5	12	15
Emissions captured	%	0	80	0
Emissions rate	kg CO2e/MWh	372.706	88.739	477.828
LCOE				
Capital cost	$/MWh	21	47	41
Fixed O&M	$/MWh	4	6	5
Variable O&M	$/MWh	2	12	15
Fuel costs	$/MWh	49	58	62
Cost of CO2 T&S	$/MWh	0	5	0
LCOE	$/MWh	75	128	123

It should be noted that if the carbon price is higher than $15/t as assumed in the table, the LCOE of the **Combined cycle gas plant with CCS** will increase. For example, for a carbon price of $30/t, the LCOE will be $134/MWh (and not $128/MWh as shown in the table**).**

5.5 Solar Thermal Technologies

5.5.1 Central Receiver Technology (CRT)

Technology Description

Due to the poor part-load behaviour of the solar thermal power, plants should be installed in regions with a minimum of around 2000 full-load hours. This is the case in regions with a direct normal irradiance of more than 2000 kWh/m2 or a global irradiance of more than 1800 kWh/m2. These irradiance values can be found in the earth's sunbelt; however, thermal storage can increase the number of full-load hours significantly.

Solar thermal technologies use sunlight to heat a medium, and then use that medium to drive a power generation system. By using mirrors, the sun's energy can be concentrated up to approximately 1,000 times. The concentrated sunlight is then focused onto a receiver containing a gas or liquid that is heated to high temperatures and used to generate steam that is delivered to a steam turbine that drives a generator to generate power.

The main solar thermal technologies include the compact linear Fresnel, parabolic trough and central receiver tower. The central receiver towers are under focus in this IETA study. The central receiver system is also popularly called solar tower and uses heliostats (two-axis tracking mirrors) to concentrate sunlight on a receiver at the top of a tower. Typically, a molten nitrate salt heat transfer medium is used. It is heated up and then pumped out of the 'cold' tank, through the receiver, and into the 'hot' tank.

These systems are based on the concept of concentrating direct normal irradiation to produce steam used in electricity generating steam turbine cycles. In solar thermal tower power plants, hundreds or even thousands of large two-axis tracked mirrors are installed around a tower. A computer calculates the ideal position for each of these, and a motor drive moves them into the sun. The sunlight is focused on the top of the tower. An absorber is situated here, and this is heated up to temperatures of 1000°C. Hot air or molten salt then transports the heat from the absorber to a steam generator; superheated water steam is produced there, which drives a turbine and electrical generator.

In this technology the solar power generating systems use mirrors that continuously track the position of the sun reflecting the radiation into a receiver that absorbs the solar radiation energy. The absorbed solar energy can be harnessed and transferred in two ways: directly or indirectly.

The direct method circulates water directly through the concentrated solar radiation path, thus directly producing steam.

The indirect method uses a heat transfer fluid which absorbs solar radiation energy and transfers the heat to water by way of a series of solar steam generator heat exchangers, thus indirectly producing steam (AETA 2012).

Performance

Gemasolar was the first commercial-scale plant in the world to apply central tower receiver and molten salt heat storage technology. The relevance of this plant lies in its technological uniqueness, since it opens up the way for new thermosolar electrical generation technology.

For this analysis, six hours storage is required which will reduce the solar field, storage capacity and associated equipment in the order of 40 per cent with an expected reduction of capital compared with Gemasolar.

For a commercial plant and given the learnings over time, capital costs are much lower than the original Gemasolar plant (AETA 2012).

Solar Tower Future Improvements

With more experience in solar thermal plants and scientific developments, the cost of the central receiver plant is expected to continue to decrease due to higher production efficiencies in key equipment and increased experience gained by manufacturers and engineers who are planning and building plants. Also, it is expected that better and cheaper heat transfer fluids will become available that can handle higher temperatures, and therefore increased efficiency will be used. The cost of storage systems is also expected to be reduced.

AETA (2012 and 2013) maintain that improvements are expected in receiver tube absorption and steam turbine efficiencies that would increase the capacity factor for these plants. The combination of a decrease in capital cost and an increase in plant output will lead to a much lower cost of electricity.

It is expected that the development and/or further refining of these systems for power generation will continue well into another twenty or thirty years.

The key performance parameters are summarized in the following Table 5.3.

Table 5.3: Key performance parameters and associated cost estimates for solar thermal technology with 6 hour energy storage

Technology description	Units	Solar thermal C. R. w 6 h storage
Construction period	y	3
New entrant plant capacity	MW	125
Capital cost	$/kW	6500
CO2 Transport & Storage	$/t	
Thermal efficiency (sent out - HHV)	%	
Average capacity factor	%	55
Fuel price	$/GJ	
Fixed O&M	$/kW-y	65
Variable O&M	$/MWh	4
Emissions captured	%	
Emissions rate	kg CO2e/MWh	0
LCOE		
Capital cost	$/MWh	128
Fixed O&M	$/MWh	13
Variable O&M	$/MWh	4
LCOE	$/MWh	146

5.5.2 Photovoltaic technology options

Solar PV fixed, and single axis tracking (SAT)

Technology Description

Solar photovoltaic (PV) generation has mainly been domestic rooftop, but large high-voltage grid connected solar farms are now operating or under development. Both wind and solar developments have been incentivised by the Indonesian government policies and all over the world. This has been supporting the development of renewables, including that of hydroelectric, biomass, geothermal, wave, tidal and other renewable energy sources.

PV technology can be installed as fixed flat plates on a large field or can be mounted on tracking devices that have single axis and two axes tracking. Solar PV technology converts light directly into energy via the photoelectric effect, which is the process in which light (photons) excites electrons into a higher energy state. This creates electricity. This solar electricity is direct current (DC). This is converted into the normal alternating current (AC) by inverters. The ratio between the DC power capacity of a solar array and the AC inverter is the inverter load ratio (ILR). Solar PV systems are optimally designed to maximise the energy production from each solar panel in the array; the key metric is the specific yield, or kWh of energy production per kW of installed capacity. When the power output from a solar PV array is greater than the rating of the inverter, the inverter limits the power from the array to the inverter's maximum nameplate power. In general, a higher ILR works well for systems that may not experience peak power output.

As with other technologies in IETA, for solar PV technologies as well a number of recent reports were utilised in providing the basis for the sizing and costs associated with the PV fixed and rotating plate technologies. The reports are Indonesian based, with some substantiating information used from the Australian field study of AETA 2013 as well.

Fixed axis versus tracking systems

Solar photovoltaic tracking refers to tracking the sun as it traverses the sky during the day. Single axis (azimuth) tracking tracks the sun from east to west. Dual axes tracking includes the ability to directly align with sun for each day of the year, i.e. accounts for seasonal variations of the sun angle in the sky. Typically the type and orientation of flat plate module support structure is selected to minimize cost of energy. Flat plate modules can be mounted in fixed orientation compared to one axis tracking, or two axes tracking. However, fixed orientation mounting systems can be at different angles with the horizon. The angle is selected to maximize annual energy production. Tilting results in increased annual energy production, but at a higher cost. Two axes tracking results in the highest annual energy production, but at an even higher capital and maintenance cost.

Performance

Performance for tracking systems is dependent on the sky clarity index. Low clarity is on a hazy or overcast day. High clarity, above 0.7 or 0.8 sky clearness index happens on a very sunny day with little pollution or particulate in the atmosphere. Here, dual axes provide returns and can achieve production of 40-45 per cent more than a fixed roof array. In general, it is expected that single axis trackers will add 27 to 32 percent additional generation compared with fixed panels and dual axes tracking will add an additional 6 to 10 percent output compared with single axis trackers.

Tracking systems provide a longer "maximum output" operating period, which may be of additional value when considering power revenue per time of the day rather than a flat rate tariff.

Anticipated improvements by 2030

Over time and especially over the past 7-8 years, the cost of electricity from photovoltaic plants has decreased rapidly and is further expected to decline into the future. For these reasons, single-axis tracking technologies are already moving towards greater deployment. Recent project evidence in Australia has indicated a continued decrease in costs in the order of 30 to 35 percent from 2010 to 2012 (AETA 2012). While this reduction is effected by the oversupply of panels in the market between 2010 and 2013, and hence this rate of cost reduction is not expected to continue into the forecast period.

This is mainly due to the improvements in the manufacturing techniques and mass production, changes in the balance of system and inverter costs, and development of new PV configurations, such as multi-junction concentrators that promise to increase cell and module efficiency. Higher efficiencies can also contribute to lower capital costs and lower O&M costs (Wei et al 2015). New materials and manufacturing techniques continue to promise significant further improvements. R&D in thin-film PV cells is creating strong interest from venture capitalists.

The key performance parameters are summarised in the following table.

Table 5.4: Key performance parameters and associated cost estimates for fixed and single axis tracking (SAT) photovoltaic systems

Technology description	Units	Solar PV - fixed	Solar PV SAT
Construction period	Y	1	1
New entrant plant capacity	MW	50	50
Capital cost	$/kW	1400	1610
CO2 Transport & Storage	$/t		

Thermal efficiency (sent out - HHV)	%		
Average capacity factor	%	22	27
Fuel price	$/GJ		
Fixed O&M	$/kW-y	21	26
Variable O&M	$/MWh		
Emissions captured	%		
Emissions rate	kg CO2e/MWh	0	0
LCOE			
Capital cost	$/MWh	65	63
Fixed O&M	$/MWh	11	11
Variable O&M	$/MWh	0	0
LCOE	$/MWh	76	74

5.6 Wind technology options

Technology Description

The working of wind technology is mentioned in earlier chapters 3 and 4. Briefly speaking, under this technology the energy extracted from the wind turns turbine blades around a rotor. The rotor, which is connected to a shaft spins a generator to create electricity.

5.6.1 On-Shore Wind

Over the past several years many types of wind turbine designs have been developed, including vertical and horizontal axes, two or three blades, direct and gearbox-drive train, and fixed-speed, two-speed, and variable-speed generators. Today, the most common wind turbine configuration is the three blades, upwind, horizontal-axis design with a three-speed gearbox, variable-speed generator and power electronics to generate 50 or 60 Hz (frequency) power needed in Jakarta.

Typically, turbine towers are constructed from steel. To support the tower, the rotor, and the nacelle, as well as the dynamic structural loads created by the rotating turbine, and depending on the soil conditions a large steel-reinforced concrete foundation is typically required. There are generally very many wind turbines in a wind plant to generate large scale electricity. At the top of the tower, the rotor blades capture the wind and transfer its power to the rotor hub, which is attached to the low-speed drive shaft. The rotor also helps to maintain a constant power output.

The turbine blade pitch is controlled to maintain a constant power output, even as the wind speed increases, and the turbine is shut down to prevent mechanical damage. All these mechanisms are not manual, and automatically work by computers (IEA 2013).

Performance and Anticipated improvements by 2030

On-shore wind is generally a matured technology; however, there are improvements happening in wind turbine components in many directions, such as condition monitoring (CM) and non-destructive evaluation (NDE) techniques, to help maintain turbine equipment, minimise plant downtime, and maximise energy generation. Wind turbines, and especially off-shore wind turbines are also expected to continue to increase in size to achieve greater economies of scale. Taller towers (hub heights of 120 metres, as opposed to 80 metres height at present) are likely to be used to access greater wind speeds, as well as larger rotors for lower wind speed locations, along with improved reliability and efficiency to help reduce the cost of wind-generated electricity. Taller towers capture greater wind speeds and increase capacity utilisation factors. Increase in rotor diameter is also on the rise. For Jakarta’s low wind speeds a 75m-long blade is sufficient (DoE 2015).

