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Integrated Energy System Planning for Equitable Access to Sustainable Energy for Remote Communities in the APEC Region Using North Sulawesi as a Pilot Project/Test Bed

APEC Energy Working Group

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Glossary

Abbreviation	Description	Definition
	Annualized Cost	The cost that, if it were to occur equally in every year of the project lifetime, would give the same net present cost as the actual cash flow sequence associated with that component.
BAT	Best Available Technology	Scenario used to evaluate the technical potential for energy efficiency afforded by the best technologies currently available on the market or designed from high-efficiency components.
BAU	Business As Usual	Scenario used in this study to forecast demand based on PLN's RUPTL 2018-2027.
	Candidate Plants	Plants with status of in planning in RUPTL 2018-2027 and RE potential plants, i.e. plants for which PLN currently has no commercial obligation to utilize but which are available options to serve additional capacity needs in the future.
	CO2 Intensity	Total emission divided by total energy production.
	Committed Plants	Plants with status of operating, in construction and in procurement in RUPTL 2017-2027, i.e. plants that PLN has a commercial obligation to utilize.
CEP	Cost Effective Potential	Scenario that represents usage of energy efficient appliances that provide the maximum energy savings that result in a net benefit to the consumer.
CCE	Cost of Conserved Energy	The cost incurred by consumers for using energy efficient appliances, which may be compared to the value of energy savings. See Appendix A.
COE	Cost of Energy	Total System Annualized Cost divided by annual energy production of the system.
DSM	Demand-side Management	Measures that influence the timing of level of electricity demand, including Energy Efficient measures.
EE	Energy Efficiency	Self-explanatory.
HFO	Heavy Fuel Oil	Self-explanatory.
	Net Generation	The amount of gross electricity generation less station losses and use produced by a generator.

NPC	Net Present Cost	The net present cost (or life-cycle cost) of a component is the present value of all the costs of installing and operating that component over the project lifetime, minus the present value of any revenues that it earns over the project lifetime.
TA	Trend Analysis	Scenario used in this study to forecast demand based on actual demand growth for the past five years instead of PLN's RUPTL 2018-2027 forecast.
	Peak Load	Maximum electrical power demand on the system.
PLTA	Pembangkit Listrik Tenaga Air	Hydro Power Plant
PLTB	Pembangkit Listrik Tenaga Bayu	Wind Power Plant
PLTBm	Pembangkit Listrik Tenaga Biomassa	Biomass Power Plant
PLTD/MG	Pembangkit Listrik Tenaga Diesel/Gas	Diesel/Gas Duel-Fuel Reciprocating Engine Power Plant
PLTG/GU	Pembangkit Listrik Tenaga Gas/Gas Uap	Open Cycle or Combined Cycle Gas Power Plant
PLTM	Pembangkit Listrik Tenaga Minihidro	Mini Hydro Power Plant
PLTP	Pembangkit Listrik Tenaga Panas Bumi	Geothermal Power Plant
PLTS	Pembangkit Listrik Tenaga Surya	Solar Power Plant
PLTSa	Pembangkit Listrik Tenaga Sampah	Waste-to-energy Power Plant
PLTU	Pembangkit Listrik Tenaga Uap	Coal Power Plant
PLN	Perusahaan Listrik Negara	Indonesia's National Electricity Company
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik	PLN's Electricity Supply Business Plan
RE	Renewable Energy	Self-explanatory.
SRMC	Short Run Marginal Cost	the cost of an incremental change in demand, holding at least one factor of production –

		generally, capacity – constant[1].
UEC	Unit Energy Consumption	The energy consumption of an electrical appliance.

[1] Kemp, et. Al. (2015). *Estimating Long Run Marginal Cost in the National Electricity Market*. NERA Economic Consulting for AEMC. Downloaded from: https://www.aemc.gov.au/sites/default/files/content/b339683c-e1ec-400d-9290-eeba7ae4551f/Technical-paper.pdf

ES 1. INTRODUCTION

In 2016, APEC conducted a policy review to develop a Low-Carbon Model Town (LCMT) for Bitung, North Sulawesi Province. APEC LCMT aims to combine energy-efficient buildings, transport, and power systems to create communities that affordably reduce energy use and carbon emissions while creating pleasant living conditions[2]. The APEC review[3], led by the Asia Pacific Energy Research Centre, identified high-level planning and policy recommendations in a number of areas relevant to a low carbon development: legal framework, sustainable urban planning, low-carbon buildings, energy management systems, renewable energy and untapped energy planning, transport and environmental planning.

To support the recommendations of the LCMT particularly with respect to renewable energy and energy efficiency, this study aims to provide a robust and practical model to assist policy makers in their regional planning for renewable energy and energy planning. This report specifically provides inputs for policy makers and local stakeholders in North Sulawesi for drafting the Regional Electricity Plan (RUKD - *Rencana Umum Kelistrikan Daerah*), which supports economic growth while reducing the emission levels. This study also provides an analytical framework that can be adopted by regional governments elsewhere in Indonesia and internationally to support energy policy making efforts.

The results of the study provide specific guidance on how to implement the recommendations of the Low-Carbon Model Town Stage 5 Final Report for Bitung. Bitung is within PLN's North Sulawesi-Gorontalo grid, which means that the electricity in Bitung can be sourced from anywhere in the grid. PLN has also provided one of its substations in Bitung SEZ, and includes the SEZ in its RUPTL. Therefore, implementation of the LCMT requires consideration of the entire grid that serves Bitung. This study defines a pathway to lower the system's emissions while serving demand growth through least-cost capacity additions.

The aim of this modelling exercise is to seek an expansion plan which can achieve at least 23% reduction in carbon emissions in the Sulbagut (*Sulawesi Bagian Utara*, North Sulawesi) system by 2032 relative to the 2022 level for Business-As-Usual (BAU) scenario, consistent with Indonesia's national emission reduction targets.

ES 2. METHODOLOGY

<u>*Scenarios definition for demand projection.*</u> The study starts by defining scenarios of future load growth. Two base scenarios are considered: (i) **Business-As-Usual** (BAU) which corresponds to PLN's Electricity Supply Business Plan 2018-2027 (*Rencana Usaha Penyediaan Tenaga Listrik* – RUPTL); (ii) **Trend Analysis** (TA) which reflects historical demand growth over the period 2013 to 2017 while also taking into account expected demand from the Bitung Special Economic Zone (SEZ). The TA scenario is created to provide comparisons to RUPTL's growth estimates which historically tend to have an upward bias.

[2] https://aperc.ieej.or.jp/publications/reports/lcmt.html
[3] https://aperc.ieej.or.jp/publications/reports/lcmt/LCMT_Stage_5_Policy_Review_final_report.pdf

Energy efficiency (EE) measures in demand projection. Scenarios are also defined to assess the impacts of energy efficiency programs on future generation capacity additions. In addition to running the two base scenarios with no expected change in energy efficiency (the “normal” scenarios), each of the base scenarios is subject to two levels of energy efficiency intervention, Cost Effective Potential (CEP) and Best-Available-Technology (BAT), which reduce demand growth, particularly peak demand growth. In total then, there are six load growth scenarios, BAU and TA each run with three energy efficiency variants: normal, CEP and BAT.

Review of electricity generation plants (RE+Non RE). This step identifies current and future supply options in the region. Renewable energy (RE) potential in the province is explored, which includes geothermal, hydro, solar, wind, waste and biomass. The majority of existing plants and plants planned by PLN in the region rely on fossil fuels, or Non RE, so these are conventional plants are also considered.

Least emission & least cost electricity system expansion plan. The HOMER Pro model (www.homerenergy.com) is then applied to determine the least-cost and least-emission generation expansion plan under each of the load growth scenarios. The analysis is conducted for three points in time: 2022, 2027 and 2032. The BAU Scenario strictly follows RUPTL’s expansion plan up to year 2027, so that generation options are considered for optimization only in 2032. On the other hand, the TA scenario only takes existing and committed generation as fixed and allows for selection of optimal additions in each of the three years.

For each of the three years, HOMER determines which of all possible configurations of fixed and optional plant are technically feasible, e.g. meet load throughout the year. HOMER then calculates the net present cost covering both investment and operational costs as well as the emissions associated with each of the feasible configurations, which can then be ranked according to price or emissions. The optimal mix in a given year is then taken as the fixed plant for the subsequent year.

Policy Recommendations. Based on the resulting least emission and least cost electricity system, a number of policy recommendations are drafted.

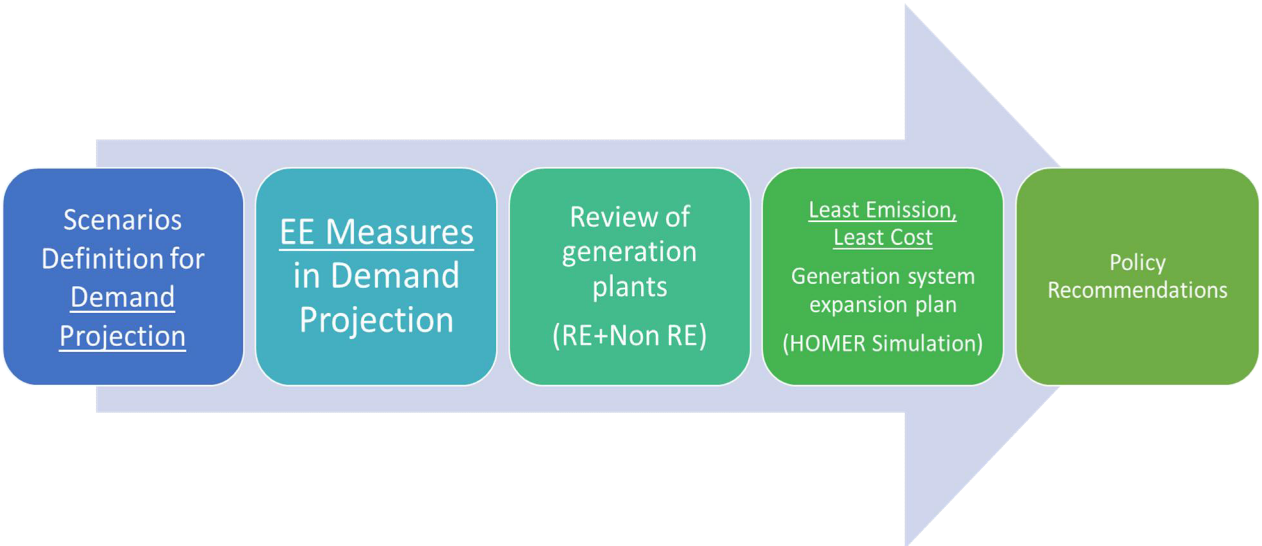

Exhibit ES 1. Modelling steps overview.

ES 3. PRINCIPAL RESULTS

With decarbonising the grid in mind, renewable energy such as geothermal and hydro are recommended as a source of large non-intermittent power required. In addition, localised solutions are also available for the city of Bitung through provision of renewable energy beyond solar power, such as waste and wind.

The results of the study also provide a more targeted and quantifiable approach to EE programs in Bitung and beyond. This study confirms the results of earlier studies[4, 5], which had shown that implementation of Demand Side Management (DSM) could reduce peak load thereby reducing the need for generation capacity additions. Other possible policy measures are the enforcement of Minimum Energy Performance Standards (MEPS) and labelling, particularly for air conditioners and refrigerators, as these appliances were expected to dominate the residential customer market in North Sulawesi. However, MEPS is typically implemented as a national, not regional, policy.

Prinicipal results of the study are as follows:

1. This study entails a total of six electricity demand scenarios, each with its own expansion plan over the year 2022, 2027 and 2032, i.e:
   - ✓ BAU, without any EE measures, or **BAU** Scenario;
   - ✓ BAU, with EE CEP measures, or **BAU+EE CEP** Scenario;
   - ✓ BAU, with EE BAT measures, or **BAU+EE BAT** Scenario;
   - ✓ TA, without any EE measures, or **TA** Scenario;
   - ✓ TA, with EE CEP measures, or **TA+EE CEP** Scenario;
   - ✓ TA, with EE BAT measures, or **TA+EE BAT** Scenario.

2. Based on the results of the six scenario simulations, the following trends are observed:
   - ✓ The lower the peak load, the lower the total installed capacity. This is because the number of installed capacity of power plants needs to increase to serve the growing demand.
   - ✓ In most scenarios, the higher the energy production, the higher the total emission levels, as the system is still driven by the conventional plants which emit CO_2 along with the electricity they produce.
   - ✓ Annualized cost increases as the installed capacity increases. This is because annualized cost is derived from the total Net Present Cost (NPC), which includes capital, operational, O&M, fuel and replacement cost. Capital costs increase as installed capacity increases. As capital is the most significant factor in determining NPC and annualized cost, the annualized cost increases in line with capacity additions.
   - ✓ Contrary to the annualized cost, the movement of COE is not entirely in line with energy production. The TA+EE BAT Scenario depicts a very small variation of COE over 2022 to 2032, and most notably a similar COE to BAU Scenario in 2032. This indicates that the small capacity factor of committed plants leads to higher cost of energy. Comparing the TA+EE BAT results with BAU+EE CEP results (i.e. the lowest COE among the BAU scenarios), the TA+EE BAT results indicate much smaller capacity factor. This means that some of the committed plants will be underutilized despite the high capital investment cost for such plants.
   - ✓ As inferred from TA+EE BAT Scenario result, the capital and fixed maintenance costs of the underutilized committed plants will burden the

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[4] Karali, N., et al (2015). Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.

[5] Hilmawan, E., Said, M. (2009). Energy efficiency standard and labeling policy in Indonesia. BPPT

system's COE. High electricity generation costs would have fiscal policy implications, particularly in Indonesia where the electricity sector is mainly operated by PLN and the central government still subsidizes certain customer classes.

3. Trends and results related to EE measures are shown below:

   - ✓ The cost related to the EE measures is calculated separately from HOMER simulation.
   - ✓ Reported Costs of Conserved Energy (CCEs) for more efficient electronic appliances in Indonesia are compared with the resulting COEs calculated from HOMER. All CCEs for the EE CEP measures are below the COEs in BAU and TA Scenarios, with EE CEP measures and without. This indicates that the EE CEP scenarios yield net benefits for consumers.
   - ✓ Application of EE CEP measures reduce annualized cost under BAU Scenario up to USD 31 million/year in 2027 and USD 84 million/year in 2032. In terms of installed capacity, using EE CEP measures can reduce the installed capacity by 100 MW in 2027, and 295 MW in 2032. As an illustration, 100 MW is equal to four units of the currently installed Lahendong geothermal power plant.
   - ✓ Examples of CEP measures include (i) phase out of less efficient ACs and adoption of ACs with EER of at least 3.7 W/W – higher than the *Bintang 4* EER standard of 3.3 W/W; (ii) phase out of incandescent lighting and adoption of CFL and LED lighting.
   - ✓ While under the TA Scenario, EE CEP measures can save up to USD 315 million/year by 2032, and reduce installed capacity by 853 MW compared to the BAU case in 2032.
   - ✓ The impact of EE on annualized cost is relatively linear, as the reduction of load due to EE measures results in lower requirements for new power plants.

4. By comparing the trends and results, the key findings by the year 2032 are:
   - ✓ Reduction in emission levels for all BAU scenarios by the year 2032 is not sufficient to achieve the reduction target of at least 23% compared to the 2022 levels.
   - ✓ All TA scenarios achieve 23% reduction of emission levels compared to BAU in 2022.
   - ✓ TA + EE BAT Scenario achieve the **highest reduction of emissions level with 37% reduction compared to BAU in 2022 levels**, and the **highest COE of USD 6.86 cents/kWh** among all scenarios in 2032.
     TA + EE CEP Scenario achieve the second highest reduction of emissions level with 30% reduction **compared to BAU in 2022 levels**, and the **lowest COE of USD 6.49 cents/kWh** among all scenarios in 2032.

5. **The optimal scenario is the TA+EE CEP Scenario**, with the installed capacity illustrated in Exhibit ES.2 below.

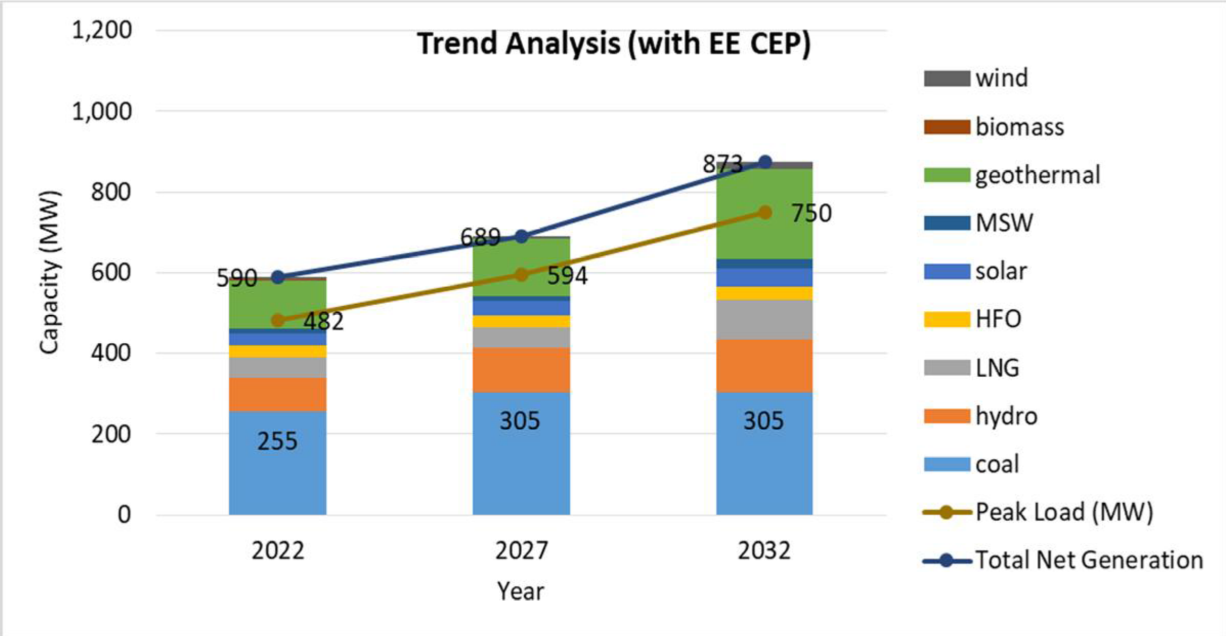


Exhibit ES 2. Generation mix result for TA+EE CEP Scenario.

As a comparison, BAU Scenario result without any EE measures is shown as ES 3. The drastic total capacity increase can be observed in the figure.

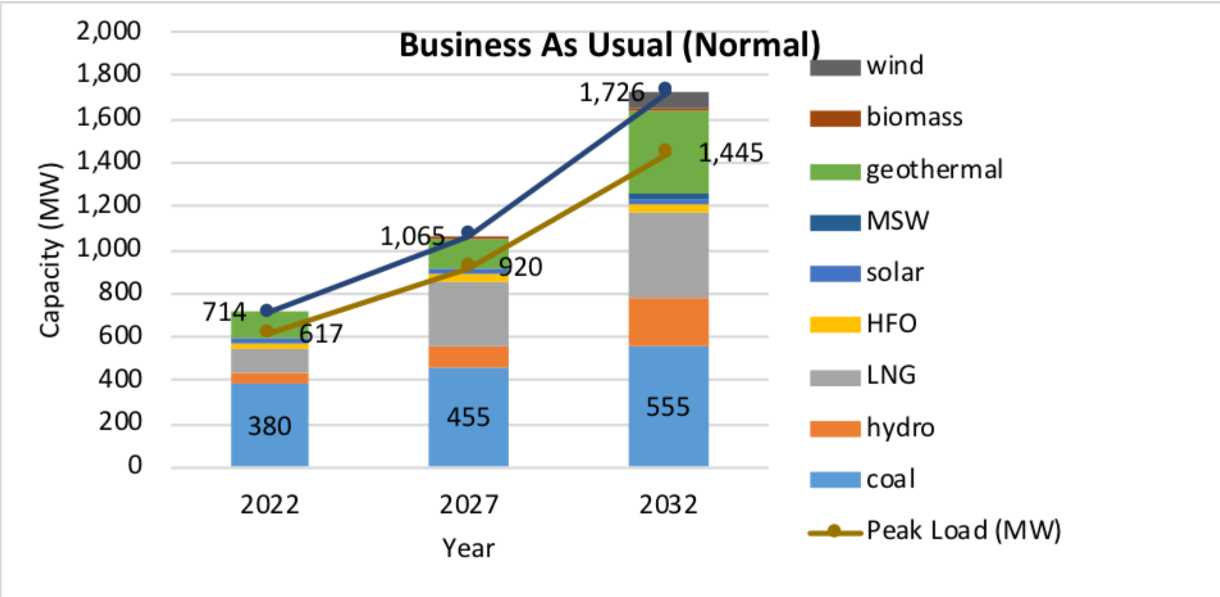


Exhibit ES 3. Generation mix result for BAU Scenario.

6. Solar PV penetration ranges from 7.2% - 8.4% of the day load for all years of study (2022 – 2032) and all scenarios. These penetration numbers are within the common practice in the system planning of PLN Suluttenggo region in which the total maximum number of solar PV capacity allowed in the grid is approximately 8% from the day load – when solar PV produces the maximum power output.

7. The low percentage of coconut shell biomass in the generation mix is due to high price of coconut shell biomass compared to other sources of energy. Experts from University of Sam Ratulangi implied the shortage of coconut shell supply in the region. Further studies will be required to confirm this.

8. Despite relatively low PV penetration and virtually no biomass power utilization, renewables represent XX% of new capacity additions and YY% of additional production by the year 2032.

9. To enable the realization of the scenario above, local government should specify the medium-term energy mix and installed capacity in RUKD. The regional government of course must then coordinate this government plan with PLN's own business plan. Moreover, incentives should be provided by local government for renewable energy developers, such as through simplicity in permit provision.

10. In terms of energy efficiency, this study finds that the use of energy efficient air conditioners for residential customers is economically attractive based on national data. However, there should be a market study to understand the energy use pattern in the province for all customer classes to ensure that the energy efficiency programs are appropriate with the local needs.

11. Lastly, not only can local government utilize HOMER to help develop the regional electricity plan (RUKD), but other local stakeholders can take advantage of **the flexibility of the tool to identify alternative power development pathways**. For example, local stakeholders can (i) adjust assumptions on the type of power plants they wish to have in the province based on local potential; (ii) adjust the growth in demand based on their own assumptions and judgements. **This kind of exercise can assist the local government and stakeholders to have an informed discussion on the future electricity planning in the province.**

1. INTRODUCTION

1.1 BACKGROUND AND RATIONALE

Background: One of the current Asia-Pacific Economic Cooperation (APEC) collaboration topics is on energy, which aims to help progress towards two aspirations, i.e. (i) double the share of renewables in the APEC energy mix, including in power generation by 2030, as set in the 2014 APEC Economic Leaders Declaration; and (ii) reduce APEC's aggregate energy intensity by 45 per cent, from 2005 levels by 2035, as set out in the 2011 APEC Economic Leaders' Declaration. These aspirations are particularly important as four of the five worlds' largest energy users are within the APEC economies. Moreover, the historical data shows that economic growth in the region is linear to the energy consumption growth, indicating the coupling between the two variables. This causes the steady increase of emissions due to fuel combustion in the Business As Usual (BAU) scenario. To mitigate climate change, economic growth must be decoupled from increasing energy production and associated emissions.

Indonesia, as one of the largest developing economies in APEC, faces the prospect of increasing its emissions as its economy grows. However, Indonesia has also ratified the Paris Agreement, with Nationally Determined Contributions (NDC) of unconditional and conditional Greenhouse Gas (GHG) reduction of 29% and 41% respectively against 2010 baseline by 2030. To achieve its NDC as well as APEC's aspirations, there is a need for Indonesia to be assisted in accelerating deployment of renewable energy and energy efficiency technologies.

Rationale: Decarbonising the economy should not hinder economic growth, particularly within communities vulnerable to poverty. There are many parts of Indonesia with unreliable power supply which may hinder the region's development. One example is Bitung Township in North Sulawesi Province, known as one of Indonesia's best diving destinations. In 2014, the national government established a plan to develop Special Economic Zone (SEZ) in Bitung. The project has received attention as it is one of Indonesia's national strategic projects. These factors make Bitung an interesting subject for a pilot project to assess the possibility of decoupling energy demand and economic growth through energy modelling based on various scenarios.

In 2016, APEC conducted a policy review to develop a Low-Carbon Model Town (LCMT) for Bitung. The APEC peer-review, led by the Asia Pacific Energy Research Centre, has identified highlevel planning and policy recommendations on various topics relevant to a low carbon development: legal framework, sustainable urban planning, low-carbon buildings, energy management systems, renewable energy and untapped energy planning, transport and environmental planning. These recommendations are classified as "immediate actions", "mid-term (2-3 years) actions" and "long-term actions".

Nevertheless, in terms of regional energy planning, particularly those related to power supply and demand, more robust and practical model is required to complement these high-level policy recommendations.

1.2 PROJECT OBJECTIVES

The project has the following objectives:

1. To create a framework for providing practical information across the APEC economies to support local governments and energy providers in the sustainable development of emerging cities such as Bitung.
2. To create an implementable action plan to attract new investment in cost-effective clean energy solutions including geothermal, solar, municipal waste-to-energy, biomass utilization, and energy efficiency measures as well as other renewable energy resources.
3. To create support across all relevant stakeholders, international agencies, local and national governments and industry, energy providers, local educational institutions, and the public and tourism industry to better understand the current and expected future energy needs of smaller developing cities such as Bitung across a range of countries in the APEC economies (location, demand type, load's daily cycle and seasonality).
4. To create a framework for building local capacity and enthusiasm for developing and implementing the decarbonisation actions plans and complement the work that was done previously, particularly work funded by APEC such as the Policy Review for APEC Low-Carbon Model Town Stage 5 Final Report Bitung, North Sulawesi, Indonesia, by the Asia Pacific Energy Research Centre, June 2016. Engagement will occur through workshops, publicly available reports, and publications as well as through collaboration.

1.3 PURPOSE OF THE REPORT

This report is prepared to provide an overview of the modeling result to achieve the least emission – least cost electricity system planning.

1.4 REPORT ORGANIZATION

This report is organized as follows:

Section 1. Introduction provides general introduction to the project and this report.

Section 2. Methodology provides detailed information on how the modeling objectives are met, including assumptions, scenarios, and modeling strategies.

Section 3. Outputs provides general overview of the modeling results.

Section 4. Analysis of results provides comparison of results, the trends, and selection of the "target" scenario.

Section 5. Results application provides an overview of how the study can be integrated into local policies and lessons learned for other APEC economies.

Section 6. Conclusions provides explanation of key outputs of this study.

1.5 MODELING OBJECTIVES

The main objectives of the energy modeling are:

- Develop an electricity system model with optimal (least cost) mix of Renewable Energy (RE) and Energy Efficiency (EE) measures in Northern Sulawesi System

(*Sulawesi Bagian Utara* – Sulbagut system)[6] up to the year 2032[7], which include Bitung City and North Sulawesi, and explicitly take into account electricity demand growth in Bitung due to development of the Special Economic Zone;
- Achieve at least 23% of reductions in emissions in Sulbagut system, compared to the 2022 level for BAU scenario;
- Build local capacity in developing electricity system model with optimal (least cost) mix of RE and EE measures.

[6] Sulbagut grid refers to the physical electricity grid that covers North Sulawesi provinces, Gorontalo province and some part of Central Sulawesi Provinces.
[7] 2032 is the year of completion of five development stages of Bitung SEZ.

2.   METHODOLOGY

This study mainly comprises energy modelling using HOMER and to assess least-cost least-emission generation options. Exhibit 2-1 provides an overview of the study approach. The study starts with scenarios definition for demand projection, which consider two scenarios, i.e. Business-As-Usual based on PLN's Electricity Supply Business Plan (*Rencana Umum Penyediaan Tenaga Listrik (RUPTL))* projections and Trend Analysis (Step 1). In projecting the electricity demand, Energy Efficiency (EE) measures are also considered to curb the demand growth in both scenarios (Step 2).

To select the type of power plant options available to meet the projected demand, a review of electricity generation plants were carried out (Step 3). The focus is mainly on the Renewable Energy (RE) types, as the Non-RE types are simply adopted from RUPTL. Both the demand projections and supply candidates are then modelled in HOMER in step 4 to seek the least-emission and least-cost expansion plan. Based on such plan, a set of policy recommendations is provided. This chapter on methodology mainly deals with scenario development, a summary of the electricity generation plants and modelling strategies in HOMER.

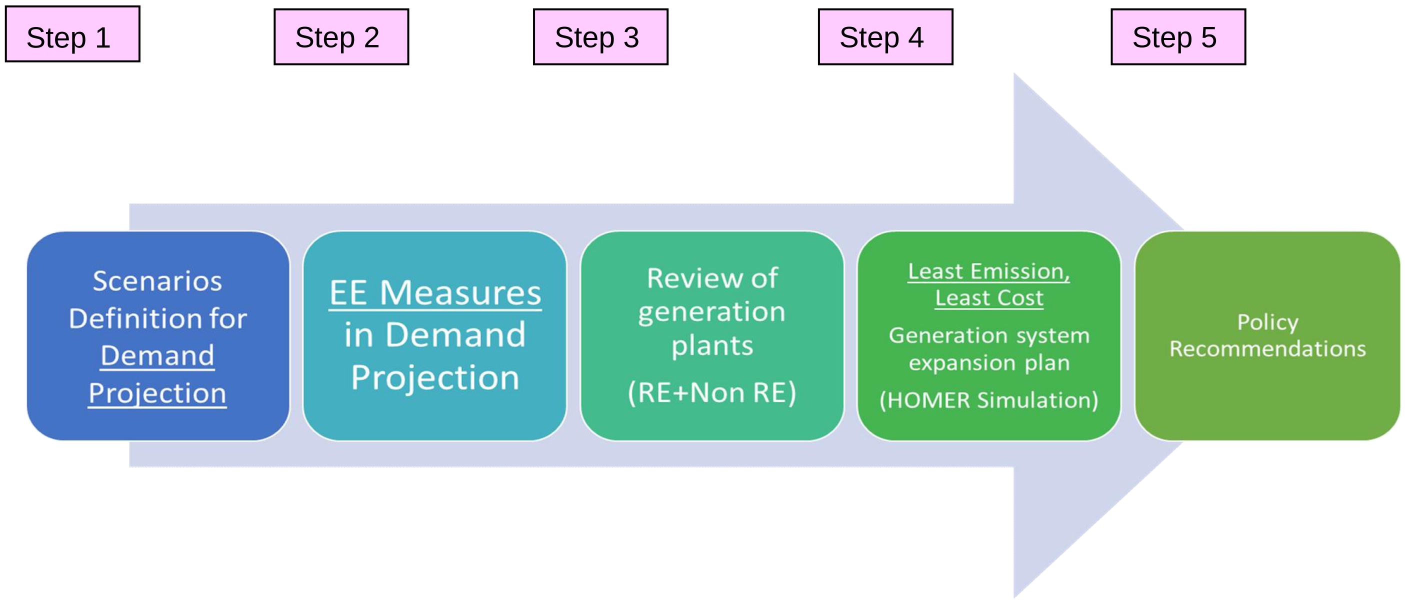


Exhibit 2-1 Modelling steps overview

further details the approach taken in this study. Step 4 is particularly important as it filters the results from HOMER with prioritization on low emission, renewable energy penetration and low cost. These results are used to determine which scenario and with which measures the emission reduction goals can be reached. Policies are then recommended to implement these measures. The results from HOMER are presented in the subsequent chapter (Chapter 3) while the analysis of results and policy recommendations assessed from the results are elaborated in Chapter 4 and Chapter 5 respectively.