The wind industry continues to aim to improve reliability by better understanding gearbox malfunctions introducing torsional limiting control devices, and torque monitoring systems to extend the life and reliability of gearboxes, as well as increase market share for direct-drive turbines (DoE2015). Anticipated improvements by 2030 in the operation and efficiency of wind turbine technology are expected to be the main driver towards decreasing the wind power costs in the future. Manufacturers are increasing the energy captured by wind turbines by increasing the swept rotor area. This is accomplished by increasing the blade length. Improvements in the power electronics and drive systems will also increase the performance of the turbines. In addition, wind-sensing equipment continues to improve, allowing for more optimised use and operation of the wind turbine farms, resulting in increased power production for the same sized wind farm (AETA 2012 and 2013,Cummings 2013, Santa Fe 2013).

The key performance parameters are summarised in the following table.

Table 5.5: Key performance parameters and associated cost estimates for on-shore wind facility

Technology description	Units	On-shore wind
Construction period	y	1
New entrant plant capacity	MW	50
Capital cost	$/kW	1950
CO2 Transport & Storage	$/t	
Thermal efficiency (sent out - HHV)	%	
Average capacity factor	%	38
Fuel price	$/GJ	
Fixed O&M	$/kW-y	60
Variable O&M	$/MWh	
Emissions captured	%	
Emissions rate	kg CO2e/MWh	0
LCOE		
Capital cost	$/MWh	63
Fixed O&M	$/MWh	18
Variable O&M	$/MWh	0
LCOE	$/MWh	81

5.7 Wave technology

Technology Description

Wave energy is the capacity of the waves to create force. The energy in waves can travel for miles before hitting on distant shores. Detailed working of the wave energy was described in chapter 3. Broadly, the power take-off system transforms mechanical energy into electrical energy. Many designs have been proposed in the context of the wave energy extraction and the research continues to develop still better ways of electricity generation from the wave power (AETA 2012 and 2013, IREE 2015).

5.7.1 Tidal In-Stream Energy Conversion (TISEC) Technology

Ocean tides occur because the gravitational forces of the sun and the moon, and centrifugal and inertial forces on the earth's waters move water with speed and direction. Many technology designs have been proposed to exploit tidal energy. These include the Axial flow where the axis of rotation is parallel to the direction of water flow; the Cross flow where the axis of rotation is perpendicular to the water stream and may be oriented at any angle, and oscillatory hydrofoil, vortex induced motion, or hydro Venturi device. The subsystems of the tidal energy conversion generally include a blade or rotor that converts the energy in the water to rotational shaft energy, a gearbox and a generator, and controls, electrical cables, and interconnection equipment.

Performance

Ocean technology is not fully developed yet, and is in its initial stages. Hence, there is no fixed type that can be prescribed. Broadly, the technology is based on the wind turbine concept, except in this case the turbines are drowned in the water to harness the energy of ocean waves. The speed of the waves is lower than the speed of water, but water's density is much more than that of the wind forcing the turbines to move.

Future Development Directions

Wave energy conversion technology is a developing technology, and many designs are evolving.

Wave Energy Conversion Technology

There are many challenges that the wave technology has to improvise. These include improvement in offshore converters to better tolerate rough waves, and improvement in mooring design to withstand wave, current, and wind.

Tidal In-Stream Energy Conversion Technology

Tidal In-Stream Energy Conversion is also a developing energy technology. This technology is installed in limited numbers in worldwide – and of not more than 10-15 MW. Most of this capacity is via the demonstration plants only. Tidal energy has much future potential, but needs to overcome current challenges, including the rough marine conditions, low capacity factor and high costs. Also developments are needed in material strength, performance, maintenance, and lifespan (CO2CRC 2015).

Studies have confirmed that there is minimal environmental impact associated with wave/tidal technology. Studies have also not observed any harm to aquatic life. The blades of wave/tidal devices rotate very slowly (around 10 rpm for an 18 metre diameter rotor).

5.7.2 Ocean Current Technology

Ocean current technology is in the early stages of development. No ocean current prototype devices have been tested in a relevant environment, and most commercial efforts are only at a demonstration stage or small-scale proof-of-concept testing. Because of its very early developmental status, much research and development have to take place to develop ocean current technology at a practical/commercial stage. Efforts are being made to develop appropriate materials for ocean conditions, life cycle analysis, and installation and maintenance. Wave, tidal and ocean technologies are related concept and research in one field can be used in the other field as well.

Commercialisation projects including multi-megawatt "wave farms" are expected to be deployed over the next decade in Europe, South America, and Australia. This will accelerate the development and spread of the wave/tidal generation industry. The key performance parameters are summarised in the following table.

Table 5.6: Key performance parameters and associated cost estimates for wave/ocean power

Technology description	Units	Wave/ocean energy
Construction period	y	3
New entrant plant capacity	MW	125
Capital cost	$/kW	3100
CO2 Transport & Storage	$/t	
Thermal efficiency (sent out - HHV)	%	
Average capacity factor	%	35
Fuel price	$/GJ	
Fixed O&M	$/kW-y	100

Variable O&M	$/MWh	4
Emissions captured	%	
Emissions rate	kg CO2e/MWh	0
LCOE		
Capital cost	$/MWh	96
Fixed O&M	$/MWh	33
Variable O&M	$/MWh	4
LCOE	$/MWh	133

5.8 Biomass technology options

Technology Description

There are three broad biomass technology options: landfill gas; sugar cane waste; and other biomass waste. Given that the sugar production is on the rise in Indonesia to save limited foreign exchange on the imports of sugar, and most of the country's sugar is produced and refined in Java, biomass sugar cane waste option is considered here. Biomass waste technology was also the selected technology for the project.

5.8.1 Sugar cane waste

In Indonesia, the current capacity of bioenergy based on-grid power plant is around 100 MW (mostly palm waste, sugar cane waste, solid waste).

In most Java sugar or palm oil plants mills, the fibrous residue of the sugar cane milling process or pam oil plants (bagasse) is the primary energy source for the operation of the mill. At each mill, bagasse is fired in a number of boilers to generate steam. Some steam is used as part of the sugar production process and some is delivered to steam turbine generator(s) for power generation.

Generally the sugar or palm oil plants are configured to achieve an energy balance between the amount of bagasse fuel produced by the plant operations and the energy requirement of the plant. If the plants have developed power plants, which operate at high efficiency, the power generated that is in excess of the plant’s requirements is exported into the utility power grid.

Expected Technological Developments

The main development has been with fluidised-bed combustors. These combustors have a high efficiency, can burn a mixture of fuels such as sugar cane waste as well as other wastes, and fuels that can contain up to 60 percent moisture. The largest boilers are grate systems (up to 100 MW thermal), which can produce about 200 ton steam/hr. Direct combustion is commercialised at present and the firing of biomass powder in ceramic gas turbines will be commercialised in the years to come. These turbines will have a capacity of 100 kW - 500 kW. Products are heat and/or high-pressure steam, which can be used to produce electricity or combined heat and electricity.

Most R&D is on technical aspects e.g. stoking, combustion air and fuel conveyance. There have been large improvements in combustion efficiency, in reduction of pollutant emissions (fly ash) and in the development of combined heat and electricity plants. R&D will also be required for Stirling engines and pressurized combustion systems.

Specific research topics on combustion are corrosion by alkalines and chlorides and methods to prevent. Economy of scale will reduce the generation cost. However, this also depends on the availability and cost of the raw material in Java. The developments will be helped if up-front investment is available. The involvement of industries in the development will be an important issue and part of the R&D should concentrate on demonstrating the environmental and energy benefits of the technologies to industries.

The key performance parameters for the biomass technology considered are summarised in the following table.

Table 5.7: Key performance parameters and associated cost estimates for a biomass waste facility

Technology description	Units	Biomass - waste
Construction period	y	1
New entrant plant capacity	MW	1100
Capital cost	$/kW	2100
CO2 Transport & Storage	$/t	0
Year available for construction		
Thermal efficiency (sent out - HHV)	%	28
Average capacity factor	%	85

Fuel price	$/GJ	0.75
Fixed O&M	$/kW-y	97
Variable O&M	$/MWh	6.5
Emissions captured	%	0
Emissions rate	kg CO2e/MWh	0
LCOE		
Capital cost	$/MWh	25
Fixed O&M	$/MWh	13
Variable O&M	$/MWh	7
Fuel costs	$/MWh	10
Cost of CO2 T&S	$/MWh	0
LCOE	$/MWh	55

5.9 Geothermal technology options

The top five countries that generate electricity using geothermal energy are the US (3,000 MW), Philippines (2,000 MW), Indonesia (1,300 MW), Mexico (958MW) and Italy (845 MW) (IGA 2017).

Indonesia expects its electricity demand increase by about ten percent per year (particularly outside the island of Java) and thus the country needs about six GW per year in additional generating capacity.

The Indonesian government has high hopes for geothermal energy. Containing the world's largest geothermal reserves, the government aims to enhance the role of geothermal power in the country's energy mix. As energy demand is rising quickly in Indonesia – because of the population growth coupled with structural economic expansion giving rise to a rapidly expanding middle class as well as the influx of new investments and industrialization - the government has made efforts to smoothen investments in geothermal power exploration after having more-or- less ignored this sector until recently. Instead, the government relied on coal, natural gas, and crude oil to fuel the country's power plants.

With about 40 percent of the world's geothermal reserves being located below the surface of Indonesia, the country is estimated to contain the world's largest geothermal energy reserves and therefore contains huge potential for this renewable energy. However, this potential remains largely untapped.

The Indonesian government has also undertaken other efforts to make investments in geothermal energy more attractive. The Geothermal Fund Facility (GFF) provides support to mitigate risks and provides information regarding the relatively high upfront costs for geothermal development.

The largest reserves of geothermal energy are located in the western part of Indonesia where energy demand is highest: Sumatra, Java and Bali. Star Energy's *Wayang Windu Geothermal Power Plant* is Indonesia's largest geothermal power station. This plant is located south of Bandung (West Java) and has a total installed capacity of 227 MW.

Technology Types

Geothermal energy arises from the heat of the Earth's molten interior and occurs mainly in geologically active areas. Geothermal energy can also occur where hot rock deposits are heated by the radioactivity of granite. Geothermal resources may be classified into three categories: hydrothermal / volcanic, hot sedimentary aquifer, and hot rocks/enhanced geothermal (Australian Mining 2015).

Hydrothermal-convection resources are subdivided further into vapour, and liquid-dominated resources, which produce mostly steam and hot water, respectively. They occur as a result of heat transfer from geologically active high-temperature belts to aquifers in close proximity. Hot rock resources are hot rock masses that lack fluid content but are close enough to the surface for heat extraction.

Geothermal plants can be of very low capacity or high capacity (0.05 MW to 200 MW) category. Thirty to 60 MW plant sizes are common for steam configurations. Energy supply may degrade over time due to reservoir degradation (AGL 2017).

Brief Description of the Technology

A brief description of each of the above ground geothermal conversion technology is given below. This is followed by a brief description of the geothermal resource by which geothermal technologies are generally categorised.

Back Pressure Conversion System

Back pressure geothermal power plant systems are simple and low cost, but have the lowest thermal efficiency compared to the other types of geothermal power plants. A backpressure turbine without a condenser might convert around half as much energy in steam to electricity, compared to a condensing turbine. They also can find application as wellhead units on isolated wells. Back pressure systems can operate on a range of inlet pressures and non-condensable gas contents, since there is no gas removal equipment required, making them well suited to proving a new field.

Hydrothermal Flash Steam Conversion System

Flashed steam hydrothermal plants are suited for high enthalpy (energy and pressure) (a thermodynamic property equal to the sum of the internal energy of a system and the product of its pressure and volume) geothermal resources. Flash steam, reservoir temperatures are hotter than 180°C. Hot water is removed from the production well and flashed in a separator (some systems require more than one separator), where the drop in pressure causes part of the water to flash to steam. Liquid from the first flash is sometimes sent to a second stage separator ("dual flash"), to produce lower pressure steam, and some triple flash units are also operating. The flashed steam is sent to the high-pressure and low-pressure inlets (if multiple flash) of a steam turbine generator. The steam is then routed through a steam turbine generator while the separated water ("brine") is re-injected into the hydrothermal reservoir. After the steam passes through the steam turbine, it is returned to the reservoir to be reheated.

Moderate-Enthalpy Binary Cycle Conversion System

Binary hydrothermal plants are best suited to moderate enthalpy geothermal resources. Geothermal water is passed through a heat exchanger, where it transfers heat to a second (binary) liquid: the working fluid. The working fluid then boils to vapour and expands through a turbine, generating electricity. The working fluid is then condensed to a liquid to begin the cycle again, while the geothermal water is returned to the reservoir via a re-injection well to be reheated.

Binary Hydrothermal Plant

Low Enthalpy Binary Cycles / Reverse Air Conditioning Cycle Conversion System

For low-enthalpy geothermal resources, a cycle based on mass-produced air conditioning components can be utilised. The cycle is based on a single stage centrifugal compressor, which runs in reverse as a radial inflow turbine and a heat exchanger originally designed for large chiller applications that transfer heat from the geothermal resource to the working fluid, a low cost R-134a fluid. Fully manufactured modules can be added to expand the power of geothermal plants with low temperature resources. In general, this low cost technology can expand the minimum temperature range for producing power from lower temperature, shallow geothermal hot springs systems from 105°C to around 80°C.

Hot Rock (HR) Resource

Potential Hot Rock resources are relatively deep masses of rock that contain little or no steam or water and are not very permeable. They exist where geothermal rock temperature reaches commercial usefulness at depths of about 3 km or more. The “operating” phase of the hot rock system involves water from the surface being pumped down injection wells, percolating through the fractures to extract energy from the rock, which is then produced at the surface from the production wells. At a sufficient temperature, the water can be flashed to steam and used to generate power. The technical challenges lie not in the power cycle, but rather the sub-surface elements of the system, notably related to deep drilling, in situ fracturing and mapping of the fractures (MIT last retrieved on 19 October2017).

Expected Technology Developments

Hydrothermal technologies are generally considered more matured than the other geothermal energy technologies. Off-the-shelf power generation equipment is readily available for hydrothermal plants and the drilling technology required for tapping the resource is now well established with lower risk than in the past. Advancements in scale inhibitor chemical technology has helped to reduce problems with wellbore and equipment scale and, in turn, reduced operations and maintenance. Better understanding also exists now of proper reservoir management to increase project life and reduce long term resource risk. However, occasionally drilling results in dry holes, which do not produce hot liquids or steam. There is also risk associated with reservoir cooling and reservoir management to maintain the reservoir output. Reservoir life depends on the success of re-injection into the geothermal reservoir, and supplemental injection may be needed to extend the reservoir life.

Hot Rock (HR) is not yet a commercial technology. Well costs increase exponentially with depth, and because HR resources are much deeper than hydrothermal resources they are much more expensive to develop. The technical feasibility of creating HR reservoirs has been demonstrated at experimental sites, but operational uncertainties regarding the resistance of the reservoir to flow, thermal drawdown over time, and water loss have so far made commercial development risky (OoEERE, Oct 2015).

Geothermal Resource Development Techniques such as fracture mapping, more accurate thermal-gradient wells, and other, untested methods should be evaluated and refined to be able to better measure the temperature, fluid characteristics, and permeability of the resource prior to committing to expensive production wells and generation equipment.

The key performance parameters for the Geothermal technologies considered are summarised in the following table.

Table 5.8: Key performance parameters and associated cost estimates for Steam and Hot Rock Geothermal technology options

Technology description	Units	Geothermal, steam	Geothermal Hot Rock
Construction period	y	1.5	3
New entrant plant capacity	MW	70	125
Capital cost	$/kW	3100	4200
CO2 Transport & Storage	$/t		
Thermal efficiency (sent out - HHV)	%		
Average capacity factor	%	80	80
Fuel price	$/GJ		
Fixed O&M	$/kW-y	48	47
Variable O&M	$/MWh	0.7	3
Emissions captured	%		
Emissions rate	kg CO2e/MWh	0	0
LCOE			
Capital cost	$/MWh	40	57
Fixed O&M	$/MWh	7	7
Variable O&M	$/MWh	1	3
LCOE	$/MWh	48	67

5.10 Nuclear Technologies

Brief Technology Description

Nuclear energy is mainly generated by the Nuclear splitting (fission) process. The change of atomic mass is converted into heat. This heat and liquid is used to produce steam, which in turn generates electricity by steam turbine similar to the steam coal plants. The fission reactions are increased by a number of neutrons. This is substantiated by moderators and control rods. Nuclear power plants generate nuclear waste and require safe storage and disposal of this waste.

5.10.1 Large Scale Nuclear Power Generation

Pressurised Water Reactor (PWR)

This is the most common type, with over 230 in use for power generation. They originated as a submarine power plant. Pressurised water reactors use ordinary water as both coolant and moderator. The design is distinguished by having a primary cooling circuit which flows through the core of the reactor under very high pressure, and a secondary circuit, which is under less pressure, in which steam is generated to drive the turbine to generate electricity. Water in the reactor core reaches about 325°C, hence it must be kept under about 150 times atmospheric pressure to prevent it boiling. Pressure is maintained by steam in a pressuriser. In the primary cooling circuit the water is also the moderator, and if any of it turned to steam the fission reaction would slow down. This negative feedback effect is one of the safety features. The secondary shutdown system involves adding boron (to absorb radiation) to the primary circuit.

Generation III reactor technology describes the current generation of light water reactor (LWR) fuelled new build advanced reactors being deployed. They are generally variants on the Generation II fleet but with major advances in safety and constructability. These large, GW scale units are similar in load profile to a large coal plant and are almost always run as base-load stations.

Large scale nuclear generators such as Generation III and III+ reactors are being constructed and continue to undergo development. As reactor designs become more standardised, the hope is that the permitting and licensing period before construction can be reduced to help control capital costs.

Expected Technology Developments

Future technological developments are likely towards uprating of the existing plants, increasing in capacity factors by reducing the length of refuelling outages, increasing burn up rates to reduce waste volumes and developing new fast reactor fuels to reduce waste toxicity. Developments are also likely in closed fuel cycle, incorporating both fast and slow (thermal) neutron reactors, with the fast reactors producing power and MOX fuel (a reactor fuel made from plutonium that has been separated from spent nuclear fuel by chemical reprocessing and mixed with natural or depleted uranium) for thermal neutron reactors. While nuclear power plants do not release atmospheric emissions, they do produce nuclear waste.

Reprocessing nuclear waste creates concerns about weapons proliferation, while disposing of nuclear waste raises issues about the safety and longevity and where to store it. Nuclear power plants also face water issues. Large amounts of water must be used for the cooling cycle in nuclear power plants. For these reasons, and since the cost of renewable technologies has been coming down, many countries do not consider the need to use nuclear generation. In addition, nuclear power plants involve high capital cost, while they may remain less expensive to operate than typical fossil fuel plants. The high upfront cost, lengthy licensing period, and financing risk remain a barrier for nuclear power development.

5.10.2 Small Modular Reactors (SMR)

Technology Description

An emerging technology, which notwithstanding licensing and other uncertainties, could be commercially available in a few years' time, and may be suitable as an additional generation source. This technology is known collectively as Small Modular Reactors (SMR) and describes a group of reactor designs intended to provide scalable generation from around 25 MW up to 1,200 MW by incrementally adding modules over time, which is comparable to gas turbine technology available today.

Indonesia currently does not have any nuclear generation plant. Given its segregated electricity market structure, small scale plant (SMRs) may be a better choice if the policy makers decide to use nuclear generation in the future in Indonesia.

The SMR technologies, in addition to modularity, have even further advances in safety and constructability over the GW scale Generation III designs.

As noted, for the purposes of this study we have focussed our LCOE review on LWR based SMRs, as this technology is the most immediately suitable in an Indonesian context. All commercial LCOE data for SMRs are based on AETA (2013, 2012) but converted to the local Jakarta conditions.

Performance

It should be noted that the LCOE analysis for Nuclear technologies does not include disposal/storage of spent fuel or provision for decommissioning of plant. The AETA (2013) study cites a report in the Journal of Economic Perspectives (Davis 2012) that puts the contribution of spent fuel storage in the order of US$1 / MWh. Also, the decommission costs have not been included for any of the technologies in the calculation of LCOE. While there is an expectation that decommissioning for nuclear plant will be higher per MW installed capacity than many other technologies, there is very little current experience of actual plant decommissioning. In addition, given the operating timeframes of new build plant, the decommissioning cost will be incurred well outside the modelled period, and unlikely to have a significant impact on LCOE.

The SMRs provide a unique feature due to their modular approach. Capital can be phased over a period of time with revenue generated as the first module is installed and used to fund the second and so on. SMRs also have shorter projected lead time to energy export compared to GW designs. Current projections stand at 24 to 36 months compared to 48 to 60 months for GW-scale. In addition the smaller power block sizes mean that less significant PPAs are required to underwrite funding when compared to a GW-scale investment.

Expected Technological Improvement

High Temperature Gas and Liquid Metal reactors

These reactors offer the potential of improved safety and relatively high reactor outlet temperatures (6000 C) with associated improved thermal efficiencies. Current designs are at the proof of the concept stage and the more advanced designs are undergoing licencing assessment by the NRC in the US.

Fast Neutron Reactors

What is termed Generation IV technology, the fast neutron reactors are able to consume U-238, which greatly improves uranium fuel utilisation compared to LWRs, which consume only

U-235. Some more advanced fast reactor designs are intended to utilise the spent fuel from LWR (Generation III/III+) technology in a manner that would actually consumes long lived actinides (radioactive element). This technology exists today and has been deployed in research reactors for over 40 years. However, it has never been developed for commercial deployment; hence, further work is underway to address this. It is possible that commercial fast reactor Gen IV fleets will be available for commercial operation around by 2030. France, for instance, has declared an intention to commission a commercial fast reactor for internal use by 2022.

Improvements are also being made to reduce the transportation of Tritium (a radioactive isotope of hydrogen) necessary in the reaction to follow (Tritium may be bred within the reactor). This will increase safety.

The key performance parameters for the nuclear, SMR technology are summarised in the following table.

Table 5.9: Key performance parameters and associated cost estimates for Nuclear-SMR technology option

Technology description	**Units**	**Nuclear - SMR**
Construction period	Y	3
New entrant plant capacity	MW	600
Capital cost	\$/kW	5400
CO2 Transport & Storage	\$/t	0
Thermal efficiency (sent out - HHV)	%	33
Average capacity factor	%	83
Fuel price	\$/GJ	1
Fixed O&M	\$/kW-y	80
Variable O&M	\$/MWh	2
Emissions captured	%	0
Emissions rate	kg CO2e/MWh	0
LCOE		
Capital cost	\$/MWh	71
Fixed O&M	\$/MWh	11
Variable O&M	\$/MWh	2
Fuel costs	\$/MWh	11

Cost of CO_2 T&S	$/MWh	0
LCOE	$/MWh	95

5.11 LCOE projections to 2050

The Australian Government's Commonwealth Scientific and Industrial Research Organisation's (CSIRO) GALLM learning curve model results were employed to develop LCOE projections to 2050.