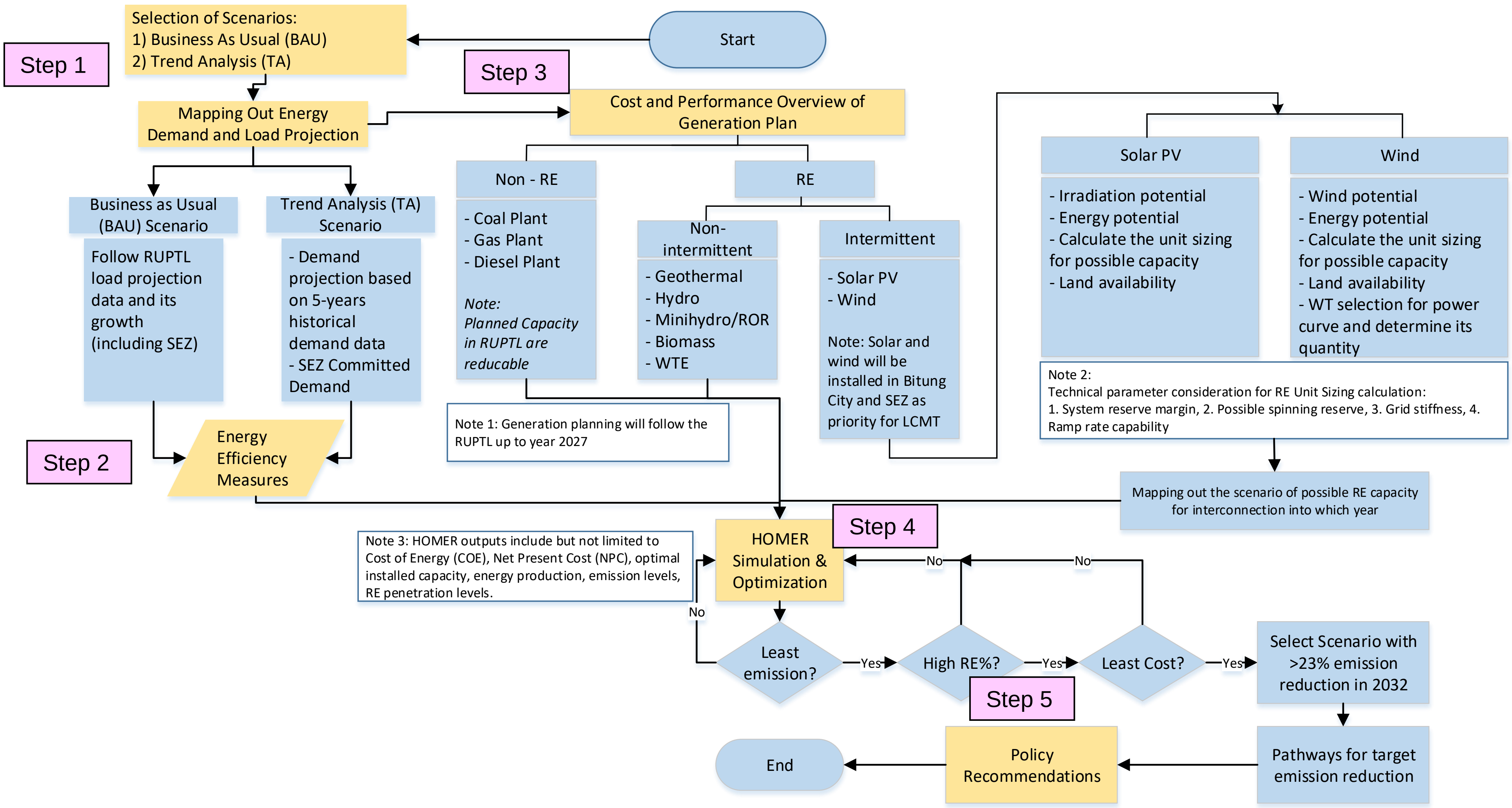


Exhibit 2-2 Flow Diagram of the Approach

2.1 SCENARIO DEVELOPMENT

2.1.1 Scenario Definition

RUPTL vs Trend Analysis

The scenario applied as the “Business as Usual” in this study is the demand projection and generation mix stated PLN RUPTL 2018-2027. RUPTL is chosen because the document is prepared by PLN, the sole electricity state-owned company in the econmy, and issued by the Ministry of Energy and Mineral Resources (MEMR). RUPTL represents an official electricity projection of national and regional electricity demand and generation mix. An alternative scenario, “Trend Analysis” is developed to provide a conservative assumption vis-à-vis PLN RUPTL.

The purpose of Trend Analysis

PLN estimates electricity growth in a bottom-up manner, based on the forecast of Gross Domestic Product (GDP) at provincial level, population growth, and new connections. Taking the estimates to national context, RUPTL demand growth estimates have exhibited an upward bias due to the relatively high economic growth assumptions[8]. Moreover, a relatively high income elasticity of demand is assumed so that high economic growth requires high electricity growth.

The upward bias may cause excessive capital deployment and the consequent underutilization of PLN’s assets. This, in turn, will affect the increase in PLN’s tariff. This upward bias is evident in the North Sulawesi case. According to the project’s Pre Modelling Report, the average actual year-on-year growth of peak demand for the last five years in North Sulawesi is 4%. As example comparisons to PLN’s projections, RUPTL 2013 and RUPTL 2018 projected average year-on-year growth rate of 9.1% and 8.4% respectively. These growth rates are compared in the figure below. The slopes of the growth in RUPTL cases are much steeper than the actual growth. Similar slopes in electricity growth can be observed in both RUPTL 2013 and RUPTL 2018 forecasts.

[8] Brown, M. (2018). *Perusahaan Listrik Negara (PLN): A Power Company Out of Step With Global Trends.* Institute for Energy Economics and Financial Analysis (IEEFA). Retrieved from: http://ieefa.org/wp-content/uploads/2018/04/PLN-A-Power-Company-out-of-Step-With-Global-Trends_April-2018.pdf

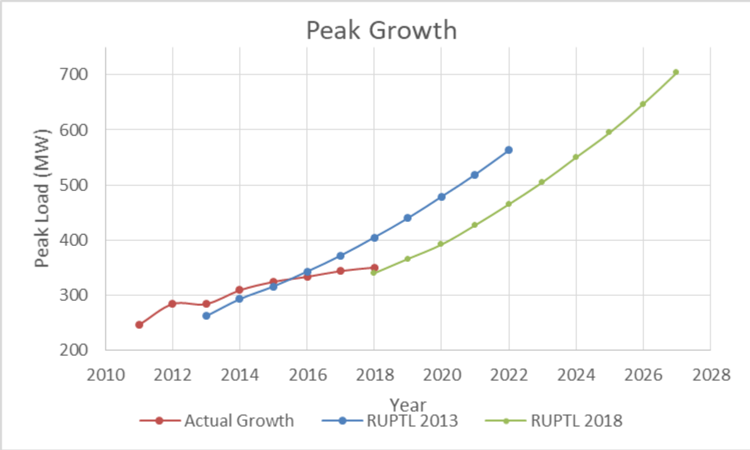


Exhibit 2-2 Actual vs RUPTL Peak Load Comparison.

The expected projected growth also contributes to the high reserve margin on the North and Central Sulawesi and Gorotalo system (*Sulawesi Utara dan Tengah dan Gorontalo* - Sulutenggo) which includes Sulbagut. The system's reserve margin significantly increased from 15.04% in 2015 to 36.21% in 2017. PLN applies a Loss of Load Probability (LOLP) of 1 day per year (= 0.274%) as its reliability criterion for system planning, which is expected to result in a reserve margin of approximately 35-40% for a system like Sulutenggo.

However, if demand fails to materialize as forecast, as has happened in recent years, reserve margins may greatly exceed the 35-40% target. While high reserve margin indicates high reliability, it also shows an excess of capacity. The excess indicates underutilization of assets, which will be reflected through increase in the tariff to consumers. Through the Trend Analysis, we aim to have an alternative view to PLN's forecasts, and assess the implications of such alternative.

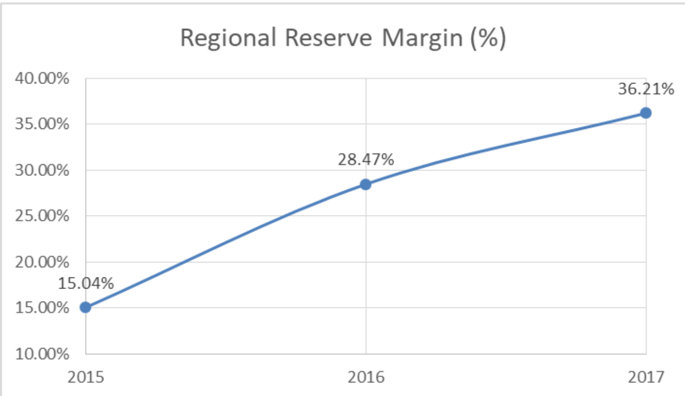


Exhibit 2-3 Regional Reserve Margin Growth.

Application of Energy Efficieny Measures and Best Available Technologies in Scenario Development

In taking into account the impact of energy efficiency measures to the demand projection and energy generation mix, there are three level of measures considered in the scenario development: (i) No Demand Side Management (DSM)/Energy Efficiency (EE) measure; (ii) introducing EE measures in the demand projection through Cost Effective Potential

(CEP) technologies; and (iii) Applying EE measures in the demand projection through the Best Available Technologies (BAT). *The CEP* takes into consideration efficiency targets that provide the maximum energy savings that result in a net benefit to the consumer (even with subsidized electricity tariffs). It is only available for the residential sector.The BAT scenario represents the technical potential for energy efficiency afforded by the best technologies currently available on the market or designed from high-efficiency components. Hence, the impact of EE and BAT is taken into account in developing the electricity demand projection of BAU and TA scenarios.

This application of CEP and BAT measures in our modelling approach is derived from study by Lawrence Berkeley National Laboratory[9]. This study had projected that the growth in population and economy in Indonesia would trigger higher attainment of electronic appliances, particularly in the residential sector and by 2030 the peak demand, particularly among residential customers, would be mainly driven by air conditioners and refrigerators. An earlier study conducted by the Indonesia's Agency for the Assessment and Application of Technology (*Badan Pengkajian dan Penerapan Teknologi* – BPPT) in 2009[10], had shown that more than 50% of the electricity usage in residential customers is for refrigerators, televisions, ACs, and lighting.

Appendix F provides etails on the impacts of Demand Side Management (DSM) and energy efficiency on system load in North Sulawesi with reference to the CEP and BAT scenarios.

Selection of Scenarios

Based on the above considerations, two base scenarios and four sub-scenarios of demand for the modeling basis are used:

1. *Scenario 1 – Business As Usual (BAU)*, which uses PLN projections as stated in RUPTL. This scenario is necessary to measure the impact of having more RE in the system. The BAU base scenario will then be subjected to the effect of DSM/EE measures as follows:
    a. *Sub Scenario 1.a* – BAU Scenario with estimation of EE measures impact with Cost Effective Potential (CEP) technologies;
    b. *Sub Scenario 1.b* – BAU Scenario with estimation of EE measures impact with Best Available Technologies (BAT).
2. *Scenario 2 – Trend Analysis (TA) demand forecast*, is instead based on historical demand growth over the last five years, with additional allowance for the expected load from Bitung SEZ. The scenario has a significantly lower growth rate than PLN's estimates. The TA Base scenario will then be subjected to the effect of DSM/EE measures as follows:
    a. *Sub Scenario 2.a* – Analyzed demand forecast scenario with estimation of EE measures impact with Cost Effective Potential (CEP) technologies;
    b. *Sub Scenario 2.b* – Analyzed demand forecast scenario with estimation of EE measures impact with Best Available Technologies (BAT).

[9] Karali, N., et al (2015). *Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.*

[10] Hilmawan, E., Said, M. (2009). Energy efficiency standard and labeling policy in Indonesia. BPPT.

2.1.2 Electricity Demand Projections

Business As Usual (BAU) Scenario

BAU Base Scenario: According to the historical energy sales and considering the regional economy as well as population growth, PLN has projected the future needs on electricity up-to year 2027 in North Sulawesi grid system (herein after referred to as *Sulbagut* system) as shown in the following exhibit.

Exhibit 2-4 Energy Demand Projection in Sulbagut System by PLN up to the year 2027

Year	Economic Growth* (%)	Energy Sales (GWh)	Energy Sales Growth (%)	Peak Load (MW)	Peak Load Growth (%)	Load Factor (%)
2018	6.4	2,484	8	421	16.9	67
2019	6.4	2,860	16	489	16.2	67
2020	6.2	3,076	8	525	7.4	67
2021	7.1	3,348	10	569	8.4	67
2022	7.1	3,640	9	617	8.4	67
2023	7.1	3,957	9	669	8.4	68
2024	7.1	4,306	9	726	8.5	68
2025	7.0	4,657	9	783	7.9	68
2026	7.5	5,061	9	848	8.3	68
2027	7.5	5,506	9	920	8.5	68
Growth (%)	6.3%	9.3%		**9.4%**		

*) Average of Economic Growth in North Sulawesi and Gorontalo Province
Source: RUPTL PLN 2018-2027, Processed by Castlerock

Under this scenario Sulbagut system electricity production will grow at 8.29% annually over the next ten (10) years. This load increase has already considered the load addition in Bitung SEZ as well as economic and population growth.

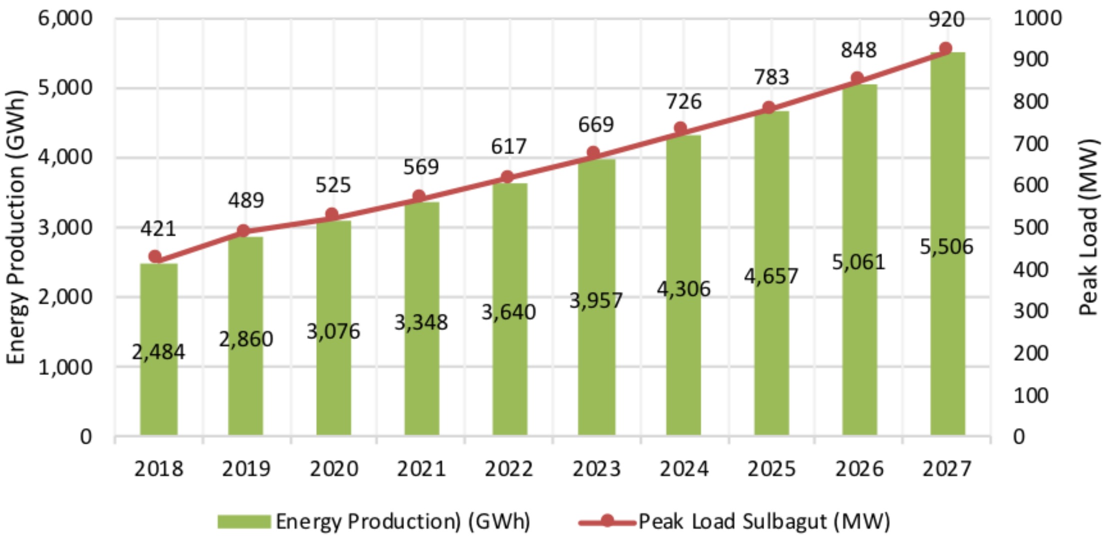


Exhibit 2-5 Sulbagut System Load Growth for BAU Scenario

Since the RUPTL only projects load up to 2027, load for 2032 is forecast maintaining the same annual growth rate as for the period up to 2027. A typical daily system load shape for each year is developed by scaling the measured 2015 system load shapes by energy production.

Below is the graph showing hourly demand projection for BAU scenario. During the first stage of Bitung SEZ operation, the peak demand in Sulbagut is around 524 MW. While during final stage-5 (250 MVA), the peak demand will reach 1,442 MW in 2032.

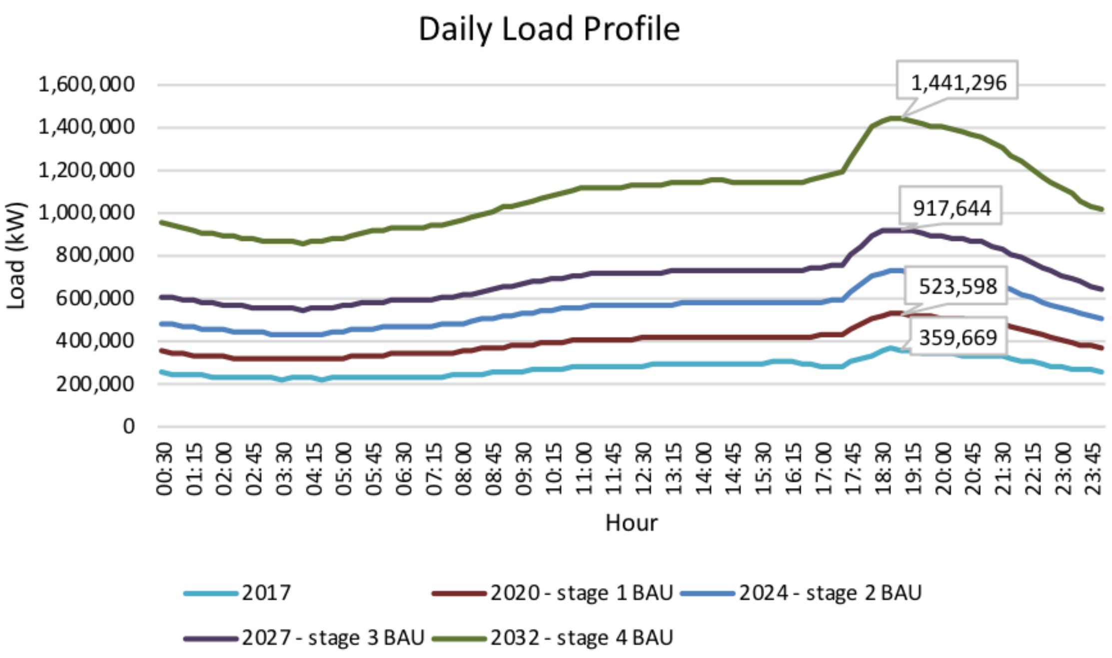


Exhibit 2-6 Hourly Demand Projection - Scenario 1 BAU

<u>Trend Analysis (TA) Demand Forecast Scenario</u>

<u>TA Base Scenario:</u> This second scenario will use the Sulbagut system historical load data in the past 5-years in order to make a more realistic forecast. This scenario also considers the Bitung SEZ load forecast based on the committed industrial growth planning. The power consumption of Bitung SEZ is added to the forecasted Sulbagut demand. As seen in the exhibit below, the energy production will grow at 5.37% Compound Annual Growth Rate (CAGR) in the next 10 years. Future peak load growth is forecast based on the growth in peak load over the period 2013-2017.

By using the available load curve data from the year 2013 to 2017, the peak load growth rate is calculated through geometric mean[11] of monthly peak loads growth from January 2013 to December 2017. The annual growth rate is the sum of monthly peak load growths in one year. To finally get the estimated growth rate, the resulting five historical annual growth rates are then obtained through their geometric mean. The resulting estimated annual peak load growth rate for 2018 and beyond is 5.9%.

[11] Geometric mean is typically used for data which exhibits serial correlation, i.e. relationship between observations of the same variable over a period of time. *Reference: https://www.investopedia.com/terms/s/serial-correlation.asp*

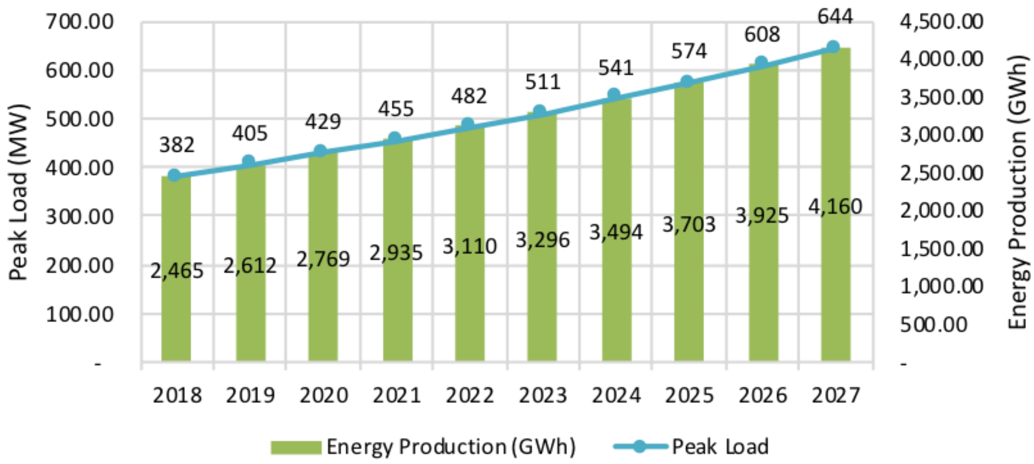


Exhibit 2-7 Sulbagut Demand Growth for Trend Analysis Scenario

During the first stage of Bitung SEZ operation (26 MVA), the estimated peak demand in Sulbagut is around 426 MW. While the estimated peak demand during the final stage-4 will reach 861 MW in the year 2032.

Once the peak loads have been estimated, the projected daily load curves are then build up using the geometric average of the historical load-to-peak data on 30-minute basis, except at 18.00-20.00 in which data are in 15-minute basis, for the last five years, i.e. January 2013 to December 2017. See exhibit below for details.

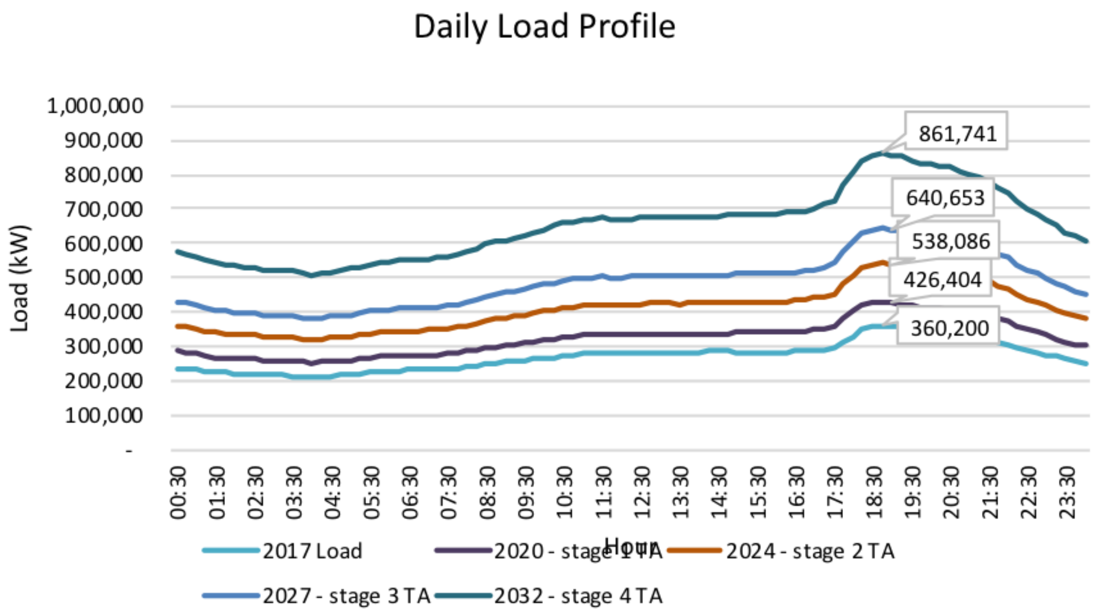


Exhibit 2-9 Hourly Demand Projection in - Scenario 2, Trend Analysis

Box 1. Demand forecasting through growth rate based method

Demand growth in this study is calculated through the growth rate based method, which utilizes the following formula:

$$D_t = D_0(1+g)^t$$

With,

$D_t = load\ at\ Year\ t;$

$D_0 = load\ at\ Year\ 0;$

g = growth rate;
t = period.

Growth rate is the key variable in the equation as it can drastically affect the resulting load projection. The steps to obtain the growth rate in this study are as follows:

1. Calculate the geometric mean of monthly growth based on historical data, which is for the last five years in this study;
2. Calculate the geometric mean growth for each year through summation of the monthly growth rate obtained above;
3. Calculate the geometric mean of the annual growth rate data

Reference:
Bhattacharyya, S. C. and Timilsina, G. R. (2009). *Energy Demand Models for Policy Formulation: A Comparative Study of Energy Demand Models*. The World Bank.

Development of BAU and TA Scenarios with Application of CEP and BAT

In applying the reductions from EE measures to peak demand, two years are used: 2027 and 2032. 2027 is the end year of the latest PLN's RUPTL, and 2032 is the expected completion of all development stages of Bitung SEZ. The reductions in the year 2027 are assumed to be the same with expected reductions in 2020, and reductions in the year 2032 are assumed to be the same with expected reductions in 2030, as reported by Karali in 2015[12], and as seen Exhibit 2-19.

In 2027 projections for BAU, approximately 70 MW and 190 MW of peak load can be reduced in CEP and BAT scenarios respectively (see Exhibit 2-10). By 2032, the reductions achieve 187 MW and 509 MW for CEP and BAT scenarios respectively (see Exhibit 2-11). This indicates the potential of using EE policy measures to reduce the load of the system at peak times and reduce the need for new power plants.

As seen in the exhibits below, a bump in demand around noon time can be observed. This is due to the assumption that the majority of savings can be obtained through household Air Conditioners (ACs), which are considered not in use in most households during working hours. Consequently, less savings in demand are observed around noon time.

Deatails of the EE measures can be found in Appendix G.

[12] Karali, N., et al (2015). *Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.* Retrieved from: https://eaei.lbl.gov/publications/potential-impact-lighting-and.

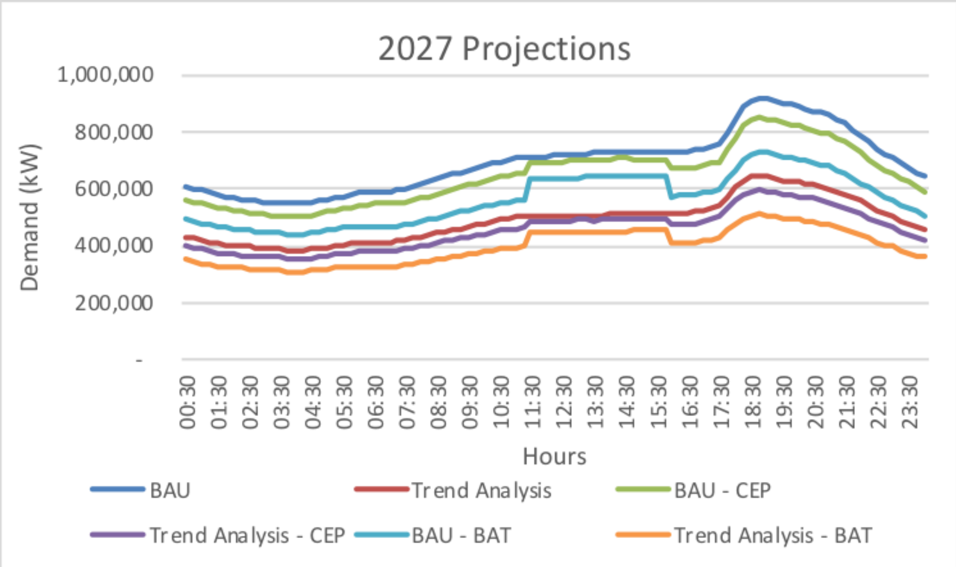


Exhibit 2-10 Demand projections at the year 2027, with EE measures[13].

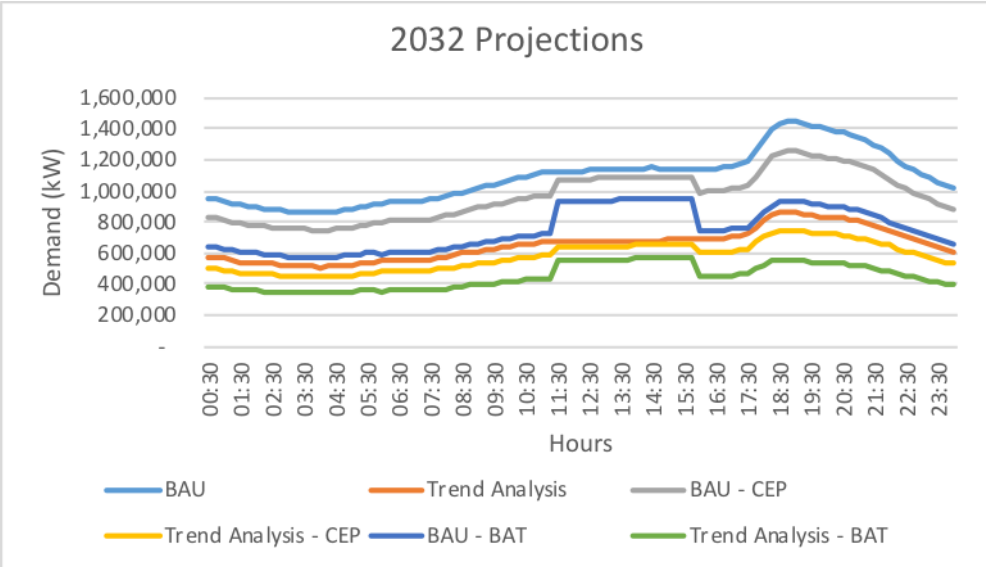


Exhibit 2-11 Demand projections at the year 2032, with EE measure.

2.1.3 Review of electricity generation plants (RE+Non RE)

Review of electricity generation plants takes into account both existing and future generation plants listed in RUPTL 2018-2027. Plants that are existing and which are committed by PLN in the RUPTL to be constructed and operated are taken as fixed plant. Candidates for serving additional demand growth beyond what can be satisfied by fixed

[13] BAU indicates Business-As-Usual scenario, and TA indicates Trend Analaysis of this study.

plant are then identified based on uncommitted plant in the RUPTL together with other renewable plant options. Details on electricity generation plants are provided in Appendix B,while the list of power plants used for modelling is given in Appendix C.

2.2 MODELING STRATEGIES FOR LEAST EMISSION AND LEAST COST EXPANSION PLAN

This section provides an overview of the strategies in achieving least emission and least cost expansion plan. Prior to discussing the strategies further, the feasibility of any generation addition identified through least-cost capacity expansion modeling must be assessed for technical feasibility, i.e. just because a particular project is optimal does not mean that it is technical feasible due to the operating characterstics of the network. Refer to Appendix F for a discussion of the factors to be considered for technical feasibility.

2.2.1 Analytical Tool Selection – Why HOMER?

A number of software application tools were considered at the beginning of the project, namely Long-range Energy Alternatives Planning System (LEAP), Network Planner, DigSilent Power Factory, Plexos, and HOMER. In selecting the tool, the following criteria are considered:

- ✓ Physical scale – whether the tool requires the model to be at a certain scale;
- ✓ Modeling approach – whether the tool can support both operational and scenario analysis;
- ✓ Energy characteristics – availability of both local RE and non RE generations;
- ✓ User interface – whether the tool is intuitive and easy to use enough for participants who do not have extensive energy engineering background. This is particularly important as the model is expected to be continued by local stakeholders.
- ✓ Economically sound – whether it requires relatively large investment to purchase the access to the tools;
- ✓ Objective – whether the tool can calculate the configuration with least cost and least emission. Specific to this study, it is important that the resulting output can be used for policy design purposes, such as drafting the RUKD (*Rencana Umum Kelistrikan Daerah*/Provincial General Electricity Plan). The resulting model must be relatively straightforward to ease integration into local policies.
- ✓ Transmission & Distribution Constraints – whether the tool can provide the impact on transmission and distribution.
- ✓ Customizable power plants entrance year – whether the tool enables users to customize entrance year. This criteria becomes relevant as the study aims to also model the power plants in PLN's RUPTL, which have specific operation years.
- ✓ Modelling additional cost to EE Measures – whether additional cost can be added to the model.

Exhibit 2-8 Comparisons of several modeling tool.

Criteria[14]	*LEAP*	*Network Planner*	*DigSilent*	*Plexos*	HOMER
Physical scale – customized at local level	x	V	V	V	V

[14] Adapted from *Beuzekom, I, (2012). Integrated energy system models. Presentation at International Conference on Energy Systems Integration 102.*

Criteria[14]	LEAP	Network Planner	DigSilent	Plexos	HOMER
Modelling Approach – scenario and operational	X	X	V	V	V
Availability of Local Generation Types	V	V	V	V	V
Easy user interface	V	X	X	X	V
Economically Sound	V	V	X	X	V
Objective – least cost least emission	V	X	X	V	V
Transmission & Distribution Constraints	X	X	V	V	X
Customizable power plants entrance year	X	X	V	V	X
Modelling additional cost to EE Measures	X	X	X	X	X

Based on the considerations above, we have selected HOMER as the main software tool. HOMER is a software widely used for microgrid and distributed generation power system design and optimization, in which it simulates the model system's performance over a single year and calculate the total cost of the system over its lifetime. HOMER provides the optimum system configuration based on the available resources and related costs. It also provides a calculation of system emission. These features make HOMER a compatible option for this project.

Despite its reputation in microgrid design, HOMER has been used to model larger grids up to 200 MW[15]. This indicates HOMER's ability to model larger grids, such as the Sulutenggo grid. Most impotantly, it gets the important things right. Further **advantages are**:

[15] Cited verbally by HOMER consultants in 2018.

- ✓ Provides good modeling functionality, e.g. calculation of carbon emissions, ease of sensitivity analysis, numerous graphical reporting formats, linkages to load, component and resource databases, etc.
- ✓ Applies chronological dispatch on net load after renewable contribution, so that contribution of variable RE can be properly considered
- ✓ Explicitly models variability in renewable resources
- ✓ Optimization based on total net present system cost (fuel+operating+capital), though results can be selected based on other metrics as well, such as carbon emissions
- ✓ Dispatch based on SRMC after variable RE contribution

Nevertheless, as can be seen in Exhibit 2-8, there are some drawbacks to HOMER, particularly in complex, expensive models that require specialist training and extensive power system training:

- ✓ Does not optimize unit commitment; only allows for user-input maintenance schedules;
- ✓ Does not take into account ramp rates;
- ✓ Does not provide stochastic optimization or treatment of loads, resources, etc.
- ✓ Does not consider transmission, nor does it provide transmission and generation co-optimization;
- ✓ Does not accommodate non-linear heat rates;
- ✓ Does not allow more than 20 generators;
- ✓ Although users can specify spinning reserve margins and maximum capacity shortages, there is no other analysis of reliability or system adequacy as it is a deterministic model;
- ✓ Does not provide multi-year optimization of capacity additions over time.