CSIRO has used a combination approach to projecting capital costs, based on the foundation of an economic model with learning curves. The GALLM model assesses a number of factors in order to establish the learning rate; current maturity of the technology in the world (ie its progression on the learning curve); expected rate of deployment of the technology world-wide; and rate of reduction of cost (with deployment).

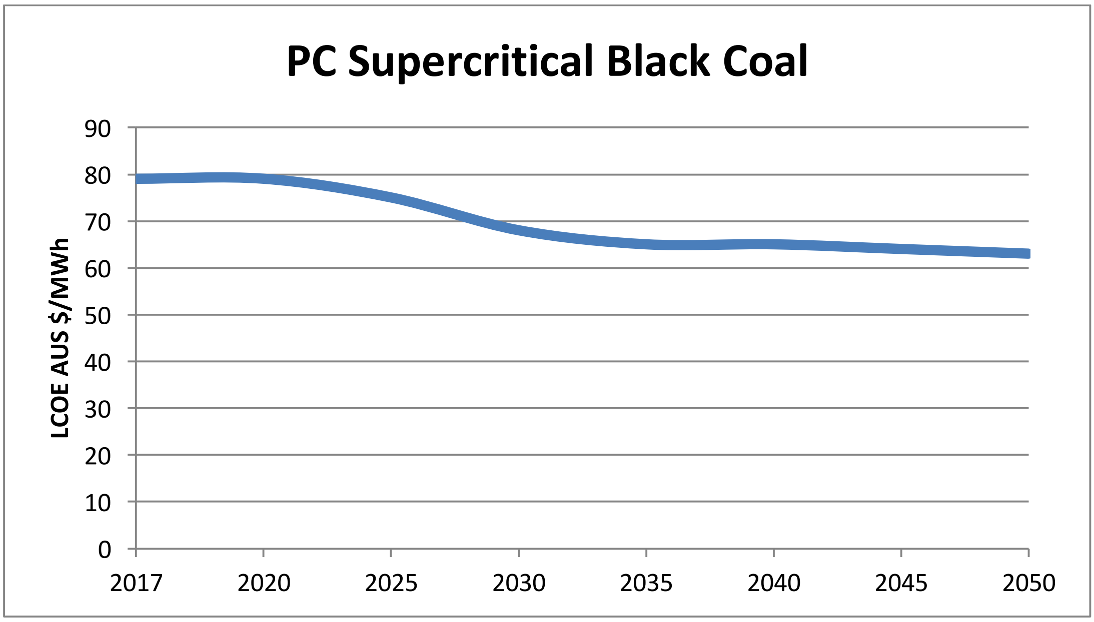
The presented learning rate is thus an effective rate, including both a forecast of the uptake of the technology and the reduction of cost associated with deployment at that rate. The GALLM technology learning (cost reduction) results were obtained for this work from CSIRO in early 2016.

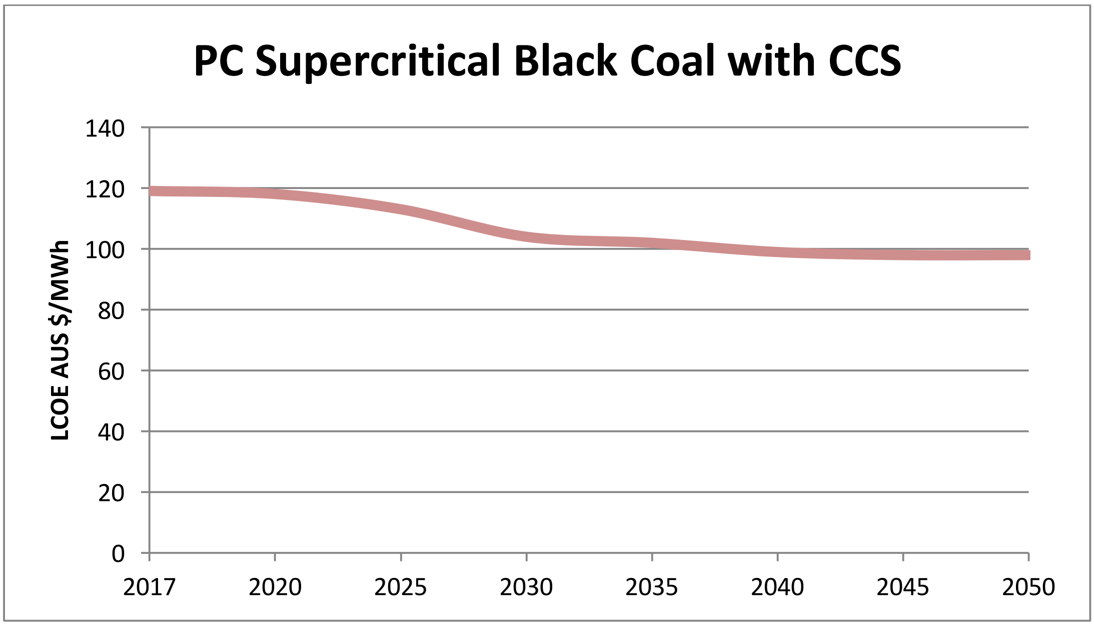
The GALLM learning rate results (cost declines) were applied to the base year results for 2017 obtained in the above analysis. These projections, which are in real Australian dollars, are presented in Table 5.10.

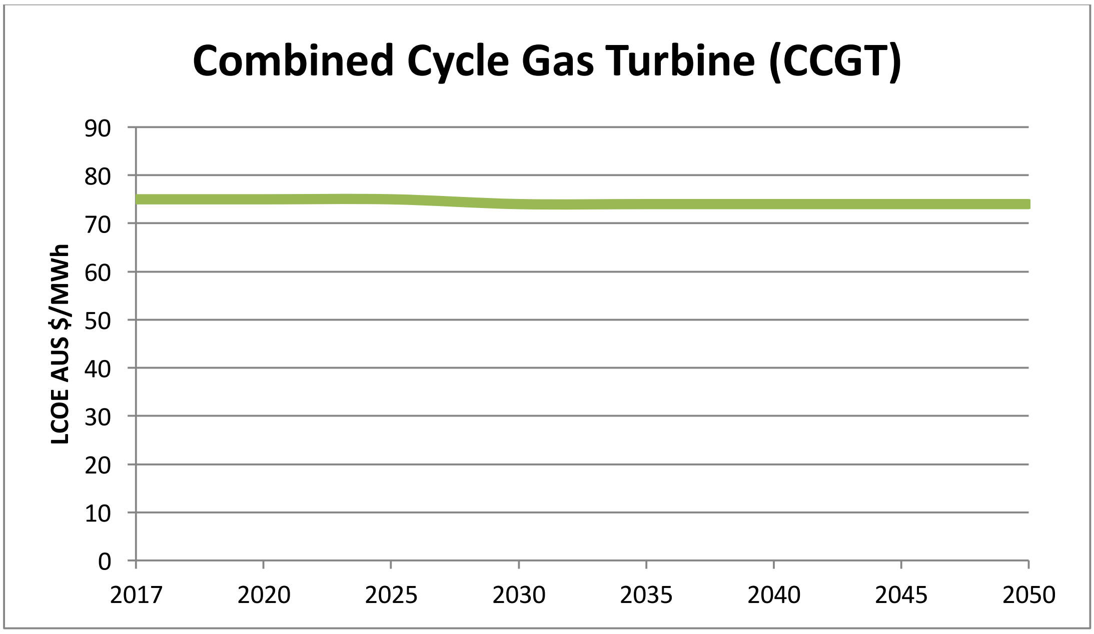
Table 5.10: LCOEs of IETA technologies to 2050, real AUS $/MWh

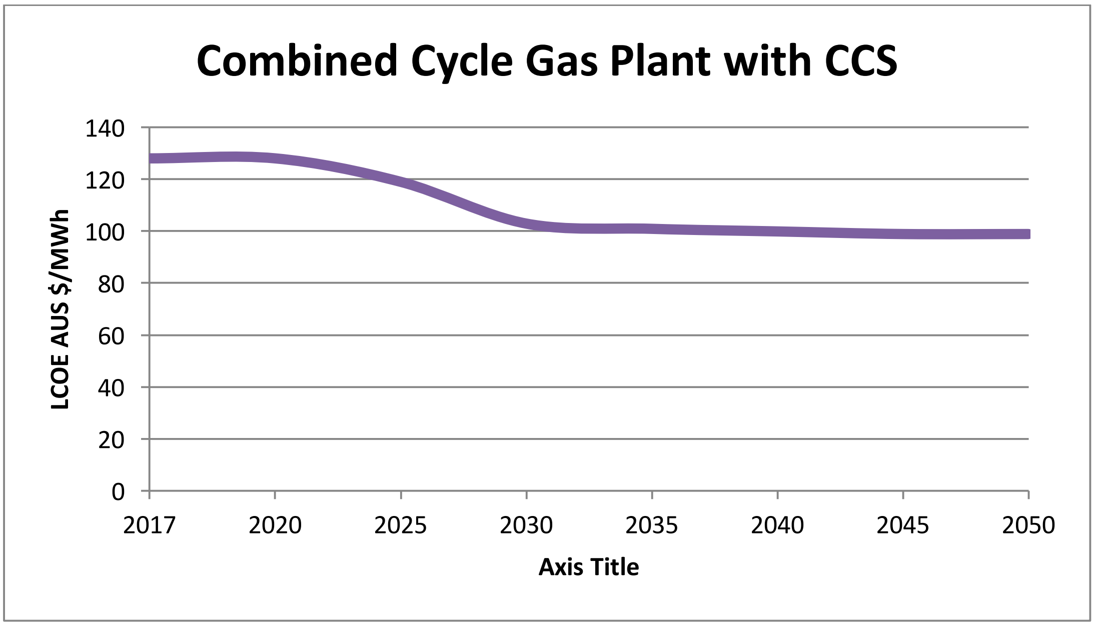
Year	2017	2020	2025	2030	2035	2040	2045	2050
PC supercritical black coal	79	79	75	68	65	65	64	63
PC supercritical black coal w CCS	119	118	113	104	102	99	98	98
Combined cycle gas turbine (CCGT)	75	75	75	74	74	74	74	74
Combined cycle gas plant with CCS	128	128	119	103	101	100	99	99
Open cycle gas turbine - aero	123	122	121	120	118	118	117	116
Solar thermal C. R. w 6 h storage	146	132	91	76	75	74	74	74
Solar PV - fixed	76	69	63	45	35	30	30	29
Solar SAT PV	74	67	61	44	34	30	29	29
On-shore wind	81	80	72	66	65	64	63	62
Wave/ocean energy	133	133	133	115	109	104	99	94
Biomass - waste	55	55	55	55	55	54	53	53
Geothermal, steam	48	48	48	47	47	47	47	47
Geothermal Hot Rock	67	67	67	66	65	65	65	65
Nuclear - SMR	95	95	95	94	94	94	93	92