2.2.2 Staged Modeling Approach with HOMER

To accommodate the multi-year nature of the study, the modeling is conducted in stages. The staged modelling approach taken in this study is provided in the following exhibit.

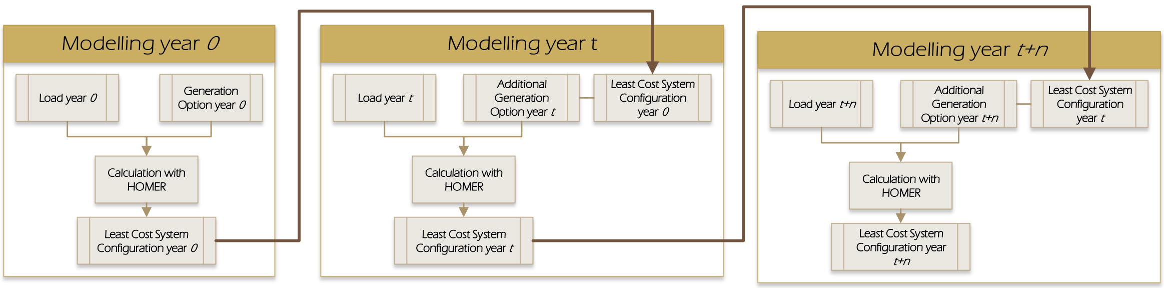


Exhibit 2-9 General staged modeling approach.

The staged approach is made to enable multi-year simulation of electricity planning with HOMER. The modeling steps are as follows:

1) Start with a certain modeling year, which will be represented as Year 0.
2) Input load and generation option at year 0, and run HOMER.
3) HOMER will produce the least cost system configuration for year 0 based on the inputs.
4) Once the least cost system configuration for Year 0, start with the next modeling year, which will be represented as Year t. Year t can be the subsequent year, or any years deemed appropriate.
5) Input load for Year t.
6) For generation option, input the least cost system configuration from Year 0 and additional generation option necessary to meet demand at Year t.
7) Repeat Step 4 to 6 above to simulate the subsequent years, e.g. Year t+n.

The steps above then apply to obtain the least cost least emission generation option with HOMER.

As noted in Section 2.2.1, the inability of HOMER to conduct multi-year optimization of capacity additions over time is a disadvantage of the model relative to more sophisticated capacity planning models like Plexos. Staged period-by-period optimization does not guarantee a globally optimal solution in the way that simultaneous multi-year optimization can. However, this application is nonetheless warranted as it: (i) provides sufficient insight into the potential for decarbonization of power supply in North Sulawesi to support policy formulation as opposed to investment planning; (ii) is an enhancement over the planning tools and techniques currently applied for power system planning in Indonesia; and (iii) is relatively accessible to users compared to more sophisticated models.

2.2.3 Key Assumptions for Base Scenarios

In applying the staged approach above to the study's base scenarios, the following key strategies are used:

1) Generation plants are categorized into two, i.e. committed and candidate plants.
    - Committed plants are plants which <u>status in RUPTL are existing, in construction, and in procurement, i.e. PLN is commercially obliged to utilize these plants</u>. In 2022, plants within this category will have total capacity of 589.2 MW in BAU scenario, and 489.2 MW in TA scenario. (The difference between these two cases assumes that the nine-year rental agreement for PLTU Amurang is not extended).
    - Candidate plants are plants which <u>status in RUPTL is "planned", together with potential renewable energy in the area</u>. In 2022, plants within this category will have total capacity of 125 MW in BAU scenario, and 107.5 MW in TA scenario.

    Note: Details of the plants above can be found in Appendix C.

2) The capacity for each type of power plant given in HOMER represented as total bulk capacity, not the size for each power plant.
3) The first modeling year in this study is 2022, as this is the last year when the committed plants in RUPTL are planned to be in operation.
4) The last modeling year in this study is 2032, as this is the year when the final stage of Bitung SEZ development is to be concluded.
5) Given that power plant financing and construction delays are common, committed plants that are planned for commissioning in 2022 are assumed to slip, so that they do not appear in 2022 but instead appear in 2027.
6) To accommodate the growth in between 2022 and 2032, the year 2027 is taken as an interim modeling year.
7) Both scenarios are subjected to Energy Efficiency (EE) measures, i.e. CEP and BAT.
8) The option of capacity inputs for candidates for Trend Analysis (TA) scenario are according to the potential capacity finding for each type of renewable source which refers to Appendix B: Review of Electricity Generation Plants.

2.2.4 Staged approach for Business As Usual (BAU) Scenario

In general, the BAU Scenario models load growth and generation expansion in accordance with PLN's RUPTL up to the year 2027. A wide range of conventional and renewable plants are considered as candidates to meet load growth from 2027 to 2032. The detailed steps are described below:

1) The modeling starts at the year 2022, with load inputs based on PLN's estimates of projected demand growth, and generation inputs based on RUPTL generation expansion plan;
2) HOMER then calculates the least cost generation expansion plan for the year 2022 based on the above inputs;
3) The modelling continues with the year 2027, with load inputs based on PLN's estimates of projected load growth;
4) The resulting least cost generation expansion plan in 2022 is taken as committed plant for 2027;
5) In addition to the generation inputs in item 4, additional power plants planned in RUPTL up to the year 2027 are included;
6) HOMER then calculates the least cost generation expansion plan for the year 2027 based on item 3, 4, and 5 above;
7) For the final modelling year, i.e. 2032, step 3 and 4 are repeated for the corresponding years;
8) As RUPTL only provides generation expansion plan up to 2027, the additional generation plan for the year 2032 considers the potential for greater renewable energy utilization in the province.
9) All the steps above are repeated for scenarios wherein Energy Efficiency measures are put in place through providing reduced load as results to such EE measures.

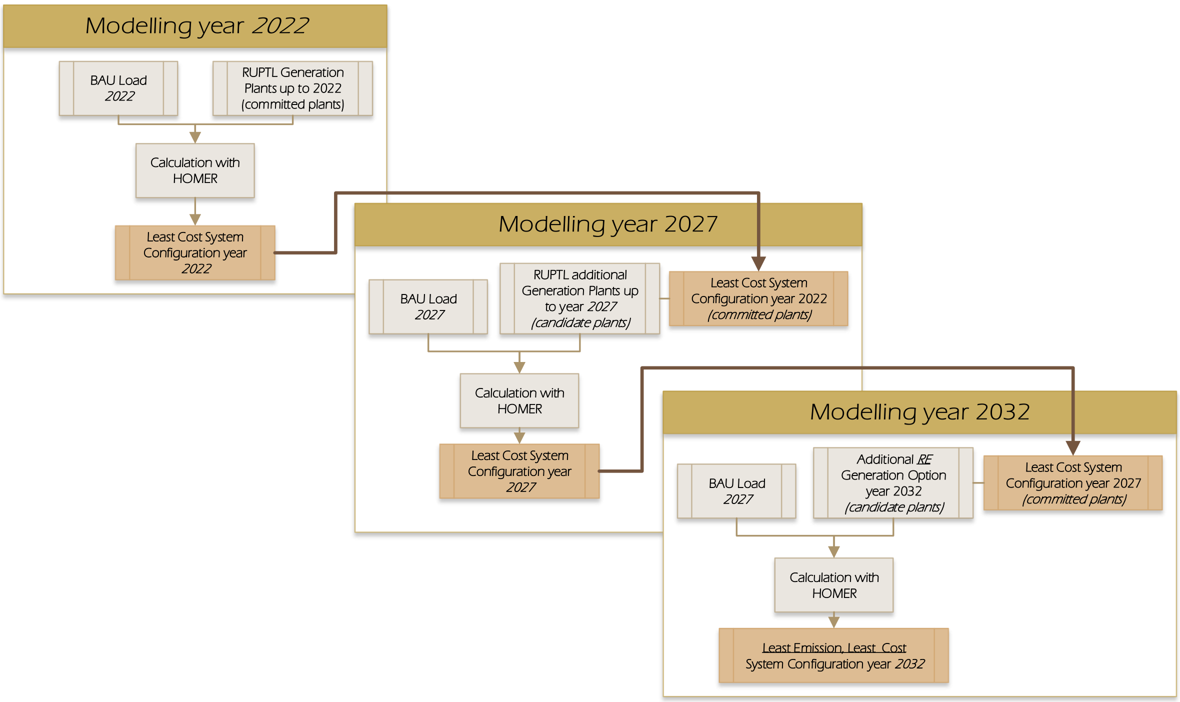


Exhibit 2-10 Staged approach for Business As Usual (BAU) Scenario.

2.2.5 Staged approach for Trend Analysis Scenario

Trend analysis scenario focuses on the electricity planning with its load estimated based on historical data. An independent demand projection is made based on historical load curve data, and system loads are calculated on an hourly basis. As seen in the exhibit below, under this scenario energy production will grow at 5.37% Compound Annual

Growth Rate (CAGR) over the next 10 years. By using the available load curve data from the year 2013 to 2017, the peak load growth rate is calculated through the geometric mean of monthly peak load growth from January 2013 to December 2017. The resulting estimated annual peak load growth rate for 2018 and beyond is 5.9%, lower than the year-on-year peak load growth of 8.4% in RUPTL 2018.

Similar to the BAU scenario, modeling is conducted for years 2022, 2027 and 2032. The generation expansion plan in each modeling year is to maximize the use of renewable energy in the electricity system with expectations to lower the emission in the system. The detailed steps are described below:

1) The modeling starts at the year 2022, with load inputs based on historical demand growth;
2) Generation inputs for 2022 are in accordance with Committed Plants in the RUPTL, but reduced through the assumption that rented power plants are not operated;
3) HOMER then calculates the least cost generation expansion plan for the year 2022 based on the above inputs;
4) The modeling continues with the year 2027, with load inputs based on the study's trend analysis of projected load;
5) As for the generation input for the year 2027, the resulting least cost generation expansion plan in 2022 is used;
6) In addition to the generation inputs in item 5, additional power plants required to meet the demand utilize potential renewable energy in the province;
7) HOMER then calculates the least cost generation expansion plan for the year 2027 based on item 4, 5, and 6 above;
8) For the final modeling year, i.e. 2032, step 5 and 6 are repeated for the corresponding years;
9) HOMER then calculates the least emission, least cost system configuration for the year 2032.
10) All the steps above are repeated for scenarios wherein Energy Efficiency measures are put in place.

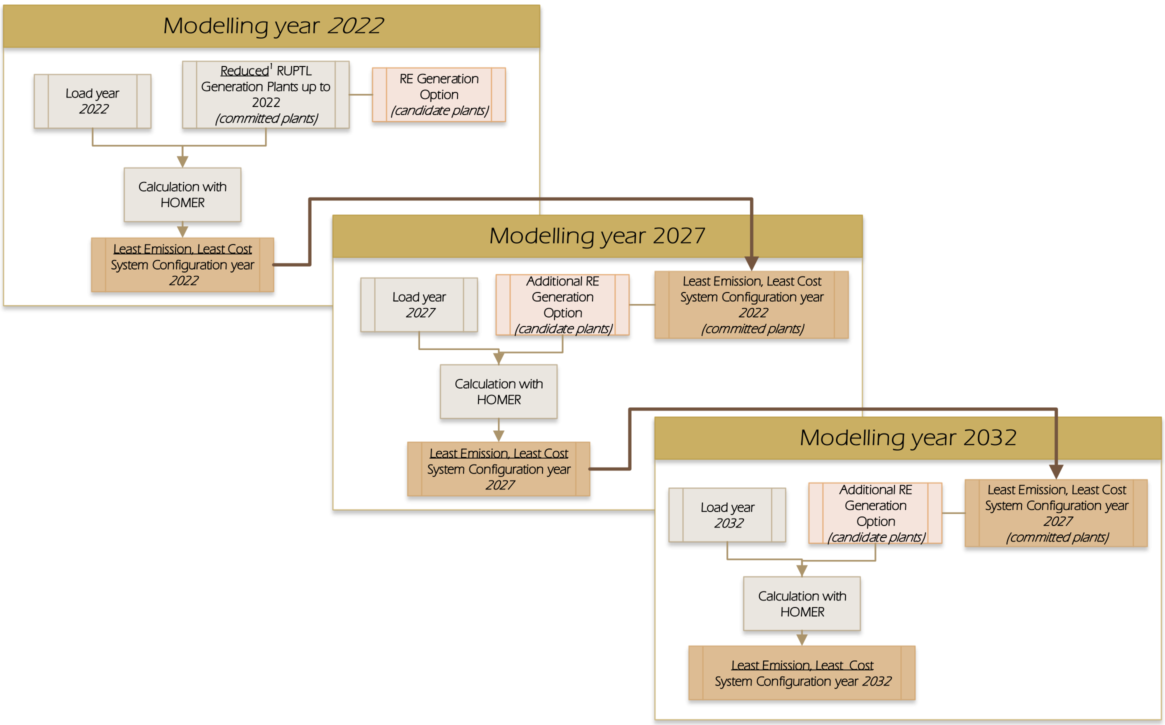


Exhibit 2-11 Staged approach for Trend Analysis Scenario.

2.3 OTHER STUDY ASSUMPTIONS

The following section provides overview of the general study assumptions used.

The assumptions used in this study include:

1. In developing trend analysis of future load projections:
    a. This scenario is developed based on interviews with PLN Suluttenggo and discussion session result during previous workshop in order to generate the future demand with lower growth number and not too optimistic compared with demand growth in RUPTL planning.
    b. No material deviation from current affordability for consumers;
    c. The growth trend will be similar to the last five years, with the addition of expected SEZ Bitung load;
    d. For an initial estimate of SEZ Bitung Load, the study will take into account the total electricity requirement at the final stage of SEZ development according to the province's Trade and Industry agency;
    e. The development of Bitung SEZ is assumed to be distinguished into 4 stages of which the first and last stages are described as follows:
        - The first stage of SEZ Bitung is assumed to be operational by 2020, in accordance with information from SEZ Administrator and province's Trade and Industry agency;
        - The last stage of SEZ Bitung is assumed to be operational by 2032, in accordance with information from SEZ Administrator and province's Trade and Industry agency;
    f. The energy intensity required for each Ha of a Special Economic Zone (SEZ) according to the Master Plan for Indonesia's Bitung SEZ prepared by the Korean Government is 0.2 kVA/Ha. However, Castlerock's survey[16] to the industries in May 2018 indicate that higher energy intensity may be required. Therefore, energy intensity of 0.5 kVA/Ha is used for "industries" area of SEZ;
    g. Based on Castlerock's discussion with PT. Membangun Sulut Hebat (MSH)[17], the available land as of May 2018 was 90 Ha. Considering the difficulties in Indonesia to obtain land for public purposes, the study then assumes that the first stage of Bitung SEZ development will be completed with an area of 90 Ha, instead of the planned 123 Ha (see Section 4.1.1 for details).
    h. Based on Castlerock's discussion with planning system division in PLN Suluttenggo region, this energy modelling simulation will focus only in capacity optimization of Renewable Energy based on its resource availability, least cost and least emission constraint. The other constraint such as network parameter / transmission grid data and grid model are limited to access since it's strictly confidential and for their own planning development purpose only. The North Sulawesi system grid model is required when do the further technical analysis for grid interconnection study purpose

2. In developing estimates for impact of Demand Side Management (DSM) measures:
    a. The ownership of end-use appliance and its usage pattern in North Sulawesi are assumed to be in line with the national estimates. This is due to the limitations of province-specific data.

[16] Based on Site Visit conducted in May 2018 to industries existing in designated SEZ area.
[17] PT. MSH is a province-owned company appointed as the developer of Bitung SEZ.

b. Considering point a. above, the reductions to the overall load due to the usage of certain energy efficient end-use appliance in North Sulawesi have the same trend as the national reduction estimates.
c. Two key years in estimating the impact of DSM, particularly EE measures, are 2027 and 2032. The former is the last year of PLN's RUPTL for the year 2018-2027, and the latter is the planned completion of the four stages of SEZ development.
d. The currently available study on the impact of EE measures in Indonesia indicates results for the year 2020 and 2030. Considering point b. above, the impact of EE measures in North Sulawesi by the year 2027 and 2032 are assumed to be similar to the impact in 2020 and 2030 respectively.
e. The impact of EE measures to load is provided in Section 3.2.2 Application of DSM in North Sulawesi.
f. **Costs related to EE measures are calculated separately from HOMER, which only generates Cost of Energy (COE).**

3. All economic results and calculations are in nominal terms. A nominal discount rate of 8% was used. Other studies have estimated nominal PLN discount rate of 10 to 12%. A lower rate is used here to reflect government's willingness to accept lower equity return for PLN

3. HOMER MODELING OUTPUTS

This section provides outputs from HOMER simulation result for each modeling scenario (BAU and TA Scenarios). The simulation and optimization through HOMER yield several generation mix in line with the least cost generation to meet the system demand.

Appendix H provides a sample of output report from Homer.

3.1 WITHOUT ENERGY EFFICIENCY MEASURES

This subsection will provide the result of HOMER output before applying the energy efficiency factor from the demand side.

3.1.1 BAU Scenario

The BAU scenario represents the PLN's grid system planning for generation plants especially for the study year 2022 and 2027 while 2032 of study year represent the mix after the addition of more renewable plants based on the HOMER simulation since there is no committed plan yet in RUPTL for that year. The Exhibit 3-1 illustrates the share of energy generated from each energy source type for the BAU scenario. As per Exhibit below, the power generation from coal power plants continues to decrease from 62.78% in 2022 to 39.22% in 2032.

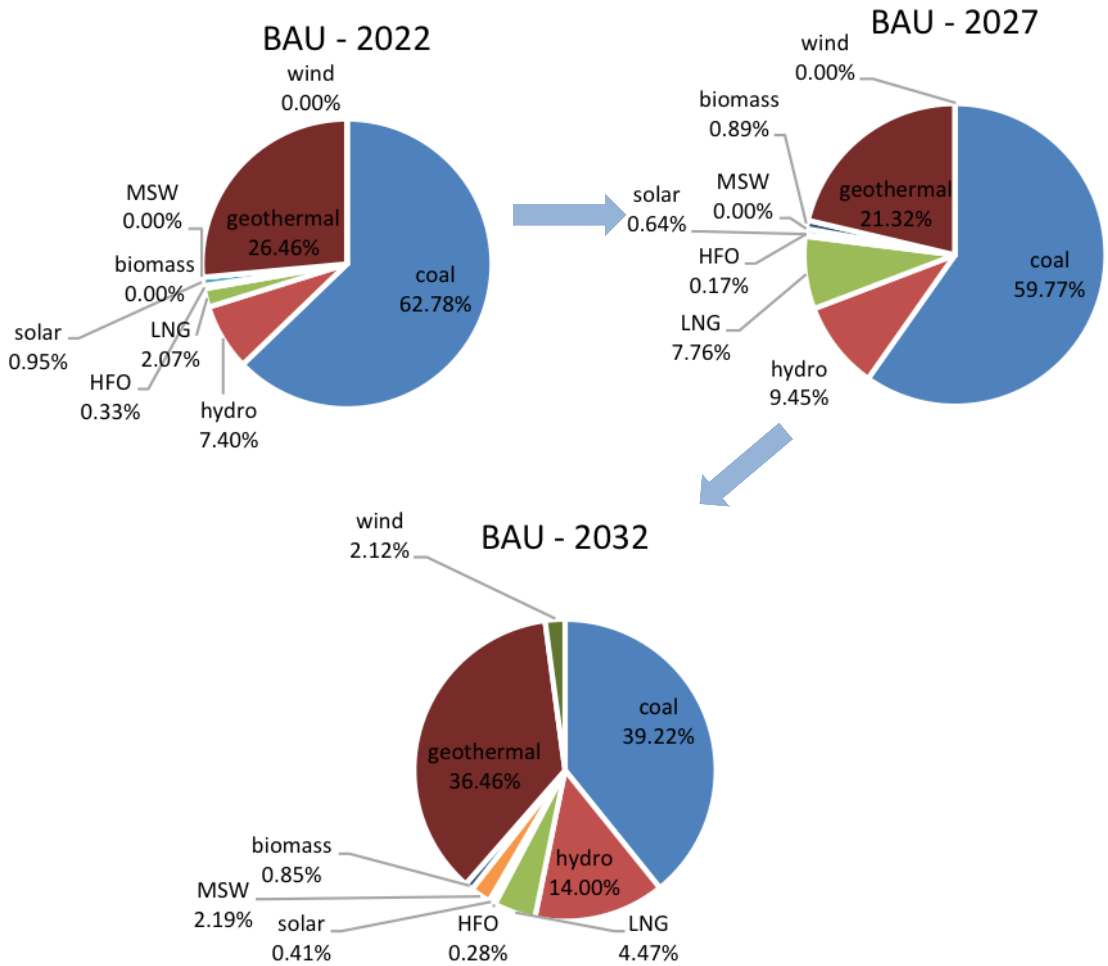


Exhibit 3-1 Generation Mix Result per year - BAU

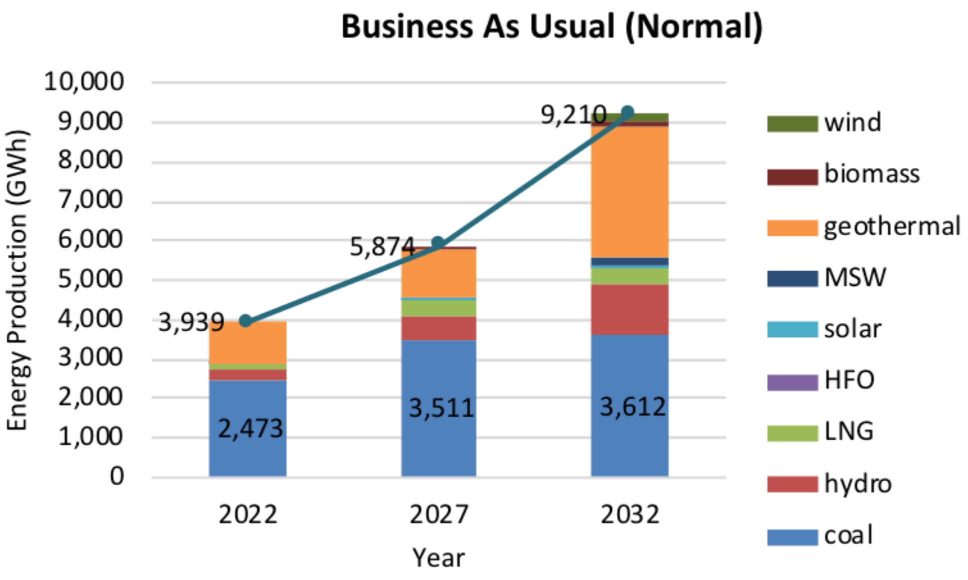


Exhibit 3-2 Energy Balance of BAU Generation Mix result

The Homer result in the BAU scenario only selects generation capacity additions based on least cost. Not all of the capacity additions planned in the RUPTL can be accommodated, i.e. the total generation capacity addition identified in the RUPTL is much greater than demand to be served. So, when entering the capacity for each power plant, it's given an optional value (i.e. based on the assumption in delay COD year) to let Homer calculate the cheapest solution to meet the demand.

The Exhibit below shows the resulting power balance under this scenario. In this BAU scenario the capacity of coal power plant increases in each study year, the the portion of capacity provided by coal plant decreases from 2022 to 2032.

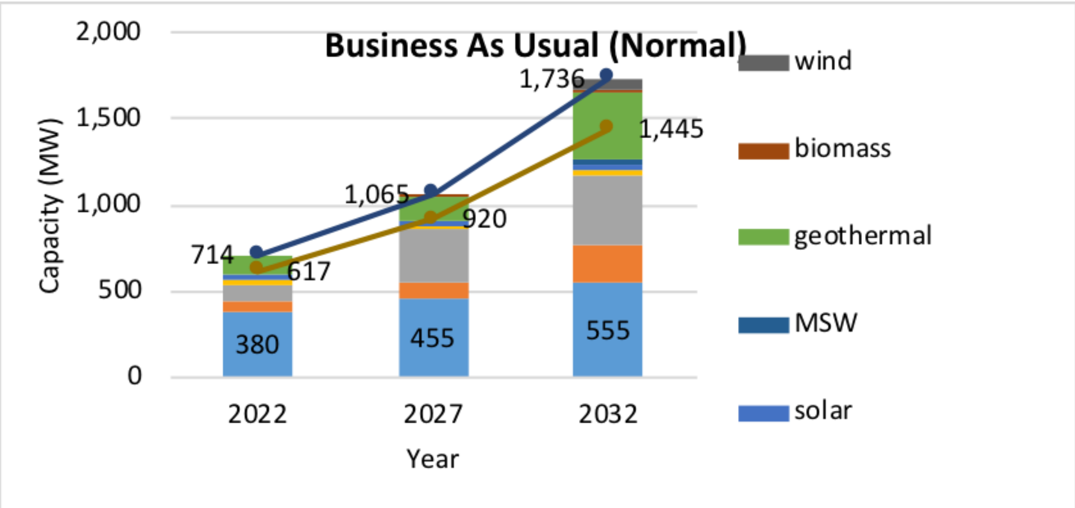


Exhibit 3-3 Power Balance of BAU Generation Mix result.

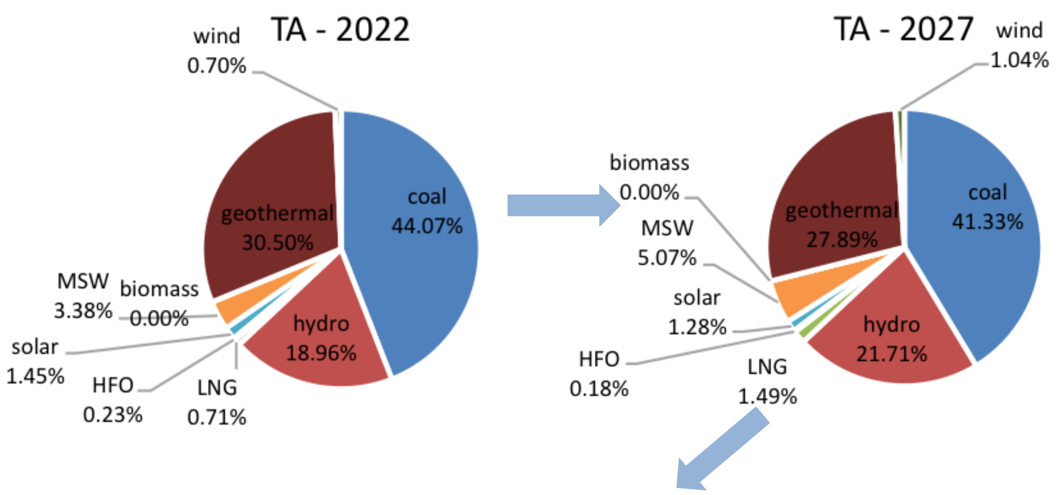
The following exhibit provides further details of the results.

Exhibit 3-4 Power Balance, COE, and GHG of BAU Result.

Name/Parameter	Type	Year		
		2022	2027	2032
TOTAL BUSINESS AS USUAL (BAU) GENERATION				
PLTU(MW)	coal	380	455	555
PLTA/M (MW)	hydro	59.2	101.2	219.2
PLTG/GU (MW)	LNG	100	300	400
PLTD/MG (MW)	HFO	30	30	30
PLTS (MW)	solar	26	26	26
PLTSa (MW)	MSW	0	0	23
PLTBm (MW)	biomass	0	10	15
PLTP (MW)	geothermal	119	143	388
PLTB (MW)	wind	0	0	70
Total Net Generation (MW)		**714**	**1,065**	**1,726**
Peak Load (MW)		**617**	**920**	**1,445**
Reserve Margin (%)		**15.8%**	**15.8%**	**20.2%**
COE (centUSD/kWh)		**7.40**	**7.39**	**6.86**
Total Annualized Cost (Mil. USD)		**291**	**434**	**633**
CO2 Intensity (kg/kWh)		**0.68**	**0.67**	**0.45**
Coal Portion (%)		**53.2%**	**42.7%**	**32.2%**
RE Portion (%)		**28.6%**	**26.3%**	**43.3%**

3.1.2 Trend Analysis

The TA scenario projects demand with trend forecast calculation and ignores all uncommitted generation plant in the RUPTL. As with the BAU scenario, the study years are set in 2022, 2027 and 2032. Exhibit 3-4 illustrates the share of energy generated from each energy source type for the TA scenario. As per Exhibit below, the coal plant fraction decreases from 44.07% in 2022 to 30.68% in 2032. Share of power generation from coal power plants is less compared to the BAU scenario. Exhibit 3-5 compares the energy production under the TA scenario with that of the BAU scenario.



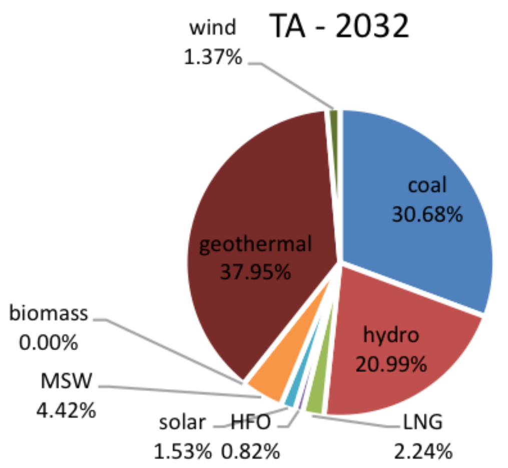


Exhibit 3-5 Generation Mix Result per year - TA

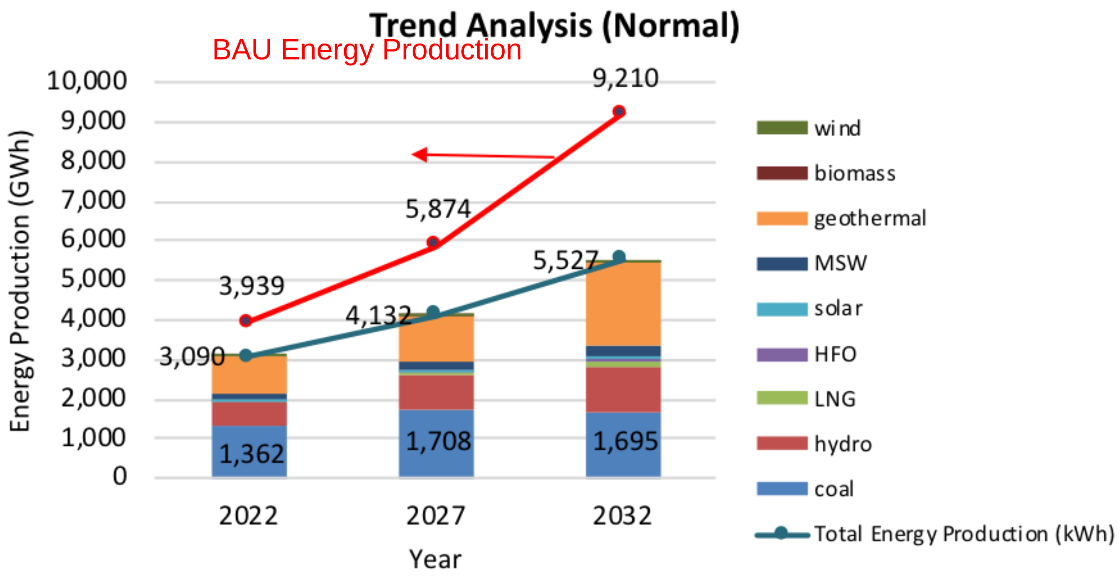


Exhibit 3-6 Energy Balance of TA Generation Mix result

The Exhibit below shows the power balance resulting from HOMER modeling of the TA scenario.

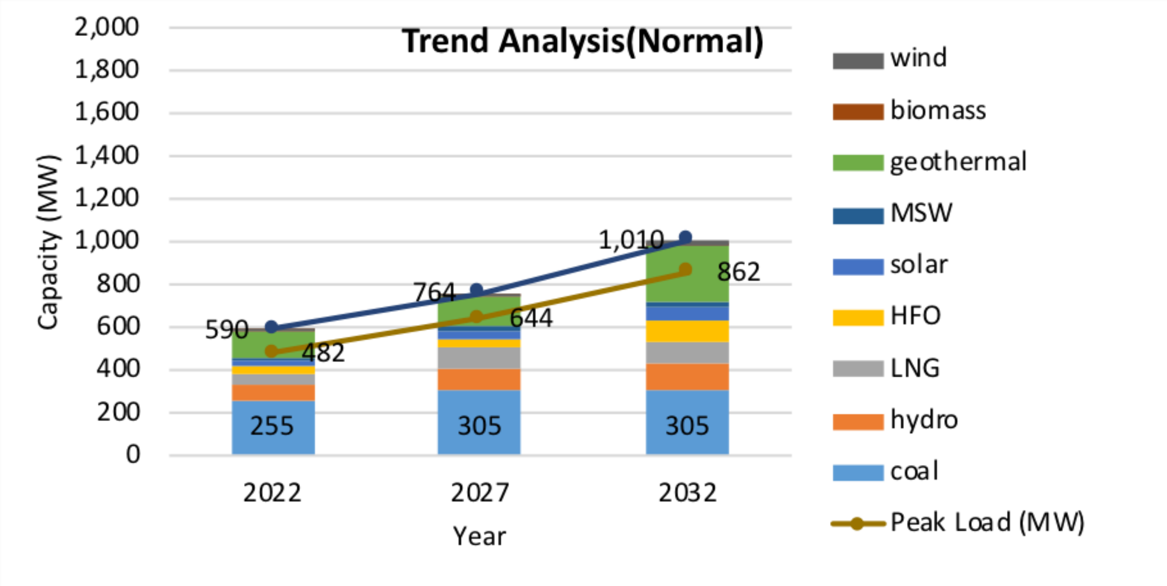


Exhibit 3-7 Power Balance of TA Generation Mix result.

As can be further observed in the following exhibit, the lower share of power generated by coal power plants – compared with BAU Scenario -- results in lower CO2 intensity.

Exhibit 3-8 Power Balance, COE, and GHG of TA Result

Name/Parameter	Type	Year		
		2022	2027	2032
TOTAL TREND ANALYSIS (TA) GENERATION				
PLTU (MW)	coal	255	305	305
PLTA/M (MW)	hydro	84.2	109.2	129.2
PLTG/GU (MW)	LNG	50	100	100
PLTD/MG (MW)	HFO	30	30	100
PLTS (MW)	solar	31	36	56
PLTSa (MW)	MSW	12	24	28
PLTBm (MW)	biomass	1	1	1
PLTP (MW)	geothermal	119	143	263
PLTB Candidates (MW)	wind	8	16	28
Total Net Generation		**590**	**764**	**1,010**
Peak Load (MW)		**482**	**644**	**862**
Reserve Margin (%)		**22.5%**	**18.6%**	**17.2%**
COE (centUSD/kWh)		**6.89**	**6.65**	**6.57**
Total Annualized Cost (Mil. USD)		**213.00**	**275.00**	**363.00**
CO2 Intensity (kg/kWh)		**0.490**	**0.466**	**0.359**
Coal Portion (%)		**43.2%**	**39.9%**	**30.2%**
RE Portion (%)		**43.2%**	**43.1%**	**50.0%**

Solar PV Penetration

PLN estimates its allowable Solar PV penetration based on its capacity divided by load at noon (Day Load) when Solar PV produce maximum output power. It can be seen that the Solar PV penetration ranges from 7.2% - 8.4% for each indicated year of study (2022 – 2032) under the TA scenario. This result shows that the solar PV additions remain within PLN's planning guidelines. PV penetration remains relatively low under the TA scenario because North Sulawesi has other renewable resources like geothermal that also provide much-needed capacity to serve growth in the evening peak.

Exhibit 3-9 Solar PV Penetration of TA Result w/o EE measure

Name/Parameter	Year		
	2022	2027	2032
Total Solar PV Capacity (MW)	31	36	56
Total Net Generation (MW)	590	764	1,010
Peak Load (MW)	482	644	862
Day Load* (MW)	373	499	668
Solar PV Penetration (%)	**8.3%**	**7.2%**	**8.4%**

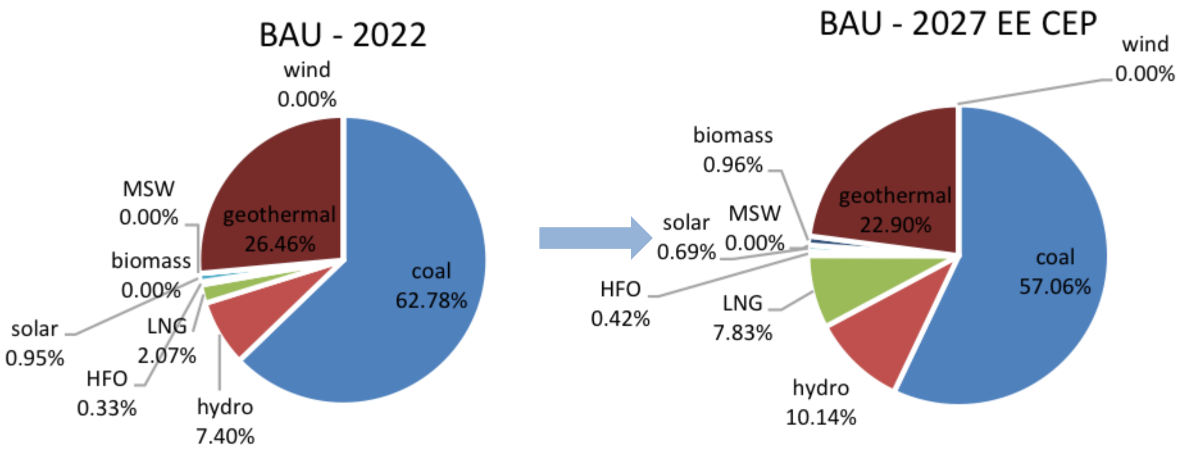
**) Day Load occurs at 12.00 pm noon time when Solar PV produce maximum output power*

3.2 WITH ENERGY EFFICIENCY INTERVENTION

This subsection gives the result of HOMER output after applying the energy efficiency (EE) on the demand side. The two EE scenarios are CEP and BAT.

3.2.1 BAU Scenario

The BAU scenario with Energy Efficiency measures is applied in the study year 2027 and 2032. This results in lower demand compared to to without-EE intervention. With EE CEP application, the share of power generation from coal power plants decreases from 62.78% in 2022 to 28.78% in 2032.



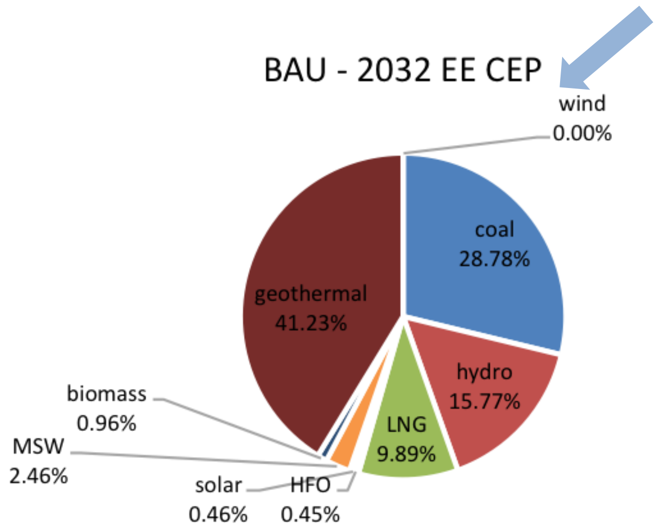
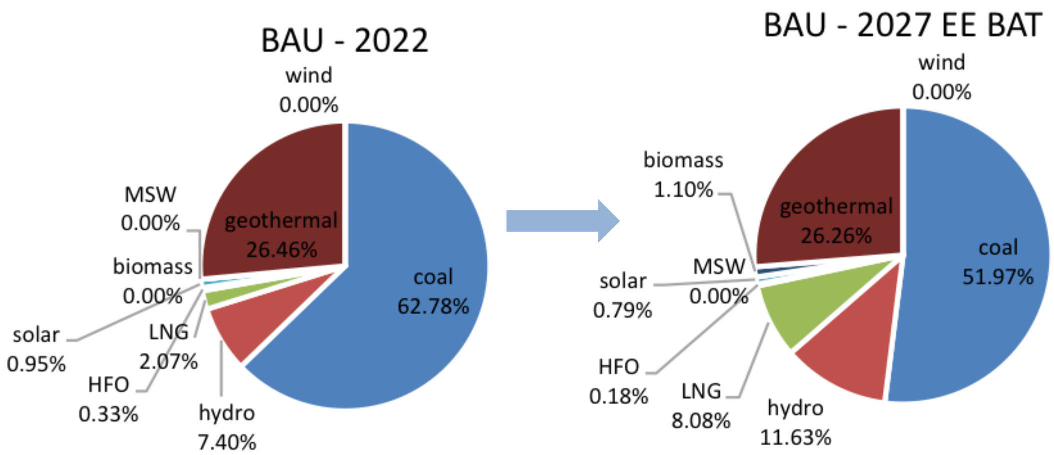


Exhibit 3-10 Generation Mix Result per year - BAU with EE CEP

When applying Energy Efficiency with BAT, the share of power generation from coal power plants is less than the BAU scenario but higher than the CEP scenario (33.46% in 2032). This is because the amount of energy produced by coal power plants are similar in both cases, but the total energy produced in BAT scenario is smaller which results in the higher percentage of coal in BAT Scenario.



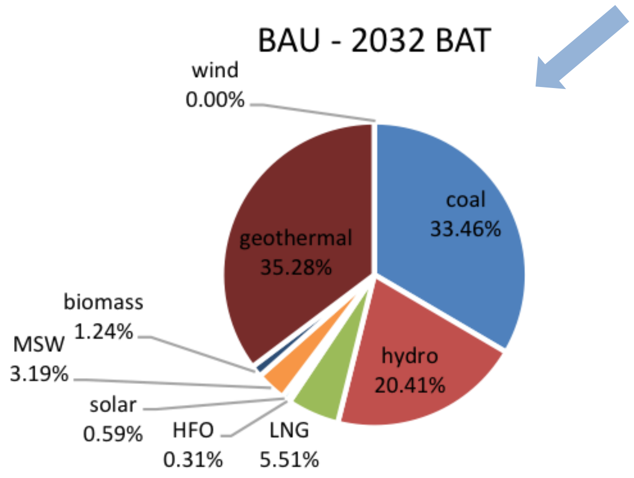


Exhibit 3-11 Generation Mix Result per year - BAU with EE BAT

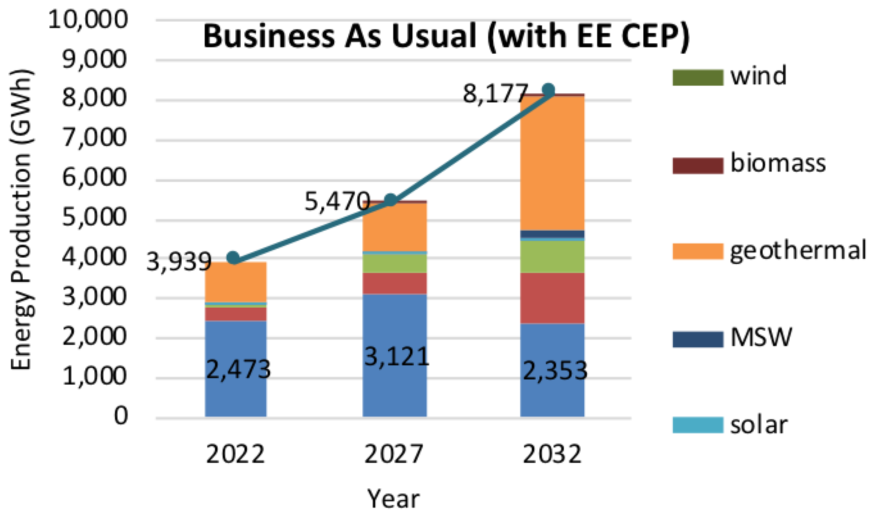


Exhibit 3-12 Energy Balance of BAU with EE CEP Generation Mix result.

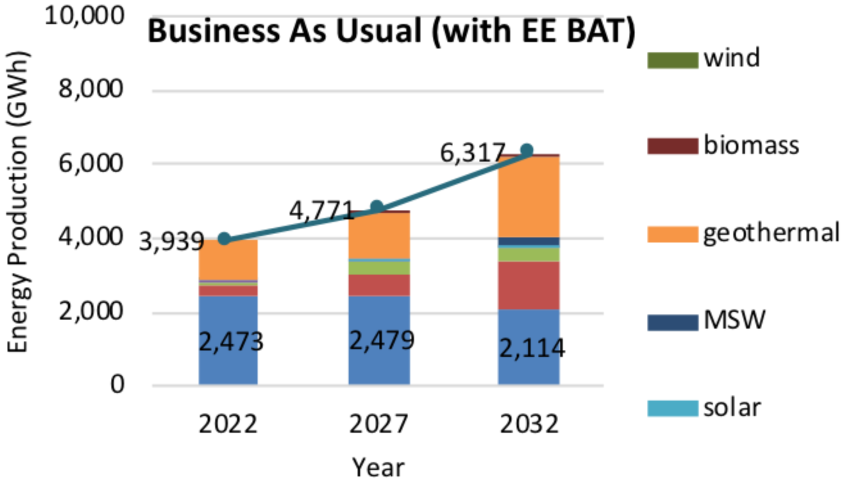


Exhibit 3-13 Energy Balance of BAU with EE BAT Generation Mix result.

Exhibit 3-14 and Exhibit 3-15 show the power balance under the BAU scenario with EE intervention.

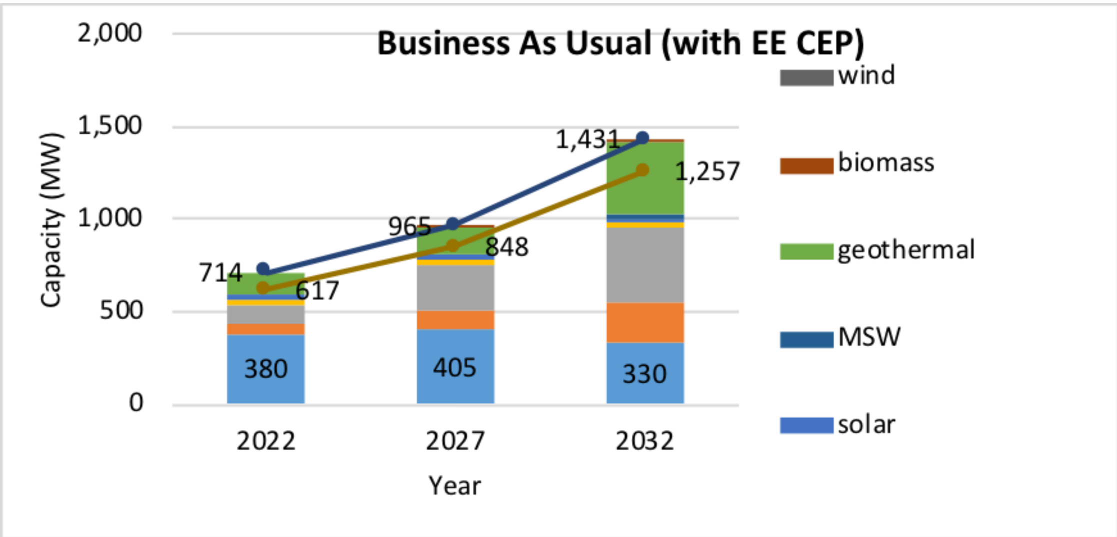


Exhibit 3-14 Power Balance of BAU with EE CEP Generation Mix result

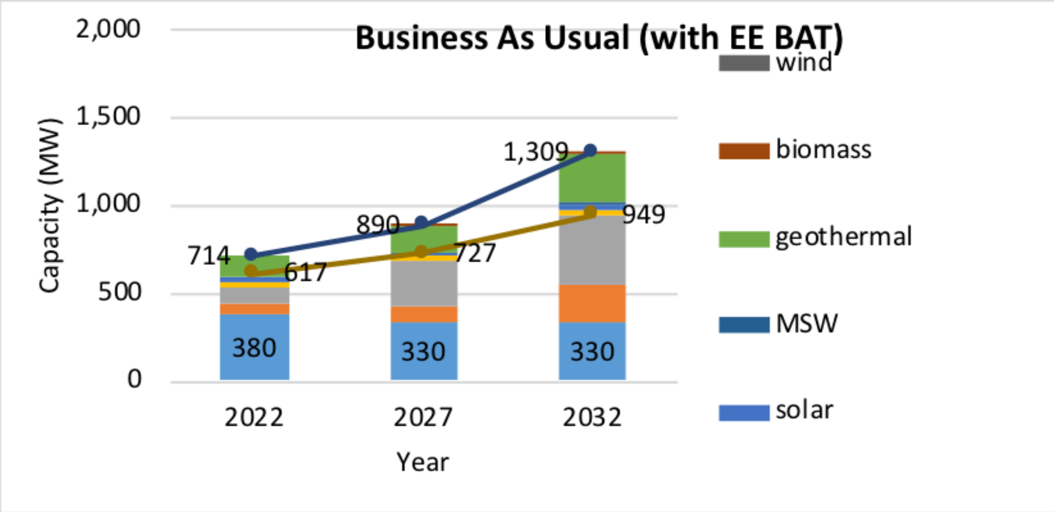


Exhibit 3-15 Power Balance of BAU with EE BAT Generation Mix result.

As can be observed from the exhibit below, similar to other scenario, trend of CO_2 intensity follows the share of power generation generated from power plants.

Exhibit 3-16 Power Balance, COE, and GHG of BAU with EE Result

Name/Parameter	Type	Year				
		2022	2027	2027	2032	2032
		Normal	EE CEP	EE BAT	EE CEP	EE BAT
TOTAL BUSINESS AS USUAL (BAU) GENERATION						
PLTU (MW)	coal	380	405	330	330	330
PLTA/M (MW)	hydro	59.2	101.2	101.2	219.2	219.2
PLTG/GU (MW)	LNG	100	250	250	400	400
PLTD/MG (MW)	HFO	30	30	30	30	30
PLTS (MW)	solar	26	26	26	26	26
PLTSa (MW)	MSW	0	0	0	23	23
PLTBm (MW)	biomass	0	10	10	15	15
PLTP (MW)	geothermal	119	143	143	388	265.5
PLTB (MW)	wind	0	0	0	0	0
Total Net Generation (MW)		**714**	**965**	**890**	**1,431**	**1,309**
Peak Load (MW)		**617**	**848**	**727**	**1,257**	**949**
Reserve Margin (%)		**15.8%**	**13.8%**	**22.5%**	**13.9%**	**37.9%**
COE (centUSD/kWh)		**7.40**	**7.36**	**7.27**	**6.71**	**6.78**
Total Annualized Cost (Mil. USD)		**291.00**	**403.00**	**347.00**	**549.00**	**428.00**
CO2 Intensity (kg/kWh)		**0.68**	**0.64**	**0.59**	**0.36**	**0.40**
Coal Portion (%)		**53.2%**	**42.0%**	**37.1%**	**23.1%**	**25.2%**
RE Portion (%)		**28.6%**	**29.0%**	**31.5%**	**46.9%**	**41.9%**

3.2.2 Trend Analysis

Modeling the TA scenario with the CEP intervention results in a decreasing portion of production from coal. At the beginning (2022) the coal portion is 44.07 %, which then decreases to the 42.89% (2027) and 33.62% by 2032. The lower energy demand in this scenario can be satisfied more by cheaper hydro plants, reducing the need for coal generation.

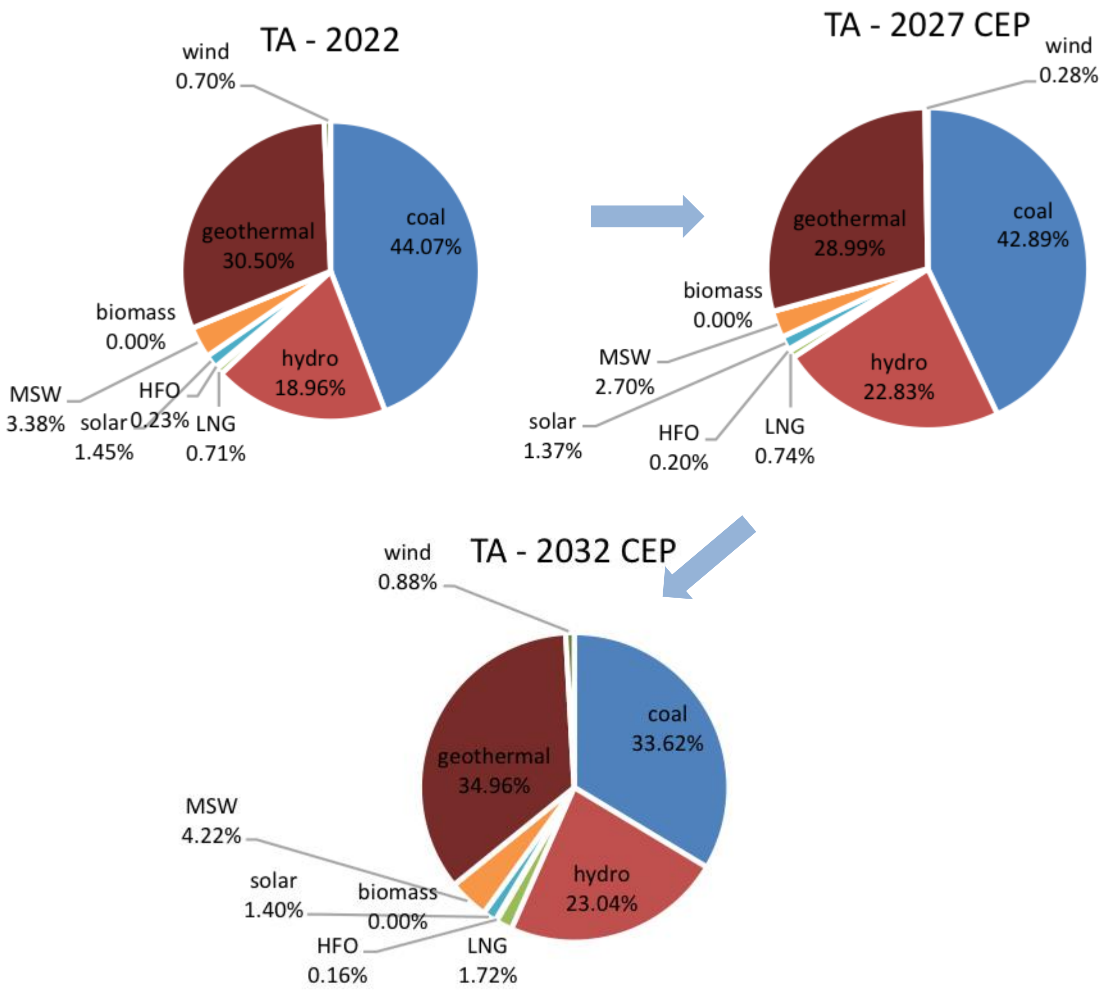


Exhibit 3-17 Generation Mix Result per year - TA with EE CEP

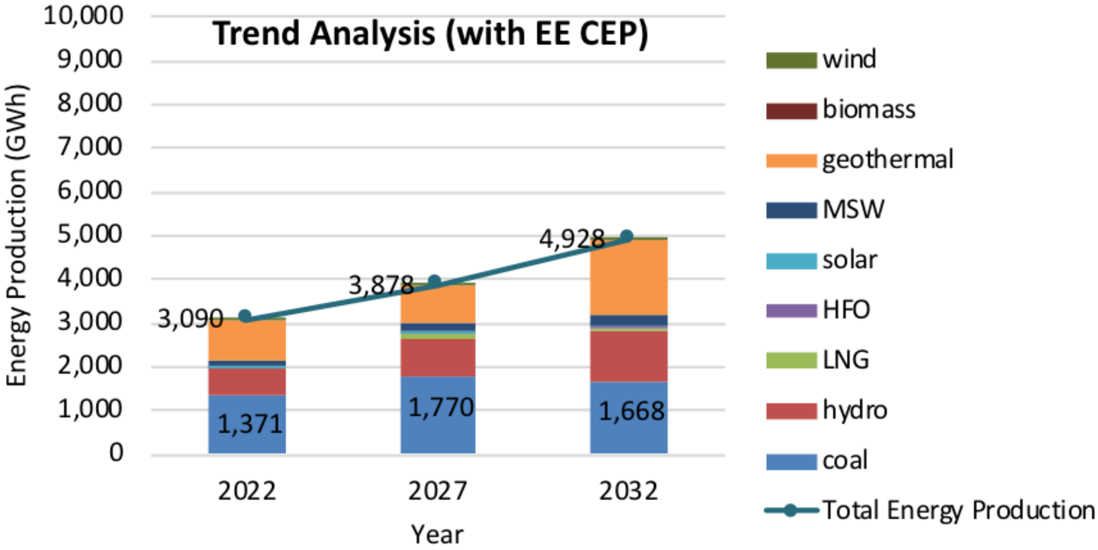
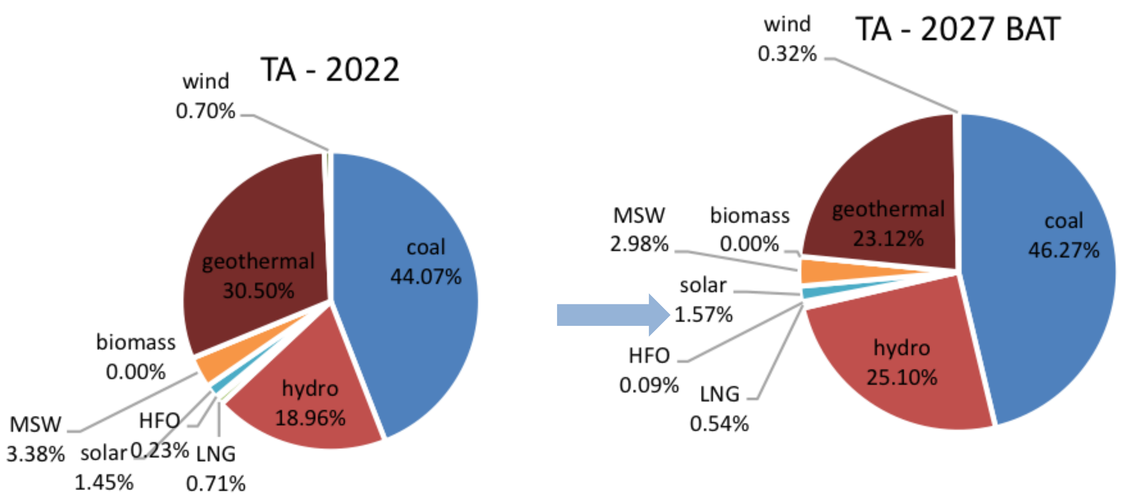


Exhibit 3-18 Energy Balance of TA with EE CEP Generation Mix result

The TA scenario with BAT intervention results in very low load growth. This low load growth means there is little need to add capacity to the system; existing and committed generators are sufficient to meet load through 2027. There is 50 MW of committed coal 2022 that slips to 2027 and ensures sufficient capacity. As a result, the percentage contribution of coal increases in 2027 under this scenario, but then declines in 2032 as more hydro and geothermal become available.



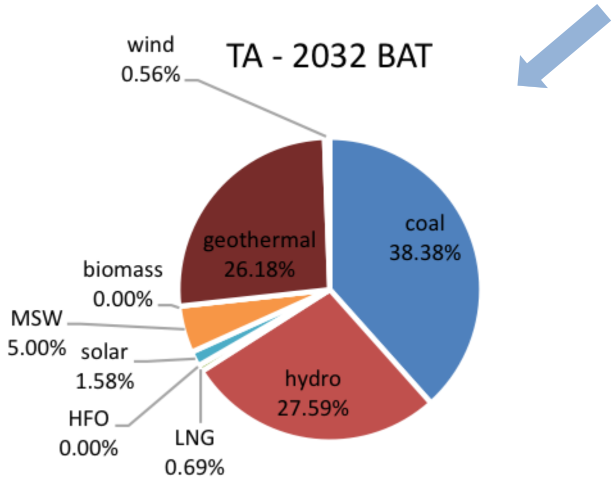


Exhibit 3-19 Generation Mix Result per year - TA with EE BAT

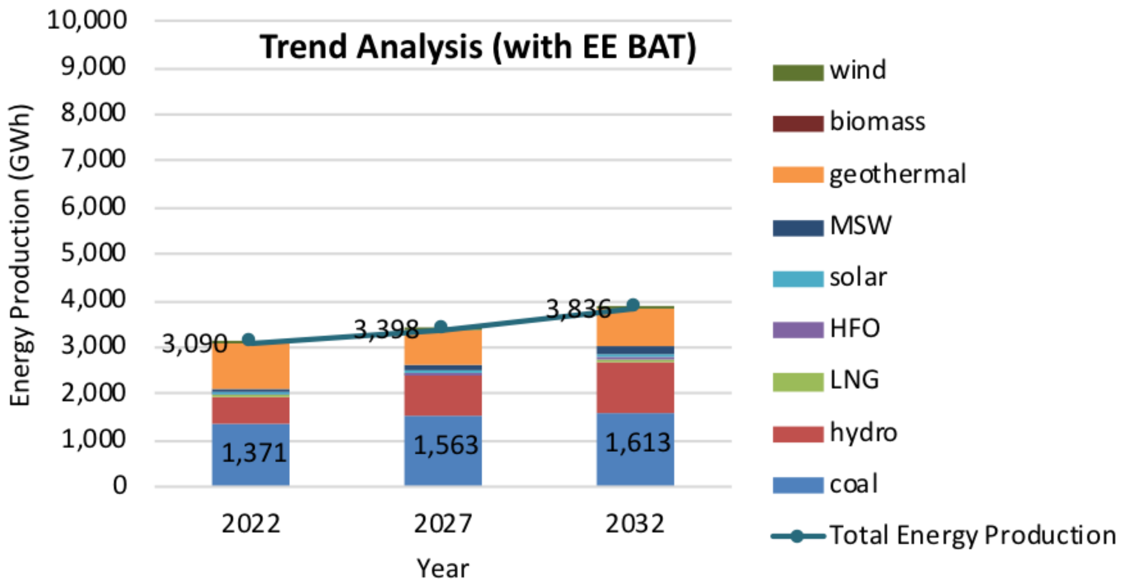


Exhibit 3-20 Energy Balance of TA with EE BAT Generation Mix Result

The optimum size of generation system for Trend Analysis scenarios are selected based on least cost, least emission and higher renewable fraction. The following exhibits show the power balance in terms of the capacity for each type of power plant in each study year.

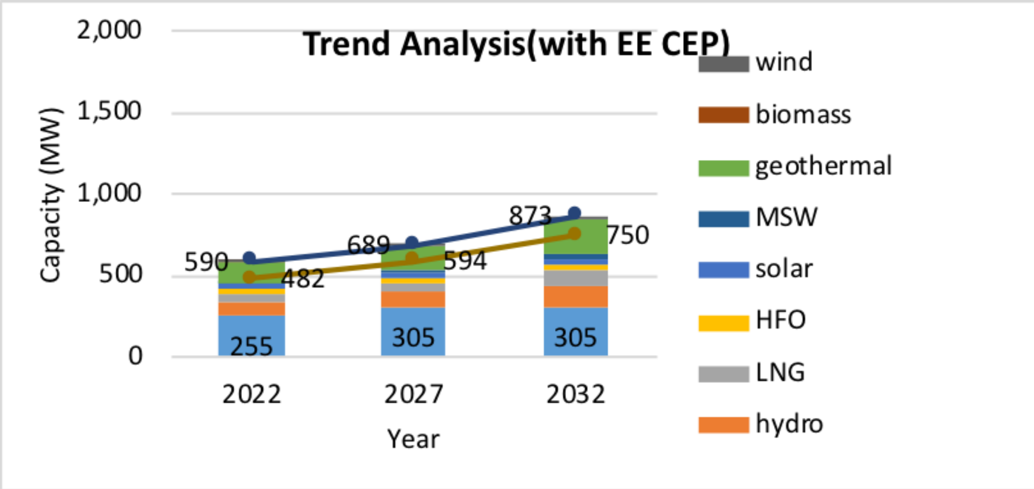


Exhibit 3-21 Power Balance of TA with EE CEP Generation Mix result.

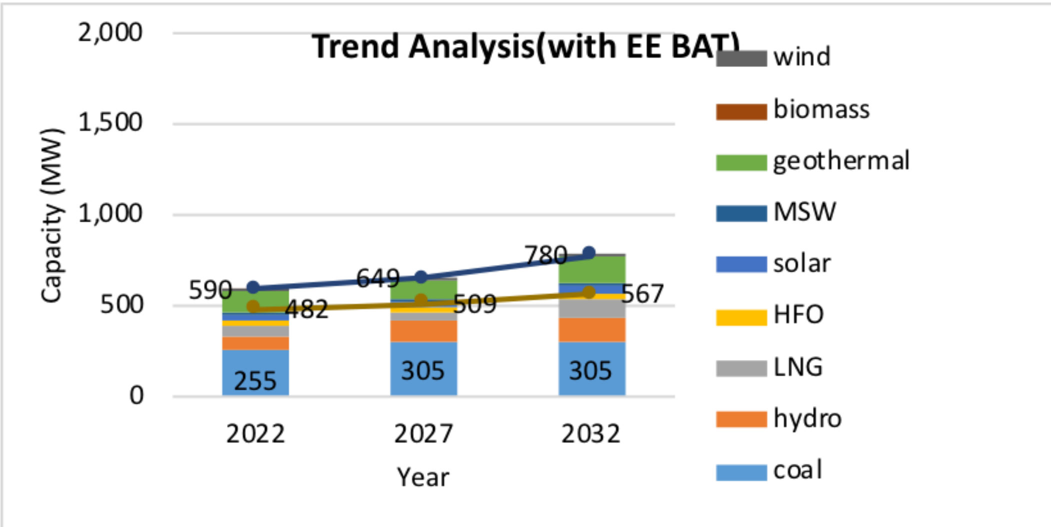


Exhibit 3-22 Power Balance of TA with EE BAT Generation Mix Result.