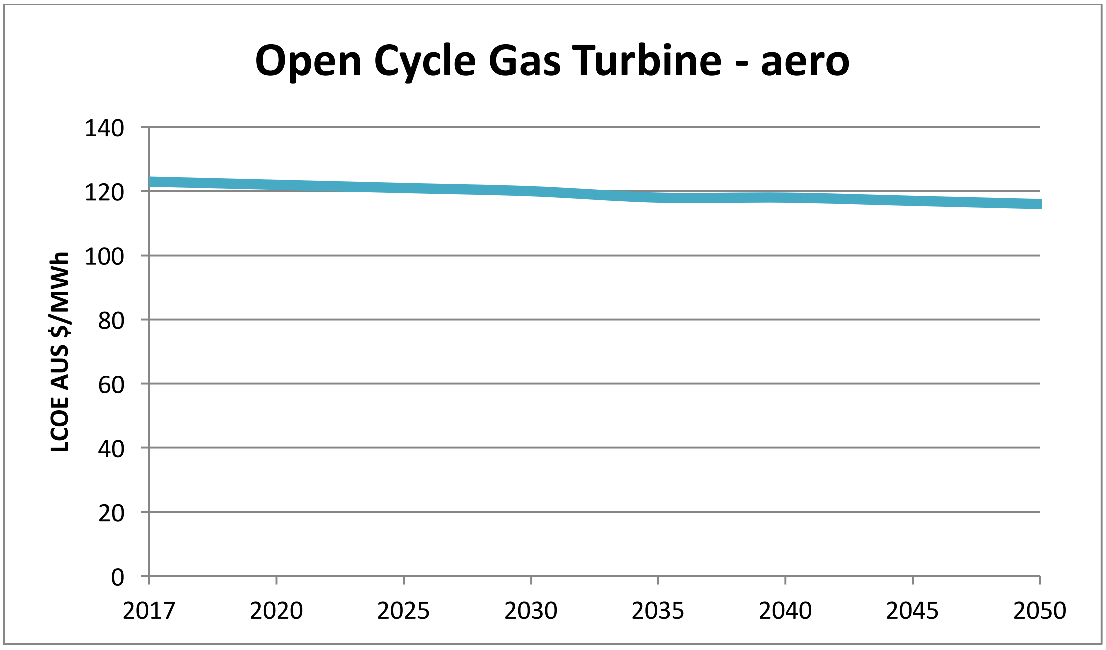
The cost curves for each technology of the 14 are plotted on the following pages.

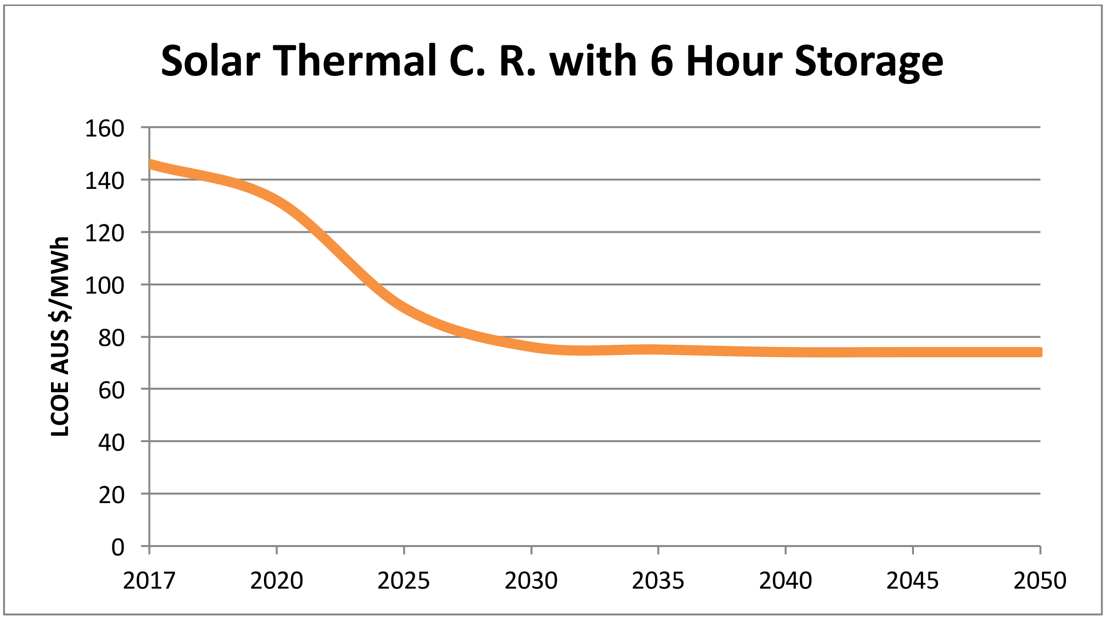


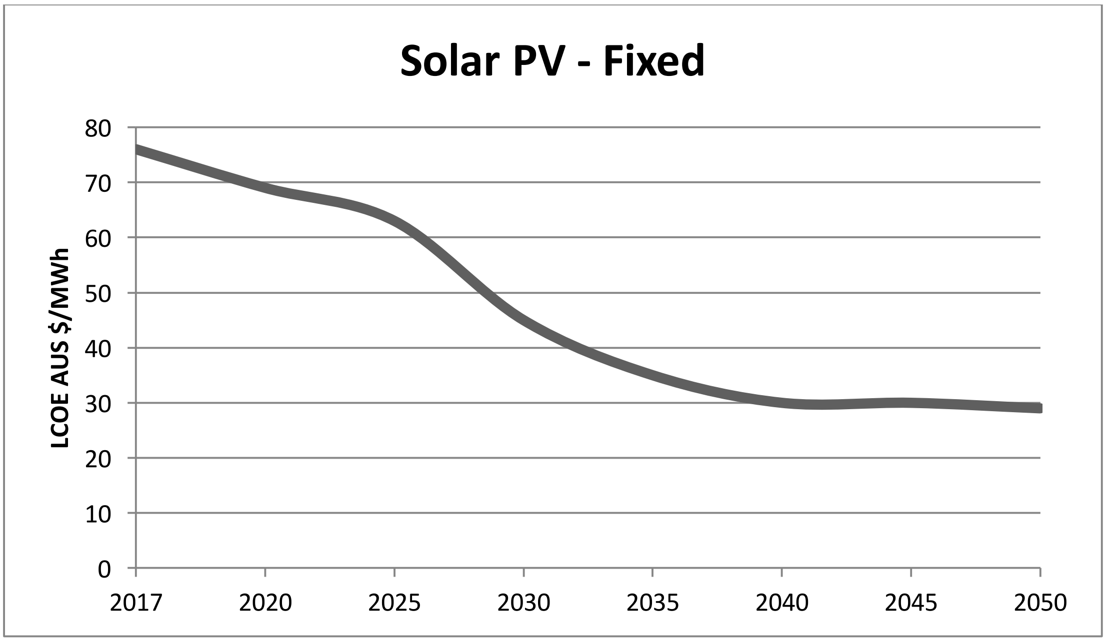

PC Supercritical Black Coal with CCS
LCOE AUS $/MWh
140
120
100
80
60
40
20
0
2017
2020
2025
2030
2035
2040
2045
2050

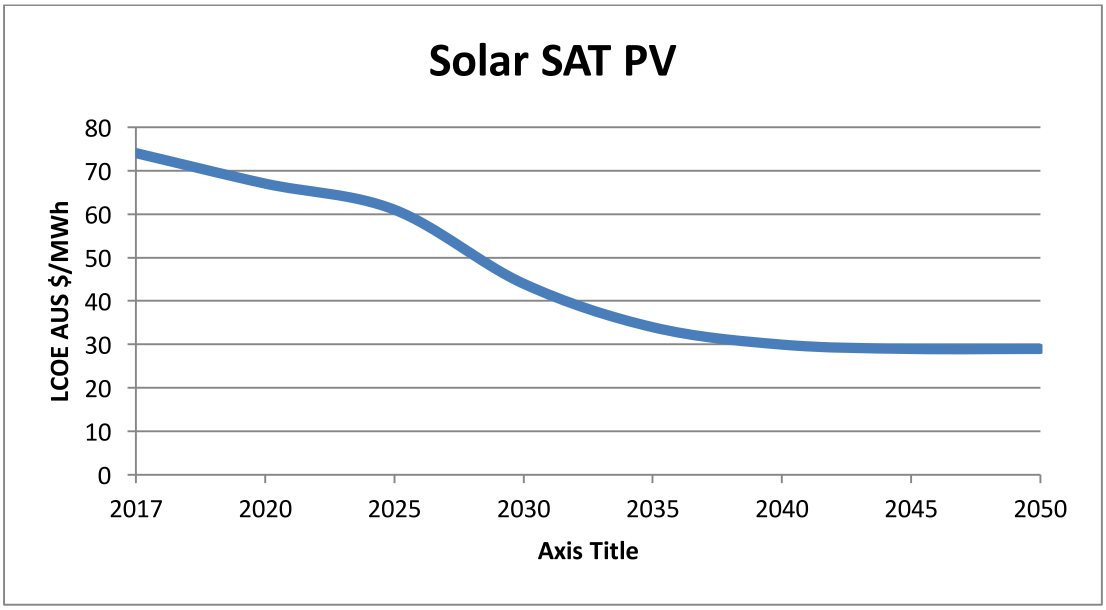

Combined Cycle Gas Turbine (CCGT)
LCOE AUS $/MWh
90
80
70
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050

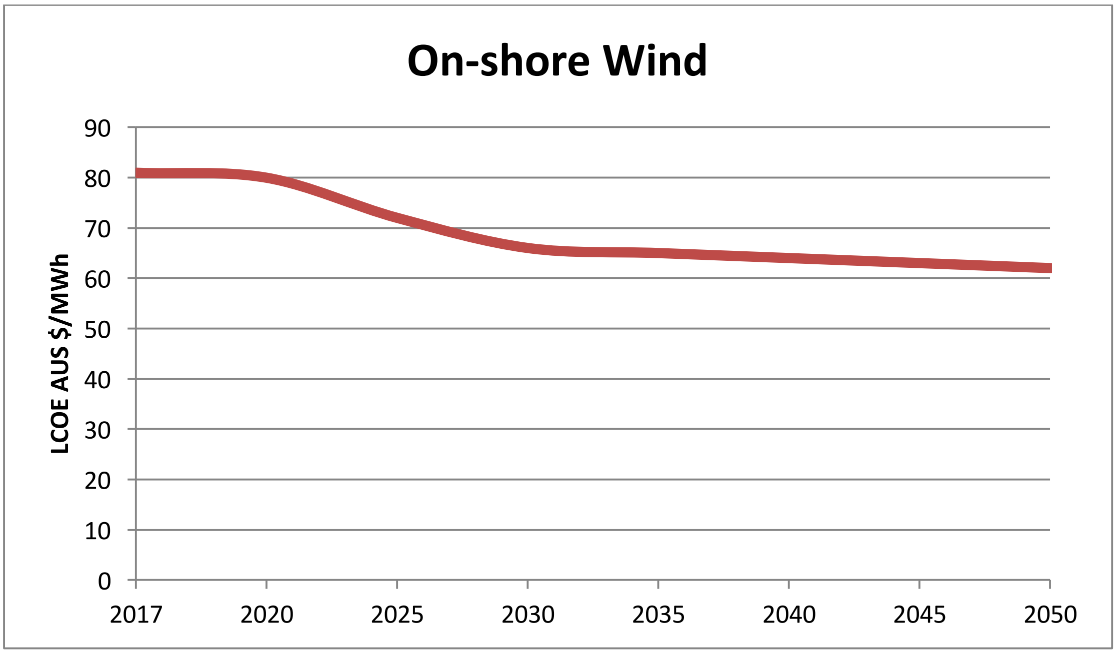

Combined Cycle Gas Plant with CCS
LCOE AUS $/MWh
0
20
40
60
80
100
120
140
2017
2020
2025
2030
2035
2040
2045
2050
Axis Title