The total optimum-sized capacity of solar PV plant can achieve up to 31 MW in 2022, then increase to 36 MW in 2027, then it will increase again up to 41 or 46 MW in year 2032 depending on which EE scenario is applied. Wind power capacity achieves its optimum-sized capacity up to 16 MW in year 2032.

In all results provided in Exhibit 3-23, solar PV and biomass (coconut shell) have relatively low capacity in the expansion plan. The low percentage of coconut shell biomass in the generation mix is due to high price of coconut shell biomass compared to other sources of energy. Experts from University of Sam Ratulangi implied the shortage of coconut shell supply in the region. Further studies will be required to confirm this.

Exhibit 3-23 Power Balance, COE, and GHG of TA with EE Result

Name/Parameter	Type	Year				
		2022	2027		2032	
		Normal	EE CEP	EE BAT	EE CEP	EE BAT

Name/Parameter	Type	Year				
		2022	2027		2032	
		Normal	EE CEP	EE BAT	EE CEP	EE BAT
TOTAL TREND ANALYSIS (TA) GENERATION						
PLTU	coal	255	305	305	305	305
PLTA/M	hydro	84.2	109.2	109.2	129.2	129.2
PLTG/GU	LNG	50	50	50	100	100
PLTD/MG	HFO	30	30	30	30	30
PLTS	solar	31	36	36	46	41
PLTSa	MSW	12	12	12	24	24
PLTBm	biomass	1	0	0	0	0
PLTP	geothermal	119	143	103*)	223	143
PLTB Candidates	wind	8	4	4	16	8
Total Net Generation		**590**	**689**	**649**	**873**	**780**
Peak Load (MW)		**482**	**594**	**509**	**750**	**567**
Reserve Margin (%)		**22.5%**	**16.0%**	**27.5%**	**16.5%**	**37.6%**
Total Annualized Cost (Mil. USD)		**213**	**259**	**232**	**318**	**260**
COE (centUSD/kWh)		**6.89**	**6.72**	**6.92**	**6.49**	**6.86**
CO2 Intensity (kg/kWh)		**0.49**	**0.475**	**0.513**	**0.384**	**0.436**
Coal Portion (%)		**43.2%**	**44.3%**	**47.0%**	**34.9%**	**39.1%**
RE Portion (%)		**43.2%**	**44.1%**	**40.7%**	**50.2%**	**44.2%**

Note:
**) The decrease in capacity of PLTP from 2022 and 2027 may be due to decrease in capacity of PLTPin RUPTL 2018-2027 in year 2023.*

Solar PV Penetration

Similar to the BAU EE scenarios, Solar PV penetration ranges between 7.5% - 8.3% for each study year (2022 – 2032) under these TA EE scenarios. As noted previously, this is within PLN's current practice.

Exhibit 3-24 Solar PV Penetration of TA Result with EE measure

Name/Parameter	Year				
	2022	2027		2032	
	Normal	EE CEP	EE BAT	EE CEP	EE BAT
PLTS	31	36	36	46	41
Total Net Generation (MW)	590	689	649	873	780
Peak Load (MW)	482	594	509	750	567
Day Load* (MW)	373	483	443	609	493
Solar PV Penetration (%)	**8.3%**	**7.5%**	**8.1%**	**7.6%**	**8.3%**

**) Day Load occurs at 12.00 pm noon time when Solar PV produce maximum output power*

3.3 GENERATION SUPPLY CURVE

HOMER calculates the following:

- Controllable generation marginal cost – For each generator that can be controlled, e.g. coal, geothermal, WTE, gas and HFO, HOMER reports the average marginal cost of production, which is the additional cost per kilowatt-hour of producing electricity from that generator. This is a function of generator efficiency, fuel cost and generator loading.

- Renewable levelized cost of energy – For each variable renewable energy (VRE) resource, such as PV, wind and run-of-river hydro, HOMER reports its levelized cost of energy, which is the total annualized cost (including capital and O&M costs) divided by the total production for the year[18].

- Total system cost of energy (COE) – HOMER reports the total net present value of capital, replacement, fuel and operating costs for each feasible system configuration. HOMER uses this metric to determine the least-cost system configuration. HOMER also annualizes this cost and divides by energy supplied to determine the total system COE.

HOMER dispatches in each time period based on controllable generation marginal cost using the following algorithm in each time step for each possible configuration of generators:

1. HOMER calculates the VRE output in that period;

2. It then determines the load to be served, and applies an operating reserve margin if specified. (Operating reserve is essentially the same as spinning reserve);

3. HOMER then calculates total load including operating reserve but net of VRE production;

4. Available controllable generation is then dispatched in order of increasing marginal cost while observing minimum load ratio constraints until total load net of VRE contribution is satisfied, subject to maximum capacity shortage, if any.

This is essentially the same way dispatch is conducted according to the grid codes for the major power systems in Indonesia: controllable generators are dispatched in order of increasing variable costs against system load net of production from VRE and "must-run" plant.

This allows the construction of the system short-run supply curve for each scenario and study year. The exhibits below show the 2032 short-run supply curves for the TA and BAU scenarios. Note that the short-run supply curve is based only on controllable generation; VRE technologies have no fuel costs, and therefore have zero short-run marginal cost. (HOMER considers operating and maintenance costs incurred per hour of operation as fixed operating costs, since they do not vary with the level of output, only whether or not the plant is operating). VRE technologies and the overall system can nonetheless be characterized by levelized cost of energy (which includes capital costs as well as fuel and operating costs). These are shown for comparison in the figure below.

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[18] Because HOMER simulates only one year of operation, it defines the levelized cost of energy as annualized cost divided by annual energy production, rather than a more common definition of present value cost divided by present value of energy production.

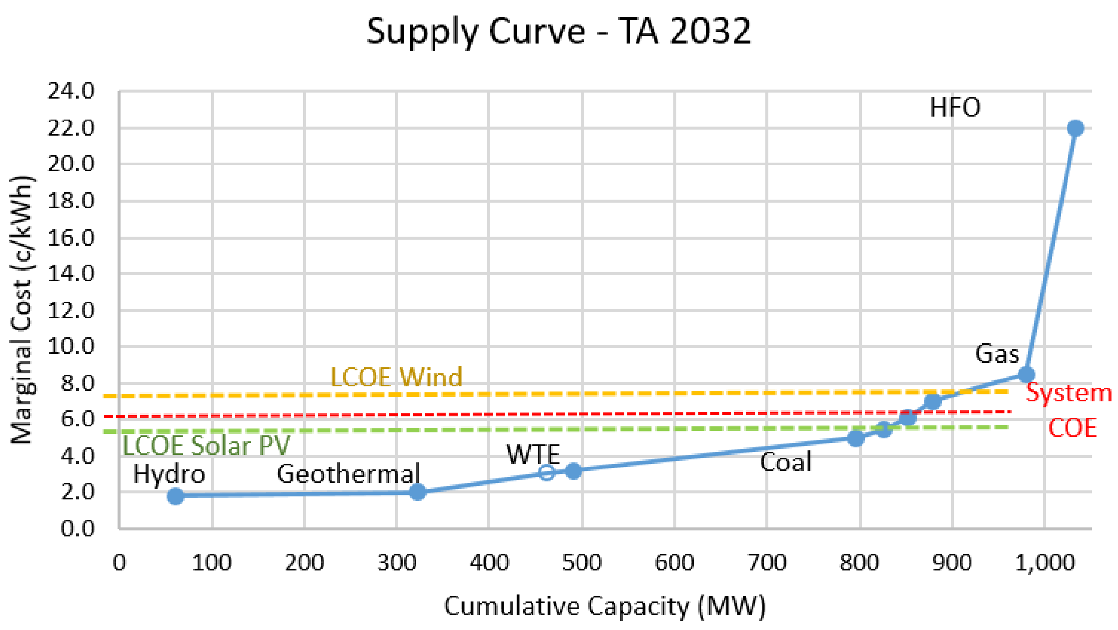


Exhibit 3-25 Generation Supply Curve for TA Scenario.

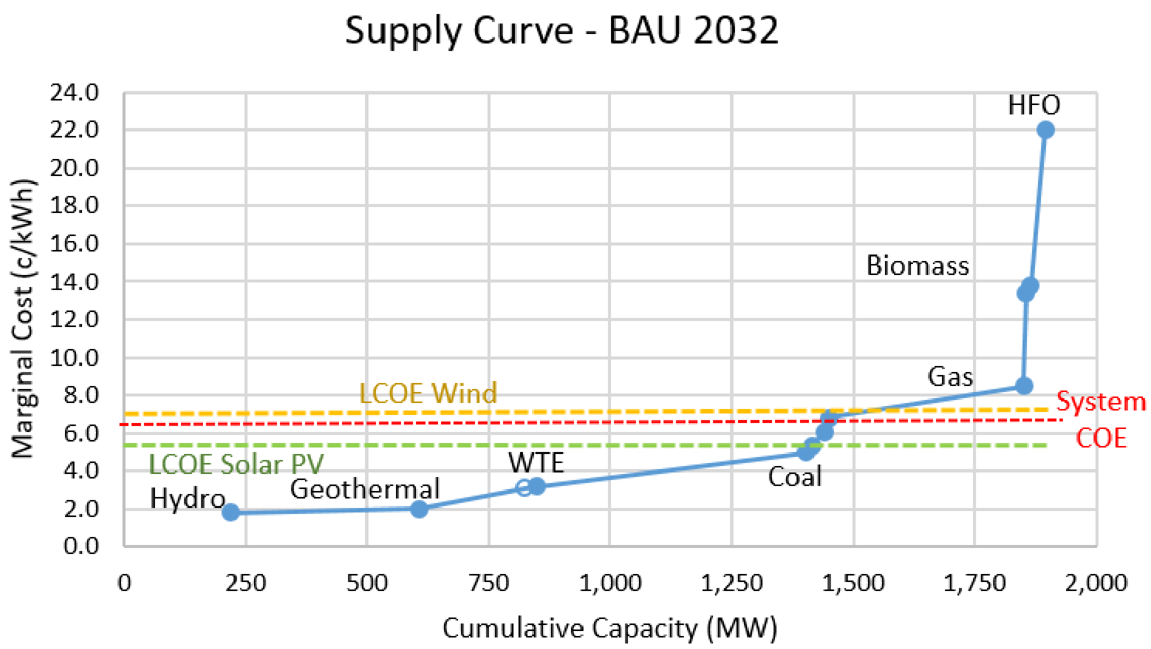


Exhibit 3-26 Generation Supply Curve for BAU Scenario.

This section provides analysis of variables affecting the outputs over the years. At the end of this section, one scenario is selected as the basis for a pathway to emission reduction in 2032.

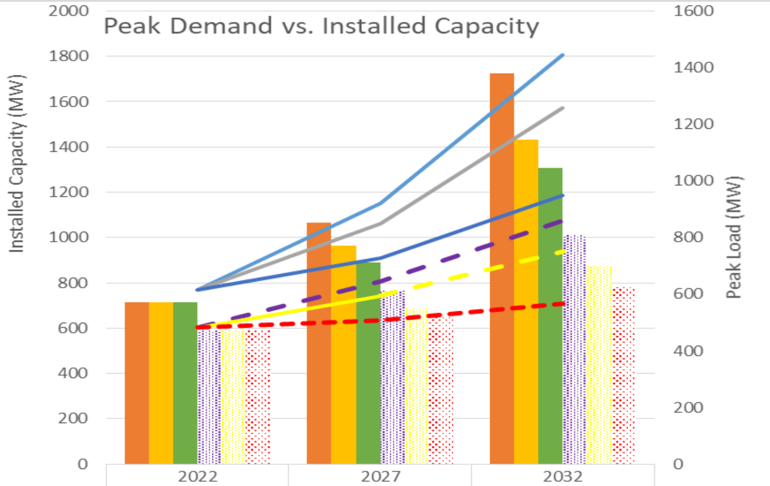
4.1 THE IMPACT OF PEAK LOAD ON FUTURE SUPPLY

Peak load is one of the key variables in long-term electricity system planning. It is expected that the supply-side capacity expansion will be larger than the peak load growth, as illustrated in the Exhibit 4-1, since not all generators can operate at the time of system peak and due to the provision of an operating reserve.

The exhibit indicates how the expected demand growth determines the generation expansion plan. The lower the peak load, the lower the installed capacity. The differences between installed capacity in BAU scenarios and TA scenarios are significant, with the highest difference between the BAU scenario and TA + EE BAT scenario of 946 MW. This is because the number of installed capacity of power plants needs to increase to serve the growing demand.

One of the main components of electricity cost is the capital cost required to construct new power plants. This means that the electricity cost can be greatly affected by the scale of the generation expansion plan. The impact will be discussed in Section 4.1.3.

It is expected that emissions will also fluctuate in line with the energy production associated with each scenario. The impact of energy production on emissions will be discussed in Section 4.1.2.



	2022	2027	2032
BAU Installed Capacity	714	1065	1726
BAU + EE CEP Installed Capacity	714	965	1431
BAU + EE BAT Installed Capacity	714	890	1309
TA Installed Capacity	590	764	1010
TA + EE CEP Installed Capacity	590	689	873
TA + EE BAT Installed Capacity	590	649	780
BAU Peak Load	617	920	1445
BAU + EE CEP Peak Load	617	848	1257
BAU + EE BAT Peak Load	617	727	949
TA Peak Load	482	644	862
TA + EE CEP Peak Load	482	594	750
TA + EE BAT Peak Load	482	509	567

Exhibit 4-1 Peak Demand Growth vs Installed Capacity in all scenarios

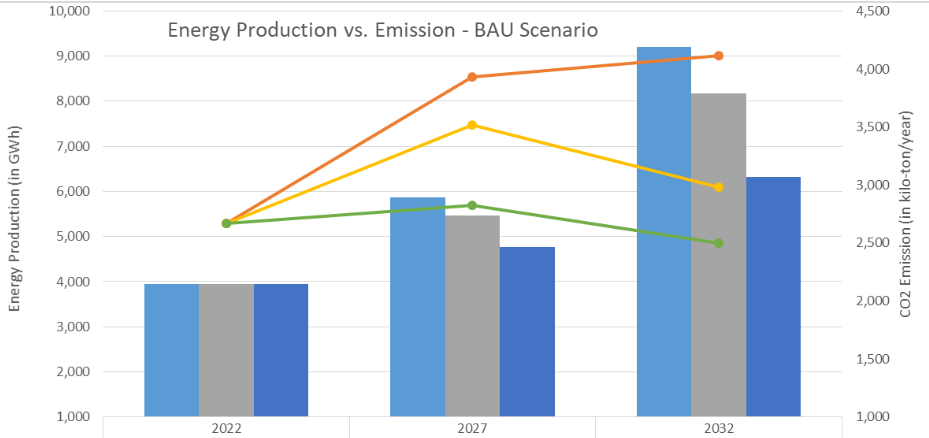
In both BAU and TA Scenarios, EE measures contribute to the reduction of peak load, hence reducing the need to construct new power plants.

4.2 THE RELATIONSHIP BETWEEN ENERGY PRODUCTION AND EMISSIONS

<u>Relationship between energy production and total emission levels</u>

CO_2 emission reduction is one of the key elements discussed in this study. HOMER calculates the emission based on the fuel consumption per unit of electricity produced. It is expected that the amount of emissions is in line with the energy production. Exhibit 4-2 shows the relationship between energy production and the resulting emissions for the BAU scenario, while Exhibit 4-3 illustrates similar correlation for the TA scenario.

For BAU scenarios, emission levels steadily increase from 2022 to 2027, which is in line with the increase in coal-fired energy production. In 2032, the emission level in the BAU scenario without EE measures slightly increases, while the emission levels in both BAU scenario with CEP and BAT measures reduce. The trend of emission level is in line with the production level of coal power plants as it contributes the most to emission.



	2022	2027	2032
Energy Production - BAU	3,939.15	5,874.29	9,210.23
Energy Production - BAU + EE CEP	3,939.15	5,469.79	8,176.75
Energy Production - BAU + EE BAT	3,939.15	4,770.93	6,317.23
CO2 Emission - BAU Scenario	2,667.9	3,930.2	4,115.9
CO2 Emission - BAU + EE CEP	2,667.9	3,520.6	2,980.4
CO2 Emission - BAU + EE BAT	2,667.9	2,823.9	2,497.6

Exhibit 4-2 Energy Production vs Emission for BAU Scenarios

Similar to the BAU scenario, the emission level for TA scenarios in 2027 significantly increases as the energy production increases. In 2032, the emission levels of TA only and TA+EE CEP Scenarios increase, while emission level for TA+EE BAT scenario decreases. The decrease in the emission level in TA+EE BAT scenario is due to decreases in production of electricity from coal, LNG and diesel fuel.

Exhibit 4-3 Energy Production vs Emission for TA Scenarios

In general, the trend observed between energy production and emission levels in both scenarios is that the higher the energy production, the higher the total emission levels for each year. While it was previously noted that LNG and diesel fuel contribute to the total emission levels, the trend in the total emission levels is driven principally by the amount of electricity produced from coal power plants, as seen in Exhibit 4-4.

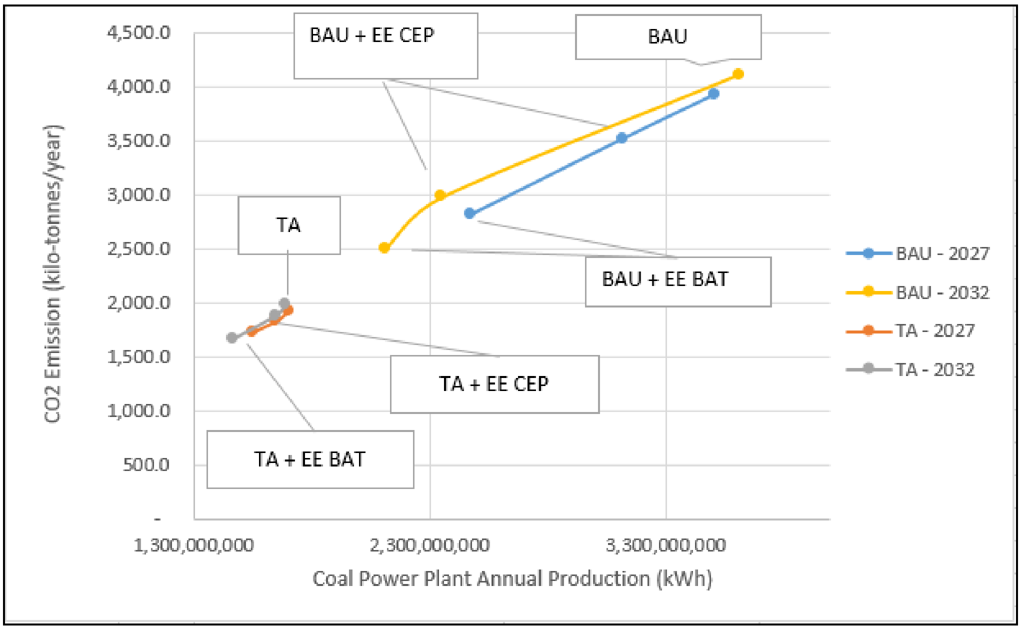
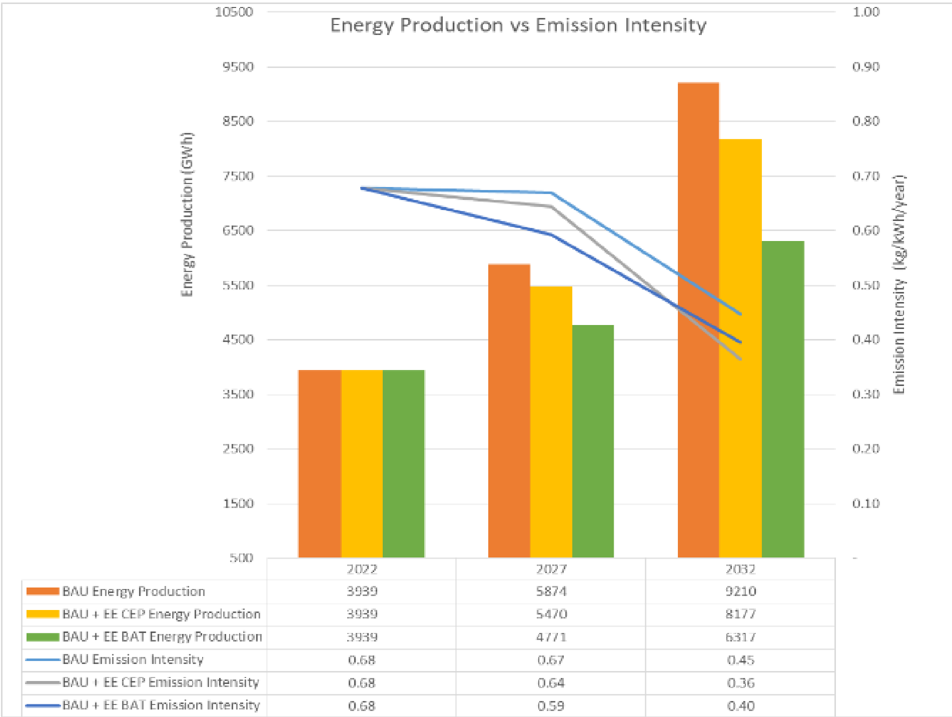


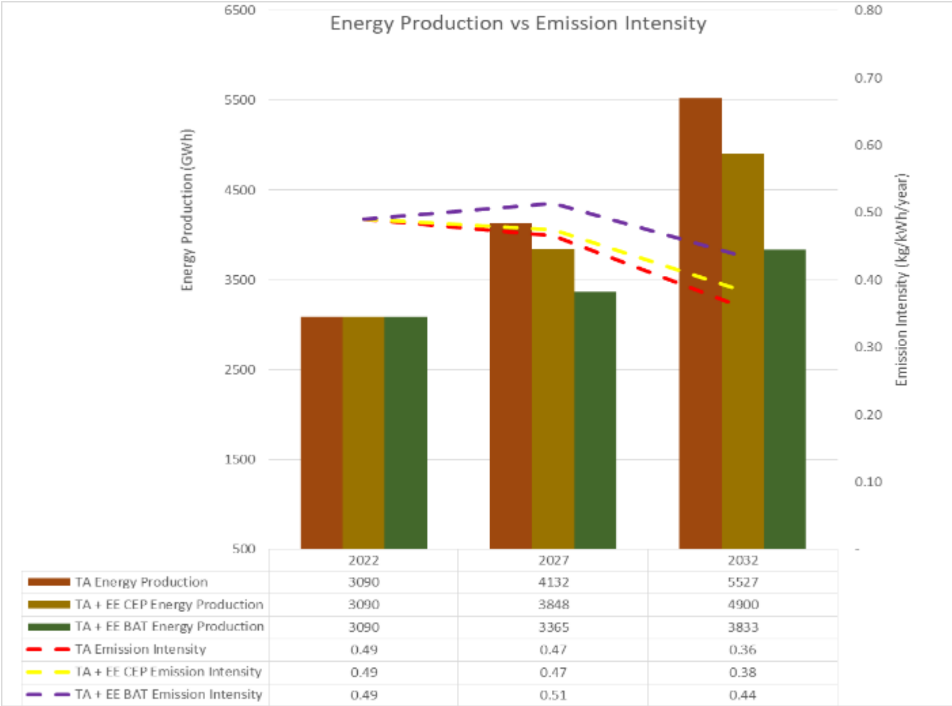
Exhibit 4-4 Comparison between coal-fired generation power plant and emission level for all scenarios at the year 2027 and 2032.

<u>Relationship between energy production and emission intensity</u>

The energy production and emission intensity trends are described in the exhibit below. In the TA scenario, the trend between the energy production and emission intensity is relatively linear, i.e. the lower the energy production, the lower the emission intensity. The same trend is not observed in the BAU Scenario, in which the emission intensity for the BAU+EE CEP scenario is lower than for the BAU+EE BAT scenario in 2032. This means that the BAU+EE BAT scenario has higher emission intensity despite lower energy production, compared to the BAU+EE CEP scenario. The trend, in fact, is similar to the percentage of coal power plants energy production in the system's energy mix, as seen in Exhibit 4-6.



(a)



	2022	2027	2032
TA Energy Production	3090	4132	5527
TA + EE CEP Energy Production	3090	3848	4900
TA + EE BAT Energy Production	3090	3365	3833
TA Emission Intensity	0.49	0.47	0.36
TA + EE CEP Emission Intensity	0.49	0.47	0.38
TA + EE BAT Emission Intensity	0.49	0.51	0.44

(b)

Exhibit 4-5 Relationship between energy production and emission intensity.

As seen in Exhibit 4-6, the BAU+EE CEP Scenario has *lower* percentage of coal in its energy mix compared to the BAU+EE BAT Scenario in 2032. In contrary, the BAU+EE CEP Scenario has *higher* percentage of coal in its energy mix compared to the BAU+EE BAT Scenario in 2027. The phenomenon occurs as the BAU+EE BAT scenario's least cost option to fulfil the electricity demand in 2032 is through increasing the capacity factor of the coal power plant, which has been set at capacity of 305 MW as committed plants. This consequently increases the percentage of coal in the energy mix. While in the BAU+EE CEP, despite having a slightly higher production of coal, the system's least emission-least cost option is also to dispatch other energy sources with less emission than coal. As emission intensity is calculated through dividing total annual emission with total energy production, the higher the percentage of coal in the energy mix, the higher the emission intensity.

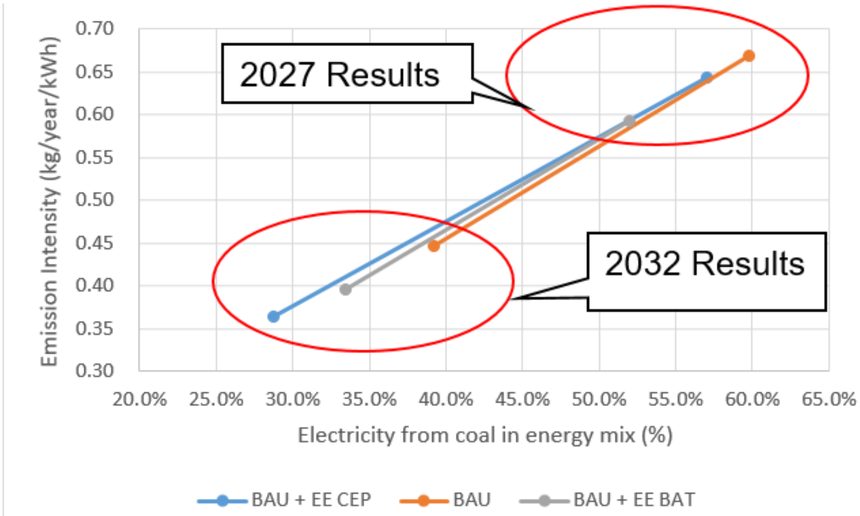


Exhibit 4-6 Comparison between emission intensity and percentage of coal in the energy mix.

<u>Impact of EE measures to energy production and emission</u>

In BAU Scenarios, EE measures contribute to a reduction in emission. The larger the impact of EE measures, the larger the emission reduction. In TA Scenarios, however, it is found that the reduction of energy production does not affect the emission in a linear manner.

For example, simulation results for TA Scenario in 2027 in which the emission in TA + EE CEP scenario is higher than the TA Scenario. This is in contrary to the common expectation that the reduction of energy production will result in emission reduction.

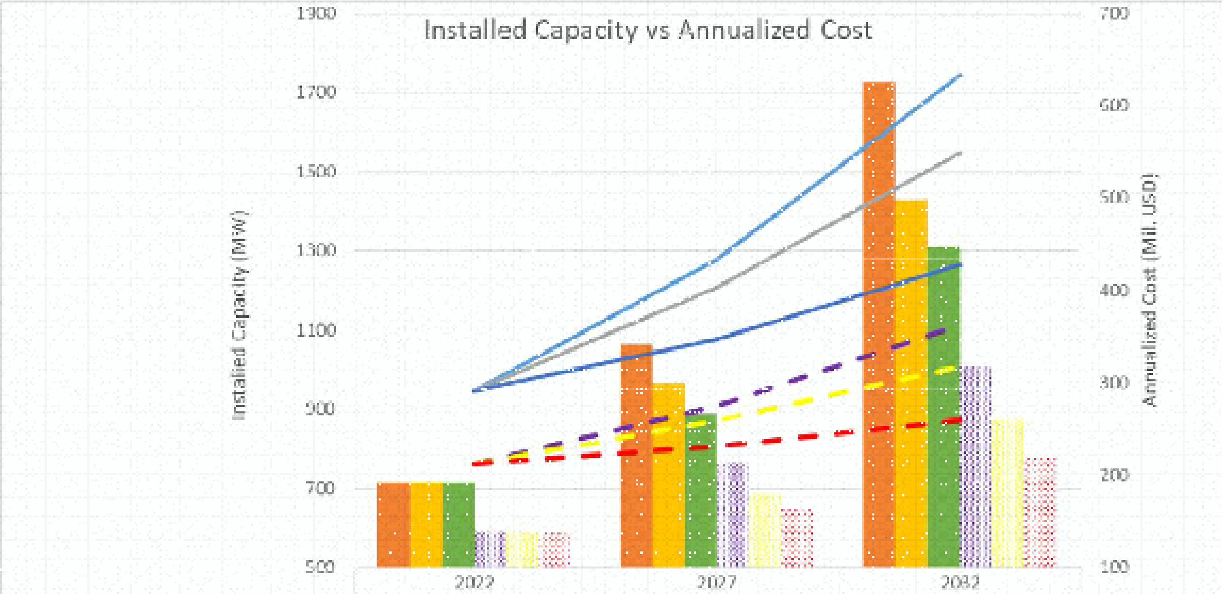
This is due to the fact that the reduction in demand due to EE CEP Scenario is quite small, causing HOMER to dispatch more coal power plants and increasing its capacity factor, rather than dispatching generation from cleaner fuel. This is because it is cheaper to purchase more coal to produce electricity from existing plants than to construct and operate a new alternative power plant.

4.3 THE COST DRIVERS IN THE ENERGY SYSTEM

There are two main economic parameters used to measure the effect of installed capacity and electricity production:

i) Annualized Cost, i.e. the annualized value of the total net present cost which in this study is mostly driven by capital cost, therefore is being used to measure the economic effect of an increase in installed capacity;
ii) Cost of Energy (COE), i.e. the average cost per kWh of useful electrical energy produced by the system, which is calculated through dividing annualized cost with annual electricity production, therefore is being used to measure the economic effect of an increase in energy production.

The exhibit below provides a comparison between the installed capacities with the annualized cost for each scenario. The graph indicates that annualized cost increases as the installed capacity increases. This is because annualized cost is derived from the total Net Present Cost (NPC), which includes capital, operational, O&M, fuel and replacement cost. Capital cost increases as installed capacity increases. As capital is the most significant factor in determining NPC and annualized cost, the increase in installed capacity is in line with the annualized cost.



	2022	2027	2032
BAU Installed Capacity	714	1065	1726
BAU + EE CEP Installed Capacity	714	965	1431
BAU + EE BAT Installed Capacity	714	890	1309
TA Installed Capacity	590	764	1010
TA + EE CEP installed Capacity	590	689	873
TA + EE BAT Installed Capacity	590	649	780
BAU Annualized Cost	291	434	633
BAU + EE CEP Annualized Cost	291	403	549
BAU + EE BAT Annualized Cost	291	347	428
TA Anualized Cost	213	275	363
TA + EE CEP Annualized Cost	213	259	318
TA + EE BAT Annualized Cost	213	232	260

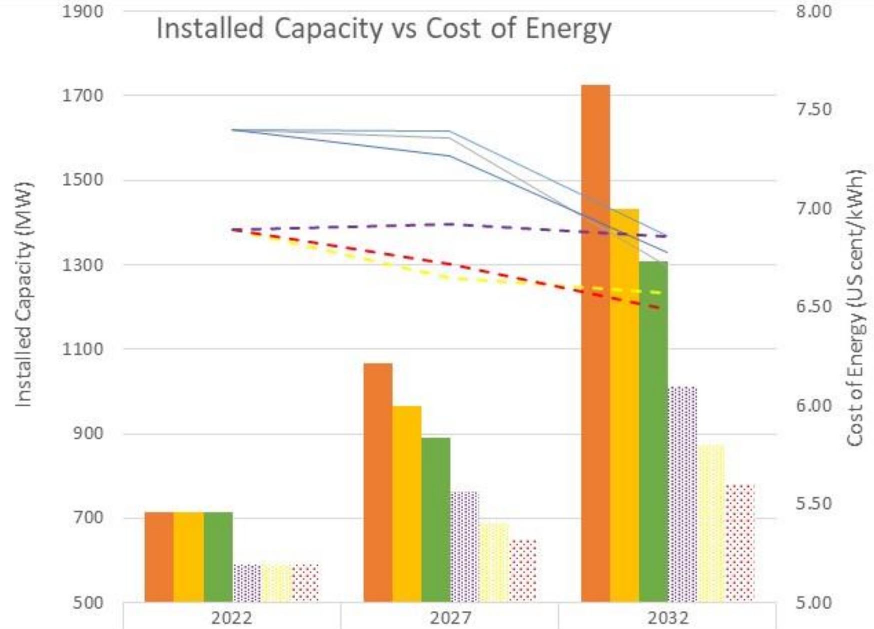
Exhibit 4-7 Installed capacity vs annualized cost for all scenarios.

The following exhibit compares energy production with COE. Contrary to the annualized cost, the movement of COE is not entirely in line with energy production. Particularly in 2032, where COE is significantly decreasing with the increase in energy production, except for the TA+EE BAT Scenario. The TA+EE BAT Scenario depicts a very small variation of COE over 2022 to 2032, and most notably a similar COE to BAU Scenario in 2032. This indicates that the small capacity factor of committed plants leads to higher cost of energy. Comparing the TA+EE BAT results with BAU+EE CEP results (i.e. the lowest COE among the BAU scenarios), the TA+EE BAT results indicate much smaller capacity factor. This means that some of the committed plants will be underutilized despite the high capital investment cost for such plants.

As inferred from TA+EE BAT Scenario result, the capital and fixed maintenance costs of the underutilized committed plants will burden the system's COE. Consequently, this burden will be borne by customers through the capacity payments payable to producers[19].

[19] Capacity payment is the cost that needs to be borne by customers to reflect the fixed cost of the installed capacity of the power plant with certain agreed availability factor.

Moreover, what is found is that the COE is highly influenced by the percentage of coal in the energy mix, i.e. the lower the percentage of coal in the energy mix, the lower the COE. The explanation for such phenomenon is that the increase in demand is fulfilled by the other sources of energy with lower annualized cost, such as geothermal, hydro, landfill gas, and some solar PV. This means that meeting the demand is possible to be done with lower cost and lower emission.



	2022	2027	2032
BAU Installed Capacity	714	1065	1726
BAU + EE CEP Installed Capacity	714	965	1431
BAU + EE BAT Installed Capacity	714	890	1309
TA Installed Capacity	590	764	1010
TA + EE CEP Installed Capacity	590	689	873
TA + EE BAT Installed Capacity	590	649	780
BAU COE	7.40	7.39	6.86
BAU + EE CEP COE	7.40	7.36	6.71
BAU + EE BAT COE	7.40	7.27	6.78
TA COE	6.89	6.65	6.57
TA + EE CEP COE	6.89	6.72	6.49
TA + EE BAT COE	6.89	6.92	6.86

Exhibit 4-8 Energy production vs the cost of energy.

Impact of EE to Annualized Cost and COE

The impact of EE on annualized cost is relatively linear, as the reduction of load due to EE measures contribute to less requirement for new power plants. The impact of EE on COE is less linear, as the EE measures reduce the production of energy from power plants which have been previously commissioned. This caused the power plants to operate less efficiently, and increase the cost of energy.

To remedy this, in future research, smaller power plants can be assumed in the simulation to avoid large steps in capital cost, i.e. to minimize the "lumpy capacity" problem.

Box 2. Stranded Assets

IEA defines stranded assets as "investment which have already been made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment brought about by climate policy[i]." An example of stranded asset is a power plant put to early retirement due to changes in policy, or underutilization of a certain power plant.

Taking the issue of stranded assets to this study, the TA + EE BAT Scenario is taken as an example. The modelling result of the scenario indicates that by 2032, the aggregated capacity factor of committed coal power plants in Sulutenggo system is 55.1% of the 305 MW installed capacity. This means that there is more than 100 MW of idle capacity under this scenario - a risk for PLN to have stranded assets.

As under the current take-or-pay commitments in PLN's Power Purchase Agreement (PPA) Models for thermal power plant the risk of stranded assets is within PLN and its consumers [i], the study can be a case in point wherein over-optimistic demand projections and expansion planning can be unnecessarily costly in the long-run.

References:

i) Chung, Y. (2017). *Overpaid and Underutilized: How Capacity Payments to Coal-Fired Power Plants Could Lock Indonesia into a High-Cost Electricity Future*. Institute for Energy Economics and Financial Analysis. Retrieved from: http://ieefa.org/wp-content/uploads/2017/08/Overpaid-and-Underutilized_How-Capacity-Payments-to-Coal-Fired-Power-Plants-Could-Lock-Indonesia-into-a-High-Cost-Electricity-Future-_August2017.pdf

4.4 ENERGY EFFICIENCY MEASURES – SIMPLIFIED COST ANALYSIS

Application of DSM measures in North Sulawesi has been provided in Appendix G. The cost related to the EE measures is calculated separately from HOMER simulation. A method to evaluate the cost associated with using energy efficient appliances is through the cost of conserved energy (CCE). The resulting CCEs are then compared with the local electricity tariff, to evaluate whether customer's investment is feasible. For example, if CCE for lighting is 4 US cents/kWh, and the local tariff is 7 US cents/kWh , a net saving for customer is then 3 US cents/kWh . The customer has the option to pay an addition 7 US cents/kWh of electricity, or purchase an equipment which does not require additional unit of electricity to achieve the same task – with an additional cost of 4 US cents/kWh .

To evaluate whether an efficient equipment will provide a net benefit to customers, CCE is then compared with the tariff. Currently, the publicly available data are only available for some electronic appliances for residential uses. The available CCEs of electronic appliances in Indonesia are compared with the resulting COEs calculated from HOMER, as seen in Exhibit 4-9 indicates that all CCEs for the CEP EE Measures are below the COEs in BAU and TA Scenarios, with EE CEP measures and without. This indicates that the net benefit for customers is still feasible under these scenarios.

From the perspective of electricity generation, applications of EE CEP measures can reduce annualized cost under BAU Scenario up to USD 31 million/year in 2027 and USD 84 million/year in 2032. In terms of installed capacity, using EE CEP measures can reduce the installed capacity of 100 MW in 2027, and 295 MW in 2032. As an illustration 100 MW is equal to four units of the currently installed Lahendong geothermal power plants. While under the TA Scenario, EE CEP measures can save up to USD 315 million/year by 2032, and reduce installed capacity by 853 MW compared to the BAU case in 2032.

Exhibit 4-9 Comparison between CCE of selected appliances for CEP Scenario and system costs under various scenarios.

Item	Unit	CCE[20]	COE[21],[22]							
			2027				2032			
			BAU	BAU+ EE CEP	TA	TA+ EE CEP	BAU	BAU+ EE CEP	TA	TA+ EE CEP
Equipment with CCE - CEP Scenario Only[20]										
Lighting	¢USD/kWh	4	7.39	7.36	6.65	6.72	6.86	6.71	6.57	6.49
Refrigerator	¢USD/kWh	3								
Air Conditioner	¢USD/kWh	5								
Fans	¢USD/kWh	3								
System Cost – Calculated with HOMER										
Annualized Cost	Mil. USD/year		434	403	275	259	633	549	363	318
Saved Annualized Cost *(BAU Annualized Cost - Scenario Annualized Cost)*	Mil. USD/year			31	159	175		84	270	315

The possible cost savings can enable the utility company to reallocate costs from generation costs to incentives for the residential users to use more efficient electricial appliances.

[20] Letschert, V., et al. (2012). *Estimate of Cost-Effective Potential for Minimum Efficiency Performance Standards in 13 Major World Economies – Energy Savings, Environmental and Financial Impacts*.
[21] Results from HOMER simulation.
[22] Comparisons to BAT results are not provided, as there has been no publicly available data of BAT costs in Indonesia.

<u>Box 3. Air Conditioners</u>

As noted in Karali (2015), Air Conditioners (AC) play a significant role in reduction of peak demand in future years. The key indicator in determining the efficiency level of AC is the Energy Efficiency Rating (EER) is the ratio of cooling capacity in Btu/hr or watt to the power consumed in watt. It illustrates the level of cooling for a certain power consumption.

The referenced air conditioner type in BAU is cooling only split AC, typically those with EER of at least 3.3 W/W[i)], or equal to approximately 11.26 Btu/hr/W. This level of EER is above the minimum EER for *Bintang 4* standard, the highest energy efficiency standard according to Indonesia's MEMR Regulation No. 57 Year 2017.

In CEP scenario as seen in **Error! Reference source not found.**, the target UEC for AC is 1,000 kWh/year, which means that it approximately requires EER of above 3.7 W/W[ii)]. A minority of manufacturers in Indonesian market offer these AC products.

In BAT scenario as seen in **Error! Reference source not found.**, the target UEC for AC is 637 kWh/year, or equal to approximately EER of 5 W/W[iii)]. BAT scenario for ACs utilize more efficient compressors, improved heat exchangers, improved fan blade design and motor efficiency, and improved expansion valves[iii)]. Currently, there are very limited manufacturers providing such products in the market[ii)].

More than 75% of the products in the current Indonesian market is labelled with *Bintang 4,* the highest possible energy efficiency labelling for ACs in Indonesian regulation. Most of these products, however, is below EER of 3.7 – the level of recommended efficiency to achieve peak reductions in CEP scenario. With this in mind, there is a need <u>to increase the energy efficiency standards</u> for ACs in Indonesia to achieve the expected peak reductions in CEP scenario, as well as BAT scenario.

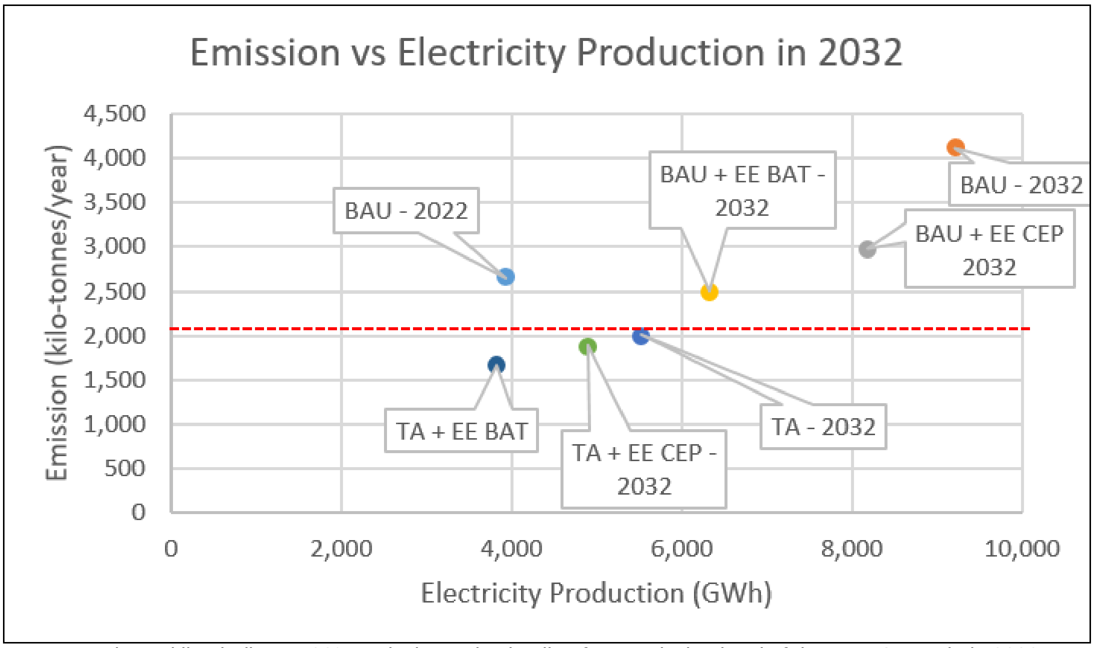
References:
i) McNeil, M. A. and Iyer, M. (2009). *Progress towards managing residential electricity demand: impacts of standards and labeling for refrigerators and air conditioners in India*. 5th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL 09). Berlin, Germany. Retrieved from: https://ies.lbl.gov/sites/all/files/lbnl-2322e_1.pdf
ii) Letschert, V., et al. (2018). *Baseline Evaluation and Policy Implications for Air Conditioners in Indonesia*. Lawrence Berkeley National Laboratory, International Energy Agency, Ministry of Energy and Mineral Resources Indonesia, U.S. Department of Energy. Retrieved from: https://storage.googleapis.com/sead-siteassets/LBNL-eedal-paper-ACs-Indonesia.pdf
iii) Letschert, V., et al. (2013). *Energy efficiency - How far can we raise the bar? Revealing the potential of best available technologies*. Energy, 59, 72-82. http://dx.doi.org/10.1016/j.energy.2013.06.067

4.5 SELECTING AN EMISSION REDUCTION PATHWAY

The key objective of this modeling is to simulate the possibility to achieve at least 23% emission reduction in 2032 compared to the BAU scenario in 2022 as the base case at the least possible cost. To compare the results, the exhibit below provides a comparison of emissions in 2032 for all scenarios and the BAU emission in 2022. <u>By comparing the results, this study can provide recommendations on a pathway to emission reduction based on one optimal scenario</u>.

Key findings are:

- ✓ The BAU scenarios, even with EE, do not yield a 23% reduction in emissions by 2032. All TA scenarios achieve 23% reduction of emission levels compared to BAU in 2022.
- ✓ TA + EE BAT Scenario achieve the highest reduction of emissions level with 31% reduction compared to BAU in 2022.
- ✓ TA + EE CEP Scenario achieve the second highest reduction of emissions level with 28% reduction compared to BAU in 2022.



Note: the red line indicates 23% emission reduction line from emission level of the BAU Scenario in 2022.

Exhibit 4-10 Emission vs electricity production in 2032.

With considerations to the key findings, there are two best options to achieve the emission reduction, i.e. TA + EE BAT scenario and TA + EE CEP scenario. By 2032, TA + EE BAT Scenario is estimated to have the highest COE of USD 6.86 cent/kWh, while TA + EE CEP Scenario have the lowest COE of USD 6.49 cent/kWh. With consideration that the objective of this modelling is to obtain both least emission and least cost electricity planning, it is recommended that the “target” scenario is the Trend Analysis with EE CEP measures (TA + EE CEP).

<u>How do we achieve the >23% emission reduction with TA + EE CEP Scenario?</u>

Section 3.2.2 provides an output of the TA + EE CEP Scenario, which serve as the basis create a practical guideline to achieve the emission reduction target. The following are the recommended steps:

1) Create a realistic load forecast.
   While there are a number of ways to forecast demand growth, this study utilizes a simplified method based on historical data of demand growth in the last five years. A realistic load growth rate can save millions of dollars from the generation expansion plan. And avoids oversupply in the grid, which becomes very expensive for consumers who carry the cost burden.
2) Promote energy efficiency measures for all customers, including residential, business and industries. Although this study only has data for residential, energy saving will be beneficial across sectors.
   The energy efficiency measures for energy intensive equipment can make a significant difference in long-term electricity system planning.

3) Create energy mix targets for mid-term planning
The recommended generation mix is created for every five years, and fully incorporates the potential for renewable capacity additions. The following exhibit provides the summary of generation mix and installed capacity for TA + EE CEP Scenario.

Exhibit 4-11 TA+EE CEP Scenario Energy Mix and Installed Capacity.

Power Plant Type	Fuel	Energy Production Mix (%)			Installed Capacity (MW)		
		2022	2027	2032	2022	2027	2032
PLTU	**coal**	44%	43%	34%	255.00	305.00	305.00
PLTA/M	**hydro**	19%	23%	23%	84.20	109.20	129.20
PLTG/GU	**LNG**	1%	1%	2%	50.00	50.00	100.00
PLTD/MG	**HFO**	0%	0%	0%	30.00	30.00	30.00
PLTS	**solar**	1%	1%	1%	31.00	36.00	46.00
PLTSa	**MSW**	3%	3%	4%	12.00	12.00	24.00
PLTBm	**Coconut shell biomass**	0%	0%	0%	1.00	0.00	0.00
PLTP	**geothermal**	30%	29%	35%	119.00	143.00	223.00
PLTB Candidates	**wind**	1%	0%	1%	8.00	4.00	16.00
TOTAL		100%	100%	100%	590.20	689.20	873.20

5. RESULTS APPLICATION

5.1 CANDIDATE POLICY INTERVENTIONS

Candidate #1: Provision of local tax for emissions from coal power plants production

As seen in the study results, coal is the key driver in determining the emission in the area. It is to be re-emphasized that limiting coal power plant production and expansion can reduce both emission and cost of electricity in the grid. Therefore, a possible solution is to tax emission from the production of electricity from coal power plants.

Candidate #2: Incentives for renewable energy developers

It is recommended that renewable energy developers be given preferential treatment through less local tax, ease in permitting and licensing, and prioritization over coal power plants. Though many regulations governing renewable energy development are set at the national level, the support of a local government can help push renewable energy development in the region.

Candidate #3: Coordination between PLN and local government

It is very much recommended that the local government and PLN coordinate with each other to ensure that local government programs related to electricity can be implemented with the support of PLN. This spans from renewable energy targets to determining future load growth.

Candidate #4: Utilization of a tool, e.g. HOMER, to assist local government in developing the the regional electricity plan (RUKD)

The study shows that a particular tool can be used to develop a model that could assist the local government in developing a regional electricity plan that takes into consideration least cost, least emissions. HOMER determines an optimal generation mix that incorporates information on emission level and cost of electricity. It is expected that local stakeholders will be able to replicate the modelling periodically, bearing in mind the flexibility of the tool when carrying out the model. For example, local stakeholders can (i) adjust assumptions on the type of power plants they wish to have in the province based on local potential; (ii) adjust the growth in demand based on their own assumptions and judgements. This kind of exercise can assist the local government and stakeholders to have an informed discussion on the future electricity planning in the province, as recommended in Recommendation #3.

Candidate #5: Local government to set specific medium-term energy mix and installed capacity

As highlighted above, local government is recommended to coordinate the study results to PLN. Specifically, in the future, it is recommended that periodical update to the simulation is conducted by academics in the province to ensure that the simulation can accommodate the changes happening in the region.

Candidate #6: Market Study and Promotion of energy efficiency measures

In helping PLN to minimize the costs necessary to operate the system, a market study can be initiated by the local government to confirm and understand the electricity end use in residential, as well as commercial and building sector. For example, while this study refers to the potential of air conditioners in reducing the electricity demand based on national data for residential customers, information specific to the province still needs to be reconfirmed. Most importantly, industrial end-use data is still limited.

A number of typical energy efficiency promotion measures which can be selected once more information is gathered include:

- Education to consumers on the benefits of Energy Efficiency;
- Energy audits, particularly for commercial and industrial efficiency;
- Rebates for installing energy efficiency appliances;
- Application of standard and labeling (S&L) for electrical appliances.

5.2 LESSONS LEARNED FOR OTHER APEC ECONOMIES

Lesson #1: Load forecasts drive generation investment requirements

To obtain an accurate sizing of the system, it is important for the system expansion plan to be based on realistic demand forecasts. In turn, this will lead to better planning in procuring different energy sources in the long run.

While an under-estimation may lead to unserved load, over-estimation lead to an increase in costs which will, in turn, be billed to customers.

Lesson #2: Stranded conventional power generation assets are likely to arise as serious decarbonization takes place

To remain realistic, this study retains PLN's committed power plants in its effort to obtain least emission and least cost electricity system expansion plan. Committed power plants are plants which already have commercial agreements with PLN. Many of such plants are large power plants with conventional fuel, such as coal. This reduces the capacity in which renewable energy power plants can fulfil. For example, the solar power plants, despite the relatively low cost in the system, cannot be maximized to their full potential. **Policy makers and business leaders need to recognize these risks and develop strategies that balance competing concerns.**

To obtain the true lowest cost and lowest emission expansion plan based on local potential, future modelling needs to maintain its flexibility through reducing or even disregard the committed plants.

6. CONCLUSIONS

The key outputs of this study are:

1. HOMER is an analytical tool which can help to define least carbon and least emission generation mix for one year at any point in time. HOMER functions as a capacity expansion model, but any particular solution needs to be checked for technical feasibility as described in Appendix F.
2. Two basic load scenarios are considered, i.e. BAU (RUPTL based) and TA (forecast based on historical growth). Both scenarios are subjected to EE measures, i.e. Cost Efficient Potential and Best Available Technology. Taking into the EE measures, there are a total of six scenarios being simulated in HOMER for the year 2022, 2027, and 2032.
3. Some scenarios results in 2032 emissions that are at least 23% less than the emission level for BAU scenario in 2022, and has the least cost among the low-emission results. The optimal scenario is TA with EE CEP intervention, which has the potential to reduce the emission up to 30%.
4. The roles and effects of EE interventions are:
    a. contribute to the reduction of peak load, hence reducing the need to commission new power plants
    b. EE reduce the annualized cost, but the effect on COE is not linear as smaller demand may lead to inefficient operation of power plants. Future planning should take into account the potential tradeoffs between smaller plant sizes and the ability to meet demand most efficiently.
    c. Considering the system operation, EE, in general, reduces the emission of the system.
5. Suggestions for policy interventions are:
    a. Provision of local tax for emissions from coal power plants production
    b. Incentives for renewable energy developers
    c. Coordination between PLN and local government
    d. Local government to set specific medium-term energy mix and installed capacity
    e. Market study and promotion of energy efficiency measures

APPENDIX A. CALCULATING COST OF CONSERVED ENERGY (CCE)

CCE is calculated through the following formula:

$$CCE = \frac{\Delta I\ (\$) \times q}{\Delta UEC\ (kWh)} = {}^{USD}/_{kWh}$$

where,
I = initial capital investment
q = capital recovery factor, which converts a present value into a future stream of payments
UEC = Annual Unity Energy Consumption
kWh = kilowatt hours

ΔI denotes the additional cost incurred to purchase a more energy efficient appliance,

compared to the baseline, whereas ΔUEC denotes efficiency savings of energy efficient appliance compared to the baseline.

The capital recovery factor is calculated through the following formula:

$$q = \frac{1}{\sum_{n=1}^{L} \frac{1}{(1+d)^n}} = \frac{d}{(1-(1+d)^{-L})}$$

where,
d = discount rate, an interest rate used to determine annual payments of an investment over *L* years;
L = the average number of years an appliance is used before it fails and is retired.

B.1 CURRENT STATE OF GRID CONDITION

This section provides an overview of current generation system condition in the Sulbagut grid. This shows the fuel mix, generation mix, and generation operation profile. The modeling will be conducted for the whole system of the North Sulawesi grid but in terms of grid assessment, the study will focus on the generation and demand side. It is to be noted that there is reluctance from PLN to provide confidential information on the grid's transmission system data. The total net capacity of existing generation plants is 492.7 MW. Below is the list of existing power plant in Sulbagut system.

Exhibit B-1 List of power plants.

No	Power Plant	Type	Owner	Net Capacity (MW)
1	PLTA Tonsealama	Hydro	PLN	11,000
2	PLTA Tanggari I	Hydro	PLN	17,000
3	PLTA Tanggari II	Hydro	PLN	19,000
4	PLTD Bitung	HSD	PLN	32,300
5	PLTD Lopana	HSD	PLN	5,200
6	PLTD Kotamobagu	HSD	PLN	5,400
7	PLTD Telaga	HSD	PLN	14,100
8	PLTD Marisa	HSD	PLN	1,500
9	PLTD Tilamuta	HSD	PLN	-
10	PLTD Lemito	HSD	PLN	-
11	PLTG Marisa/Gorontalo	HSD	PLN	100,000
12	Sewa Paguat (HSD)	HSD	Rent	7,000
13	LMVPP	HSD	Rent	96,000
14	PLTU Amurang	Coal	PLN	40,000
15	PLTU Molotabu / sulut 2	Coal	IPP	21,000
16	PLTP Lahendong 1	Geothermal	PLN	18,000
17	PLTP Lahendong 2	Geothermal	PLN	18,000
18	PLTP Lahendong 3	Geothermal	PLN	18,000
19	PLTP Lahendong 4	Geothermal	PLN	18,000
20	PLTP Lahendong 5	Geothermal	IPP	20,000
21	PLTP Lahendong 6	Geothermal	IPP	20,000
22	PLTM Poigar	Hydro	PLN	2,400
23	PLTM Mobuya	Hydro	PLN	3,000
24	PLTM Lobong	Hydro	PLN	1,600
25	PLTM Mongango	Hydro	PLN	1,200
26	PLTM Taludaa	Hydro	PLN	2,000
27	PLTS Sumalata/Isimu	Solar	IPP	1,000
TOTAL				**492,700**

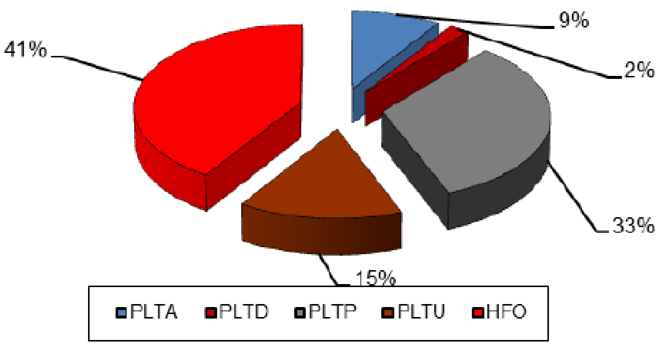
Source: PLN Suluttenggo - Monthly Operation Evaluation Report

B.1.1 Generation Mix

There are three (3) subsystems in the Sulbagut grid, which are (i) Minahasa subsystem in North Sulawesi Province, (ii) Kotamobagu system in North Sulawesi Province, and (iii) Gorontalo subsystem in Gorontalo Province.

The energy contribution in Minahasa subsystem (North Sulawesi) are mainly sourced from renting power plant (LMVPP) about 78,617 MWh (40.94%), then 53,521 MWh (33.32%) of geothermal, 24,842 MWh (15.47%) of coal, 14,589 MWh (9.08%) of hydro, and 3,633 MWh (2.26%) of diesel as shown in Exhibit B-2

In Kotamobagu subsystem, the energy contribution composition is mainly sourced from hydro by 3,680 MWh (97.36%) and diesel by 63 kWh (1.68%), while the energy contribution in Gorontalo subsystem are mainly sourced from diesel by 10,158 MWh (57.98%), 6,310 MWh (36.01%) of coal, 222 kWh (1.26%) of hydro and 831 MWh (4.74%) of solar PV.



Abbreviations:

PLTA = *Pembangkit Listrik Tenaga Air* / Hydro Power Plant

PLTD = *Pembangkit Listrik Tenaga Diesel* / Diesel Power Plant

PLTP = *Pembangkit Listrik Tenaga Panas Bumi* / Geothermal Power Plant

PLTM = *Pembangkit Listrik Tenaga Minihidro* / Mini Hydro Power Plant

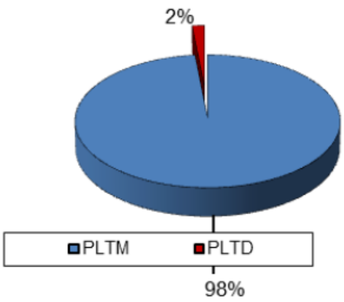
PLTU = *Pembangkit Listrik Tenaga Uap* / Coal Power Plant

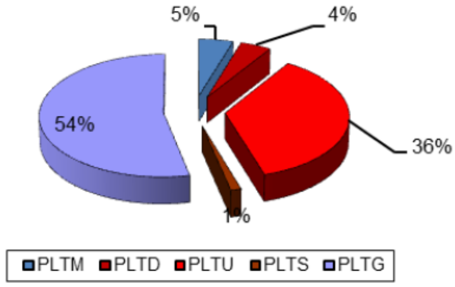
PLTS = *Pembangkit Listrik Tenaga Surya* / Solar Powe Plant

PLTG = *Pembangkit Listrik Tenaga Gas* / Gas Power Plant

HFO = Heavy Fuel Oil Power Plant

Exhibit B-2 Energy Production Composition in Minahasa subsystem (PLN)





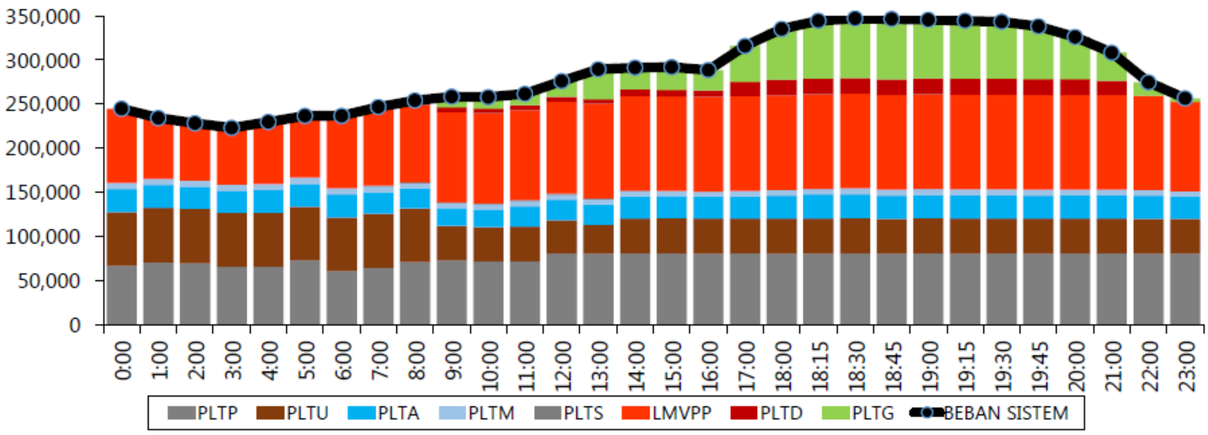
Abbreviations:

PLTA = *Pembangkit Listrik Tenaga Air* / Hydro Power Plant
PLTD = *Pembangkit Listrik Tenaga Diesel* / Diesel Power Plant
PLTP = *Pembangkit Listrik Tenaga Panas Bumi* / Geothermal Power Plant
PLTM = *Pembangkit Listrik Tenaga Minihidro* / Mini Hydro Power Plant
PLTU = *Pembangkit Listrik Tenaga Uap* / Coal Power Plant
PLTS = *Pembangkit Listrik Tenaga Surya* / Solar Powe Plant
PLTG = *Pembangkit Listrik Tenaga Gas* / Gas Power Plant
HFO = Heavy Fuel Oil Power Plant

Source: PLN Suluttenggo - Monthly Operation Evaluation Report

Exhibit B-3 Energy Production Composition in Kotamobagu subsystem (left) and Gorontalo subsystem (right), PLN

The exhibit below shows the daily generation operation profile in February 2018.



Source: PLN Suluttenggo

Abbreviations:

PLTA = *Pembangkit Listrik Tenaga Air* / Hydro Power Plant
PLTD = *Pembangkit Listrik Tenaga Diesel* / Diesel Power Plant
PLTP = *Pembangkit Listrik Tenaga Panas Bumi* / Geothermal Power Plant
PLTM = *Pembangkit Listrik Tenaga Minihidro* / Mini Hydro Power Plant
Beban Sistem = System Load
PLTU = *Pembangkit Listrik Tenaga Uap* / Coal Power Plant
PLTS = *Pembangkit Listrik Tenaga Surya* / Solar Powe Plant
PLTG = *Pembangkit Listrik Tenaga Gas* / Gas Power Plant
LMVPP = Leasing Marine Vessel Power Plant

Exhibit B-4 Daily Operation Profile

Based on the disturbance report of all generation plants that impact on system frequency deviation, the estimate of grid stiffness in Sulbagut system is about 25.28 MW/Hz.

According to the Monthly Operation Evaluation Report (*Evaluasi Operasi Bulanan,* EOB) by PLN, the generation cost in Sulbagut system is 1,622 IDR/kWh. The most expensive one is cost from diesel generation while the cheapest one comes from hydro-power plant.