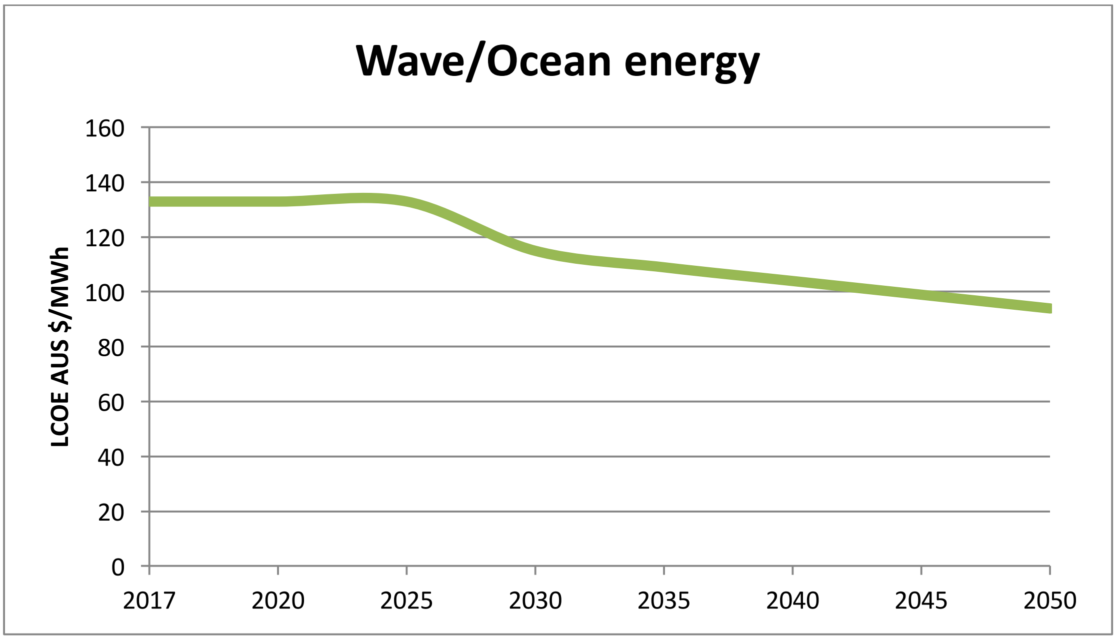

Open Cycle Gas Turbine - aero
LCOE AUS $/MWh
0
20
40
60
80
100
120
140
2017
2020
2025
2030
2035
2040
2045
2050

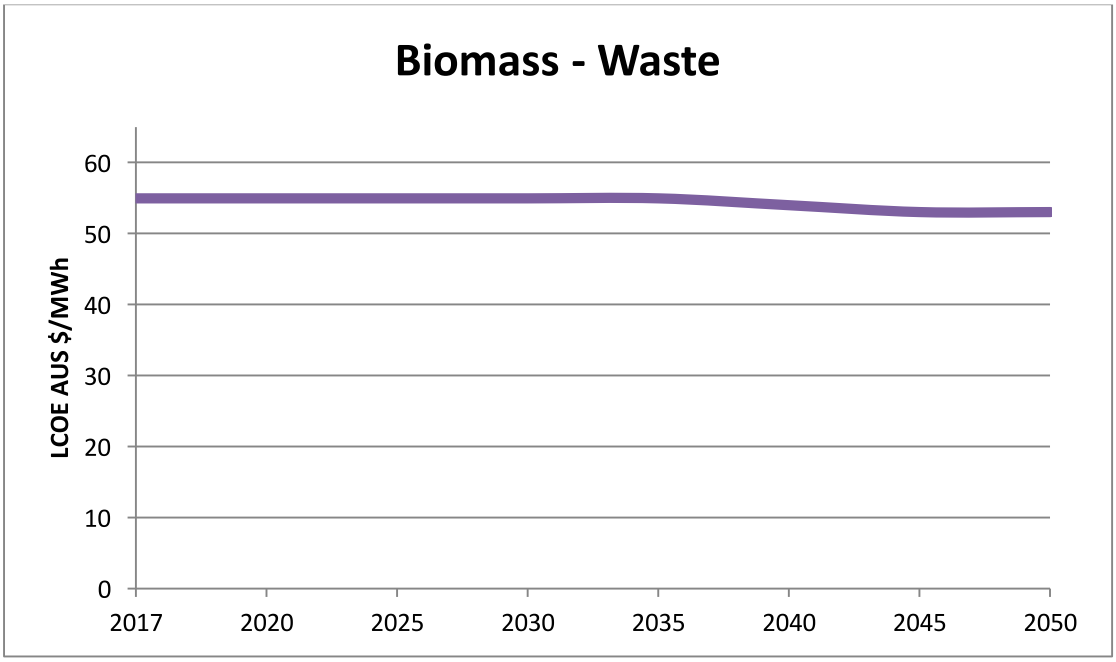

Solar Thermal C. R. with 6 Hour Storage
LCOE AUS $/MWh
160
140
120
100
80
60
40
20
0
2017
2020
2025
2030
2035
2040
2045
2050

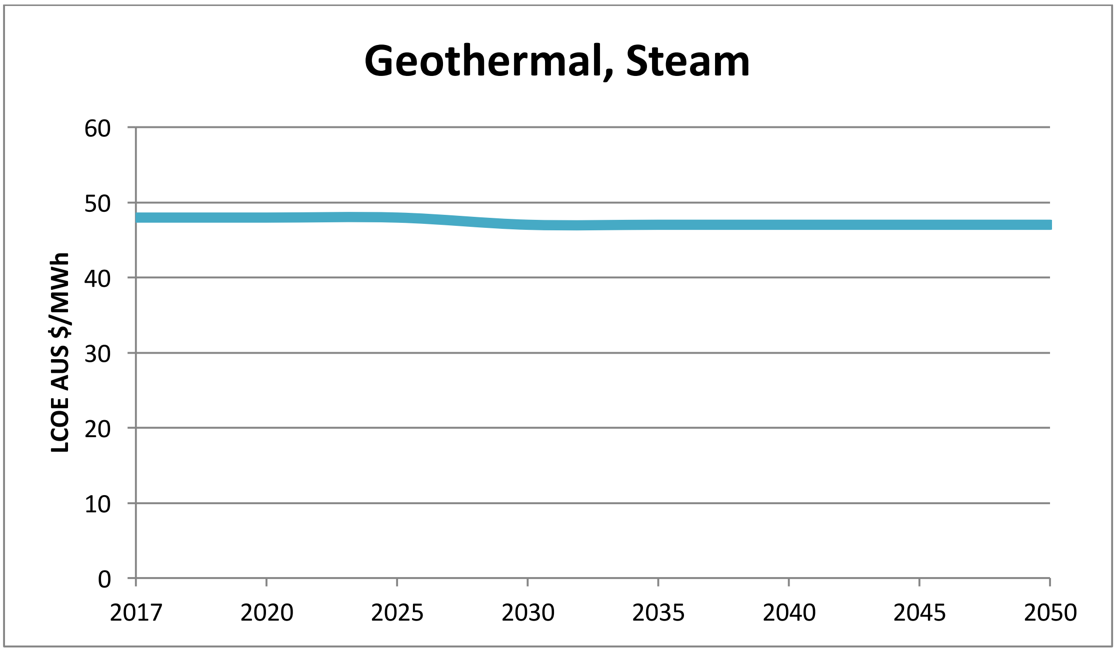

Solar PV - Fixed
LCOE AUS $/MWh
80
70
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050

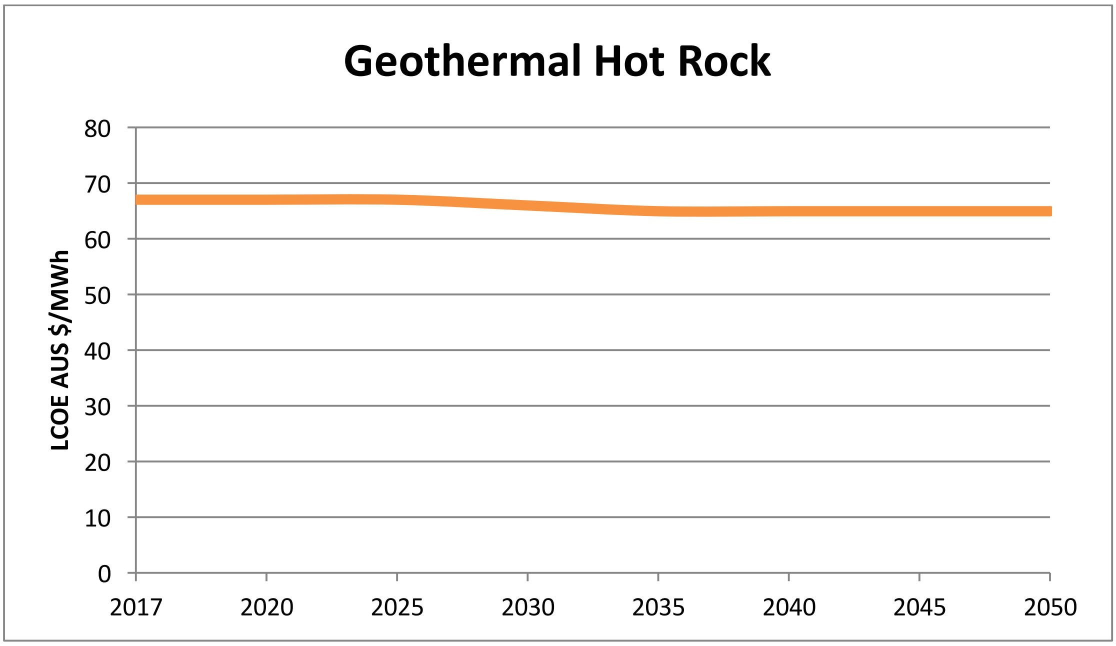

Solar SAT PV
LCOE AUS $/MWh
80
70
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050
Axis Title

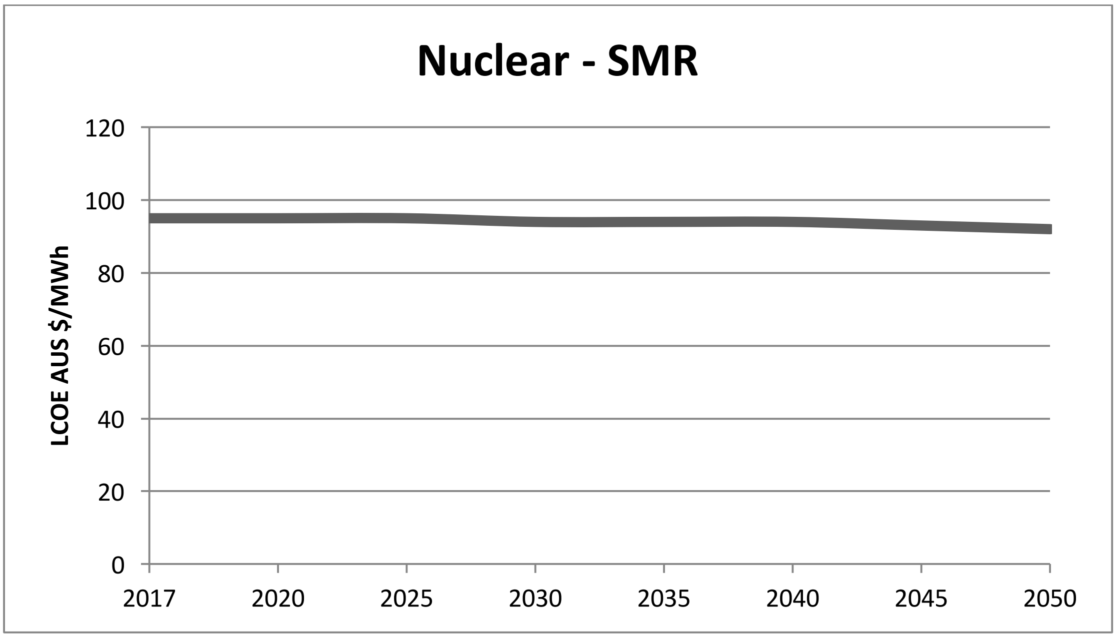

On-shore Wind
LCOE AUS $/MWh
90
80
70
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050


Wave/Ocean energy
LCOE AUS $/MWh
160
140
120
100
80
60
40
20
0
2017
2020
2025
2030
2035
2040
2045
2050


Biomass - Waste
LCOE AUS $/MWh
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050


Geothermal, Steam
LCOE AUS $/MWh
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050


Geothermal Hot Rock
LCOE AUS $/MWh
80
70
60
50
40
30
20
10
0
2017
2020
2025
2030
2035
2040
2045
2050



Sensitivity analysis

As described above for each technology in detail, with more experience in especially renewable generation plants, and also in fossil fuel technology plants the cost of all technologies is expected to continue to decrease due to scientific developments and higher production efficiencies in key equipment and increased experience gained by manufacturers and engineers who are planning and building plants. Also, it is expected that better and cheaper heat transfer fluids will become available that can handle higher temperatures resulting in increased efficiency.

Capital cost of renewable technologies has been declining fast since 2011. Given the degree of research work going on in further technological development of renewable technologies world-wide (see above text in this report), and also because of the increased manufacturing and market economies as China's renewable production rises, it can be reasonably expected that capital costs of all renewables will decline, albeit to varying degrees – probably more so in the case of solar technologies. However, in the sensitivity analysis below, we have reduced all renewable technology capital costs by 20 per cent uniformly.

It is not expected that cost parameters for fossil fuel technologies will go down much in the near future, given that these are matured technologies. For this reason, the sensitivity analysis below assumes a reduction of 5 per cent in the cost of capital for all technologies – coal and gas, including nuclear.

Other than the changed capital cost parameters, under the sensitivity analysis most other cost and performance parameters retain the same value as in the LCOE costing tables above. For this reason, full costing tables (as above) are not repeated below. Table 11 shows the base year LCOE results for 2017 for each technology. In addition, similar to the analysis above, GALLM model results were used to project the LCOE values to 2050.

Note: This note refers to both the cost parameters used in the sensitivity analysis (Table 11) as well as in the earlier LCOE costing Tables 5.1 to 5.10. The cost parameters used in these tables are based on a review of literature, and advice obtained from energy and technology experts in Indonesia and Australia. It is possible that users of this report may like to examine the impact on an LCOE using their own parameter values. For this reason the Energy Change Institute, ANU is planning to produce a generalised LCOE costing model. This model will allow the users to generate an LCOE using their own values for the chosen parameters (capital costs, fuel cost, operational costs, capacity factors, or thermal efficiency, etc.).

Table 5.11: LCOEs of IETA technologies to 2050, real AUS $/MWh, with reduced capital costs

Year	2017	2020	2025	2030	2035	2040	2045	2050
PC supercritical black coal	77	77	73	66	64	64	63	61
PC supercritical black coal w CCS	116	115	110	101	99	97	96	96
Combined cycle gas turbine (CCGT)	74	74	74	73	73	73	73	73
Combined cycle gas plant with CCS	126	126	117	101	99	98	97	97
Open cycle gas turbine - aero	121	120	119	118	116	116	115	114
Solar thermal C. R. w 6 h storage	126	114	79	66	65	64	64	64
Solar PV - fixed	67	61	55	40	30	26	26	26
Solar SAT PV	64	58	53	38	29	26	25	25
On-shore wind	72	71	64	59	58	57	56	55
Wave/ocean energy	114	114	114	99	93	89	85	81
Biomass - waste	51	51	51	51	51	50	49	49
Geothermal, steam	42	42	42	41	41	41	41	41
Geothermal Hot Rock	58	58	58	57	56	56	56	56
Nucler - SMR	91	91	91	90	90	90	89	88

Chapter 6
LCOE Results and Conclusions

The LCOE results discussed in this chapter were derived in Tables 5.1 to 5.10. That is, the main results obtained for this report are summarised below. The sensitivity analysis results are not repeated below.

6.1 LCOE Results

Key points

- Estimated costs of solar photovoltaic technologies have declined dramatically in the past two to three years as a result of a rapid increase in global production of photovoltaic modules.
- Differences in the cost of generating electricity, especially between fossil fuel based and renewable electricity generation technologies, are further expected to decline in the future.
- Throughout the projection period to 2050, Geothermal Steam, Biomass, and some Solar electricity generation technologies remain the most cost competitive forms of electricity generation.
- Among the non-renewable technologies, PC supercritical black coal and combined cycle gas turbine offer the lowest LCOE over most of the projection period.

6.2 Individual technologies

For each of the 14 technologies analysed, tables and charts are provided to summarise LCOE out to 2050. The IETA costings provide component and LCOE costs for each technology in the Jakarta region.

For many of the renewable technology options, the LCOE is projected to decline fast over time. On the other hand for established fossil fuel technologies the rate of decline is low since, not much technological development is expected in these technologies. The rates of change in LCOEs shown in IETA over time are net changes that is net of positive and negative changes caused by different factors, such as the technology improvement (decline), and fuel price growth (increase), etc.

6.3 Technology Cost comparisons

This section provides a relative ranking of the IETA technologies.

Key points

- LCOE costs are provided for the years 2017, 2020, 2025, 2030, 2035, 2040, 2045 and 2050 (see table 5.10 in section 5).
- LCOEs presented here represent the mid-point values of the LCOEs ranges
- LCOE costs vary substantially across the technologies from AUS $48/MWh to AUS $146/MWh in 2017 and AUS $29/MWh to AUS $116/MWh in 2050.

Figure 6.1 to 6.8 provide a relative ranking of technology LCOEs by 2017, 2020, 2025, 2030, 2035, 2040, 2045 and 2050 for Jakarta. The figures illustrate how the LCOE of various technologies change over time. Differences are explained by a multiplicity of factors including the technical developments, learning rates or cost reductions, and fuel prices.