Exhibit B-5 Generation Cost for all generation Plants in Sulbagut System

No	Power Plant	Type	Generation Cost (IDR/kWh)
1	PLTA Tonsealama (3 unit)	Hydro	133.50
2	PLTA Tanggari I (2 unit)	Hydro	192.50
3	PLTA Tanggari II (2 unit)	Hydro	146.00
4	PLTD Bitung	HSD	2,798.75
5	PLTD Lopana	HSD	4,889.00
6	PLTD Kotamobagu	HSD	4,130.20
7	PLTD Telaga	HSD	1,939.17
8	PLTD Marisa	HSD	3,443.00
9	PLTG Marisa/Gorontalo	HSD	2,160.00
10	LMVPP	HSD	2,329.00
11	PLTU Amurang (2 unit)	Coal	780.00
12	PLTU Molotabu (2 unit)	Coal	1,107.00
13	PLTP Lahendong 1	Geothermal	1,059.00
14	PLTP Lahendong 2	Geothermal	1,002.00
15	PLTP Lahendong 3	Geothermal	1,143.00
16	PLTP Lahendong 4	Geothermal	1,311.00
17	PLTP Lahendong 5	Geothermal	1,554.00
18	PLTP Lahendong 6	Geothermal	1,554.00
19	PLTM Poigar	Hydro	106.50
20	PLTM Mobuya	Hydro	1,032.00
21	PLTM Lobong	Hydro	92.00
22	PLTM Mongango	Hydro	8.00
23	PLTM Taludaa	Hydro	999.00
24	PLTS Sumalata/Isimu	Solar	3,096.00
Overall Generation Cost (IDR/kWh)			**1,622.00**

Source: PLN Suluttenggo - Monthly Operation Evaluation Report

B.1.2 Reserve Margin

A reserve margin typically depends on system characteristics and operating reserve requirements. PLN determines the reserve margin based on Loss of Load Probability (LOLP) standard of approximately 25-30%. While high reserve margin indicate high reliability, it can also indicate an excess of capacity. The system’s reserve margin significantly increased from 15.04% in 2015 to 36.21% in 2017.

International Energy Agency (IEA) recommends a reserve margin in the range of 20-35%[23]. As a comparison, in the United States, planning reserve margin standards range from 10-20%[24]. In neighbouring countries, Thailand and Malaysia have targets reserve margin of 15%[25] and 25%[26]. With such comparison, it can be inferred that the regional reserve margin is relatively high, and has optimisation potential.

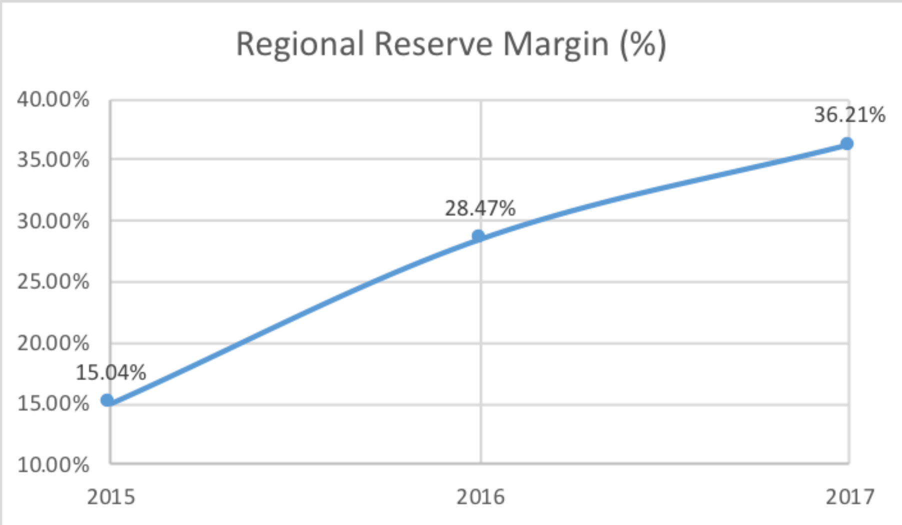


Exhibit B-6 Historical reserve margin.

B.2 PROJECTED GENERATION PLANT

In the North Sulawesi province, the electricity needs up-to 2027 projected above is planned to be fulfilled by additional 757 MW to be injected into Sulbagut system as listed below.

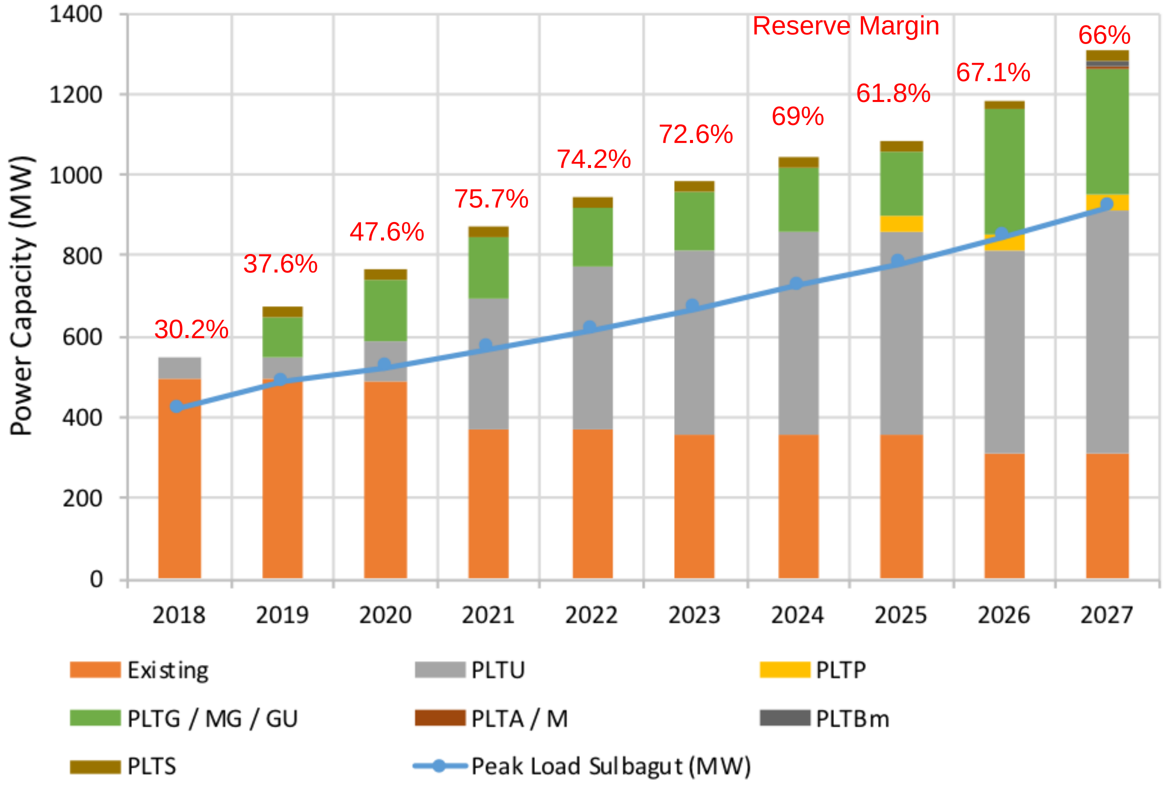
Exhibit B-7 List of Planned Generation Plant in North Sulawesi within the Sulbagut Grid

No	Grid System	Type	Power Plant	Installed Capacity (MW)	COD target	Status	Owner
1	Sulbagut	Coal	Amurang	2x25	2018	Construction	Rent
2	Sulbagut	Solar	Likupang	15	2019	Construction	IPP
3	Sulbagut	Gas	Minahasa	150	2019/ 20	Planning	PLN
4	Sulbagut	Coal	Sulut 3	2x50	2021	PPA	IPP

[23] CLP Group (2012). Fact Sheet – Generating and Capacity Reserve Margin. Retrieved from: https://www.clpgroup.com/en/Media-Resources-site/Current%20Releases%20Documents/20121211/generatingcapacity_reservemargin_eng.pdf
[24] Energy and Environmental Economics, Inc. (2015). *Estimating the Economically Optimal Planning Reserve Margin*. Retrieved from: https://www.epelectric.com/files/html/PRM_Report.pdf
[25] Thai Ministry of Energy (2015). Thailand Power Development Plan 2015-2036. Retrieved from: https://www.egat.co.th/en/images/about-egat/PDP2015_Eng.pdf
[26] Bahagian Penyelidikan Parlimen Malaysia (2016). Security of Energy Supply. Retrieved from: https://www.parlimen.gov.my/images/webuser/artikel/ro/amy/Security%20of%20Energy%20Supply%2026%20September%202016.pdf

No	Grid System	Type	Power Plant	Installed Capacity (MW)	COD target	Status	Owner
5	Sulbagut	Coal	Sulut 1	2x50	2021/22	Procurement	PLN
6	Sulbagut	Hydro	Poigar 2	30	2023	Planning	IPP
7	Sulbagut	Hydro	Sawangan	2x6	2024	Planning	PLN
8	Sulbagut	Steam and Gas	Sulbagut 1	150	2026	Planning	*Unallocated*
9	Sulbagut	Coal	Sulbagut 2	100	2027	Planning	*Unallocated*
10	Sulbagut	Biomass	Sulut Tersebar	10	2027	Planning	*Unallocated*
11	Sulbagut	Geothermal	Lahendong VII & VIII	2x20	2025	Planning	IPP
TOTAL				**757**			

While the planned additional generation plants in Sulbagut grid system is represented in the figure below. By 2027, the reserve margin increases from 30.2% to 66% from the year 2018. According to the graph, the additional planned coal power plants are dominant (green stack).



Source: RUPTL PLN 2018-2027

Abbreviations:

PLTA/M = *Pembangkit Listrik Tenaga Air atau Minihidro* / Hydro or Mini-hydro Power Plant

PLTBm = *Pembangkit Listrik Tenaga Biomassa* / Biomass Power Plant

PLTP = *Pembangkit Listrik Tenaga Panas Bumi* / Geothermal Power Plant

PLTU = *Pembangkit Listrik Tenaga Uap* / Coal Power Plant

PLTS = *Pembangkit Listrik Tenaga Surya* / Solar Power Plant

PLTG/MG/GU = *Pembangkit Listrik Tenaga Gas atau Mesin Gas atau Gas Uap* / Gas or Gas Engine or Steam and Gas Power Plant

Exhibit B-8 Planned Additional Generation Plant in Sulbagut System

From the year 2018 to 2027, the number of Existing power plants will decrease because the derating factor of some generators and discontinuation of rental power plant such as LMVPP.

PLN has planned to install additional substation up to 950 MVA up to the year 2027 that are shown in the exhibit below.

Exhibit B-9 Substation Planning in North Sulawesi

No	Substation Name	Voltage Level (kV)	Remark	Capacity (MVA)	COD	Status
1	Otam	150/20	Ext	60	2018	Construction
2	Otam	150/20	Line bay ext	2 LB	2018	Construction
3	Telling (GIS)	150/20	Ext	60	2018	Construction
4	Likupang (IBT)	150/70	New	60	2018	Planning
5	Tonsealama	70/20	Uprating	30	2018	Planning
6	Kawangkoan	150/20	Ext	30	2018	Procurement
7	Tomohon	150/20	Ext	60	2018	Procurement

No	Substation Name	Voltage Level (kV)	Remark	Capacity (MVA)	COD	Status
8	Molibagu	150/20	New	30	2018	Planning
9	Paniki	150/20	Line bay ext	2 LB	2018	Planning
10	Paniki	150/20	Ext	60	2018	Planning
11	Kema/Tanjung Merah	150/20	Ext	60	2018	Planning
12	Tasik Ria	150/20	Ext	30	2018	Planning
13	Sario (GIS)/Manado Kota	150/20	New	60	2018	Planning
14	Likupang	150/20	Line bay ext	2 LB	2019	Planning
15	Pandu	150/20	New	60	2019	Planning
16	Tutuyan	150/20	New	30	2019	Planning
17	Kema/Tanjung Merah	150/20	Line bay ext	2 LB	2020	Planning
18	Bitung (IBT)	150/70	New	60	2020	Planning
19	Bitung Baru	150/20	New	60	2020	Planning
20	Bintauna (Town Feeder)	150/20	New	20	2021	Planning
21	Molibagu	150/20	Line bay ext	2 LB	2022	Planning
22	Kema/Tanjung Merah	150/20	Line bay ext	2 LB	2022	Planning
23	Belang	150/20	New	30	2022	Planning
24	Belang	150/20	Line bay ext	2 LB	2022	Planning
25	Lopana	150/20	Ext	60	2022	Planning
26	Ratahan	150/20	New	30	2022	Planning
27	Tutuyan	150/20	Line bay ext	2 LB	2022	Planning
28	Telling (GIS)	150/20	Ext	60	2027	Planning
TOTAL				**950**		

Source: RUPTL PLN 2018-2027

According to the energy demand projection by RUPTL PLN the peak load will reach 920 MW at the year 2027. Those planned additional 950 MVA substation's capacity in North Sulawesi capacity will serve the load demand.

A detailed capacity balance of all substation will be assessed over the next ten (10) years once it gets a result of optimum least cost renewable energy plant from HOMER simulation.

APPENDIX C. CANDIDATE AND COMMITTED PLANTS

1. Homer Simulation Output Summary for BAU Scenario

Name/Parameter	Type	Capacity (MW)						
		2022	2027	2027	2027	2032	2032	2032
		Normal	Normal	EE CEP	EE BAT	Normal	EE CEP	EE BAT
TOTAL BUSINESS AS USUAL (BAU) GENERATION								
Peak Load (MW)		**617**	**920**	**848**	**727**	**1,445**	**1,257**	**949**
Total Net Generation (MW)		**714**	**1,065**	**965**	**890**	**1,726**	**1,431**	**1,309**
Reserve Margin (%)		**15.8%**	**15.8%**	**13.8%**	**22.5%**	**19.5%**	**13.9%**	**37.9%**
Committed Power Plant								
PLTU Committed	coal	355	330	330	330	455	330	330
PLTP Committed	geothermal	119	103	103	103	143	143	143
PLTA/M Committed	hydro	59.2	59.2	59.2	59.2	101.2	101.2	101.2
PLTD/MG Committed	HFO	30	30	30	30	30	30	30
PLTS Committed	solar	26	26	26	26	26	26	26
PLTBm Committed	Biomass	0	0	0	0	10	10	10
PLTG/GU Committed	LNG	100	100	100	100	300	300	300
Candidates Power Plant								
PLTU Candidates	coal	25	125	75	0	100	0	0
PLTA/M Candidates	hydro	0	42	42	42	118	118	118
PLTG/GU Candidates	LNG	0	200	150	150	100	100	100
PLTS Candidates	solar	0	0	0	0	10	0	0
PLTSa	MSW	0	0	0	0	23	23	23
PLTBm Candidates	biomass	0	10	10	10	5	5	5
PLTP Candidates	geothermal	0	40	40	40	245	245	122.5
PLTB Candidates	wind	0	0	0	0	70	0	0

2. Homer Simulation Output Summary for Trend Analysis Scenario

Name/Parameter	Type	Capacity (MW)						
		2022	2027			2032		
		Normal	Normal	EE CEP	EE BAT	Normal	EE CEP	EE BAT
TOTAL TREND ANALYSIS (TA) GENERATION								
Peak Load (MW)		**482**	**644**	**594**	**509**	**862**	**750**	**567**
Total Net Generation		**590**	**764**	**689**	**649**	**1,010**	**873**	**780**
Reserve Margin (%)		**22.5%**	**18.6%**	**16.0%**	**27.5%**	**17.2%**	**16.5%**	**37.6%**
Committed Power Plant								
PLTU Committed	coal	255	305	305	305	305	305	305
PLTP Committed	geothermal	119	103	103	103	143	143	143
PLTA/M Committed	hydro	59.2	59.2	59.2	59.2	59.2	59.2	59.2
PLTD/MG Committed	HFO	30	30	30	30	100	30	30
PLTS Committed	solar	26	26	26	26	26	26	26
PLTBm Committed	Biomass	0	0	0	0	0	0	0
Candidates Power Plant								
PLTU Candidates	coal	0	0	**0**	**0**	0	0	0
PLTA/M Candidates	hydro	25	50	50	50	70	70	70
PLTG/GU Candidates	LNG	50	100	50	50	100	100	100
PLTS Candidates	solar	5	10	10	10	30	20	15
PLTSa	MSW	12	24	12	12	28	24	24
PLTBm Candidates	biomass	1	1	0	0	1	0	0
PLTP Candidates	geothermal	0	40	40	0	120	80	0
PLTB Candidates	wind	8	16	4	4	28	16	8

APPENDIX D. HOMER INPUT ASSUMPTIONS

HOMER requires extensive inputs to run the simulation, which include fuel, generator features, emission, and cost.

i) Fuel Assumption

Exhibit D-1 Fuel Input Data

Fuel Assumptions					
No.	**Generation Source**	**Inputs**	**Value**	**Unit**	**References**
1	Coal	LHV	26.45	MJ/kg	https://www.engineeringtoolbox.com/classification-coal-d_164.html HBA reference coal price in july 2018 with caloric value of 6,322 kcal/kg. No data available on specific coal utilized in these plants.
		Density	793	kg/m3	
		Price	0.117	USD/kg	
2	Gas/Natural Gas	LHV	45	MJ/kg	power guide 2017 by pwc price is equivalent to USD 8.8 / mmBtu at the burner tip
		Density	0.79	kg/m3	
		Price	0.32	USD/m2	
3	High Fuel Oil	LHV	43.2	MJ/kg	http://www.infohargabbm.com
	(HFO)	Density	938	kg/m3	
		Price	0.62	USD/litre	
4	Geothermal	LHV	2.76	MJ/kg	http://www.thermopedia.com/content/1150/ PLN purchases steam from Pertamina. The price is based on EOB (Monthly Evaluation Operation Report by PLN) data
		Density	4.16	kg/m3	
		Price	0.02	USD/kg	
5	Biomass	LHV	18.6	MJ/kg	https://phyllis.nl/Browse/Standard/ECN-Phyllis
		Density	1.6	kg/m3	
		Price	0.55	USD/kg	
6	WTE Landfill	LHV	50.4	MJ/kg	IPCC GHG inventory Guidelines 2006, Vol 2, chapter 1, Page 1.19
		Density	0.716	kg/m3	
		Price	0	USD/kg	

ii) Generator Feature Assumption

Exhibit D-2 Generation Input Data

No.	**Generation**	**Inputs**	**Value**	**Unit**	**Used HOMER Component**
	Thermal Power Plant*				
1	PLTU / CFPP	Min Load Ratio	50	%	Generic Large Genset
		Lifetime	25	year	Self-size capacity
		Min Operating	4,320	hour	
		Intercept Coef	0.033	kg/hr/Prated	
		Slope	0.424	kg/hr/Pout	
2	PLTG-GU / GTPP or CCPP	Min Load Ratio	30	%	Generic Large Genset
		Lifetime	25	year	Self-size capacity

No.	Generation	Inputs	Value	Unit	Used HOMER Component
		Min Operating	4	hour	
		Intercept Coef	0.021	kg/hr/Prated	
		Slope	0.265	kg/hr/Pout	
3	PLTG-MG / GEPP	Min Load Ratio	30	%	Generic Large Genset
		Lifetime	25	year	Self-size capacity
		Min Operating	4	hour	
		Intercept Coef	0.014	kg/hr/Prated	
		Slope	0.22	kg/hr/Pout	
4	PLTP / Geothermal	Min Load Ratio	60	%	Generic Large Genset
		Lifetime	30	year	Self-size capacity
		Min Operating	4,320	hour	
		Intercept Coef	0	kg/hr/Prated	
		Slope	1	kg/hr/Pout	
	Non-thermal Power Plant				
5	PLTA-MH / Hydro	Min Load Ratio	25	%	Generic Large Genset
		Lifetime	20	year	Self-size capacity
		Min Operating	4	hour	
		Intercept Coef	0	kg/hr/Prated	
		Slope	0	kg/hr/Pout	
6	PLTA-MH / Hydro	Lifetime	20	year	SeaGen-S 2MW/unit
7	PLTS / Solar PV	Derating factor	80	%	Generic Flat PV
		lifetime	20	years	
8	PLTBm / Biomass	Min Load Ratio	60	%	Generic Large Genset
		Lifetime	20	year	Self-size capacity
		Min Operating	4,320	hour	
		Intercept Coef	0.13	kg/hr/Prated	
		Slope	0.25	kg/hr/Pout	
9	PLTSa / Landfill	Min Load Ratio	60	%	Generic Large Genset
		Lifetime	20	year	Self-size capacity
		Min Operating	4,320	hour	
		Intercept Coef	0.47	kg/hr/Prated	
		Slope	0.253	kg/hr/Pout	
10	PLTB / Wind	Lifetime	20	year	Letwind 1 MW/unit
		Hub height	80	meter	

*Thermal generators consist of multiple units. It is rare for all units to be shutdown simultaneously. Therefore, generators shows high number of operating hours as a result of aggregated operation of individual unit.

iii) Emission Assumption

Exhibit D-3 Emission Input Data

Emission Assumptions

No.	Generation	Inputs	Value	Unit	References
1	PLTU / CFPP	Fuel Sulfur Proportion	10.86	%	https://www3.epa.gov/ttnchie1/conference/ei20/session5/mmittal.pdf
		Nitrogen Oxides	5.811	g/kg of fuel	
2	PLTG-GU / GTPP / CCPP	Carbon Monoxide	1.346	g/kg of fuel	https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf
		Particulate Matter	0.122	g/kg of fuel	
		Nitrogen Oxides	3.044	g/kg of fuel	
3	PLTG-MG / GEPP	Carbon Monoxide	0.6	g/kg of fuel	https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s03.pdf
		Particulate Matter	1.2	g/kg of fuel	
		Nitrogen Oxides	5.64	g/kg of fuel	
4	Landfill Gas	Carbon Monoxide	3.6	g/kg of fuel	Environmental Protection Agency (AP-42: Compilation of Air Emissions Factors)
		Particulate Matter	0.35	g/kg of fuel	
		Nitrogen Oxides	1.4	g/kg of fuel	

iv) Generation Cost Assumption

Exhibit D-4 Generation Cost Assumption*)

No	Type of Power Plant	Fuel Source	Capacity (kW)*	Capital ($)	Replacement ($)	O&M ($/op.hour)
1	PLTU Committed	Coal	1000	1,700,000	1,700,000	5.55
2	PLTU Candidates	Coal	1000	1,650,000	1,650,000	5.30
3	PLTP Committed	Geothermal	1000	3,700,000	3,700,000	2.48
4	PLTA/M Committed	Hydro	1000	2,200,000	2,200,000	5.35
5	PLTA/M Candidates	Hydro	1000	2,200,000	2,200,000	5.28
6	PLTD/MG Committed	HFO	1000	820,000	820,000	2.87
7	PLTG/GU Candidates	LNG	1000	770,000	770,000	2.76
8	PLTS Committed	Solar PV	1000	830,000	830,000	15,000/year
9	PLTS Candidates	Solar PV	1000	830,000	830,000	15,000/year
10	PLTSa	MSW	1000	8,700,000	8,700,000	51.92
11	PLTBm Candidates	Biomass	1000	2,800,000	2,800,000	11.18
12	PLTB Candidates	Wind	1000	1,500,000	1,500,000	60,000/year

No	Type of Power Plant	Fuel Source	Capacity (kW)*	Capital ($)	Replacement ($)	O&M ($/op.hour)
13	PLTSa (Landfill)	Landfill Gas	1000	2,500,000	2,500,000	17.3

*) *Reference: Technology Data for Indonesian Power Sector, DEN, Dec 2017*

APPENDIX E. FUTURE IMPROVEMENT SUGGESTIONS FOR MODELING

The simulation results have been reviewed by HOMER technical personnel, with the following improvement notes for future development:

1) Request to add more generator's component for machines larger than 10 MW. This to accommodate the modeling for coal power plant, combined cycle power plant, gas turbine power plant, a gas engine power plant which has the high capacity per 1 unit (e.g for a gas turbine is Siemens SGT-800 gas turbine generator 57 MW, etc.)
2) Request to add minimum Capacity Factor (%) input in the properties of the generator's component, but still, keep the 'minimum load ratio' input. This is to consider accurately for some generators which have minimum contract capacity factor of its PPA
3) For all generation's component and not limited to Solar PV, Wind, hydro, etc. it needs an optional input whether its generation plant 'in service' or 'out of service'. Then, when enabling a multiyear function, the generation plant that's not 'in service' at the first year, please provide an input for choosing its COD year (whether it will be operated at the 2nd year, 3rd year, etc.)
4) Improve multiyear function simulation performance by enabling the component to use its Optimizer's function. This to give a more comprehensive result when Homer can calculate an optimum capacity sizing every year within a certain year of the project lifetime.

In order to assess technical feasibility by considering network constraint and grid model condition, it's suggested to do the grid system simulation for the further step of study. The grid system simulation will analyze the interconnection impact of Candidates Power Plant as a result capacity from Energy modelling in Homer.

A set of detailed parameters that need to be assessed in grid system simulation are explained below in Appendix F. it's clipped from Castlerock's project reference titled 'A Framework for Power Sector Planning, Private Participation and Rural Electrification in Fiji', an ADB Project TA 8971-FIJ: Support for Energy Sector Regulatory Capacity and Electrification Investment Planning (Output 2), 13 August 2018

APPENDIX F. ASSESS TECHNICAL FEASIBILITY AND IDENTIFY GRID AUGMENTATION

F.1 ASSESS TECHNICAL FEASIBILITY

The solution of the constrained optimisation problem will yield the least cost generation and transmission expansion plan, but there is no guarantee that this plan is technically feasible[27].

This is because optimisation programs typically do not consider power system-specific constraints such as thermal and voltage limits, short circuit limits, stability limits and system security limits. Such considerations are excluded for practical reasons, as including them would significantly increase the program's complexity and execution time, while also raising the likelihood of unsolvable cases.

Moreover, the search space for suitable augmentations required to counter a broad range of potential power system issues would need to be developed *a priori*. This is a task that is more difficult for the system planner than finding specific solutions to an acute set of problems. There is also no guarantee that the search space would be sufficiently complete and would cater for any power system issue encountered.

In the majority of planning environments, solutions to power system-specific issues are developed in support of or in response to specific generation and transmission capacity expansion plans or options. For example, if a planned grid expansion leads to potential voltage problems, then these specific issues need to be resolved in order to support the grid expansion. In most cases, the cost of network augmentations to tackle power system issues is small relative to planned expansions in generation and/or transmission capacity.
The following technical constraints in a power system are typically studied by system planning engineers:

- Thermal limits (for overhead lines, cables and transformers)
- Voltage limits
- Short circuit current limits
- Stability limits
- System security limits (N-1)

The technical constraints in the power system are evaluated with software models and simulation tools. The following simulation studies are normally performed:

- Load flow (or power flow) study – to assess voltage and thermal limits,
- Short circuit study – to assess short circuit limits
- Transient stability study – to assess stability limits
- Contingency analysis – to assess N-1 system security limits

In the past, utilities developed their own in-house simulation tools for performing power system studies, but most utilities have now migrated their power system models to commercial software packages such as Siemens PSSE, DIgSILENT PowerFactory, GE PSLF, PowerWorld and ETAP. These commercial packages are capable of modelling a power system and performing the system planning studies outlined above.

[27] This appendix is adapted from work conducted by Castlerock and funded by the Asian Development Bank under ADB TA 8971-FIJ: Support for Energy Sector Regulatory Capacity and Electrification Investment Planning (Output 2), August 2018.

Each of these technical constraints is discussed in turn below.

F.1.1 Thermal Limits

Electric current flowing through a conductor such as an overhead line, cable or transformer produces heat and temperature rise within the conductor (relative to the outside atmosphere) that has undesirable impacts on the equipment, e.g.

- Overhead line wires expand at higher temperatures causing line sag. The sag limit for an overhead line is the minimum ground clearance (for safety reasons so that people underneath power lines are not electrocuted and that the line does not come into contact with trees and other vegetation)
- Extreme temperature cycles (high and low) cause annealing of metal conductors, reducing its mechanical strength
- Excess heat can cause the gradual breakdown of cable or transformer insulation leading to eventual failure

All overhead lines, cables and transformers are specified with thermal limits, which is the maximum current that can flow continuously through the equipment to avoid the undesirable effects listed above. When the current flowing through an overhead line, cable or transformer exceeds its thermal limit, then the equipment item is said to be *overloaded*.

Thermal limits are contingent on environmental factors such as ambient temperature, installation method, soil conditions (for buried cables), wind speed and the intensity of direct sunlight (for overhead lines). System planners typically either use fixed ratings with conservative assumptions or capture the variability of environmental conditions with dynamic ratings, e.g. seasonal, night/day, temperature-dependent ratings, etc.

The electric currents that are expected to flow in the power system are studied using simulation models in order to check that the thermal limits for all equipment are respected. Where potential overhead line, cable or transformer overloading has been identified, remedial actions should be taken, including but not limited to the following:

- Upgrading the overhead line, cable or transformer to a higher thermal rating
- Installing an additional overhead line, cable or transformer in parallel
- Re-configuring the network and/or changing generator dispatch patterns to alter the flow of currents in the system and prevent overloading of a specific element

F.1.2 Voltage Limits

Power systems are designed to operate within an acceptable range around *nominal voltages* (in Fiji, the nominal voltages are 132kV, 33kV, 11kV or 415V). From the FEA Grid Code, the acceptable voltage range is between 95% and 105% of nominal voltage during normal operation.

Operating all or parts of the system continuously outside the acceptable voltage range has negative impacts to both the utility and consumers alike:

Condition	Undesirable Effects
Voltage sag / Under-voltage (<95%)	• Reduced performance of some appliances, e.g. heaters, incandescent light bulbs • Overheating and burnout of induction motors • May cause unstable behaviour in digital circuits

Voltage swell / Over-voltage (>105%)	• Electrical breakdown of insulation leading to faults • Overheating and burnout of electronic components • Increased power consumption and reduced lifespan of some appliances, e.g. light bulbs

The prospective voltages at each node in the power system are studied using simulation models in order to check that the voltage limits are within the acceptable range. Where potential voltage issues have been identified, remedial actions should be taken, including but not limited to the following:

- Installation of reactive power compensation, e.g. shunt capacitor banks (to deal with under-voltages), shunt reactors (to deal with over-voltages), static VAR compensators (SVC), synchronous condensers, etc.
- Upgrade overhead lines and/or cables to limit voltage drops across long lines / cable runs
- Adjust transformer tap changer settings and/or generator voltage setpoints

F.1.3 Short Circuit Limits

A short circuit is an electrical fault where a conductive path is created between two or more live wires and/or live wires and earth. A conductive path can be created as a result of:

- Actual contact between live wires and/or earth
- Contact with objects, e.g. trees, vegetation, animals
- Insulation breakdown leading to electrical arcing
- Lightning strikes

A short circuit is characterised by very high current flows, which can cause extreme heat and mechanical stress on equipment. Short circuits also significantly increase the risk of electrical arcing, which can ultimately lead to fire and explosion.

The short circuit levels in a power system are affected by changes in generation and transmission capacity and to a lesser extent changes in the distribution network configuration. In general, short circuit levels increase with additional generation and transmission capacity. Short circuit levels are also location dependent, and the short circuit level at any particular node comprises contributions from local generation, remote generators via the network and induction motors in the system. As a result, short circuit levels are typically highest near large power plants.

Substation equipment such as switchgear, circuit breakers, disconnectors and busbars are normally specified with short circuit ratings, indicating the maximum short circuit level that the equipment can withstand without failure. The prospective short circuit levels in the power system are calculated using simulation models that are checked against the equipment short circuit ratings. There are a number of internationally accepted standards for the calculation of short circuit levels with which the simulation algorithm should adhere. The applicable standards in Fiji are international standard IEC 60909 and Australian Standard AS 3851.

Where potential short circuit issues have been identified, remedial actions should be taken, including but not limited to the following:

- Upgrade substation equipment with higher short circuit ratings
- Network re-configuration and operational measures to manage short circuit levels, e.g. network splitting / segregation, opening selected circuit breakers, having redundant lines and transformers out of service, etc.

- Installation of series reactors on overhead lines and/or cables
- Joint planning with power plant developments to control the specification of sub-transient reactances in new machines

F.1.4 Stability Limits

Power system stability is typically broken down into small-signal (small disturbance) and transient (large disturbance) stability.

Small-signal (or steady-state) instability occurs when generators or groups of generators exhibit undamped or poorly damped oscillations around their operating points after small disturbances (such as load fluctuations). Small-signal instability has traditionally not been an issue in small power systems such as those found in Fiji.

Transient stability is concerned with the ability of a power system to remain intact and operational after a large disturbance, such as a short circuit or power plant trip. This means that 1) a large disturbance does not lead to a system-wide blackout, 2) voltage and frequency return back to a normal operating range after the disturbance, and 3) all generators remain synchronised. Note that electricity service to some parts of the system may be lost as a result of the disturbance.

Large disturbances are dynamic in nature and cause system-wide swings in voltages and frequency. The major factors that affect transient stability are as follows:

- Types, capacity and location of power plants
- System inertia and impact of variable renewable energy generation
- Strength of major transmission corridors used for bulk power transfer
- Speed of fault clearing (e.g. high speed protection devices)
- Response of generator control systems (e.g. speed-governors and excitation systems)

The transient stability of a system is assessed using simulation models that *stress-test* the system against credible events, e.g. short circuits and plant trips. Where potential stability issues have been identified, remedial actions should be taken, including but not limited to the following:

- Upgrading of protection and generator control systems to speed up response times after a disturbance
- Strengthen major bulk transmission corridors between power plants
- Adjust generator dispatch patterns to limit bulk power transfers between major groups of power plants (even if not economically optimal)

F.1.5 System Security Limits

Power system security is the ability of a power system to remain in a secure operating state (i.e. stable with demand satisfied and no thermal or voltage limits violated) after a foreseeable event, e.g. line or generator outage (referred to as a *contingency*).