Figure 6.1: LCOE for technologies, Jakarta, 2017

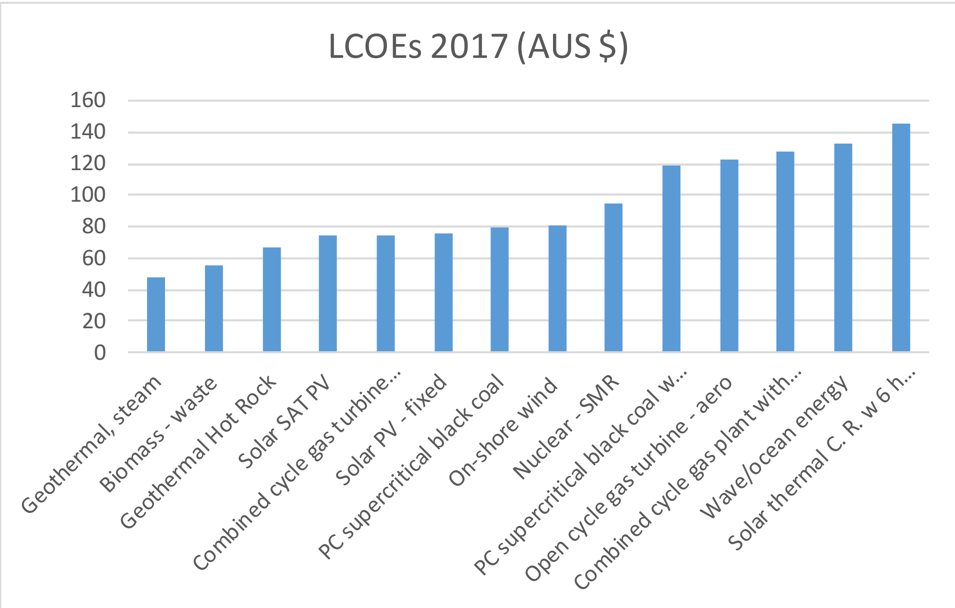


Figure 6.2: LCOE for technologies, Jakarta, 2020

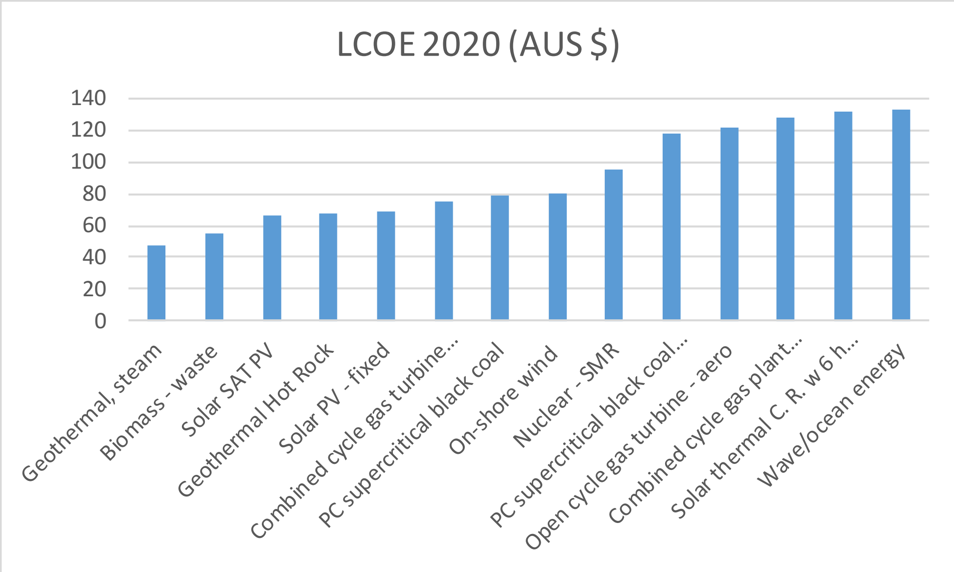


Figure 6.3: LCOE for technologies, Jakarta, 2025

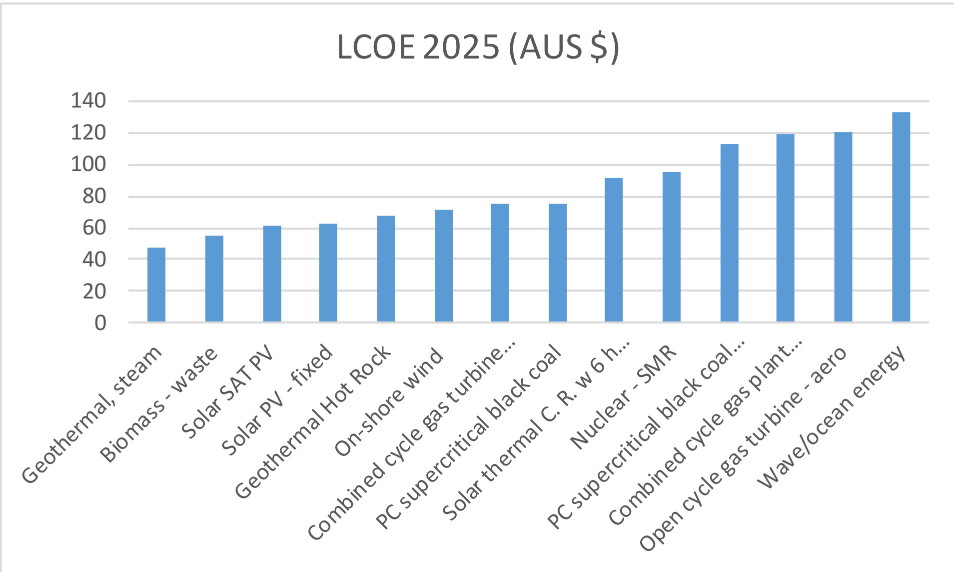


Figure 6.4: LCOE for technologies, Jakarta, 2030

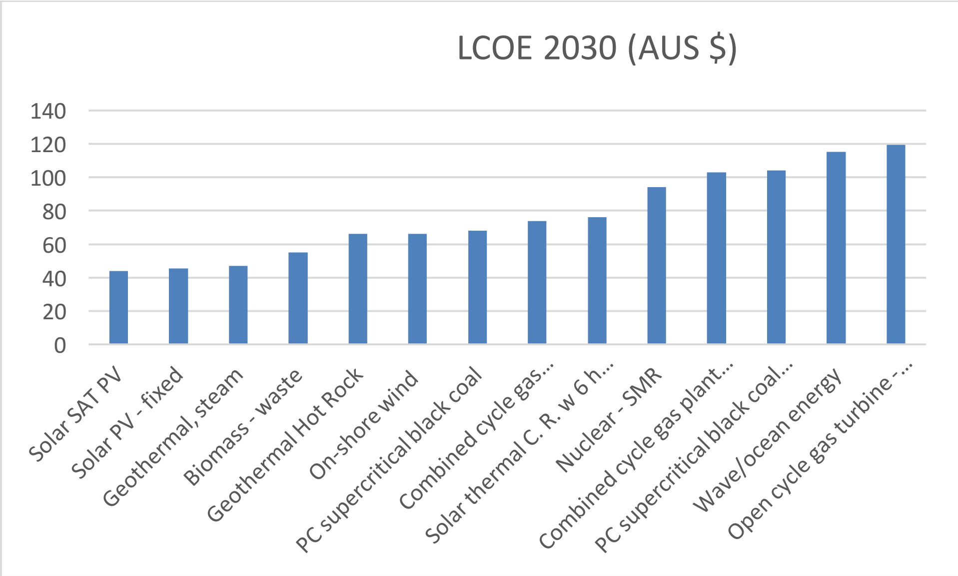


Figure 6.5: LCOE for technologies, Jakarta, 2035

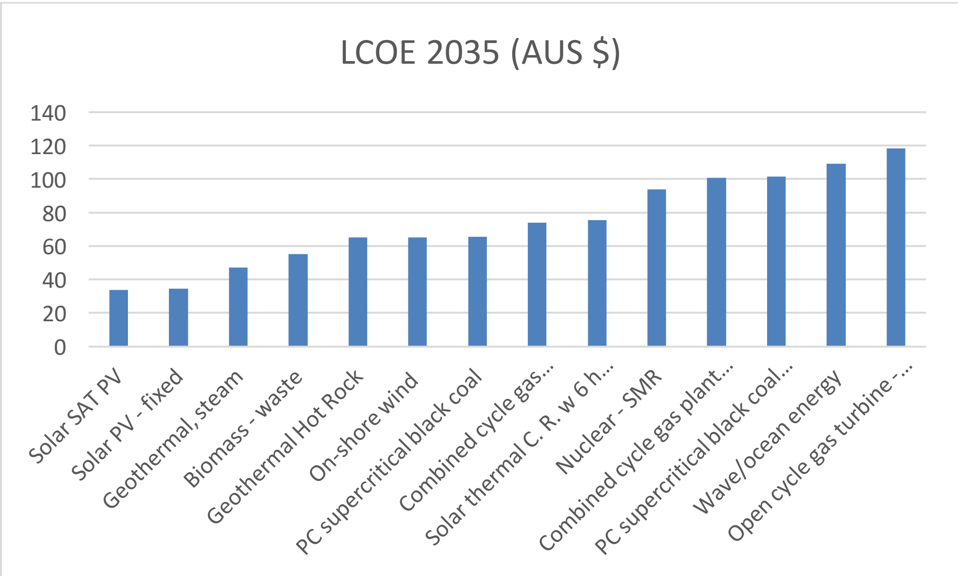


Figure 6.6: LCOE for technologies, Jakarta, 2040

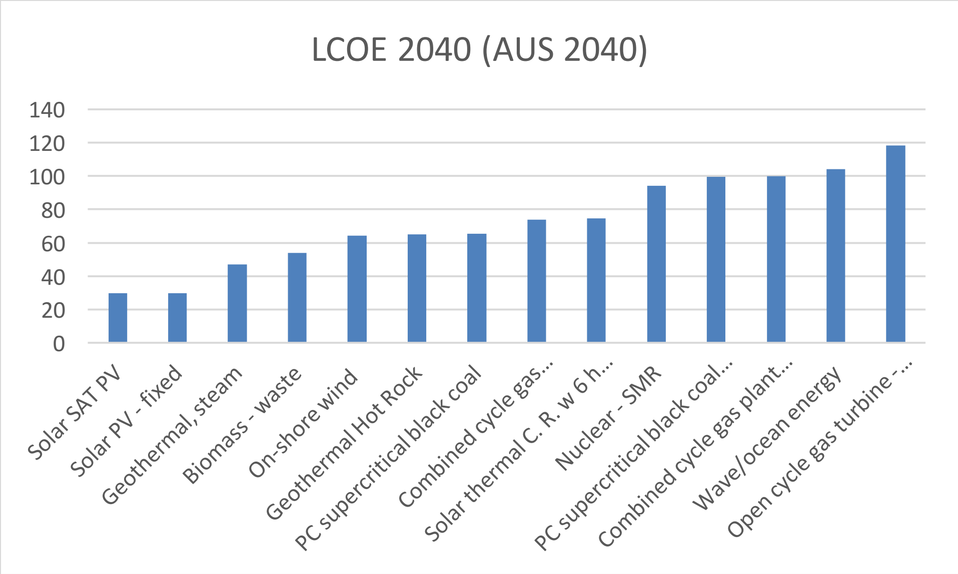


Figure 6.7: LCOE for technologies, Jakarta, 2045

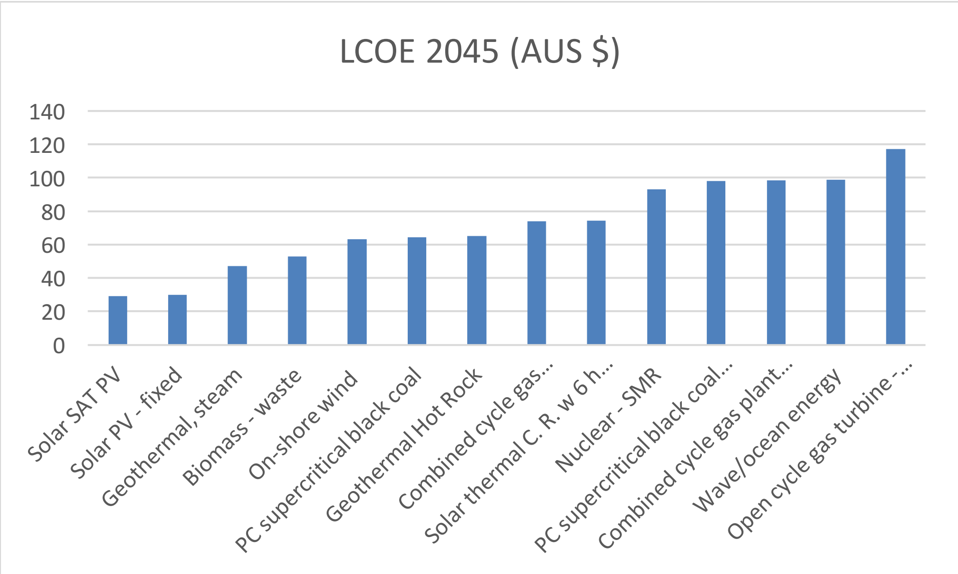
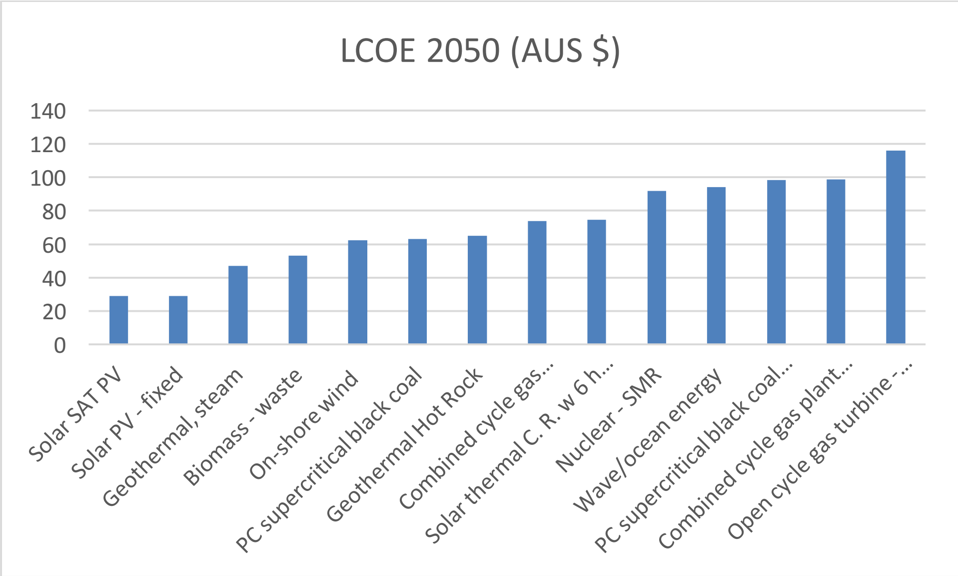


Figure 6.8: LCOE for technologies, Jakarta, 2050



The inter-technology LCOE comparisons figures (see Figures 6.1 to 6.8) reveal changes in relative costs of technologies over time.

6.4 Conclusion

This Indonesian Energy Technology Assessment (IETA) study provides the best available and most up to-date cost estimates for 14 electricity generation technologies under Indonesian, specifically the Jakarta region conditions. To ensure that the cost estimates for the various technologies are consistent, all important common input costs (capital, fuel prices, fixed and operational maintenance costs, operational efficiency, etc.) are itemised in tables for each technology.

IETA has been developed in consultation with Indonesian experts, and Indonesian technology input cost studies especially for the selected values of fuels prices, performance parameters and interest rates.

A key finding of the study is that the costs of renewable technologies would drop rapidly as a result of a rapid increase in global production and technological developments in these technologies.

The IETA cost estimates suggest that Jakarta's electricity generation mix out to 2050 is likely to be very different to the current technology mix. This is because the investment in renewable technologies will increase, and technology uptake will change compared to the current levels with the change in the cost of technologies.

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