The N-1 criterion is often used as a benchmark for system security, and is defined as the ability of the system to withstand the loss of any one system element, e.g. line, transformer, generator, etc (also called a *single contingency*). The N-1 criterion is referred to as a deterministic criterion because it does not consider the probability of an outage or the supply capability of the system at any given time (for example, the system may not be operating at full capacity due to planned maintenance activities). However, the N-1 criterion is simple to evaluate and relatively conservative.

The alternative is a risk-based probabilistic approach, which can take into account long-term historical statistics regarding equipment failure rates and other reliability metrics. There is currently no universally accepted method for performing probabilistic system security studies, and any probabilistic approach proposed would need to be assessed on its own individual merits.

In conducting system security studies with the N-1 criterion (often called *contingency analysis*), system planners prepare a list of events that can potentially occur in the system (*credible contingencies*) and stress-test the system via computer simulation. Very rare or force majeure events are typically excluded from the list of credible contingencies. These events can include:

- Two transmission towers in geographically different parts of the system going down simultaneously
- Loss of multiple cables in a single trench
- Simultaneous loss of multiple power plants

The simulation results are used to identify weak areas in the system where network augmentations may be required.

F.2 IDENTIFY GRID AUGMENTATIONS

The technical evaluation of the least cost generation and transmission expansion plan may identify specific parts (or all) of the system where the technical network requirements are not met (e.g. due to line or transformer overloading, insufficient fault ratings, under/over voltage, system instability, etc). In such cases, grid augmentations are necessary to overcome these problems and render the plan feasible.

If the proposed grid augmentations have materially significant costs, then the least cost optimisation routine may need to be re-run with the capital costs associated with the grid augmentations apportioned to the capital cost of the generation and transmission expansion plan. This is done to prevent selecting a capacity expansion plan that is not actually least cost when grid augmentations are taken into account, i.e. there could be a more expensive capacity expansion plan that requires fewer grid augmentations leading to a lower overall (combined) cost.

Note that grid augmentations can include non-network solutions such as demand side management, distributed generation and energy storage (also called “non-wires alternatives”).

F.3 Overloading and System Security Issues

If a branch element (line, cable or transformer) is overloaded or does not satisfy system security requirements (N-1 contingency), the following grid augmentation options may be considered:

a) **Replacement:** the line, cable or transformer is replaced with a higher capacity unit. In the case of an overhead line, the conductors may be upgraded without having to also replace the towers or poles (this is called *reconductoring*).

b) **Parallel addition**: an additional line, cable or transformer is installed in parallel to the existing plant thus providing more pathways for power and current flow. This option requires additional switchgear to be installed, but has the advantage of keeping the existing plant in service. Short circuit levels must also be checked again whenever parallel branch elements are added.

c) **Demand side management:** if overloading only occurs for short periods at times of system peak load, it may be cost-effective to implement a demand side management program, where consumers in a targeted area are paid to limit their load demand in order to prevent overloading of the line, cable or transformer supplying them.

d) **Distributed generation and energy storage:** local power generation and/or the strategic placement of energy storage can also be used to alleviate acute overloading issues.

F.3.1 Voltage Issues

Steady-state voltage issues tend to arise when there is load growth at the edge of the grid, near the extremities of long radial feeders or in areas that have low levels of voltage control / support (e.g. from power plants or reactive plant).

The selection and staging of generation capacity may also influence steady-state voltages. For example, a system with power plants that are evenly distributed geographically will typically exhibit better voltage performance than a system with power plants that are lumped together in a single location or small geographic area.

The following grid augmentation options may be considered to resolve voltage issues:

a) **Line or cable upgrade:** overloading and under-voltage issues often occur together along radial feeders. Both issues can potentially be resolved by upgrading the feeder (or by adding a parallel branch or creating a network mesh).

b) **Upgrade to transmission voltage:** rapidly developing geographic areas with high demand growth (such as industrial parks) may experience voltage issues and potential overloading because they are still supplied via the distribution network. An extension of the transmission system to provide coverage to the affected growth areas is an attractive option if there is an expectation of persistent growth, and where ad hoc solutions will only suffice for a short time.

c) **Reactive plant:** fixed reactive plant such as capacitor banks and shunt reactors can be installed to provide voltage support at substations. These are on/off devices that are normally switched on a time-of-day basis, or only when required. Alternatively, power electronic devices such as static Var compensators (SVCs) or static compensators (STATCOMs) can be installed to provide continuous voltage control, albeit at higher capital cost.

d) **Transformer tap changer control and series regulators**: transformers with on-load tap changers (OLTC) can be installed to automatically control system voltages. Similarly, series regulators can be installed on long radial feeders to provide voltage regulation.

e) **Distributed generation and energy storage:** local power generation and/or the strategic placement of energy storage can also be used to provide voltage support and control. For example, the placement of distributed generators along long feeders or near the grid edge can the improve voltage profile significantly with the added benefit of also reducing losses.

F.3.2 Short Circuit Issues

Short circuit problems will typically occur as a result of adding new generation capacity and/or increasing network meshing (e.g. by adding more parallel lines, cables or transformers).

Again, the selection and staging of generation capacity may adversely affect short circuit levels in the system. For example, the clumping of power plants in a small geographic area can lead to short circuit issues that would otherwise not exist if the power plants were more dispersed.

The following grid augmentation options may be considered to resolve short circuit issues:

a) **Substation upgrade:** substation apparatus such as busbars, circuit breakers, disconnectors and instrument transformers can be replaced with apparatus of higher short circuit withstand capacity.

b) **Fault limiting devices:** such as series reactors and I_S-limiters can be installed to constrain prospective short circuit levels to within equipment short circuit withstand capacities. Note that the installation of series reactors will affect the voltage profile and may lead to downstream voltage issues.

c) **Network splitting:** is an operational solution where parts of the network are deliberately disconnected under system normal operation in order to limit short circuit levels. This can have significant knock-on effects and may cause material changes to generator dispatch patterns, equipment overloading, voltage issues, system security violations, higher losses and potential system islanding and stability issues.

F.3.3 Stability Issues

Transient stability issues can arise when new generation capacity is added to the system. Therefore, similar to the discussion on voltage and short circuit issues, the selection and staging of generation capacity can influence stability performance. However, unlike the voltage and short circuit issues, a power system is generally more stable when generating plant are co-located in small geographic areas rather than dispersed.

A power system is typically also more stable among similar types and capacities of generating plant (e.g. hydro turbines of uniform capacity and make/model), as these machines will tend to respond to a disturbance in a similar fashion and will more likely act in unison rather than in opposition to each other.

The following grid augmentation options may be considered to resolve stability issues:

a) **Transmission system strengthening:** including upgrading of transmission lines and adding new parallel transmission lines, particularly to strengthen the bulk transmission corridors between groups of large generators.

b) **Protection and control upgrades:** generator control systems and system protection can be upgraded to speed up response times after a disturbance and improve stability performance.

c) **Generator dispatch constraints:** incorporate constraints for generator dispatch patterns to limit bulk power transfers across tie-lines between major groups of power plants. These constraints will need to be fed back into the least cost optimization routine.

d) **Energy storage:** deployment of fast acting energy storage systems can rapidly respond to transient events and help arrest stability issues such as transient frequency sags.

APPENDIX G. ENERGY EFFICIENCY MEASURES FOR SCENARIO DEVELOPMENT

G.1 DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) is the planning, implementation, and monitoring of utility activities designed to encourage customers to modify their electricity consumption patterns, both with respect to the timing and level of electricity demand. The primary objective of DSM is to manipulate the timing or level of customer demand so as to achieve the financial, economic and environmental benefits. There are six principal ways in which DSM programs can influence consumer demand:

- *Peak clipping*, which refers to the reduction of utility loads during peak demand periods. This can defer the need for additional generation capacity. The net effect is a reduction in both peak demand and total energy consumption.
- *Valley filling*, entails the building of off-peak loads. This may be particularly desirable when the long-run incremental cost is less than the average price of electricity. This is often the case when there is underutilized capacity that can operate on low-cost fuels. The net effect is an increase in total energy consumption, but no increase in peak demand.
- *Load shifting*, which involves shifting load from on-peak to off-peak periods. The net effect is a decrease in peak demand, but no change in total energy consumption.
- *Strategic conservation*, which refers to a reduction in end-use consumption. There are net reductions in both peak demand (depending on coincidence factor) and total energy consumption.
- *Strategic load growth*, which consists of an increase in overall sales. The net effect is an increase in both peak demand and total energy consumption.
- *Flexible load shape*, which refers to variations in reliability or quality of service. Instead of influencing load shape on a permanent basis, the utility has the option to interrupt loads when necessary. There may be a net reduction in peak demand and little if any change in total energy consumption.

G.2 APPLICATION OF DSM IN NORTH SULAWESI

G.2.1 Why DSM is required

Growing electricity demand

In countries with rapidly growing demand, peak clipping or strategic conservation may be used to help defer costly new capacity addition, reduce the use of peaker and load follower generators, and reduce environmental impacts.

Compared to 2013, the peak load in North Sulawesi in February 2018 has grown 23%, with the average annual growth of 4%. RUPTL 2018-2027 described expected annual growth of peak load ranging in 7-9%, significantly higher than the average actual growth over the last five years. RUPTL takes into account growth based on estimated economic growth and population growth, in accordance with data from Statistics Central Agency (*Badan Pusat Statistik* – BPS). There are instances where the economy does not grow as expected, causing oversupply in the system. The system peak in 2018 is approximately 350 MW, while the total installed capacity is 492.7 MW. However, information obtained from academics in Universitas Sam Ratulangi during our site visit indicated that the production capacity of the power plants is much less than the installed capacity, as many of the plants cannot be operated at its optimum capacity. This may be one of the causes of the oversupply based on existing installed capacity.

Through applying DSM measures, **particularly for peak clipping and conservation**, there is an opportunity to reduce the peak growth.

Exhibit G-1 Load summary.

Year	2013	2014	2015	2016	2017	2018[28]
Peak						
Peak[29] (kW)	283,987	309,019	324,385	333,437	343,960	350,350[30]
Annual Growth		9%	5%	3%	3%	2%
Average Peak Growth 2013-2018	4%					
Peak Growth 2013-2018	23%					
Average						
Average hourly demand	216,083	230,282	244,633	257,768	273,511	260,831
Annual Growth		7%	6%	5%	6%	-5%
Average Annual Growth 2013-2018	6%[31]					
Average demand growth 2013-2018	21%					

High Potential for Growth in Ownership of Electrical Appliances

According to a study by Lawrence Berkeley National Laboratory, Indonesia had low rates of appliance ownership. The growth in population and economy would trigger higher attainment of electronic appliances, particularly in the residential sector[32].

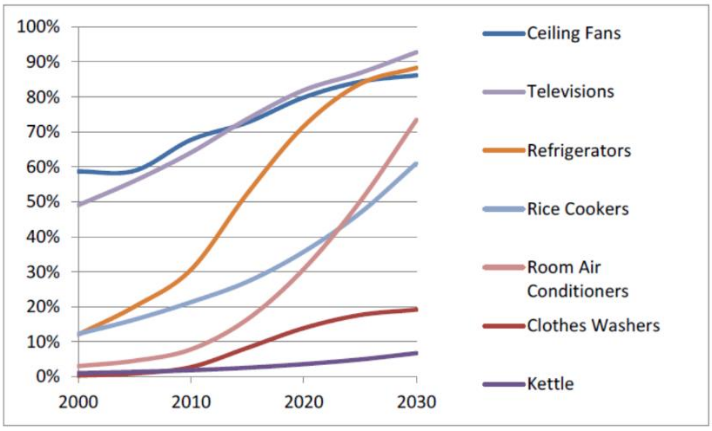


Exhibit G-2 Projected diffusion (units per household) of residential appliances (2000-2030) Error! Bookmark not defined.**.**

North Sulawesi province has higher Gross Domestic Regional Product (GDRP) growth rate than the average GDRP growth in Indonesia. The annual growth rate of GDRP in

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[28] Only based on data in January and February 2018.
[29] Data taken from PLN's record.
[30] Peak load in February 2018.
[31] The average exclude 2018 data.
[32] Karali, N., et al (2015). *Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.* Retrieved from: https://eaei.lbl.gov/publications/potential-impact-lighting-and.

North Sulawesi ranges in 6.12%-6.38%, whereas the average GDRP growth in Indonesia ranges in 4.88%-5.56%[33]. Housing and household equipment consumption expenditure at current market prices is relatively low at IDR 3,200,164.53 million in 2014 compared to, for example, DKI Jakarta at IDR 1,065,088,137.67 million[34]. This implies the potential for an increase in attainment of electronic appliances.

Appropriate Types of DSM Application for North Sulawesi

The energy consumption in North Sulawesi is dominated by the residential customer class. Coupled with the possible increase in electrical appliance ownerships, load in the system is expected to continue to grow, particularly for residential customers. With these considerations, **peak clipping and strategic conservation** are the most appropriate DSM measures. Such measures can reduce the need for new generation plants, peaker, and load follower plants. The two latter types of plants often use conventional energy sources, such as diesel fuel and gas. Both measures can be implemented through the use of efficient end-use appliances.

While valley filling seems to be one of the possible DSM measures due to the high irradiance levels in the region, the types of appliances and usage profile are limiting factors to the measure, i.e. the main contributors to peak load in residential customers are mainly used in the evenings. Moreover, for residential customers, no peak and non-peak tariffs are applicable. In other words, flat tariffs are applicable for residential customers. This significantly reduces the incentive for the residential customers to reduce their consumption at peak hours.

G.2.2 Targeted Application of Efficient Appliances

Typical end-use of electricity users in Indonesia

As most updated information on typical end-use of electricity in Indonesia, particularly North Sulawesi, is not available, a study done by Indonesia's Agency for the Assessment and Application of Technology (*Badan Pengkajian dan Penerapan Teknologi* – BPPT) in 2009 provides information on the pattern of usage in residential and commercial customers. The information is essential in determining the savings which may be possible from the application of energy efficient appliances.

Exhibit G-3**Error! Reference source not found.** displays the typical electric power consumption in Indonesia for residential customers. Customers having connections of 900 VA use electricity mostly for refrigerators, other electrical appliances, and television. Customers having connections of 1,300 VA and above use their electricity most significantly for Air Conditioners (AC), other electrical appliances, refrigerator, and television. Cumulatively, more than 50% of the electricity usage in residential customers is for refrigerators, televisions, ACs, and lighting.

[33] BPS (2017). *North Sulawesi in Numbers*.
[34] BPS (2017). *Gross Regional Domestic Product of Province in Indonesia by Expenditure 2012-2016.*

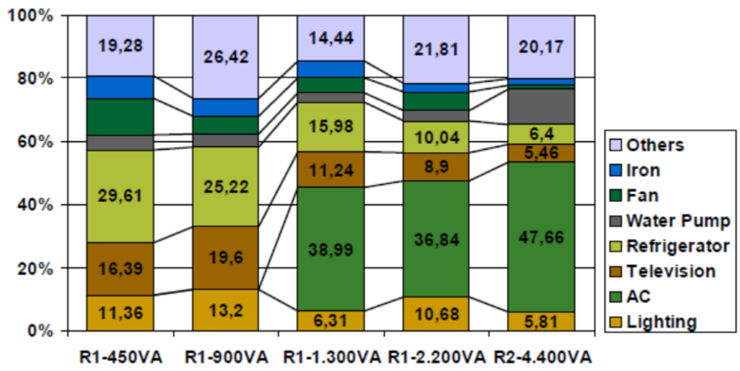


Exhibit G-3 Typical residential electric power consumption in Indonesia[35].

Error! Reference source not found. Exhibit G-4 displays the typical electric power consumption in Indonesia for commercial building customers. In almost all types of commercial customers, ACs and lighting dominate the electric consumption.

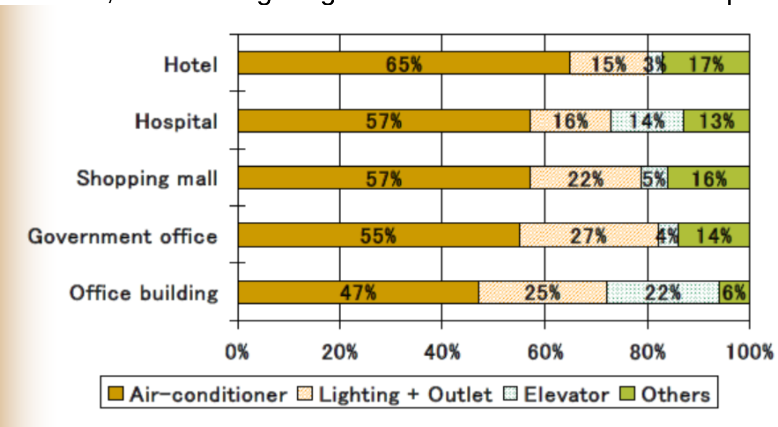


Exhibit G-4 Typical electric power consumption in Indonesia in commercial building.

Potential Impact of Electricity Efficient Appliances in Indonesia

A study conducted by Lawrence Berkeley National Laboratory[36] estimated the daily load curve of electricity consumption in Indonesia for a number electrical appliances, as seen in **Error! Reference source not found.**. According to the study, the peak load in 2010 is driven by lighting by almost 25% and television by 14%. The commercial and industrial sectors together made up 38% of the peak load in 2010. However it is estimated that by 2030 the peak demand will be mainly driven by Air Conditioners, particularly the residential ones (29%), commercial and industrial sector (38%), residential lighting (10%) and refrigerators (8%). The significant increase in AC usages is due to the high projected uptake of the technology, as seen in **Error! Reference source not found.**Exhibit G-5.

[35] Hilmawan, E., Said, M. (2009). Energy efficiency standard and labeling policy in Indonesia. BPPT.

[36] Karali, N., et al (2015). *Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.* Retrieved from: https://eaei.lbl.gov/publications/potential-impact-lighting-and.

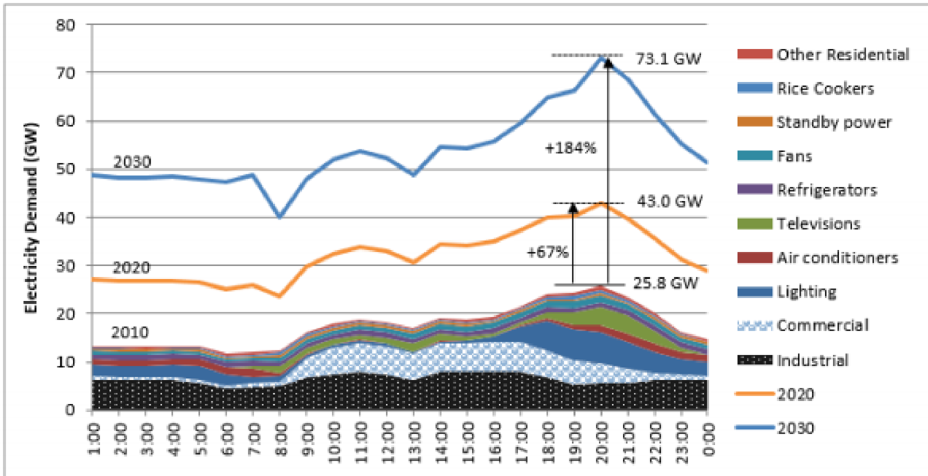
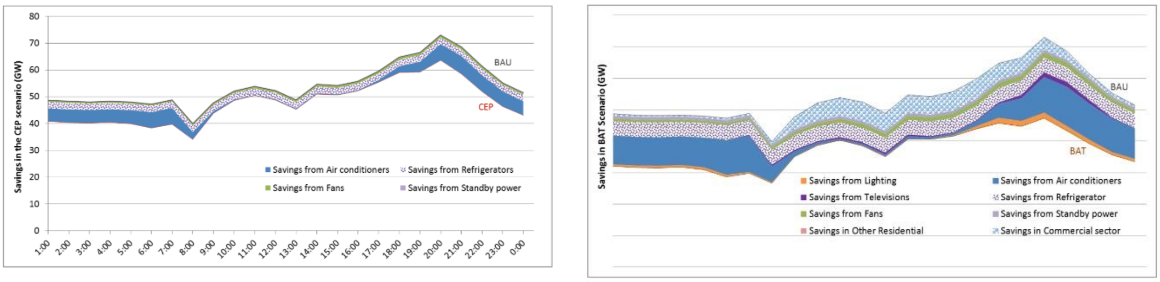


Exhibit G-5 Development of Indonesia's average daily load curve in the Business-As-Usual (BAU) scenario between 2010 and 2030[17]

In estimating the possible reduction of peak load, the study utilizes the two following scenarios:

- *The CEP (Cost Effective Potential)* scenario takes into consideration efficiency targets that provide the maximum energy savings that result in a net benefit to the consumer (even with subsidized electricity tariffs). It is only available for the residential sector.
- *The BAT (Best Available Technology)* scenario evaluates the technical potential for energy efficiency afforded by the best technologies currently available on the market or designed from high-efficiency components. It is only available for the residential sector end-uses, commercial lighting, air conditioners, and refrigerators.

The potential reduction for both scenarios is shown in **Error! Reference source not found.**, with the total peak reductions of 13% and 35% for CEP and BAT scenario respectively.



(a) CEP Scenario savings (b) BAT Scenario savings

Exhibit G-6 Potential savings for the two considered scenarios.

As seen in the exhibit above, both scenarios indicate significant savings through the use of energy efficient air conditioners. By 2030, usage of energy efficient air conditioners has the potential to contribute to 8.3% to peak reduction in CEP scenario, and 15.5% in BAT scenario. The second-most potential reduction comes from the usage of more efficient refrigerators. By 2030, usage of energy efficient refrigerators can contribute to 3.4% peak reduction in CEP scenario and 6.3% in BAT scenario.

With the considerations above, the demand side management efforts should be focused on the usage of a more energy efficient air conditioners and refrigerators.

Cost and performance of energy efficiency equipment

The energy consumption of some selected electronic appliances in BAU, CEP, and BAT scenarios for Indonesia are shown in the exhibit below. The most significant reductions for appliance unit energy consumption (UEC) by 2030 are air conditioners, refrigerators, fans, and LCD televisions.

Exhibit G-7 Unit Energy Consumption (UEC) for selected appliances[37].

Technology	Unit Energy Consumption (in kWh)					
	BAU		**CEP**		**BAT**	
	2020	2030	2020	2030	2020	2030
Air Conditioners	1,416	1,415.6	1,000	1,000	637	637
Refrigerators	618	650	345	370	117	117
Televisions						
LCD	53	53	53	53	14	14
CRT	176	176	N/A in CEP	N/A in CEP	N/A in BAT	N/A in BAT
Plasma	224	224	N/A in CEP	N/A in CEP	14	14
Fans	224	224	164	164	103	103
Washing Machine	150	150	150	150	135	135
Rice Cooker	242	242	242	242	242	242
Kettles	216	216	216	216	216	216

A method to evaluate the cost associated with using energy efficient appliances is through the cost of conserved energy (CCE). Calculating CCE allows the evaluation of cost and benefits of certain appliances over their lifetime. Formulas used to calculate CCE are described in Appendix A. Exhibit G-8 provides selected CCEs for selected equipment. This further emphasizes the need to prioritize air conditioners in DSM measures.

Exhibit G-8 Cost and performance of selected electronic appliances in Indonesia[38,39].

Technology	Potential Savings					Remarks
	Baseline UEC	**Baseline Price**	**Target UEC**	**Target Price**	**CCE**	
	(kWh/yr)	**(USD)**	**(kWh/yr)**	**(USD)**	**(USD/kWh)**	
Air Conditioners	1,400.00	450.00	1,000.00	600.00	0.05	
Refrigerators	470.00	N/A*	330.00	29.00	0.03	
Televisions	33.00	290.00				

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[37] Karali, N., et al (2015). *Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.* Retrieved from: https://eaei.lbl.gov/publications/potential-impact-lighting-and.
[38] Letschert, V., et al. (2012). *Estimate of Cost-Effective Potential for Minimum Efficiency Performance Standards in 13 Major World Economies – Energy Savings, Environmental and Financial Impacts*.
[39] Except for Air Conditioner information, the other data are based on India's data. India is considered as having similar climate and socioeconomic conditions to Indonesia.

Technology	Potential Savings					Remarks
	Baseline UEC	Baseline Price	Target UEC	Target Price	CCE	
	(kWh/yr)	(USD)	(kWh/yr)	(USD)	(USD/kWh)	
Fans	150.00	N/A	69.00	17.00	0.03	
Lighting	88.00	1.20	22.00	6.80	0.04	CFL, 60 W, 4hrs/day
Electric Motors						
0.75-7.5 KW	1,500.00	130.00	1,300.00	180.00	0.04	
7.5-75 KW	20,000.00	1,100.00	19,000.00	18,000.00	0.10	
>75 KW	400,000.00	11,000.00	No CCE below tariff			

Application in North Sulawesi – Methodology

The main objectives of using DSM measures are to estimate the possibility of reductions in peak load, as well as the daily load. To estimate these ideally, information of end-uses and their energy consumption in North Sulawesi is required. However, such information is not yet available, and only energy consumption per customer class and daily load curve is available. As an alternative, we will use the results of a study on the potential of using energy efficient appliances to reduce peak load in Indonesia[40]. The modelling method used in the study is called Bottom-Up Energy Analysis System (BUENAS). In the study, the daily load profile and its growth are built on the energy consumption of each appliance and typical hours of usage. That said, reduction in peak load driven by a reduction of appliance's energy consumption will also reduce the energy consumption on the typical hours when it is used. For example, the study suggested that the usage of energy efficient AC can reduce up to 8.3% of the peak load. This means that 8.3% of energy consumption is also reduced in hours which the ACs are assumed to be used. The following exhibit provides an outline of the details of the potential impact of usage of selected appliances with their typical hours of use.

Exhibit G-9 Contribution of sectors and end-users to the reduction of peak demand in 2020 and 2030 in Indonesia

Equipment	2020		2030		Typical hours of use
	Reduction in CEP	Reduction in BAT	Reduction in CEP	Reduction in BAT	
Lighting	1.90%	4.90%		2.40%	16:00-11:00, with very minimum usage at 12:00-15:00
Refrigerator	2.22%	4.10%	3.40%	6.30%	00:00-23:59, 24 hrs.
Air Conditioner	2.57%	4.80%	8.30%	15.50%	16:00-11:00, with very minimum usage at 12:00-15:00
Fans	0.88%	1.80%	1.10%	2.20%	00:00-23:59, 24 hrs.
Televisions		1.70%		2.10%	06:00-00:00

[40] Karali, N., et al (2015). *Potential Impact of Lighting and Appliance Efficiency Standards on Peak Demand: The Case of Indonesia.* Retrieved from: https://eaei.lbl.gov/publications/potential-impact-lighting-and.

Standby power	0.19%	1.10%	0.20%	1.10%	00:00-23:59, 24 hrs.
Other residential				0.10%	00:00-23:59, 24 hrs.
Commercial sector		2.60%		5.60%	00:00-23:59, 24 hrs.
Industrial sector					
TOTAL	7.76%	21.00%	13.00%	35.30%	

APPENDIX H. HOMER OUTPUT REPORT SAMPLE

The following screenshots are summary pages of the output report for Trend Analysis Scenario with EE CEP Measures in 2032.

HOMER PRO

System Simulation Report

File: Sulut System 2032 - Scenario 2 OA V2.homer

Author: Castlerock

Location: Unnamed Road, Aertembaga Satu, Aertembaga, Kota Bitung, Sulawesi Utara, Indonesia (1°27.8'N, 125°12.3'E)

Total Net Present Cost: $3,682,955,000.00

Levelized Cost of Energy ($/kWh): $0.0649

Notes:

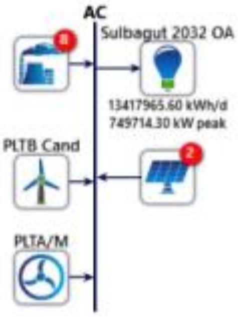
Sensitivity variable values for this simulation

Variable	Value	Unit
Sulbagut 2032 OA EE Scaled Average	13,417,966	kWh/d

System Architecture

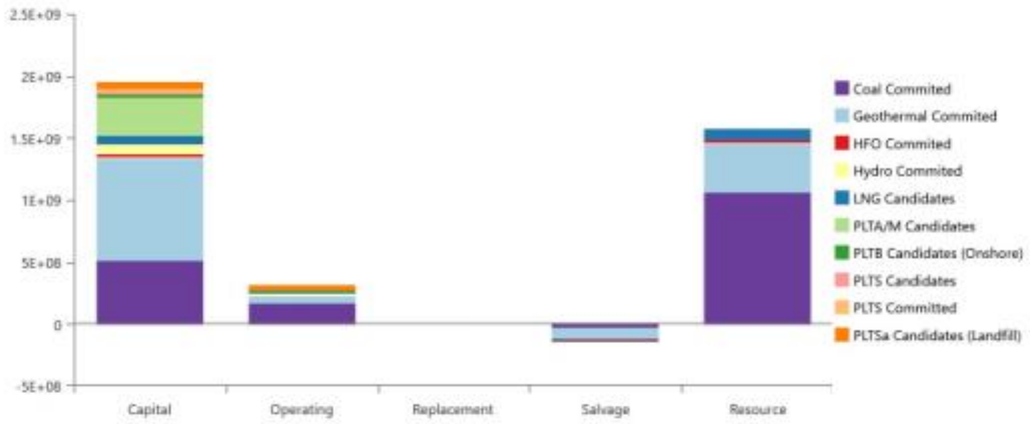
Component	Name	Size	Unit
Generator #1	Coal Commited	305,000	kW
Generator #2	Geothermal Commited	223,000	kW
Generator #3	HFO Commited	30,000	kW
Generator #4	LNG Candidates	100,000	kW
Generator #5	Hydro Commited	33,276	kW
Generator #6	PLTSa Candidates (Landfill)	24,000	kW
PV #1	PLTS Committed	26,000	kW
PV #2	PLTS Candidates	20,000	kW
Wind turbine	PLTB Candidates (Onshore)	16	ea.
Hydrokinetic	PLTA/M Candidates	70.0	quantity
Dispatch strategy	HOMER Load Following		

Schematic



HOMER PRO

Cost Summary



Net Present Costs

Name	Capital	Operating	Replacement	Salvage	Resource	Total
Coal Commited	$519M	$171M	$0.00	-$33.3M	$1.07B	$1.72B
Geothermal Commited	$825M	$56.1M	$0.00	-$87.8M	$397M	$1.19B
HFO Commited	$24.6M	$858,470	$0.00	-$7.23M	$23.9M	$42.2M
Hydro Commited	$73.2M	$15.6M	$0.00	-$3.24M	$0.00	$85.5M
LNG Candidates	$77.0M	$8.45M	$0.00	-$18.6M	$84.9M	$152M
PLTA/M Candidates	$308M	$7,863	$0.00	$0.00	$0.00	$308M
PLTB Candidates (Onshore)	$24.0M	$11.1M	$0.00	$0.00	$0.00	$35.1M
PLTS Candidates	$16.6M	$3.47M	$0.00	$0.00	$0.00	$20.1M
PLTS Committed	$21.6M	$4.52M	$0.00	$0.00	$0.00	$26.1M
PLTSa Candidates (Landfill)	$60.0M	$42.1M	$0.00	-$26,203	$0.00	$102M
System	$1.95B	$314M	$0.00	-$150M	$1.57B	$3.68B

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Annualized Costs

Name	Capital	Operating	Replacement	Salvage	Resource	Total
Coal Commited	$44.8M	$14.8M	$0.00	-$2.87M	$92.0M	$149M
Geothermal Commited	$71.3M	$4.84M	$0.00	-$7.58M	$34.3M	$103M
HFO Commited	$2.12M	$74,132	$0.00	-$623,991	$2.07M	$3.64M
Hydro Commited	$6.32M	$1.34M	$0.00	-$279,995	$0.00	$7.38M
LNG Candidates	$6.65M	$729,468	$0.00	-$1.61M	$7.33M	$13.1M
PLTA/M Candidates	$26.6M	$679.00	$0.00	$0.00	$0.00	$26.6M
PLTB Candidates (Onshore)	$2.07M	$960,000	$0.00	$0.00	$0.00	$3.03M
PLTS Candidates	$1.43M	$300,000	$0.00	$0.00	$0.00	$1.73M
PLTS Committed	$1.86M	$390,000	$0.00	$0.00	$0.00	$2.25M
PLTSa Candidates (Landfill)	$5.18M	$3.63M	$0.00	-$2,263	$0.00	$8.81M
System	$168M	$27.1M	$0.00	-$13.0M	$136M	$318M